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March 16, 2009

California Energy Commission
Docket Office
1516 Ninth Street
Sacramento, CA 95814-5512

RE: Docket Number 09-IEP-1D Transmission Planning

Enclosed please find the 2009 IEPR Transmission Planning Form of San Diego Gas & Electric Company (SDG&E) in the referenced docket. Related appendices will be on CD-ROM per the instructions set forth in the Forms and Instructions for Submitting Electric Transmission-Related Data and mailed to the docket office.

If you have any questions regarding the forms, please feel free to contact Victor Kruger at 858-654-1619 or VKruger@semprautilities.com

Sincerely,

Signed/

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

The Nevada Hydro Company, Inc. Docket No. ER06-278-007

ORDER GRANTING REHEARING FOR
FURTHER CONSIDERATION

(May 21, 2008)

Rehearing has been timely requested of the Commission's order issued on March 24, 2008, in this proceeding. *The Nevada Hydro Company, Inc*., 122 FERC ¶ 61,272 (2008). In the absence of Commission action within 30 days, those requests for rehearing (and any timely requests for rehearing filed subsequently)[1] would be deemed denied. 18 C.F.R. § 385.713 (2007).

In order to afford additional time for consideration of the matters raised or to be raised, rehearing of the Commission's order is hereby granted for the limited purpose of further consideration, and timely-filed rehearing requests will not be deemed denied by operation of law. Rehearing requests of the above-cited order filed in this proceeding will be addressed in a future order. As provided in 18 C.F.R. § 385.713(d), no answers to the rehearing requests will be entertained.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[1] *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange*, 95 FERC ¶ 61,173 (2001) (clarifying that a single tolling order applies to all rehearing requests that were timely filed).

122 FERC ¶ 61,272
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

The Nevada Hydro Company, Inc. Docket Nos. ER06-278-000
ER06-278-001
ER06-278-002
ER06-278-003
ER06-278-004
ER06-278-005
ER06-278-006

ORDER ON RATE INCENTIVES AND COMPLIANCE FILINGS

(Issued March 24, 2008)

1. In this order, the Commission accepts in part and denies in part The Nevada Hydro Company, Inc.'s (Nevada Hydro) requested rate incentives for the proposed TE/VS Interconnect.[1] Specifically, the Commission grants Nevada Hydro an incentive equity return set within the upper end of the zone of reasonableness to be determined through a subsequent proceeding under section 205 of the Federal Power Act (FPA) and a hypothetical 50 percent equity/50 percent debt capital structure during the construction period. However, the Commission denies Nevada Hydro's request for full recovery of Construction Work in Progress (CWIP), abandonment costs and a three-year rate moratorium for this transmission project, as discussed herein. With respect to the Lake Elsinore Advanced Pump Storage project (LEAPS, LEAPS project, or LEAPS facility), the Commission finds that this pumped hydro storage facility may not be operated and/or managed by the California Independent System Operator Corporation (CAISO) or functionalized as transmission for rate recovery purposes for the reasons discussed below.

[1] The Talega-Escondido/Valley-Serrano Interconnect project (TE/VS Interconnect) is a 30-mile, 500 kV transmission line that will connect San Diego Gas & Electric Company's (SDG&E) transmission system with Southern California Edison's (SCE) system.

Based in part on the information submitted by CAISO in compliance with our November 17, 2006 Order,[2] the Commission has determined that the LEAPS project is ineligible for incentive rate treatment pursuant to Order No. 679.[3]

I. Background

2. On December 1, 2005, as amended on December 22, 2005, Nevada Hydro submitted a filing, pursuant to section 205 of the FPA,[4] to request approval of certain rate incentives that it states will enable it to attract financing for the LEAPS project and the TE/VS Interconnect (Combined Project).[5] On November 17, 2006, the Commission issued an order which deferred ruling on the merits of the rate incentives requested by Nevada Hydro, pending submission of additional information directed by the Commission to complete its analysis.[6] In particular, CAISO was directed to convene a

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[2] *See The Nevada Hydro Company, Inc.*, 117 FERC ¶ 61,204 (2006) (November 17 Order).

[3] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007) (Order No. 679).

[4] 16 U.S.C. § 824d (2000).

[5] Order No. 679 requires applicants seeking transmission rate incentives to submit, in the first instance, either a petition for declaratory order or a filing under section 205 of the FPA outlining its request. Nevada Hydro's request, which preceded Order No. 679 by approximately seven months, is more akin to a request for declaratory order, notwithstanding the characterization provided by Nevada Hydro. The Commission's rules and regulations do not allow the submission of "partial" filings under section 205 of the FPA. *See*, e.g., Nevada Hydro's December 1, 2005 filing at 5 (Initial Application) (stating that it "does not seek to put into effect specific rates or charges to be collected from customers"). Thus, Nevada Hydro's application has been reviewed by the Commission as a petition for declaratory order. Nevada Hydro's request for waiver of sections 35.3 and 35.12 of the Commission's rules and regulations is moot, since petitions for declaratory orders have no cost of service filing requirements. However, because the requirement of a petition for declaratory order was announced in Order No. 679, after Nevada Hydro had made its filing, the Commission grants waiver of the filing fee under 18 C.F.R. § 385.207 (2007).

[6] The procedural history from the date of Nevada Hydro's initial filing to the issuance of the November 17 Order is set forth in the November 17 Order.

stakeholder process to explore primarily the operational/management aspect of Nevada Hydro's proposal for the LEAPS facility. On December 18, 2006 and May 1, 2007, Nevada Hydro and CAISO submitted compliance filings with the November 17 Order, respectively.

A. Description of the Projects

3. Nevada Hydro proposes to build the TE/VS Interconnect project, which consists of an approximately 30-mile, 500 kV transmission line that will run through federally-owned public lands managed by the United States Forest Service (Forest Service) and connect San Diego Gas & Electric Company's (SDG&E) transmission system with Southern California Edison's (SCE) system, and the LEAPS project, which is intended to be a pumped hydro storage facility with an installed generating capacity of 500 MW and a pumping capacity of 600 MW. These projects will be located in Riverside County, California at Lake Elsinore, California and this lake will serve as the lower reservoir for the LEAPS facility. The upper reservoir will be constructed above the crest of the Elsinore Mountains.

4. Nevada Hydro states that it combined the Combined Project for the purpose of this filing, in accordance with the provisions of sections 1223[7] and 1241[8] of the Energy Policy Act of 2005 (EPAct 2005), under which the Commission was directed to encourage, when appropriate, the deployment of energy storage devices as "advanced transmission technology." Nevada Hydro, a single purpose entity created to develop and construct the Combined Project, requests the following rate incentives for its Combined Project: (1) an initial post-tax rate of return on equity (ROE) of 14.5 percent for the LEAPS project and 13.5 percent for the TE/VS Interconnect project;[9] (2) a hypothetical 50/50 capital structure for at least the first three years of service; (3) a three-year rate moratorium; (4) full recovery of prudently incurred construction work in progress

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[7] Pub. L. No. 109-58, § 1223, 119 Stat. 594, 953 (2005).

[8] Pub. L. No. 109-58, § 1241, 119 Stat. 594, 961-62 (2005) (to be codified at section 219 of the FPA, 16 U.S.C. § 824s).

[9] In its Initial Application, Nevada Hydro requested a 14.5 percent ROE on the TE/VS Interconnect project. Initial Application at 5. It later amended its proposal by stating that if the Commission preferred not to approve the requested 14.5 percent ROE for the Combined Project, it would accept a 13.5 percent ROE for the TE/VS Interconnect project. Response of Nevada Hydro Company at 16 (January 27, 2006) (Nevada Hydro Answer).

(CWIP);[10] and (5) abandonment costs should these projects be approved and, then, cancelled or abandoned for reasons beyond Nevada Hydro's control.[11] Further, Nevada Hydro does not seek any special depreciation of the Combined Project's capital costs as a rate incentive but requests a final determination on the period of depreciation so that financing can be structured accordingly.[12]

5. Nevada Hydro intends to turn the Combined Project over to the operational control of CAISO and, thus, expects compensation through CAISO's Open Access Transmission Tariff (Tariff) protocols and other governing agreements. Specifically, Nevada Hydro states that it expects both the LEAPS and the TE/VS Interconnect projects to be considered transmission assets, the full costs of which should be included in CAISO's Transmission Access Charge (TAC) and collected from all users of the CAISO's transmission grid.[13] Nevada Hydro had originally estimated the cost of the Combined Project to be approximately $750 million,[14] and Nevada Hydro will be the sole owner of both projects.[15]

6. According to Nevada Hydro, the LEAPS facility will be environmentally friendly and will "help the [CAISO] manage grid operations, shift off-peak energy closer to the

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[10] *See* Nevada Hydro Compliance Filing at 11 (December 18, 2006) (Nevada Hydro Compliance Filing).

[11] *Id*.

[12] As we discuss later, Nevada Hydro may raise this issue again when it submits its full section 205 filing to the Commission for review.

[13] CAISO's TAC consists of a High Voltage (HV) Access Charge; a Low Voltage Access Charge; four Transmission Access Charge (TAC) areas defined by the three former control areas of the Original Participating Transmission Owners (TO) (i.e., PG&E, SDG&E and SoCal Edison), and LADWP's control area should LADWP choose to become a Participating TO; and a ten-year transition period. Over the ten-year transition period, the HV Access Charge of each TAC Area will progressively combine to form a single CAISO grid-wide HV Access Charge through blending the HV Transmission Revenue Requirements of each TAC area by an additional ten percent each year.

[14] Nevada Hydro now estimates the cost of the combined Project to be over $1 billion.

[15] In a separate proceeding, the LEAPS project hydropower license application was filed with the Commission in August 2004 (Project No. 11858).

demand center during peak periods, and enhance the reliability of the Southern California transmission grid while helping the State of California achieve its renewable resource use goals."[16] Additionally, Nevada Hydro states it is seeking a special use permit to cross public lands from the Forest Service for the TE/VS Interconnect project.

7. During the course of this proceeding, CAISO conducted a stakeholder process to evaluate the feasibility of Nevada Hydro's proposal for a CAISO-managed and/or operated LEAPS facility. Stakeholders also considered the appropriateness of including the LEAPS plant costs in the TAC and socializing its cost over all users of CAISO grid. Based on input from this stakeholder process, CAISO concluded that TAC-recovery for the LEAPS facility should not be allowed and that CAISO should not be required to assume operational control of this generation facility, as discussed in greater detail herein.[17]

8. In its Initial Application, Nevada Hydro asked the Commission to consider the Combined Project as a single project for purposes of determining the applicability of Order No. 679. Following the CAISO's recommendation to the Commission on the appropriate treatment of the LEAPS facility, Nevada Hydro filed a subsequent request that the Commission evaluate the TE/VS Interconnect as a stand-alone, independent project for the same transmission rate incentives previously requested for the Combined Project.[18] Therefore, in this order, the Commission will discuss its evaluation of each project individually. First, after summarizing the procedural history in this proceeding, the order will address Nevada Hydro's request for transmission rate incentives for the TE/VS Interconnect and, then, the LEAPS project, beginning with the threshold issue of whether to treat the LEAPS facility as a transmission asset for rate basing purposes. In

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[16] Initial Application at 6. Further, Nevada Hydro states that the facility's pump-turbine units will operate under an average net head of approximately 1600 feet, making the LEAPS facility one of the most efficient pumped storage facilities in the world, with the highest lift in the continental United States. Moreover, Nevada Hydro asserts that peak energy will be available over a 16-hour period and will be dispatchable in approximately 15 seconds, serving a variety of ancillary service needs for the CAISO market.

[17] Comments of the CAISO in response to the November 17, 2006, Order on Rate Request (May 1, 2007) (CAISO Compliance Filing).

[18] *See* Nevada Hydro Answer to CAISO Compliance Filing at 29.

each discussion, we will address the pleadings made to both Nevada Hydro's December 18, 2007 Compliance Filing and CAISO's May 1, 2007 Compliance Filing. As discussed below, we will examine the TE/VS Interconnect and the LEAPS project separately for purposes of our analysis under Order No. 679.

B. Overview of Issues in Nevada Hydro's Initial Filing

9. As described in the November 17 Order, several parties filed comments and/or protests in response to Nevada Hydro's original filing. Specifically, CAISO expressed its concern regarding how the LEAPS facility, which it classifies as a generation resource, would function in CAISO's market-based environment. Other arguments by protestors included: (1) Nevada Hydro's filing is premature and Commission action should be deferred until the proposal was considered in the CAISO's regional planning process; (2) the proposal would have the Commission treat the TE/VS Interconnect as a reliability and/or economic network transmission upgrade, while it appears to be a gen-tie not eligible for network treatment; (3) Nevada Hydro's proposed 14.5 percent ROE is too high for the risk Nevada Hydro would incur, as there is a high degree of certainty of return to investors if the project is approved and built.

10. In its answer, Nevada Hydro stated that its requested cost-based treatment for the LEAPS facility was reasonable, as Congress had already labeled pumped hydro as an advanced transmission technology under EPAct 2005. Nevada Hydro also argued that the Combined Project will increase import capability in the region, reduce RMR contract costs, and provide value in the ancillary services market, as well as provide significant environmental benefits. In a supplemental filing, Nevada Hydro suggested three approaches CAISO could take to exert functional control of the LEAPS facility without becoming a *de facto* market participant: (1) CAISO would assume operational control and bid and schedule the LEAPS facility into the market but create a firewall between the actual operators of the LEAPS facility and transmission personnel to ensure that the LEAPS operators would have no access to non-public information; (2) CAISO would periodically auction its right to operate the LEAPS facility to market participants; and (3) CAISO would contract with a third party and would be prohibited from sharing non-public information with this third party.

11. On November 17, 2006, the Commission issued an order which deferred ruling on Nevada Hydro's requested rate incentives pending submission of additional information by Nevada Hydro and CAISO. The Commission found that the LEAPS facility met the requirements of EPAct 2005 section 1223, as an "advanced transmission technology."[19]

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[19] November 17 Order, 117 FERC ¶ 61,204 at P 27.

The Commission concluded, however, that Nevada Hydro's proposal required further analysis and development concerning, in particular, how a CAISO-operated pumped hydro storage facility could be implemented effectively in a market-driven environment.[20]

12. The November 17 Order also found that CAISO had not addressed whether the services provided by the LEAPS facility would benefit CAISO ratepayers in such a way as to warrant special treatment (e.g., cost recovery of the LEAPS project through the TAC). Accordingly, the Commission directed CAISO to convene a stakeholder process and submit a compliance filing at the conclusion of the stakeholder process.[21] The Commission directed CAISO to address: operation/management options and recommendations; cost recovery options given CAISO's determination of the extent to which the Combined Project reduces congestion costs or ensures reliability; whether CAISO can effectively operate the Combined Project in the context of being an independent system operator; whether it is appropriate to include a cost-based, fixed revenue requirement for a facility in its TAC, where the benefits associated with that revenue requirement would be determined by the daily operation of the market and; whether CAISO recommends inclusion of the LEAPS costs in its TAC.[22] Additionally, the Commission directed CAISO to address, within 60 days of the date of the November 17 Order, whether CAISO-operation of the LEAPS facility would adversely affect CAISO's tax-exempt status.[23]

13. The Commission also found, in the November 17 Order, that Nevada Hydro had not provided sufficient evidence to support its requested equity returns and, therefore, directed Nevada Hydro to provide an analysis to show that the requested returns fell within the range of reasonable returns.[24] The Commission noted that the requested hypothetical capital structure, the three-year rate moratorium, and the proposal for 100

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[20] *Id.* P 32.

[21] *Id.* P 30.

[22] *Id.*

[23] On January 8, 2007, the CAISO requested and was thereafter granted an extension of time to file its response to the November 17 Order by May 1, 2007.

[24] *Id.* P 32.

percent CWIP recovery would be subject to a future determination that the Combined Project has met all elements of Order No. 679 before the Commission grants any of these incentives.[25]

II. Notice of Filings and Responsive Pleadings

14. Notice of Nevada Hydro's filing, as later amended, was published in the *Federal Register*, 70 Fed. Reg. 74,796 (2005) and 71 Fed. Reg. 1,424 (2006), with interventions and protests due on or before December 22, 2005 and January 12, 2006, respectively. Timely motions to intervene and/or protests were filed by the SCE, PG&E and SDG&E, as later corrected. Late motions to intervene and/or comments or protests were filed by CAISO, the California Department of Water Resources State Water Project (DWR), as supplemented, the California Public Utilities Commission (CPUC), the Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (Cities), the California Electricity Oversight Board (CEOB), and the Elsinore Valley Municipal Water District (Elsinore Valley). Nevada Hydro filed answers on January 27, 2006 and May 16, 2006.

15. On March 20, 2006, as supplemented on March 29, 2006 and April 7, 2006, Nevada Hydro filed its response to the Commission's data request.[26] Nevada Hydro's filing also contained a number of clarifications concerning the status of its proposals before the CPUC and CAISO. Notice of Nevada Hydro's responses to the Commission's request for more information was published in the *Federal Register*, 71 Fed. Reg. 19,493 (2006) and 71 Fed. Reg. 21,008 (2006), with interventions and protests due on or before April 21, 2006 and April 28, 2006, respectively. SDG&E and SCE filed comments. Nevada Hydro filed an answer.

16. On December 18, 2006, Nevada Hydro submitted its compliance filing. Notice of Nevada Hydro's filing was published in the *Federal Register*, 71 Fed. Reg. 78,422 (2006), with interventions, protests, and comments due on or before January 8, 2007. In this filing, Nevada Hydro provided an equity analysis, which incorporated a proxy group

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[25] *Id*.

[26] The bulk of this response is an interconnection study performed by an independent third party in March 2005.

of 25 publicly-traded companies[27] and developed a range of equity returns from 7.41 percent to 15 percent.[28]

17. In response to Nevada Hydro's Compliance Filing, the Transmission Agency of Northern California filed a timely motion to intervene. M-S-R Public Power Agency and the City of Santa Clara, California (M-S-R), the CPUC, and Modesto Irrigation District (Modesto) filed protests. SDG&E and SCE filed comments. Calpine Corporation and Williams Power Company, Inc. (Williams) filed motions to intervene out-of-time. Nevada Hydro filed an answer.

18. On May 1, 2007, after concluding its stakeholder process, CAISO submitted its compliance filing. Notice of CAISO's compliance filing was published in the *Federal Register*, 72 Fed. Reg. 29,151 (2007), with interventions, protests, and comments due on or before May 22, 2007.[29] Voith Siemens Hydro Power Generation, Inc. (Voith); M-S-R; the California Department of Water Resources; Modesto; Devine, Tarbell, & Associates (Devine); Jacqueline Ayer; California Municipal Utilities Association; and Nevada Hydro filed comments. CAISO, SCE, and SDG&E filed answers to Nevada Hydro's comments. The Northern California Power Agency filed a motion to intervene. Thereafter, Nevada Hydro made a supplemental filing.

III. Discussion

A. Procedural Matters

19. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2007), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. We will allow the late interventions and comments of CAISO, DWR, the CPUC, CEOB, the Cities, Williams, Calpine Corporation, and Elsinore Valley because they have each demonstrated an interest in this proceeding that cannot be adequately represented by any other party. Given this fact and the lack of undue prejudice or delay, we will grant the late-filed motions to intervene. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R.

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[27] Nevada Hydro states that it has no publicly-traded stock at the time and argues that it faces a much higher risk profile than any of the electric utilities in the proxy group, particularly in light of the need to attract financing for the Combined Project.

[28] *See* Nevada Hydro Compliance Filing, Attachment 1 Gaske Testimony at 7.

[29] On May 15, 2007, Nevada Hydro requested and was thereafter granted an extension of time to file its response to CAISO's May 1, 2007 filing until June 22, 2007.

§ 385.213(a)(2) (2007), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept SCE's, SDG&E's, Nevada Hydro's and CAISO's answers because they have provided information that assisted us in our decision-making process.

B. Ripeness

1. Comments and Protests

20. In response to Nevada Hydro's Initial Application, SDG&E and SCE argued that Nevada Hydro's proposal was premature, as the project appeared to be at the very early stage of regulatory development, both in terms of analysis and in terms of commercial development. SDG&E stated that the timing of Nevada Hydro's proposal may have been an attempt to circumvent state planning and siting processes. SDG&E argued that Nevada Hydro's system impact study application was only recently submitted to CAISO and had not yet been acted upon. SCE requested that the Commission defer action until the proposal made its way through CAISO regional planning process. If the Commission considers granting the requested rate principles prior to Nevada Hydro receiving CAISO-approval for its proposal, SCE requests the Commission hold a hearing to explore additional factual issues.[30]

2. Commission Determination

21. As we note above, we are approving incentives for Nevada Hydro's proposed TE/VS Interconnect under section 219 of the FPA and Order No. 679 to provide the regulatory certainty necessary for Nevada Hydro to proceed with its project. Our decision therefore is confined to the particular incentives being approved in the instant proceeding and does not constitute approval of any particular rate. As we discuss below, the justness and reasonableness of any such rate will be determined through a future FPA section 205 proceeding. Accordingly, we find that it is appropriate to address Nevada Hydro's petition at this time.[31]

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[30] Southern California Edison Company's Motion to Intervene and Protest at 3 (January 12, 2006) (SCE Protest).

[31] *See*, e.g., *American Electric Power Service Corp.*, 116 FERC ¶ 61,059, at P 26-28 (2006) (rejecting the argument that Commission's approval of certain rate principles was premature in the context of section 219 of the FPA).

C. Section 219 Requirements

22. Section 1241 of EPAct 2005 added a new section 219 to the FPA directing the Commission to establish, by rule, incentive-based (including performance-based) rate treatments related to the transmission of electric energy in interstate commerce.[32] The Commission issued Order No. 679, which set forth processes by which a public utility could seek transmission rate incentives pursuant to section 219, including the incentives requested here by Nevada Hydro.

23. Order No. 679 provides that a public utility may submit a petition for declaratory order or a filing under FPA section 205 to obtain incentive rate treatment for transmission infrastructure investment that satisfies the requirements of FPA section 219, i.e., the applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[33] Order No. 679 also establishes a rebuttable presumption (as modified by Order No. 679-A) for: (i) a transmission project that results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (ii) a project that has received construction approval from an appropriate state commission or state siting authority.[34] Order No. 679-A also clarifies the operation of this rebuttable presumption by noting that the authorities and/or processes on which it is based (i.e., regional planning process, a state commission, or siting authority) must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.[35]

24. To comply with the Commission's FPA section 219 requirement, Nevada Hydro relies on independently supplied reliability studies. In its March 20, 2006 Response to the Commission's data request, Nevada Hydro submitted the Comparative Reliability Evaluation for Alternative New 500 kV Transmission Lines into San Diego by John Kyei, CAISO Grid Planning Department (Reliability Study);[36] and the Lake Elsinore

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[32] 16 U.S.C. § 824s (2007).

[33] *See* 18 C.F.R. § 35.35(i) (2007).

[34] *See id.*; Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 47.

[35] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 49.

[36] According to the Executive Summary provided in the Reliability Study, which references the 2003 Southwest Transmission Expansion Plan (STEP) Study, San Diego is in desperate need of a new 500 kV line to serve future load growth to increase San

(continued…)

Advanced Pump Storage System Study prepared by Utility System Efficiencies, Inc. (USE Interconnection Study). The main objective of the Reliability Study was to evaluate the relative reliability benefits of three transmission options: (1) the Imperial Valley-Ramona 500 kV line, which is part of the Imperial Valley-San Diego Expansion Plan (ISEP); (2) the TE/VS 500 kV line (without the 500 MW LEAPS facility) and (3) both projects combined and connected to the same substation in San Diego.[37] In the Reliability Study, power flows were conducted for each of the above transmission options evaluated, modeled on various assumptions, to determine the maximum San Diego import level, which, at the time, was 2850 MW. This study revealed that "[a] combination of the ISEP and LEAPS projects provides additional benefits such as a 3800 MW import capability to San Diego," a 950 MW increase from the then existing 2850 MW import capability.[38]

25. Likewise, in the USE Interconnection Study, the TE/VS Interconnect was evaluated as a stand-alone transmission option. USE concluded that the addition of this line "would inject another source of power to the SDG&E 230-kV system; resulting in a more robust system."[39] Potential decreases in Reliability Must Run (RMR) contracts and increased transfer capabilities associated with Path 43 (North of San Onofre) and Path 44 (South of San Onofre) were also mentioned in the USE Interconnection Study as potential benefits.[40]

26. Based on the evidence provided by Nevada Hydro, we find that these power flow analyses affirm that the proposed TE/VS Interconnect will add another major transmission path into the San Diego area with a potential for increasing San Diego's

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Diego's import capability, which is currently 2850 MW. STEP study results concluded that this deficiency is "primarily due to the inability to permit the Valley-Rainbow 500 kV line, the planned retirement of the South Bay generation units in 2009, and increasing load in San Diego." *See* Nevada Hydro's March 20, 2006 Response, Exhibit No. TNHC-1.

[37] *Id*. at 3.

[38] Additionally, the Reliability Study determined that both projects would require additional facilities or upgrades beyond the basic project scope to achieve this 3600 MW import limit. *Id*. at 34.

[39] *Id*.

[40] *Id*.

import capability including relief on currently limiting Paths 43 (North of San Onofre) and 44 (South of San Onofre) while maintaining adequate system reliability and, therefore, satisfy the Commission's FPA section 219 requirement. In its initial application, Nevada Hydro stated that the 2003 STEP Report "concluded that a new high-voltage electrical transmission line between Riverside and San Diego Counties is critically needed to serve future load growth."[41] If built today, the TE/VS Interconnect would be the first 500 kV transmission line connecting SCE and SDG&E's transmission systems.[42] Moreover, the USE Interconnection Study determined that the addition of the TE/VS Interconnect would have benefits to both the SCE and SDG&E systems for the above stated reasons.

27. We therefore find that Nevada Hydro, through independent evidence provided in this proceeding, has adequately demonstrated that its TE/VS Interconnect project will ensure reliability, consistent with the requirement of Order No. 679.

D. Incentives and the Commission's Nexus Requirement for the TE/VS Interconnect Project

28. In addition to satisfying the requirement under FPA section 219 mentioned above, a proposed incentive rate must also be shown to have a nexus between the incentive sought and the investment being made. In evaluating whether an applicant has satisfied the required nexus test, Commission precedent requires an examination of the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the project.[43] Applicants must provide sufficient explanation and support to allow the Commission to evaluate the incentives.

29. In Order No. 679-A, the Commission clarified that its nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[44] By its terms, this

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[41] Initial Application at 13.

[42] We recognize that competing proposals have been submitted to the CAISO regional planning group for review. Our finding here is not an endorsement of Nevada Hydro's proposal over any other proposal.

[43] 18 C.F.R. § 35.35(d) (2007); Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26. *See also* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 21.

[44] *Id.* P 40.

nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis.[45] Notably, the Commission chose not to adopt a list of criteria or characteristics that must be met by every applicant before an incentive would be approved. The Commission recognized that it would be impossible to identify every conceivable challenge or risk faced by an applicant, or to develop an *a priori* menu of incentives that would or would not be appropriate given a particular set of risks and challenges.

30. As part of our evaluation of whether the incentives requested are "tailored to address the demonstrable risks or challenges faced by the applicant," the Commission has found the question of whether a project is "routine" to be particularly probative. In *BG&E*,[46] the Commission clarified how it will evaluate projects to determine whether they are routine and the effect this evaluation has on an applicant's request for incentives.

31. Specifically, to determine whether a project is not routine, the Commission will consider all relevant factors presented by the applicant. For example, an applicant may present evidence on: (i) the scope of the project (e.g., dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (ii) the effect of the project (e.g., improving reliability or reducing congestion costs); (iii) the challenges or risks faced by the project *(*e.g., siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments).[47] Further, applicants must provide detailed factual information in support of the factors they rely upon. For example, an applicant asserting that the scope of any proposed transmission expansion project is not routine should submit data distinguishing the project from other transmission projects or upgrades that are constructed in the ordinary course of maintaining a utility's transmission system to provide safe and reliable service to its customers. An applicant also may, as in *Duquesne*,[48] compare the total investment in a range of projects to some other aggregate measure of investment, such as total rate base or recent annual investment levels, as delineated in *BG&E*.[49] When an applicant has adequately

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[45] *Baltimore Gas & Electric Co.*, 120 FERC ¶ 61,084 (2007) (*BG&E*).

[46] *Id*. P 54-55, 61.

[47] This list is not exhaustive. These are merely examples of evidence that may help inform the Commission on the question of whether a project is routine in nature.

[48] *Duquesne Light Co.*, 118 FERC ¶ 61,087 (2007).

[49] *See BG&E*, 120 FERC ¶ 61,084 at P 53.

demonstrated that the project for which it requests an incentive is not routine, that applicant has, for purposes of the nexus test, shown that the project faces risks and challenges that merit an incentive.

32. We find that the TE/VS Interconnect project is not routine, based on the project's scope, effects, challenges or risks, in addition to other factual information provided by Nevada Hydro, as discussed below.

33. In *BG&E*, the Commission stated that "[t]he scope of a project involves factors such as size, dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions and effect on the region."[50] In its Initial Application, Nevada Hydro estimated the costs of the TE/VS Interconnect to be $350 million; however, the actual cost may prove higher if Nevada Hydro includes certain facility additions or upgrades to achieve the maximum San Diego import level of 3600 MW. As mentioned earlier, the proposed TE/VS Interconnect will be the first 500 kV link between the SCE and SDG&E's systems and provide much needed import capability to the distressed southern California region. The effect of a project involves factors such as improving reliability or reducing congestion costs, and, as we note in the previous section, Nevada Hydro has satisfied this showing through independent studies.

34. The Commission has previously stated that the challenges or risks faced by a project include: siting, internal competition for financing with other projects, long lead times, regulatory risks, specific financing challenges and other similar impediments.[51] Nevada Hydro states that it "has pursued the development of the [Combined Project] as a solution to California's electricity infrastructure problems entirely at risk, having taken the risk of the loss of all of its development costs and expenses if the Commission were not to accept the rate principles" requested by Nevada Hydro.[52] Thus, as a start-up and single asset entity, Nevada Hydro is shouldering all risks associated with permitting, financing and constructing a project of this size. The CEC report filed in this proceeding helps demonstrate that the LEAPS project faces substantial economic uncertainty and regulatory risk.[53]

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[50] *Id*. P 52.

[51] *Id*.

[52] Initial Application at 3.

[53] Nevada Hydro Answer, citing CEC Strategic Transmission Investment Plan at 106 (October 25, 2007) (stating that the "LEAPS project has reached several critical

(continued…)

35. Accordingly, we find that Nevada Hydro has satisfied the Commission's nexus requirement for certain rate incentives.

1. Incentive ROE for the TE/VS Interconnect

a. Nevada Hydro's DCF Analysis

36. Nevada Hydro requests a 13.5 percent return on equity (ROE) for its TE/VS Interconnect project. In support of this request, Nevada Hydro's Compliance Filing provided an equity analysis incorporating a proxy group of 25 publicly-traded companies. Based on this study, Nevada Hydro developed a range of equity returns from 7.41 percent to 15 percent.[54] Nevada Hydro Witness J. Stephen Gaske determined that, given the greater risks of Nevada Hydro's proposed project in relation to the proxy group, "it is unlikely that the proposed rates of return include much, if any, incentive above the cost of capital to encourage the construction [of the LEAPS facility]."[55] Nevada Hydro proffers that it has no publicly-traded stock and argues that it faces a much higher risk profile than any of the electric utilities in the proxy group, particularly in light of the need to attract financing for the Combined Project.

b. Comments and Protests

37. In its protest to Nevada Hydro's compliance filing, M-S-R argues that the issues raised in Nevada Hydro's testimony require testing through discovery and cross-examination. Specifically, M-S-R asserts that, in its analysis, Nevada Hydro fails to recognize that its proposed recovery of costs through the TAC will greatly mitigate the risks it claims justify a high ROE. Additionally, M-S-R objects to Nevada Hydro's

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permitting milestones but there are still issues to be resolved and permits to be issued. . . . The project received interconnection approval from the California ISO, for both the SCE and SDG&E interconnections in March 2007; however, this approval was contingent upon completion of an operational study. The transmission portion of the project will require a CPCN for modifications to both the SCE and SDG&E transmission grids. . . . However, there are major financial and cost recovery issues that could delay the development of this project").

[54] Nevada Hydro Witness J. Stephen Gaske, in his testimony, states that "For the purposes of this testimony, I have relied on several analytical approaches for estimating the cost of common equity. My primary approach relies on a DCF analysis." *See* Nevada Hydro Compliance Filing, Attachment 1 Gaske Testimony at 7.

[55] *Id.* at 4.

reliance on rates of return for unregulated companies to justify its proposed rate of return as a regulated entity, and concludes that all these issues would require further investigation by the Commission. Lastly, M-S-R argues that Nevada Hydro's proposal still does not meet the requirements of Order No. 679, as "Nevada Hydro does not demonstrate either its effect on the reliability of CAISO Controlled Grid or its potential for congestion relief by producing a report of its own."[56]

38. The CPUC argues that Nevada Hydro's ROE should be no more than 11 percent.[57] The CPUC states that, while Nevada Hydro's project may offer operational and economic benefits to southern California, Nevada Hydro has inaccurately represented the revenue requirements for both projects, inappropriately applies Order No. 679, exaggerates its transmission risk, and relies on a faulty ROE and capital structure analysis.

39. The CPUC argues that Nevada Hydro cannot claim to face higher risk while simultaneously requesting an enhanced ROE.[58] Next, the CPUC protests Nevada Hydro's claims of increased transmission risk as exaggerated because risks for a regulated transmission owner with a guaranteed return are significantly lower than Nevada Hydro's requested 13.5 percent ROE, especially for a bundled generation service disguised as transmission, where generation risk will be removed and protected through transmission rates as opposed to market recovery. The CPUC also claims the following flaws in Nevada Hydro's discounted cash flow (DCF) analysis: (1) Nevada Hydro chose proxy companies with risk profiles varying from less risky to extremely risky, which resulted in an artificially high estimate of ROE; (2) Nevada Hydro inappropriately inflates the ROE estimate by including flotation costs, which is antithetical to Commission precedent; and (3) the final ROE figure chosen by Nevada Hydro is arbitrary since it chose a number drawn from the proxy companies' highest ROEs.

40. SCE states that the Commission should withhold issuing a final decision on Nevada Hydro's proposal until all economic and reliability studies have been completed,

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[56] M-S-R January 8, 2007 Protest at 9. M-S-R argues that instead of producing its own report, Nevada Hydro points to a preliminary report produced by CAISO staff that estimates the economic benefits of the combined Project. M-S-R asserts that the report is not comprehensive, makes no recommendation, and was found by the Commission to not be "definitive and complete."

[57] Protest of the California Public Utilities Commission at 6 (January 8, 2007) (CPUC Protest) (the CPUC claims this ROE should consist of a 10 percent baseline ROE and a 100 basis point adder).

[58] *Id*. at 4.

or alternatively, until the Commission has held a hearing allowing all interested parties to present their arguments.

41. SDG&E challenges an assumption provided by Nevada Hydro in its expert testimony by Phillipe Auclair, that the TE/VS Interconnect project provides 1000 MW of transfer capacity for the benefit of SDG&E's customers. SDG&E states that achieving an increase in the total capability limit would require substantial transmission improvements, a factor that Mr. Auclair does not take into consideration in his analysis.

42. Modesto protests the increased cost to California ratepayers for incentive rate treatments for new investment. Modesto states that it is not only troubled by the rate incentives proposed in this proceeding, but the cumulative effect of piling on other requests for incentive treatment for transmission projects in California, which could sum to a substantial amount for California ratepayers to bear.

c. Nevada Hydro's Answer

43. In its answer, Nevada Hydro addresses the CPUC's assertion that the Commission should permit a 10 percent ROE with an incentive adder of 100 basis points for Nevada Hydro's project. Nevada Hydro argues that the DCF analysis performed by Witness Gaske is designed and supported to comply with the Commission's requirement for incentive rates, while the CPUC alternative is not adequately supported. Moreover, Nevada Hydro believes that the CPUC is improperly using this proceeding to argue broad concepts which ignore the Congressional intent of granting a return on equity that attracts new investment in transmission facilities.[59] In response to SCE, Nevada Hydro acknowledges that the proposed TE/VS Interconnect will not be the first link between SCE and SDG&E, but it will be the first 500 kV interconnection between these two systems. Nevada Hydro also responds to M-S-R's assertion that additional study is needed by stating that it provided, in its compliance filing, the information requested by the Commission. Nevada Hydro states further that it has determined that the project will benefit reliability and provide economic benefits.[60] Nevada Hydro states that the independent review of CAISO staff should provide the Commission with sufficient objective evidence regarding these factors.

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[59] Nevada Hydro does not specifically address the "flaws" in its DCF analysis as alleged by the CPUC.

[60] Answer of The Nevada Hydro Company, Inc., at 9-10 (January 23, 2007).

d. Commission Determination on the ROE Incentive

44. Consistent with our finding that Nevada Hydro has met the Commission's FPA section 219 and nexus requirements for the TE/VS Interconnect project, we find that an incentive ROE to build this transmission line is appropriate.[61] As explained below, this determination is consistent with our precedent of providing incentives for infrastructure investment pursuant to section 205 of the FPA,[62] and our obligation under FPA section 219 to establish incentive-based rate treatments that specifically provide an ROE that attracts new investment in transmission facilities.

45. Order No. 679 establishes certain measures and options for evaluating an incentive-based ROE: (1) any incentive-based ROE must fall within the range of reasonableness established by the Commission for the particular entity requesting the ROE for its investment in new transmission facilities;[63] (2) while the incentive-based ROE will continue to fall within the traditional zone of reasonableness it will be adjusted upward and will be higher than would otherwise have been granted absent the incentive;[64] (3) no specific ROE adders are established;[65] (4) the Commission will determine the level of the incentive-based ROE on a case-by-case basis when an application for an incentive-based ROE is filed with the Commission;[66] and (5) to receive an incentive-based ROE, a public utility must support the ROE request by demonstrating how the new facilities will ensure reliability or reduce transmission congestion.

46. In the November 17 Order, the Commission noted that Nevada Hydro had not provided any evidence or analysis (e.g., DCF study) to date that would show the requested returns were within the range of reasonable returns. We cannot conclude that, based on the evidence Nevada Hydro has provided, it has satisfied this requirement. As

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[61] As discussed below, the LEAPS facility may not be turned over to the operational control of the CAISO for scheduling and dispatch and, therefore, this facility is ineligible for the requested 14.5 percent equity return.

[62] *See American Electric Power Service Corp.*, 116 FERC ¶ 61,059, at P 41 (2006).

[63] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 91-93.

[64] *Id*.

[65] *Id*.

[66] *Id*. P 93.

the Commission stated in *Trans-Allegheny Interstate Line Co.*, applicants must submit "compelling evidence to support a deviation from our general policy of requiring a proxy group to be comprised of transmission owners with a direct link to the same RTO or Independent System Operator in which the applicant is located."[67] Nevada Hydro has provided no such evidence in support of its proxy group. In addition, Nevada Hydro uses a two-step DCF analysis.[68] Finally, Nevada Hydro has not justified its use of flotation cost adjustments and risk premiums, among other things.[69]

47. Based on our above findings of the special risks Nevada Hydro faces with the TE/VS Interconnect, the Commission grants Nevada Hydro an ROE incentive for the TE/VS Interconnect to be set within the upper end of the zone of reasonableness. However, the DCF analysis submitted by Nevada Hydro is neither consistent with Commission policy nor complete and as such the Commission cannot establish the level of return. Accordingly, when Nevada Hydro submits its FPA section 205 filing to establish its rates, including its proposed return on equity, it must use the Commission's established DCF methodology and our recent direction in *Atlantic Path* regarding proxy groups.[70] Nevada Hydro should employ single-step DCF analysis, justify all other assumptions and adjustments, and use a proxy group consistent with *Atlantic Path*. A complete section 205 filing consistent with Commission policy and directives will allow the Commission to establish an incentive return on equity, which is not to exceed the

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[67] *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219, at P 40 (2007).

[68] The Commission has previously rejected proposals to apply a two-step DCF model to an electric utility. *See Southern California Edison Co.*, 92 FERC ¶ 61,070, at 61,261-63 (2000) (rejecting SCE's proposal to apply a two-step growth rate, explaining in detail Commission policy on its single-step DCF (for electric utilities) and the model of a two-step DCF (for natural gas companies), and noting the critical differences between these two industries which warrant this distinction).

[69] *See Allegheny Generating Co.*, 65 FERC ¶ 63,026, at 65,179 (1993), *order aff'g settlement*, 70 FERC ¶ 61,334 (1995) (requiring evidence of common stock issuance in the near term for permission to use flotation cost adjustments); *Boston Edison Co.*, 66 FERC ¶ 63,013, at 65,084 (1994), *aff'd in pertinent part*, Opinion No. 411, 77 FERC ¶ 61,272, at 62,172 (1996) (outlining the Commission formula for calculation of flotation cost adjustments in cases where they are permitted).

[70] *See Atlantic Path 15, LLC*, 122 FERC ¶ 61,135 (2008) (*Atlantic Path*).

requested 13.5 percent. This return will be used in the development of rates for the TE/VS Interconnect when Nevada Hydro files with the Commission under section 205 to recover the costs of its facility through the CAISO TAC.

2. Commission Determination on the Hypothetical Capital Structure and Three-Year Rate Moratorium for the TE/VS Interconnect

48. As stated in Order No. 679-A, use of hypothetical capital structures "can be an appropriate ratemaking tool for fostering new transmission in certain relatively narrow circumstances."[71] The Commission found, however, that adoption of such a hypothetical capital structure would require a demonstration of the required nexus between the need for a hypothetical capital structure and the proposed investment project.[72]

49. Some intervenors object to Nevada Hydro's use of a hypothetical capital structure. For example, the CPUC argues that "[a]s a matter of broad policy, it is intrinsically unjust and unreasonable for ratepayers to be required to support a hypothetical 50/50 capital structure if and when a project's actual capital structure is more like 70 percent debt/30 percent equity."[73] However, in Order No. 679, the Commission stated that "we do not believe that the Commission's recent approvals of hypothetical capital structures for electric transmission companies have resulted in abnormally high equity ratios or over-compensation for the equity holder at the expense of the ratepayer."[74] Thus, we believe the 50/50 capital structure is reasonable given the reasons stated above and the fact that Nevada Hydro lacks an actual capital structure.

50. Nevada Hydro proposes the use of a 50 percent equity/50 percent debt capital structure during the first three years of service of the proposed transmission line. We approve Nevada Hydro's use of this hypothetical capital structure, but only during the construction phase of the TE/VS Interconnect project instead of a three-year period. After construction is completed, Nevada Hydro should use its actual capital structure to derive its annual Transmission Revenue Requirement.

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[71] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 93.

[72] *Id.*

[73] CPUC Protest at 12.

[74] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 134.

51. We find that Nevada Hydro has demonstrated a sufficient nexus for the hypothetical capital structure during construction in the following ways. First, as a start-up company, Nevada Hydro lacks an actual historical capital structure. Second, Nevada Hydro, through use of a hypothetical capital structure, will be able to vary its financing vehicles to the needs of construction, such as timing of expenditures, regulatory developments, and changes in financial market conditions, enabling Nevada Hydro to achieve the most workable outcomes during construction. Moreover, use of a hypothetical capital structure during the construction phase of the projects is consistent with Commission precedent.[75] Accordingly, the Commission finds that a sufficient nexus has been shown to support the use of a hypothetical capital structure during the construction period.

52. With respect to Nevada Hydro's request for a three-year rate moratorium, Nevada Hydro makes no attempt to show why a three-year moratorium is necessary. Nevada Hydro's request for this incentive appears intertwined with its request for the use of a hypothetical capital structure for the first three years of operation. Because we are allowing the use of hypothetical capital structure only during the construction period and Nevada Hydro has not provided an explanation to support the use of a hypothetical capital structure once the TE/VS Interconnect enters commercial operation, we deny this request.

3. Commission Determination on CWIP Incentive and Recovery of Abandonment Costs

53. In Order No. 679, the Commission stated it would grant public utilities, where appropriate, the ability to include 100 percent of prudently incurred transmission-related CWIP in rate base and to expense prudently incurred pre-commercial costs.

54. Additionally, in Order No. 679, the Commission stated that an applicant may request 100 percent of prudently-incurred costs associated with abandoned transmission projects in transmission rates if such abandonment is outside the control of management. The Commission stated further that, "a utility that receives approval to recover abandoned plant in rate base would likely face lower risk and thus may warrant a lower ROE than would otherwise be the case without this assurance."[76]

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[75] *Trans-Allegheny Interstate Line Company*, 119 FERC ¶ 61,219, at P 74-6 (2007).

[76] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 167.

55. In its September 2006 supplemental filing, following the issuance of Order No. 679, Nevada Hydro amended its request for rate incentives to include full recovery of CWIP and abandoned plant costs. With respect to the former, Nevada Hydro stated, "[a]llowing recovery of CWIP would reduce costs by an estimated $100 million, further benefiting ratepayers."[77] Nevada Hydro also noted that the Commission had granted this incentive to American Electric Power. Similarly, in its Compliance Filing, Nevada Hydro requested that, "if the LEAPS and TE/VS projects are cancelled or abandoned for reasons that are outside of Nevada Hydro's control, the Commission allows [Nevada Hydro] to recover all prudently incurred costs associated with the transmission facilities," including the ability to recover development costs.[78]

56. Beyond these simple statements, Nevada Hydro has failed to show how these requested incentives are related to the risks it faces. Accordingly, we deny Nevada Hydro's request for these rate incentives without prejudice to Nevada Hydro resubmitting its request for recovery of CWIP and abandoned plant costs. Any subsequent request, however, will be evaluated against the total package of incentives granted in this proceeding. Order No. 679-A provides that if some of the incentives in the total package reduce the risk of the project, that fact will be taken into account for any request for an enhanced ROE.[79]

4. <u>Total Package</u>

57. With respect to Nevada Hydro's request for rate incentives for the TE/VS Interconnect, we find that Nevada Hydro has demonstrated a nexus between certain incentives sought and the investment being made and that the proposed transmission project is not routine in nature, but will provide a critical link between two major transmission corridors in California, linking the San Diego basin to the main CAISO grid. With respect to the other incentives requested for the TE/VS Interconnect, we note that Nevada Hydro is free to request these incentives again in its subsequent filing under section 205 of the FPA.

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[77] Supplemental Response of the Nevada Hydro Co. at 12 (September 11, 2006).

[78] *Id*. at 11, citing *Allegheny Energy, Inc*., 116 FERC ¶ 61,058 at P 127 (permitting recovery of prudently-incurred development and construction costs associated with abandoned transmission projects as appropriate to encourage new investment and consistent with Order No. 679 and the intent of FPA section 219).

[79] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 8.

E. Incentives for the LEAPS Facility

1. CAISO's Recommendation

58. In response to the November 17 Order requiring a stakeholder process on the issues raised regarding the Combined Project, CAISO submitted its response on May 1, 2007, stating that it had conducted a robust stakeholder process, issued two draft white papers with opportunity for comment and held two face-to-face meetings to solicit stakeholder input on all of the issues raised in the November 17 Order.[80] CAISO submits that, based on stakeholder input and its own evaluation of the issues, recovery of the LEAPS facility through CAISO's TAC should not be permitted and CAISO should not assume operational control of the LEAPS facility, other than its normal role with respect to the operation of generating units. Thus, CAISO recommends market recovery for the LEAPS facility, pursuant to the Large Generator Interconnection Procedures (LGIP) in the CAISO Tariff.

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[80] White Paper 1 evaluated six potential options for the control and operation of the LEAPS facility: (1) CAISO will schedule/bid LEAPS into the market, with a firewall separating operating personnel; (2) CAISO will auction the right to schedule/bid LEAPS into the market for a specific period of time; (3) CAISO contracts with a third-party to schedule/bid LEAPS into the market, with the terms set by CAISO; (4) LEAPS will be incorporated into the grid as any other transmission facility of a transmission owner; (5) hybrid TAC and market cost recovery – Nevada Hydro would schedule/bid LEAPS into the market and receive a portion of its fixed revenue requirement from the TAC with the remainder coming from CAISO markets, similar to a Condition 1 RMR unit; and (6) if LEAPS is not completed, abandoned plants costs would be shared between Nevada Hydro and TAC. Of the 86 participants of the first stakeholder meeting, CAISO states that only one party did not reject the proposals of cost recovery through the TAC and CAISO involvement in operating the LEAPS facility. White Paper 2 reflected that conclusion.

At the second stakeholder meeting, CAISO recommended that the LEAPS facility's costs should be excluded from the TAC unless further study revealed that the LEAPS facility's services could not be obtained from other sources, that its benefits far exceeded its costs, that it would not be developed but for cost recovery in TAC, and that it would not compromise CAISO's independence or tax status. All of the commentors responding to White Paper 2, with the exception of Nevada Hydro, agreed that market recovery for the LEAPS facility is the only appropriate scenario, pursuant to the Large Generator Interconnection Procedures (LGIP) in CAISO OATT.

59. CAISO maintains that EPAct 2005 does not compel a particular cost recovery mechanism for an "advanced transmission technology." CAISO argues that classifying such technologies as transmission for cost recovery purposes could distort the market price signals. Further, Order No. 679 and the other statutory sections cited by Nevada Hydro create a framework in which the Commission must conduct a case-by-case policy determination based on record evidence, and do not establish a legal mandate.

60. CAISO opposes TAC cost recovery for the LEAPS project. First, CAISO argues it would be inappropriate to discriminate between LEAPS and existing pumped storage hydro units that are currently interconnected to CAISO network and provide generation services to California ratepayers.[81] Although these existing pumped storage hydro facilities produce the same type of benefits and services offered by the LEAPS facility, their costs are not included in TAC, and they pay transmission rates and CAISO load-based charges (e.g., intra-zonal congestion, reliability costs) when in pumping mode. Further, having CAISO control the LEAPS facility would provide Nevada Hydro with substantial benefits not provided to owners of other pumped storage hydro units in CAISO. Second, CAISO states that providing TAC cost recovery for LEAPS could disrupt the development of competitive markets, including the implementation of locational marginal pricing (LMP). Finally, CAISO concurs with shareholders' concern that Nevada Hydro's proposed, unprecedented cost recovery scheme for LEAPS would shift the development risks of a generation project to the ratepayers. CAISO argues that the benefits provided by the LEAPS project should be derived from the market in the same way that other merchant generation facilities are compensated.

61. Next, CAISO opposes taking operational control of the LEAPS facility. CAISO argues that any transfer of control analyzed in its proceedings would compromise CAISO's independence as envisioned in Order No. 2000 (or create the perception thereof).[82] CAISO argues that placing it in this untenable position of being both a

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[81] CAISO Compliance Filing at 19. CAISO notes that one of these units is owned and operated by PG&E, one is owned and operated by SCE, and the others are owned and operated by the California Department of Water Resources State Water Project. *Id*.

[82] The CAISO states that an RTO must be independent of any entity whose economic or commercial interests could be significantly affected by the RTO's actions or decisions; otherwise, it would be difficult for an RTO to act in a non-discriminatory manner. Also, an ISO/RTO's control of generation should be through a market where generators offer their services and the ISO/RTO chooses the least cost option, stressing that an RTO should attempt to rely on market mechanisms to the maximum extent practicable to manage congestion, citing *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at P 195, 384 (1999), *order on reh'g*, Order

(continued…)

generator operator and overseer of the transmission network is a step backwards from the restructured, efficient, competitive market that CAISO has worked hard to achieve. Further, CAISO operation of LEAPS could dramatically affect on-and-off peak pricing. CAISO contends that by establishing a "bidding and scheduling arm" of CAISO (Option 1 of CAISO's White Paper), CAISO would become an interested market participant that will compete with other market participants in CAISO markets rather than function wholly as an independent and neutral market facilitator. Efficient operation of the LEAPS facility would necessitate making use of the excess capacity from LEAPS after all reliability needs are met, thus creating an inconsistency with CAISO's stated mission to provide "cost effective and reliable service, well-balanced energy market mechanisms, and high quality information for the benefit of the customers."

62. CAISO contends that Options 2 and 3 (noted *supra* in footnote 80) would also compromise CAISO's independence by requiring indirect control over the manner by which services provided by LEAPS are bid into the market because CAISO would have to establish the terms of the auction or third-party contract, continuously supervise to ensure third-party compliance with the contract, and structure the auction. Option 4 would involve direct involvement on the part of CAISO regarding operational decisions, as well as a lack of separation between CAISO bidding and transmission functions and a lack of motivation to optimize the revenue stream produced by LEAPS. Stakeholders considered Option 5 to be a step in the wrong direction as CAISO is moving away from using RMR contracts in favor of more competitive solutions.

63. In response to the Commission's inquiry regarding the status of CAISO's discussions with the IRS, CAISO states that it would be premature to initiate discussions with the IRS until the specific circumstances under which CAISO would assume operational control had been determined.

2. <u>Comments and Protests</u>

64. CDWR, CMUA, Modesto, and M-S-R submitted comments in support of CAISO's recommendations and urged the Commission to accept those recommendations. CMUA asserts that transmission rate-based treatment for pumped storage is not a statutory requirement, and Modesto contends that EPAct 2005 allows the Commission considerable discretion in determining when an "advanced transmission technology" should be encouraged, noting that such encouragement does not include inclusion of such costs in a transmission charge. M-S-R adds that there is no justification for forcing ratepayers to accept the risk that the costs of the LEAPS project will far outweigh its

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No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

questionable benefits. CMUA expresses its concern that this task is outside CAISO's core competency and would be a major initiative that will distract CAISO from meeting other goals.

65. Additionally, Jacqueline Ayer and the CEOB submitted comments. Jacqueline Ayer states that since the LEAPS facility is not a transmission facility but is a generation facility, its designation under EPAct 2005 section 1223 is irrelevant for purposes of the instant filing. Further, noting that the interconnection diagram provided in Nevada Hydro's application does not include a grid intertie line connecting the LEAPS facility to the TE/VS Interconnect, Jacqueline Ayer argues that since the TE/VS Interconnect is intended to operate as a fully integrated transmission line for years before the LEAPS facility is completed, a grid intertie line will be required before power from the LEAPS facility is put on the grid. Finally, Jacqueline Ayer asserts that the only viable alternative for Nevada Hydro's proposal is that Nevada Hydro retains control and seeks cost recovery through the market.

66. The CEOB argues that the cost of the Combined Project will outweigh the benefits accruing to California ratepayers because: (1) based on the CEOB's analysis, the expected revenue from the sale of energy and ancillary services will not be sufficient to cover the Project's costs; (2) Nevada Hydro's proposal will operate as an imperfect hedge because the price spread between peak and off-peak energy prices will shrink over time, proving fewer opportunities for ratepayers to recover their stranded costs in the Project; and (3) any economic benefit arising from the imperfect price hedge will dissipate over time as California implements its comprehensive energy and environmental policies.[83] The CEOB opposes including any costs for the LEAPS facility in the TAC and any transfer of control of the LEAPS facility, noting potential conflicts with California's resource adequacy policy.

67. Voith and DTA submitted comments opposing CAISO's recommendations in its filing. Voith and DTA state that CAISO erred by classifying the LEAPS project as the same as any other type of generation and that CAISO needs to focus on the benefits of pumped storage power plants to the system grid from a transmission, ancillary service, and reserve generation scenario. DTA argues that the primary function of pumped storage units is not to produce energy but to provide significant grid stabilization benefits to balance load and power flow, by permitting the grid system operator the flexibility to

[83] The CEOB explains that California has adopted a policy of maximizing peak savings, which will result in a decrease in the spread between peak and off-peak energy prices. Further, it argues California's Greenhouse Gas initiative may impact the project's benefits.

manage power swings of about 2000+ MWs in a ten minute period. Voith asserts that the transmission business and ancillary service business is not defined in a manner that allows pumped storage projects to continue forward on a non-rate based basis; many past projects were financed on the utility balance sheet as a rate-based investment. Voith claims that the direct non-energy benefits attributable to the LEAPS project are estimated to be nearly $175 million.

3. Responses of Nevada Hydro and CAISO

68. Nevada Hydro responds that the plain meaning of section 1223 compels treatment of the LEAPS project as a transmission facility, including inclusion in the TAC, because Congress' selection of the word "transmission" in "advanced transmission technology" should be given meaning and consequence. Thus, although the Commission has discretion to grant incentives to be applied to advanced transmission technology, it cannot ignore that pumped hydro storage is transmission and deny basic transmission treatment such as cost recovery under just and reasonable rates. Further, Nevada Hydro argues that there is no basis to disallow cost recovery for advanced transmission facilities simply because they are advanced and not traditional. Nevada Hydro argues the list of advanced transmission technologies enumerated in section 1223 includes both wire and non-wire technologies. Congress' treatment of these technologies as transmission implements a sensible policy vision. All of the enumerated technologies in section 1223 promise to reduce congestion, either by building new or better wires or by reducing the need for wires.

69. Nevada Hydro states that, under longstanding jurisprudence, the Commission has treated natural gas storage facilities[84] as transmission with their costs recovered under cost-based rates, and it argues that electricity storage is transmission as well. CAISO answers that the concept of storage differs between the natural gas and electricity industries,[85] and the Commission has traditionally treated hydroelectric facilities, including pumped storage facilities, as part of the generation function.

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[84] Nevada Hydro states that interstate natural gas systems often have underground gas storage facilities that are traditionally used to meet seasonal load variations on the system and that such natural gas storage facilities are treated as transmission for rate making purposes.

[85] Specifically, when natural gas is gathered, it already contains all of its energy without going through a change of physical state. In contrast, electric energy must be generated by undergoing a change of form, from chemical or kinetic energy to electric energy.

70. Nevada Hydro refutes claims that the costs of the LEAPS project outweigh the benefits, arguing that the Combined Project and the TE/VS Interconnect Project[86] alone will result in cost savings of $151 million and $23 million in 2015, respectively. Further, Nevada Hydro states that the LEAPS and TE/VS Interconnect Projects in tandem will provide annual benefits to ratepayers aggregating about $324 million in 2015, or nearly $179 million per year in excess of the combined levelized annual cost of $145.33 million.

71. Nevada Hydro contends that CAISO's argument that TAC recovery for LEAPS leads to discrimination effectively amounts to a request to the Commission to ignore the implementation of EPAct 2005, as Congress intended to encourage the enumerated technologies in section 1223.

72. Nevada Hydro refutes CAISO's contention that there is nothing "unique or compelling" about the LEAPS and TE/VS Interconnect Projects that cannot be provided in the market because Nevada Hydro's analysis shows that both projects would bring substantial savings to the market and LEAPS provides unique storage capability. Nevada Hydro argues that LEAPS will not displace generation or disrupt markets because it is a storage device that produces no net energy and will simply resolve congestion by shifting load from peak to off-peak.[87]

73. Nevada Hydro claims that CAISO's argument that the implementation of LMP will be undermined implies that inefficiencies must be preserved to allow LMPs to give stronger signals.

74. According to Nevada Hydro, CAISO's arguments that operational control of LEAPS will compromise its independence and distort markets are exaggerated and based on the faulty view that a storage facility is the same as a generator. Nevada Hydro states that to the extent that LEAPS, a transmission addition, could impact any relevant markets, it is no different than any new transmission wire, tower, substation, transformer, switch, or other facility. Nevada Hydro states that it has carefully crafted its proposal to avoid distortion; CAISO would take its ancillary services consistently and to the extent

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[86] Nevada Hydro notes that LEAPS cannot be built without a connection to the grid (i.e., the TE/VS Interconnect project).

[87] Nevada Hydro explains that a pumped hydro storage device must expend as much electric energy to pump water into storage before it can produce any electric energy. During an off-peak period, the device uses electric energy to pump water from a stagnant body of water into an elevated reservoir. During peak periods, the water is released from the reservoir to produce electric energy. The value of the reduced peak energy exceeds the cost of off-peak pumping energy, but no net electricity is produced.

required from LEAPS, and Nevada Hydro would consistently bid LEAPS' stored energy in at zero. CAISO would not be involved in operational decisions, as energy will be taken as needed by CAISO's computerized dispatch model, not based on some subjective standard. Nevada Hydro states that storage and release can add market stability and system reliability not cause market distortion.

75. As to the potential effect to CAISO's tax status, Nevada Hydro points out that tax exemption is not a required characteristic for an RTO/ISO and that CAISO does not provide evidence that its tax status will change, as CAISO will provide LEAPS service to the grid in the same manner it provides service on any other transmission facility.

76. Finally, Nevada Hydro clarifies that the Commission should grant all requested incentives to the TE/VS Interconnect Project as a stand-alone transmission upgrade, in the event that LEAPS is not constructed. Nevada Hydro states that this Project, as a stand-alone facility, would yield energy savings of $22 million in 2015 and total net benefits of more than $96 million per year, and it notes that this request is not protested.

77. CAISO replies that Nevada Hydro must follow the existing CAISO processes to seek approval and TAC cost recovery for the TE/VS Interconnect project, noting that Nevada Hydro has not yet done so.

78. CAISO answers that simply because the November 17 Order found that the LEAPS project was an advanced transmission facility that does not automatically mean that LEAPS' costs should be rolled-in TAC rates. It states that while Congress did not mandate the treatment of any particular advanced transmission technology in any particular way, including rolled-in rate treatment, Congress did specify that both sections 1223 and 1241 must be applied in a manner that is consistent with the FPA, and inclusion of LEAPS' costs in CAISO's rolled-in TAC would be unduly preferential and discriminatory.[88]

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[88] Further, the CAISO argues that the Commission's policies under sections 205 and 206 of the FPA have recognized that including the costs of some transmission facilities in rolled-in transmission rates would not result in just and reasonable rates because those facilities do not form part of the integrated network from which transmission customers benefit, citing *Kentucky Utilities Co.*, 85 FERC ¶ 61,274, at 62,111-13 (1998) (finding that generation step-up transformers should be excluded from rolled-in transmission rates); *Nevada Power Co.*, 100 FERC ¶ 61,077, at P 13-14 (2002) (excluding the costs of radial generator leads from rolled-in transmission rates, even though they are transmission facilities).

79. Assuming *arguendo* that LEAPS would provide service analogous to gas storage, CAISO argues that the Commission requires gas pipelines to unbundle gas transportation services from gas storage services and stresses that costs associated with the pipeline's merchant storage capacity must be recovered by the pipeline solely as part of its market-based sales rate.[89] In contrast, Nevada Hydro wants to bundle recovery of the costs for LEAPS storage service with the rate for transmission service on CAISO grid. Further, the Commission has stated that a pipeline proposing a new project must be prepared to financially support the project without relying on subsidization from existing customers.[90] Thus, CAISO contends that in order for LEAPS to receive rolled-in rate treatment, Nevada Hydro must show that LEAPS would be financially viable without subsidies from existing customers. However, Nevada Hydro has not shown any contracts with a load-serving entity.

80. CAISO argues that Nevada Hydro's claims of cost savings undermines the foundation of its proposal – to the extent that Nevada Hydro is correct that LEAPS would provide a large economic benefit, the less Nevada Hydro would need to rely on TAC cost recovery rather than the market. CAISO responds that section 1223 does not condone or require undue discrimination and the fact that LEAPS is newer than other participating generators and participating loads is a weak basis for allowing guaranteed cost recovery for LEAPS only. CAISO also states that LEAPS would essentially combine the attributes of a participating load, when it consumes energy to pump water into storage, and the attributes of a participating generator, when it produces energy and ancillary services by using the stored water to run turbines. Thus, LEAPS should be considered a hybrid device, not a unique storage device that should be treated as transmission.[91] Further, all pumped storage facilities function as both loads and generators, as recognized by the

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[89] Citing *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation, and Regulation of Natural Gas Pipelines After Wellhead Decontrol*, Order No. 636, FERC Stats. & Regs., Regulations Preambles ¶ 30,939, n.140 (1992).

[90] Citing *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227, at 61,746 (1999), *order clarifying statement of policy*, 90 FERC ¶ 61,128, at 61,392 (2000).

[91] The CAISO points out that the CAISO OATT does not categorize either participating generators or participating loads as transmission or include their costs in TAC rates.

Commission,[92] and the fact that LEAPS would do both of those things in a single entity does not change the fact that it will be consuming and selling products in CAISO markets.

81. CAISO responds that since energy from LEAPS would be bid into CAISO markets at zero dollars, not at the marginal cost, energy from LEAPS would be the lowest priced energy available in the bidding process and would always be selected whenever it was offered, even when use of other resources might be more efficient. CAISO expresses concern that over time, zero-dollar bids would artificially depress market prices, discouraging entry by other suppliers who will not have similar TAC recovery for their costs, possibly leading to shortages or to other suppliers seeking similar cost recovery. Moreover, even if LEAPS' output is bid into the market at a price of zero, CAISO's independence would still be compromised, as it would still have to decide when LEAPS would operate, how much energy it would produce, and when it would operate the pumps to store water for future generation.

4. Commission Determination

82. The Commission concludes that it would not be appropriate to require CAISO to assume any level of operational control over the LEAPS facility. In reaching this conclusion, we examined an extensive record in this proceeding and the results of and whitepapers from CAISO's stakeholder process in which it sought comment from market participants on whether operational control of the LEAPS facility could be turned over to CAISO. Through this stakeholder process, CAISO explored six alternatives under which it could, directly or indirectly, operate the LEAPS facility. After reviewing these proposals and comments in support of and against CAISO's evaluation of these proposals, the Commission agrees with the majority of intervenors on this issue that it would be inappropriate for CAISO to assume control of the LEAPS facility. Despite the numerous opportunities for comment this Commission and CAISO have provided in this docket, Nevada Hydro has not persuaded us that in this instance it is reasonable (or necessary) to require CAISO to take operational control of the LEAPS facility. As such, we deny the request of Nevada Hydro to require the CAISO to assume operational control of the LEAPS facility.

83. As to the issue of cost recovery through the CAISO's TAC, we find that it would not be appropriate to allow the costs of the LEAPS facility to be rolled-in through

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[92] Citing *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,236, at P 187 n.160 (2004); *California Independent System Operator Corp.*, 105 FERC ¶ 61,140, at P 34 n.26 (2003).

CAISO's transmission rates. The purpose of the TAC is to recover the costs of transmission facilities under the control of the CAISO; the purpose is not to recover bundled services. As discussed above, we are denying the request that the LEAPS facility be placed under the CAISO's operational control. For these reasons, the LEAPS facility's costs are not properly recovered through the TAC. In addition, as CAISO points out, each of the existing pumped hydro facilities in CAISO's footprint provides generation services and none receives the benefits of rolled-in transmission pricing.[93] Although Nevada Hydro describes many of the benefits of pumped hydro in general, there is not sufficient record support to justify treating LEAPS differently from these other pumped hydro facilities.[94] Absent such information, we conclude that allowing LEAPS to receive a guaranteed revenue stream through CAISO's TAC would create an undue preference for LEAPS compared to these other similarly situated pumped hydro generators. Therefore, the Commission must reject Nevada Hydro's proposal to include the costs of the LEAPS facility in CAISO's rolled-in transmission charges.

84. Moreover, we are not persuaded that section 1223 of EPAct 2005 compels us to provide any rate-related incentives for LEAPS in this case. The Commission is mindful of the importance that "advanced transmission technologies" such as those listed in section 1223 of EPAct 2005 will have in securing affordable and reliable energy. Nevertheless, under that section, the Commission is required to "encourage, *as appropriate*," such technologies.[95] In Order No. 679, the Commission observed that we would consider on a case-by-case basis whether any "advanced transmission technologies" under section 1223 of EPAct 2005 should be considered for incentive-based rates.[96]

85. In the November 17 Order, the Commission recognized that pumped storage is an advanced transmission technology identified in section 1223 of EPAct 2005. However, for the reasons discussed above, we do not agree with Nevada Hydro or Voith that transferring control of LEAPS to CAISO or allowing Nevada Hydro to pursue cost

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[93] CAISO Compliance Filing at 20.

[94] As we note *supra* at n.16, Nevada Hydro asserts that LEAPS, once built, will be the largest and most powerful pumped hydro facility. These characteristics, on their own, fail to persuade us that the LEAPS facility should be treated differently than other pumped hydro facilities in CAISO's footprint.

[95] Pub. L. No. 109-58, § 1223(b) (emphasis added).

[96] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 288-93.

recovery for LEAPS through CAISO's TAC is an appropriate means of encouraging the deployment of such technologies. We note that this determination does not foreclose Nevada Hydro from seeking other regulatory incentives for the LEAPS project.

The Commission orders:

(A) We will grant certain of the requested incentives for the TE/VS Interconnect project, as discussed in the body of this order.

(B) We will deny the requested incentives for the LEAPS project, as discussed in the body of this order.

By the Commission. Commissioner Kelly dissenting in part with a separate statement attached.
Commissioner Wellinghoff concurring in part with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

The Nevada Hydro Company, Inc.	Docket Nos. ER06-278-000 ER06-278-001 ER06-278-002 ER06-278-003 ER06-278-004 ER06-278-005 ER06-278-006

(Issued March 24, 2008)

KELLY, Commissioner, *dissenting in part:*

This order addresses, among other things, the Nevada Hydro Company, Inc.'s (Nevada Hydro) requested rate incentives for the proposed Talega-Escondido/Valley-Serrano Interconnect project (TE/VS Interconnect). Nevada Hydro proposes to build the TE/VS Interconnect project, a 30 mile, 500 kV transmission line, as well as the Lake Elsinore Advanced Pump Storage project (LEAPS facility). In response to Nevada Hydro's request, the Commission grants certain incentives for the TE/VS Interconnect but finds that the LEAPS facility may not be operated and/or managed by the California Independent System Operator Corporation (CAISO) or functionalized as transmission for rate recovery purposes. I agree with these decisions. What I disagree with is the decision to provide incentives for the transmission line *even if* the LEAPS facility is not built.

Because the Commission concludes that it would be inappropriate to require CAISO to assume any level of operational control over the LEAPS facility, it is not apparent that Nevada Hydro will proceed with development of the LEAPS facility, and there is nothing in the record that provides guidance on this question. If Nevada Hydro were to construct the 30 mile, 500 kV transmission line but not construct the pumped storage project, I am concerned that the benefits flowing only from the transmission line would not be sufficient to justify the award of incentives to it.

It is the record developed in this case that leads to my concerns. As part of its response to Commission requests for additional information,[1] Nevada Hydro filed a technical analysis that included an examination of a "transmission line only" alternative, which estimates the effects of building the TE/VS Interconnect but not the LEAPS facility. Based on the results of the "transmission line only" alternative, Nevada Hydro's submitted analysis concludes that "the transmission line would be under utilized by simply constructing a transmission line between the two proposed points of connection."[2] The report also concludes that, based on a 2009 heavy summer set of assumptions, 13 MW would flow in the north-to-south direction without the LEAPS facility. I cannot, at this time, support incentive rate treatment for a transmission line (with an estimated cost of at least $350 million) that, in the absence of the LEAPS facility, will be under utilized and does not appear to provide proportionate benefits to those paying the incentive rates, at least initially. I dissent in part from this order because I would prefer to see the Commission defer ruling on incentives for the TE/VS Interconnect until the future of the LEAPS is clearer. The TE/VS Interconnect will provide greater benefit in conjunction with the LEAPS facility than if built on its own and a Commission ruling on incentives in the absence of a clear future for the LEAPS facility strikes me as premature.

For these reasons, I respectfully dissent from this order.

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Suedeen G. Kelly

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[1] See Exhibit No. TNHC-2 to Nevada Hydro's Response of The Nevada Hydro Company, Inc. to Commission's Letter dated February 17, 2006, filed March 20, 2006 in Docket Nos. ER06-278-000 and ER06-278-002.

[2] Exhibit No. TNHC-2 at p 7.a

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

The Nevada Hydro Company, Inc.	Docket Nos. ER06-278-000 ER06-278-001 ER06-278-002 ER06-278-003 ER06-278-004 ER06-278-005 ER06-278-006

(Issued March 24, 2008)

WELLINGHOFF, Commissioner, concurring in part:

In today's order, the majority finds that an incentive ROE adder is appropriate for Nevada Hydro's proposed TE/VS Interconnect, a 500 kV transmission line that would connect the transmission systems of SoCal Edison and SDG&E. Specifically, the majority grants Nevada Hydro an ROE incentive for the TE/VS Interconnect to be set within the upper end of the zone of reasonableness. The majority also finds that Nevada Hydro's ROE, including any incentive ROE adder, is not to exceed the requested 13.5 percent. The majority states, however, that the DCF analysis submitted by Nevada Hydro is neither complete nor consistent with Commission policy and, as such, precludes setting a precise level of return. The majority also provides direction on how Nevada Hydro can correct those shortcomings when it submits its FPA section 205 filing to establish its rates, including its proposed ROE.

I agree that some incentive ROE adder is likely to be appropriate for the TE/VS Interconnect and that the Commission cannot yet establish a precise ROE for the project. I write separately to explain considerations that led me to that conclusion and to highlight additional information that I encourage Nevada Hydro to include in its section 205 filing as support for its proposed ROE.

As I have stated before, in considering an incentive ROE adder for transmission, the Commission should focus on encouraging investment decisions beyond upgrades simply required to meet a utility's service obligations or the minimum standard of good utility practice. An incentive ROE adder should be more narrowly targeted to transmission investments that provide incremental benefits, such as those that result from the deployment of "best available

technologies" that increase operational and energy efficiency, enhance grid operations, and result in greater grid flexibility.[1] Such investments recognize that efficient transmission facilities and state-of-the-art transmission technologies are essential to solving our energy delivery problems.

In addition, promoting such investments is consistent with section 1223 of EPAct 2005, in which the Congress directed the Commission to "encourage, as appropriate, the deployment of advanced transmission technologies."[2] For the reasons discussed in today's order, I agree with the majority that Nevada Hydro has not demonstrated that transferring control of the proposed Lake Elsinore Advanced Pump Storage (LEAPS) project to CAISO or allowing Nevada Hydro to pursue cost recovery for the LEAPS project through CAISO's Transmission Access Charge is an appropriate means of encouraging the deployment of advanced transmission technologies. Nonetheless, because the Congress and the Commission have recognized pumped hydro as an advanced transmission technology, it is important to recognize that increasing the availability of pumped hydro is one purpose of the TE/VS Interconnect. I believe that this potential incremental benefit warrants recognition with some incentive ROE adder.

The TE/VS Interconnect may well warrant some incentive ROE adder in the event that the LEAPS project is not constructed, though I believe that the argument for the incentive would be less compelling in those circumstances. Among other considerations, it is noteworthy that the TE/VS Interconnect, as described in today's order, will provide a critical link between two major transmission corridors, linking the San Diego basin to the main CAISO grid. Another important consideration, however, is missing from the record because Nevada Hydro has not submitted the technology statement required by Order No. 679.[3] That failure may be attributable to the unusual procedural history of this case, in which Nevada Hydro's original filing predated the Commission's issuance of Order No. 679. Subsequently, the Commission stated its intention to apply

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[1] *See, e.g.*, *Southern California Edison Co*., 121 FERC ¶ 61,168 (2007), Wellinghoff concurrence at 1.

[2] *See* Pub. L. No. 109-58, § 1223, 119 Stat. 594, 953-54 (2005).

[3] Order No. 679 at P 302 ("In as much as EPAct 2005 requires the Commission to encourage the deployment of transmission technologies, we will require applicants for incentive rate-treatment to provide a technology statement that describes what advanced technologies have been considered and, if those technologies are not to be employed or have not been employed, an explanation of why they were not deployed.").

Order No. 679 in this case,[4] and Nevada Hydro did not request rehearing on that issue.

I have frequently highlighted the importance of the technology statement requirement in Order No. 679, and I have stated the use of advanced technologies and their corresponding efficiency and reliability benefits deserve significant consideration in the Commission's evaluation of requests for incentive ROE adders.[5] Consistent with those statements and recognizing the unusual procedural history of this case, I strongly encourage Nevada Hydro to submit a technology statement for the TE/VS Interconnect as part of its FPA section 205 filing to establish its rates, including its proposed ROE.

For these reasons, I concur in part with today's order.

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Jon Wellinghoff
Commissioner

[4] *The Nevada Hydro Company, Inc*., 117 FERC ¶ 61,204 at P 32 (2006).

[5] *See, e.g.*, *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 (2007), Wellinghoff dissent in part at 2-3.

Appendix A: Previous Report and USFWS Comment Letter

Appendix A
List of Documents

A-1 Response to USFWS Comment Letter Regarding Formal Section 7 Consultation for the Lake Elsinore Advanced Pump Storage and Talega-Escondido/Valley-Serrano 500-kV Interconnect Projects, FERC No. 11858, dated January 14, 2008.

A-2 Formal Section 7 Consultation for the Lake Elsinore Advanced Pumped Storage Project (P-11858), Riverside County, California; FERC/OSEC Receipt date July 3, 2007.

January 14, 2008

Michael Brandman Associates

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

Subject: **Revised Response to USFWS Comment Letter Regarding Formal Section 7 Consultation for the Lake Elsinore Advanced Pump Storage and Talega-Escondido/Valley-Serrano 500-kV Interconnect Projects, FERC No. 11858**

Dear Ms. Bose:

This letter serves as a response to comments given in the United States Fish and Wildlife (USFWS) letter dated June 26, 2007 to the Federal Energy Regulatory Commission (FERC) regarding additional information necessary to complete Formal Section 7 Consultation. This letter report contains project specific impact information requested by the USFWS in order to complete the Formal Section 7 Consultation for the Lake Elsinore Advanced Pump Storage and Talega-Escondido/Valley-Serrano 500-kV Interconnect Projects (LEAPS and TE/VS). This revised letter also addresses the December 2007 designation of final critical habitat for the coastal California gnatcatcher and any changes in impacts related to that report.

For the purpose of this response, MBA and The Nevada Hydro Company (Nevada Hydro) analyzed project impacts as described in the Final Environmental Impact Statement (FEIS), which includes one reservoir location (Decker Canyon), one powerhouse facility (Santa Rosa Facility), two transmission line alternatives (FERC Staff's alternative and Co-Applicant's alternative), a loop-line transmission alignment, two substations (a northern and a southern substation), 316 total transmission line towers, and associated access roads.

As part of the Pre-Certification Process, FERC has requested that Elsinore Valley Municipal Water District and Nevada Hydro coordinate with the USFWS office in order to assist in preparation of the Biological Opinion. MBA has prepared this letter report on behalf of Nevada Hydro as part of the consultation process requested by FERC. MBA has addressed all USFWS comments contained in the June 26, 2007 comment letter. Individual comments are quoted with their corresponding response in the Response to USFWS Comments of June 26, 2007 section below.

MBA, under direction of Nevada Hydro, completed a habitat assessment and focused surveys for quino checkerspot butterfly (*Euphydryas editha quino*), arroyo toad (*Bufo californicus*), and coastal California gnatcatcher (*Polioptila californica*), within all suitable habitat areas within the originally proposed facilities and transmission line alignments. Focused surveys for quino checkerspot butterfly, arroyo toad, and coastal California gnatcatcher were conducted from 2001 to 2006 with negative results (Michael Brandman Associates, 2004 [MBA 2004], Terrestrial Biological Resources Study Lake Elsinore Advanced Pump Storage/Talega-Escondido/Valley-Serrano Interconnect Project).

MBA recently completed an updated analysis of the potential impacts associated with the LEAPS and TE/VS projects on quino checkerspot butterfly, arroyo toad, coastal California gnatcatcher, and Stephens' kangaroo rat as requested by FERC. A habitat assessment based on the FEIS including the

FERC Staff's alternative transmission alignment, the Co-applicant's modified transmission alignments as well as associated access roads was conducted for the four listed species mentioned above. Based on these new transmission line alignments, no new suitable habitat areas were identified for the above-mentioned sensitive species.

Methods

The impact assessment began with a thorough review of existing biological documentation including, but not limited to general biological resource studies, focused surveys for sensitive plant and wildlife species, Jurisdictional Delineation of the Reservoir Sites, the Draft EIS, and the FEIS.

The FERC Staff's alternative, as described in the Draft EIS was used for the initial impact analysis, which includes a single reservoir within Decker Canyon, a northern and southern transmission line alignment, a loop-line transmission line alignment, a single powerhouse location, two substations, associated access roads and several construction staging areas. These project elements were overlaid on a United States Geological Survey (USGS) 7.5-minute topographic quadrangle map and recent aerial photograph in order to begin project assessment. Following the submittal of the FEIS, the new Co-applicant's modified transmission alignment was also overlaid and these new areas were updated prior to completing this response letter.

Nevada Hydro provided MBA with an estimated tower footprint area and an average length between towers as well as several construction staging areas in order to estimate all project related impacts. MBA used this information within the confines of general route localities analyzed in years of field studies and refined more specific tower locations based on vegetation community, close association to existing access roads, and location of existing drainage features (MBA 2004).

Once the estimated tower locations were selected, a more refined assessment of tower location habitat was conducted. The proposed tower locations were overlaid on a 3-dimensional topographic map using an elevational modeling software program. The software provides the ability to place proposed tower locations along ridgelines and gentle slopes, while avoiding steep slopes and canyon bottoms. The 3-dimensionality of the program also allows for accurate placement of towers so that topography would not interfere with transmission lines height requirements or locations.

The vegetation associated with each tower was determined based on the existing plant community data collected by MBA over 6 years of study (MBA 2004). After the tower locations were identified, tower access roads were designed to minimize project impacts to sensitive habitat areas. Existing access roads were not included in the assessment unless it was determined that road widening or other improvements were needed that would create additional impacts to roadside areas. Access roads were placed in areas for ease of access to each site as well as to minimize impacts to potentially sensitive plant and wildlife habitat.

All project-related layers were entered into a Geographical Information System (GIS) database for analysis. Information used during the analysis included the following layers, but was not limited to: topographic maps, recent aerial photographs, soils, critical habitat, California Natural Diversity Data Base (CNDDB), Multiple Species Habitat Conservation Plan (MSHCP) Layers, blue-line drainage crossings, and Stephens' kangaroo rat fee and core reserve areas.

Discussion

As shown in Table 1 and Table 2 in Appendix A, project impacts will result in the removal of seven plant communities and two geographic features including open water and disturbed areas (Appendix B, Plant Community Maps). The vegetation trimming impacts associated with the vegetation management areas will occur within the temporary workspace surrounding the permanent tower impact area and is included in the impact calculations in Table 1 and 2.

The removal of common plant communities such as non-native grasslands, chaparral, ornamental woodlands, disturbed areas, open water, and agricultural areas do not require mitigation measures under National Environmental Policy Act (NEPA) Guidelines. Removal of coastal sage scrub, southern willow scrub, and oak woodland habitat may considered adverse with respect to potential impacts to quino checkerspot butterfly, arroyo toad, coastal California gnatcatcher, and Stephens' kangaroo rat, as these habitats have the potential to support these species.

Based on the FEIS, impacts to coastal sage scrub will be replaced at a 1:1 ratio. Final plant community impacts will be calculated once a final plan has been designed. Although impact amounts are anticipated to be less than indicated in the FEIS, the mitigation ratio will remain the same. A Restoration Mitigation Plan will be prepared to restore suitable habitat areas temporarily impacted by project installation for the federally listed threatened and endangered species mentioned above.

Road impacts have been divided into three separate categories; Existing Roads, Improved Roads, and New Roads. Total impacts associated with access road construction are shown in Table 4 in Appendix A. Where possible, access roads were contained within the 600-foot wide buffer area surrounding the transmission route centerline. The buffer area has been thoroughly surveyed for several years to determine presence/absence of sensitive wildlife species. Access roads that are located outside of the buffer area were not surveyed at the same amount of effort as the transmission line right-of-way, but have recently been evaluated for suitable habitat concerning federal and/or state listed species. These roads are separated based on whether they occur within the existing transmission line right-of-way or outside the right-of-way within Table 4.

The FERC Staff's transmission alignment alternative and Co-applicants' modified transmission line alignment occur within designated critical habitat for quino checkerspot butterfly and California gnatcatcher as well as San Bernardino Kangaroo Rate Fee Area and San Bernardino kangaroo rat core reserve areas included in Table 3 of Appendix A.

The following information is based on the project facilities presented in the FEIS. All areas have been surveyed and assessed and are included in the impact calculations provided in this letter report.

Quino Checkerspot Butterfly

MBA began conducting focused surveys for quino checkerspot butterfly in 2001 based on the approved USFWS protocol. All surveys were conducted east of Interstate (I) 15 within 157.9 acres of marginally suitable habitat based on the previous transmission line alternatives (MBA 2004), but includes both the FERC Staff Alternative and the Co-applicant modified transmission line alignment. Brenda McMillan, a former USFWS representative, recommended focused quino checkerspot butterfly surveys at the time of the original habitat assessment in 2001. The marginal quality habitat is dominated by non-native grasslands with elements of coastal sage scrub. The coastal sage scrub

does not contain a sufficient amount of cover to be considered a separate plant community. The survey area for quino checkerspot butterfly also contains hilltop areas, rocky outcrops, scattered patches of plantago, and cryptogrammic crusts.

Survey areas for this species are shown in Appendix C, Exhibit 1. Surveys for quino checkerspot butterfly were continued for six consecutive years, ending in 2006. No quino checkerspot butterfly were observed or otherwise detected within any of the marginally suitable habitat areas. Common butterfly species observed during the surveys were considered typical for the region suggesting that conditions of the surveys were acceptable for quino observations. The closest recorded occurrence of QBC is approximately 5 miles east of the project site.

There is approximately 8.0 acres of the project facilities located within designated critical habitat for quino checkerspot butterfly (Appendix C, Exhibit 2). This area is located in the northern portion of the transmission line route north of I-15 and includes fourteen transmission line towers and several proposed access roads.

After six years of surveys, MBA has determined that even though there are several elements commonly associated with quino checkerspot butterfly habitat, the portion of the transmission line and the loop-line north of I-15 is considered unoccupied by this species. It is unlikely that this species will occur within the project site or immediate vicinity in the near future.

Arroyo Toad

MBA began conducting focused surveys for arroyo toad in 2001 within marginally suitable riparian habitat. Following the 2001 survey, the areas where re-evaluated and determined to be unsuitable for this species. Subsequently, surveys were not conducted in 2002 or 2003. During MBA's resource agency consultation in 2003, a known occurrence of arroyo toad was recorded by the United States Geological Service within the vicinity of established LEAPS/TV/VS study area near Los Alamos Creek. Surveys for arroyo toad were again conducted in 2004 and continued in both 2005 and 2006.

Marginally suitable habitat for arroyo toad is found at the base of Corona Lakes (formerly Lee Lake) and at the Los Alamos Creek crossing of the transmission line within the Cleveland National Forest (Appendix C, Exhibit 1). The drainage feature that flows from the Corona Lakes Dam is approximately 20 to 30 feet wide and ranges from one to six feet in depth. The drainage contains swift moving water for the majority of the year. The drainage feature does not contain the sand bars and alluvial deposits often associated with this species. There are several ephemeral drainage features west of the main drainage feature, but these features do not provide suitable habitat for arroyo toad.

Los Alamos Creek is an intermittent drainage feature that is approximately four feet wide and less than one foot deep along the portion of the drainage feature potentially affected by transmission line crossing. More suitable habitat is located downstream of this location. Although there are some elements commonly associated with suitable arroyo toad habitat, these areas are not considered moderate to high quality habitat for this species.

Arroyo toad surveys were conducted in four of the last six years, with the last three years being consecutive. No arroyo toads were observed or otherwise detected within the marginally suitable habitat areas that were surveyed.

After four years of surveys, MBA has determined that even though there are several elements commonly associated with arroyo toad habitat, the portion of Los Alamos Creek and Temescal Wash near Corona Lakes, that the transmission line crosses is considered unoccupied for this species. Although direct impacts are not likely to occur during project construction, indirect impacts may occur at occupied habitats located downstream from the project site. The use of erosion control measures and best management practices (BMPs) will eliminate any indirect impacts. BMPs will be specifically described in a Sensitive Species Management Plan. For a more detailed description of the plan please refer to Response to Comment 5 below.

Coastal California Gnatcatcher

MBA began conducting focused surveys for California gnatcatchers in 2001. Suitable habitat is found from the foothills of the Cleveland National Forest to the area near I-15. Survey areas for these species are shown in Appendix C, Exhibit 1. The largest survey area was located at the proposed powerhouse location. Approximately 48.3 acres of coastal sage scrub habitat occurs at this location. California gnatcatcher surveys were conducted within the proposed Powerhouse Facility and selected portions of the transmission line alignment as well as surrounding habitat. Surveys for California gnatcatcher were continued for 6 consecutive years and were completed in 2006. No California gnatcatcher were observed or otherwise detected within any of the suitable habitat areas including all transmission line alignments, project facilities, access roads, and/or additional work space areas.

Total impacts to California sage scrub (CSS) associated with tower impacts is approximately 4.3 acres including both permanent and temporary impacts, which is less than 5 percent of the total amount of impacts to CSS (88 acres). The remaining 83.7 acres includes the powerhouse, northern substation, construction staging areas, and access roads, all of which is outside the designated critical habitat for this species.

Approximately six tower locations are within final designated critical habitat for California gnatcatchers (December 2007). A total of 2.6 acres will be impacted by project related activities, both temporary and permanent within final designated critical habitat for California gnatcatchers (Appendix C, Exhibit 2). The critical habitat areas within the project site are located within the northern portion of the transmission line route and include six tower locations and two access roads. This area includes both the FERC Staff Alternative and the Co-applicant modified transmission line alignment as well as the proposed loop line.

The habitat within the portions of the project site within the designated critical habitat is dominated by non-native grasslands. Suitable California gnatcatcher habitat is located in distinct patches within the vicinity of the project site, but is not directly within the proposed alignment.

After six years of surveys, MBA has determined that even though there are elements associated with suitable habitat for coastal California gnatcatcher habitat, the transmission line alignment, substation, and powerhouse facility are considered unoccupied for this species and coastal California gnatcatchers are not likely to occur within the project site.

Stephens' Kangaroo Rat

Project-specific focused surveys were not conducted for Stephens' kangaroo rat because the site-specific tower locations, access roads, and staging areas were not designed until 2007. For assessment purposes, the following information was obtained in order to determine the significance of project-related impact to Stephens' kangaroo rat.

The project site contains approximately 50.2 acres of temporary and permanent impacts within the Stephens' kangaroo rat fee area only. This area includes both the FERC Staff's Alternative and the Co-applicant modified transmission line alignment. An additional 8.0 acres, (7.6 acres of temporary and 0.4 acres of permanent impact) occur within the Stephens' Kangaroo Rat Core Reserve Area, including 14 transmission line towers and several proposed access roads (Appendix C, Exhibit 1). These acreages represent the worse-case scenario and project related impacts will likely be less than the above mentioned areas, but will not be any more than what is stated above.

Results

Based on the presence/absence surveys conducted within the project site from 2001 to 2006, MBA has determined that it is unlikely that quino checkerspot butterfly, arroyo toad, and coastal California gnatcatcher occur within any of the proposed impact areas within the project site. Although we cannot completely rule out the possibility that these species may occupy the habitat onsite in the future, the likelihood of these species establishing significant populations in the near future is unlikely. It is highly likely that Stephens' kangaroo rat occupies at least some portion of the survey area north of I-15 due to the close recorded occurrence adjacent to the site and the presence of suitable habitat.

The information presented above and verified with six years of surveys, coupled with comprehensive reviews of the vegetation communities and potentials for these communities to support sensitive species under consideration, provides the foundation for response to USFWS requests listed below.

Response to USFWS Comments of June 26, 2007

MBA and Nevada Hydro have prepared the following responses to the specific USFWS requests as stated in the June 26, 2007 letter. These responses are intended to clarify circumstances regarding impacts to the four federally listed species currently under consideration for Biological Opinion.

> **Comment 1.** "The analysis in the FEIS does not include the potential effects of temporary and permanent roads associated with the construction and operation of the project. Please identify the proposed location of the roads, the acreage of habitat affected, any survey results, and an analysis of effects associated with road building, use and maintenance on federally-listed species."
>
> > **Response to Comment 1**. Included as Appendix A, the Project Impact Tables include all project related impacts as assessed under the FEIS transmission line alignments, project facilities, staging areas, vegetation management areas, and access roads with regard to plant community and suitable habitat for federally listed species. Appendix B includes maps indicating the specific location of the transmission line alignments, loop-line, proposed access roads, tower locations, substations, reservoir

location, powerhouse, and staging areas and the plant communities associated with them (Exhibits 1 to 12b). Appendix C includes maps of the project site illustrating focused survey areas (Exhibit 1) and designated critical habitat areas (Exhibit 2).

An increase in recreational use caused by the installation of additional access roads is not anticipated. Representatives for USFS have specifically stated that all new or improved access roads will be blocked prohibiting recreational activity. Nevada Hydro has agreed to incorporate the USFS policy to all access roads constructed outside of the Forest boundary.

Comment 2. "The FEIS indicates that intensive vegetation management will occur surrounding the proposed structures and transmission lines, but the potential effects of the vegetation management activities do not appear to be fully described. Please identify the acreage of habitat affected, any survey results, and an analysis regarding vegetation management and effects to federally-listed species."

Response to Comment 2. It is likely that some vegetation trimming may be required at each transmission line tower; these areas are referred to as vegetation management areas. A vegetation and road management plan will be required prior to initiation of construction activities. The plan will cover issues such as erosion control, migratory bird treaty act issues, restoration activities, and biological monitors. The plan will be designed as a working document for construction foreman to assist construction crews in avoiding significant biological resources during construction activities. An initial educational program and periodic updates on sensitive species issues will be required for construction workers prior to working on the project. Information necessary for minimizing impacts includes the identification of suitable habitat, species activity periods, species identification, and construction equipment requirements, such as vehicle speed and noise levels.

The vegetation trimming associated with the vegetation management areas will occur within the temporary workspace surrounding the permanent tower impact area and is included in the impact calculations in Table 1. Currently, there are no plans to go beyond the limits of temporary work space. In the event that additional vegetation trimming is required outside of the temporary workspace area, resource agencies will be contacted to discuss the appropriate action prior to implementation if suitable habitat for listed species will be impacted.

Comment 3. "Please specify what noxious weed control measures will be implemented in areas with threatened or endangered species habitats."

Response to Comment 3. Nevada Hydro proposes to design and implement an integrated pest management plan to prevent the introduction of weeds during construction and to control any populations of weeds that are identified near construction sites during project implementation. USFS revised preliminary 4(e) condition no. 33 is very similar, specifying that the Nevada Hydro should consult with the USFS to develop and implement a plan to monitor and control noxious weeds and non-native invasive species, but the USFS specifies this plan should be continued

through any license period. Nevada Hydro has agreed to fulfill these requests not only on USFS lands, but on all project facilities and transmission line alignments.

USFS also indicates that the vegetation and invasive weed management plan should be consistent with guidance provided in the Cleveland National Forest Land Management Plan, including consulting with USFS to design and conduct an invasive non-native plant and noxious weed risk assessment, using weed lists that are current at the time of survey. Implementation of USFS revised preliminary 4(e) condition no. 29, which provides for annual employee awareness training, would apply to noxious weeds and invasive nonnative plants, as well as to special status plants, as described above.

Although the co-applicants may not propose to construct any new project features during the license period, routine project maintenance could cause ground disturbance at project facilities, and project-related traffic could pose a risk of introducing and spreading weeds. Public use of any access roads would have an especially high potential for adverse effects because it would likely be difficult to control. Implementation of a noxious weed management plan throughout the term of any new license for both USFS and non-USFS lands within the project boundary would reduce these risks and help to protect native plant communities and wildlife habitat values. This approach would minimize planning costs and would provide coverage for weeds and invasive exotic plants throughout the project area, as a whole.

Comment 4. "Please provide a focused discussion regarding the potential effects of the proposed project on habitat conditions and the distribution of federally-listed species for the whole project area. In addition to the lack of complete habitat assessment/survey information for roads and vegetation management activities described above, the FEIS indicates on page 3-137 that "Surveys were not conducted in areas where the co-applicants' proposed alignment or staff alternative transmission alignment differ from the original alternatives, or at the southern substation that is currently included in both the co-applicants proposal and the staff." In order to address the missing information documented above for roads, vegetation management, and the proposed facilities, we recommend the completion of habitat assessments and appropriate presence/absence surveys for areas where these studies have not been done."

Response to Comment 4. Portions of the Co-applicants' modified transmission line alignment were re-designed for the FEIS. A habitat assessment was conducted on the Final Staff's Alternative and Co-applicants' modified transmission line alignment as well as the additional work-space areas, access roads, powerhouse facility, loop-line transmission line, and substation facilities with respect to the presence/absence of suitable habitat to support federally or state listed threatened or endangered species. Based on the transmission line locations in the FEIS, the impacted habitat is similar with respect to vegetation communities to the previous route described in the MBA 2004 report (Terrestrial Biological Resources Study). Although these portions of the transmission line routes are in different locations, the habitat type and quality are similar making the conclusions to the impact analysis also similar with respect to the presence/absence of suitable habitat for the four listed species

mentioned above. The re-designed portions of the transmission line alternative contains no additional suitable habitat for the four listed wildlife species.

The majority of the additional access roads required for transmission line tower access are contained within the original 500 foot buffer survey area and focused surveys were conducted where appropriate as part of the FEIS with negative findings. There are two proposed roads in the northern portion of the transmission line alignment that are outside of the original survey area. These roads have been designed to avoid all potentially suitable quino checkerspot butterfly habitat in the area. The roads are located in dense non-native grassland areas that avoid all plantago patch locations in the local vicinity. These areas are not within suitable habitat for quino checkerspot butterfly and surveys are not required. The remaining access roads are located in disturbed areas or dense northern mixed chaparral, which is not considered suitable habitat for any of the above mentioned sensitive species.

Comment 5. "The May 23, 2007, letter provides additional information regarding the potential for release of Lake Elsinore water into the San Juan watershed. Your letter indicates that water from Lake Elsinore would primarily be released into the San Juan watershed during flood events. Please estimate how often these releases could potentially occur, the magnitude of the potential releases, and the nature of the effects to the water quality. Also, the FEIS indicates that remediation measures will be implemented upon the release of non-native species into San Juan Creek. Please specify what measures would be implemented. Finally, the proposed project indicates that transmission towers would be located outside of riparian areas to avoid adverse effects to riparian vegetation and stream habitat. Please specify how far transmission towers will be located from drainages where arroyo toads occur and what erosion control measures will be implemented."

Response to Comment 5. There has been a great deal of concern regarding potential impacts to downstream populations of arroyo toad as a result of over-topping of the reservoir during extreme rain events. The following are examples of minimization measures that will be included in the Sensitive Species Management Plan. Reservoir levels will be monitored constantly during the rain season to make sure the reservoir does not over-top. In the event that the reservoir fills to a point where over-topping can occur, the valves will be opened lowering the reservoir level by allowing the water used for power generation to flow into Lake Elsinore.

A filtering system will be installed into the pipe system, which will prevent larger non-native invasive wildlife species from entering the upper reservoir from Lake Elsinore, thus reducing the potential for invasive species from entering the freshwater drainage system. There is no way of completely eliminating the possibility of invasive species entering the upper reservoir. A biological monitor will conduct annual surveys downstream of the reservoir for approximately 1,000 linear feet to monitor for any non-native invasive plant and wildlife species, which may adversely affect the downstream populations of arroyo toad or other sensitive species. If observed, all invasive species will be removed immediately and surveys will be conducted monthly

for six months following the removal and return to annual surveys at the discretion of the monitor.

Based on the results of MBA's focused surveys, arroyo toad does not occur within any of the drainage features crossed by transmission lines. The proposed tower locations located near Los Alamos Creek and Temescal Creek are greater than 500 feet from either side of the drainage feature. This project design completely avoids the drainage feature and provides protection for occupied arroyo toad habitat further downstream. BMPs associated with erosion control and water quality will be in place throughout the project area. These BMPs will be designed to protect all project area drainages from erosion and sedimentation.

Comment 6. "Specify whether or not the proposed transmission lines impact the Habitat Conservation Plan for the Stephens' Kangaroo Rat Core Reserve lands and identify the extent of the effects within these area. We also requested specific information regarding any proposed off-setting measures."

Response to Comment 6. Since the project site is located within the established Stephens' kangaroo rat fee area as determined in the 1995 Habitat Conservation Plan (HCP), mitigation measures include payment of the standardized Stephens' kangaroo rat fee for all areas that occur within the Stephens' kangaroo rat fee area. The applicant will comply with all parameters of the HCP. Due to the nature of the project, the fee area will only include the project footprint and not the entire survey area. The total project area of disturbance that occurs within the fee area is 50.15 acres. In addition, 8.0 acres of both temporary and permanent impacts are located within the Stephens' kangaroo rat core reserve area. This area includes 0.4 acres of permanent impacts associated with fourteen of the transmission line towers.

Focused surveys for Stephens' kangaroo rat, although not required, are necessary to determined presence/absence of this species within impact areas once the final tower locations have been designed. If occupied habitat is present at a facility location, options to avoid or minimize impacts will be explored. This could include: relocation of the project facility to another unoccupied location, reduction of the construction footprint, tower design changes, and/or elimination of access roads.

The following mitigation measure will be implemented for compensation with regard to direct and indirect impacts associated with Applicant-initiated ground-disturbing activities undertaken within the Stephens' kangaroo rat (SKR) Core Reserve Area, the Applicant shall acquire, lease, or otherwise obtain possessory interests in compensatory real property containing suitable SKR habitat and subject to the following criteria: (1) compensating real property, off-setting physically disturbed acreage in the Core Reserve Area, shall be on a 1:1 basis, based on the actual area of disturbance; (2) to the extent feasible, the off-setting property or properties shall be located within or directly adjacent to the boundaries of the Lake Mathews-Estelle Mountain Core Reserve Area; (3) the off-setting property or properties shall be occupied by SKR or shall contain suitable habitat for that species; (4) the property shall be maintained for conservation purposes by the existing landowner, the

Applicant, and/or by a wildlife conservation agency; (5) with regards to the selected property or properties, the Applicant shall obtain the concurrence of the United States Fish and Wildlife Service (Service), which shall not be unreasonably withheld. Implementation shall occur within twelve months of commencement of project-related ground-disturbing activities.

As defined by the Riverside County Habitat Conservation Agency, "suitable habitat" shall constitute "lands which are occupied by SKR, as well as lands that are not occupied by SKR but which would benefit SKR if included in a reserve operated and maintained to preserve SKR and its habitat, including, but not limited to potential SKR habitat, wildlife corridors, areas connecting patches of occupied SKR habitat, and areas buffering SKR occupied habitat from adjacent land uses."

In the event that properties cannot be reasonably obtained within or contiguous to the boundaries of the Lake Mathews-Estelle Mountain Core Reserve Area or in the event that the cost to acquire and maintain suitable off-setting properties within that area exceeds the cost of acquiring and maintaining such lands in an established mitigation bank located in southwestern Riverside County, the Applicant shall be authorized to fulfill these obligations through participation in the mitigation bank associated with the Southwest Riverside County Multi-Species Reserve. Purchase of compensating mitigation bank credits at a 1.5:1 ratio shall constitute full compliance with the criteria identified herein.

Applicant's obligations hereunder shall run concurrent with but not extend beyond the terms of any permits, licenses, and/or other approvals issued to the Applicant defining the duration of the Applicant's entitlements and shall terminate on the revocation of such permits, licenses, and/or approvals and/or upon the cessation of facility operations, the removal of related improvements within the Core Reserve Area, and the revegetation of the areas of disturbance with suitable native plant materials.

Comment 7. "Upon development of the above information, we recommend discussions with our agency regarding the inclusion of specific conservation measures to minimize effects to listed species for incorporation into the proposed action. The May 23, 2007, letter indicates that the proposed action is to recommend the development of plans to minimize effects to listed species to the applicant, but does not commit to implementing specific measures. We recommend committing to implementing specific conservation measures as part of the proposed action and including these specific measures in the proposed action. If conservation measures are included, please provide detailed information regarding the proposed measures, especially with regards to the acquisition and dedication of replacement habitat as part of the proposed action."

Response to Comment 7. MBA and Nevada Hydro have ongoing informal consultation with USFWS to assist in providing additional information necessary to complete a Biological Opinion for the Lake Elsinore Advanced Pump Storage and Talega-Escondido/Valley-Serrano 500-kV Interconnect Projects. Nevada Hydro has agreed to commit to all recommended measures in the FEIS as part of the proposed

action and includes these specific measures in an Impact Assessment Letter Report prepared for USFWS in July 2007. Please refer to the EIS report for detailed information regarding the proposed measures. Furthermore, Nevada Hydro agrees to all of the USFS conditions as stated in the Revised Forest Service Preliminary Section 4(e) Conditions, submitted in 2006 and where appropriate will implement these conditions throughout the project area for all project components. In addition, all BMP's in the Cleveland National Forest Land Management Plan will also be reviewed and implemented where appropriate. All mitigation measures required for this project will be implemented prior to or during ground disturbance activities.

Thank you for reviewing these responses to the USFWS comments. If you have further questions, please feel free to call me at 714.508.4100.

Sincerely,

Scott Crawford, M.A.
Section Manager of Natural Resources
Michael Brandman Associates
220 Commerce, Suite 200
Irvine, CA 92602

Enclosures: Appendix A: Project Impact Tables
Appendix B: Project Community Maps
Appendix C: Sensitive Species Maps

cc: Peter Lewandowski, The Nevada Hydro Co.
James Fargo, FERC

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Appendix A: Project Impact Tables

Table 1: Permanent and Temporary Impacts to Natural Communities
Co-Applicant's Modified Transmission Alignment (June 12, 2006)

Natural Community	Main Transmission Line Temporary Tower Impacts	Main Transmission Line Permanent Tower Impacts	Loop-Line Temporary Tower Impacts	Loop-Line Permanent Tower Impacts	Reservoir Impacts	Powerhouse Impacts	Northern Substation Impacts	Southern Substation Impacts	Construction Staging Areas	Access Road Impacts	Total Temporary Impacts	Total Permanent Impacts	Total Impacts	Total Survey Area
Non-Native Grassland	2.7	0.5	1.9	.4	0	0.8	13.2	30.3	27.9	10.6	32.5	55.5	88.0	294.0
Coastal Sage Scrub	0	0	0	0	0	48.3	3.6	0	4.4	0	4.4	51.9	56.3	75.2
Northern Mixed Chaparral	31.1	5.7	0	0	96.7	0	0	0	47.0	81.0	78.1	183.4	261.5	1,977.1
Coast Live Oak Woodland -	0	0	0	0	4.7	0	0	1.9	0.9	0.3	0.9	6.9	7.8	114.9
Southern Willow Scrub	0	0	0	0	0	0	0	0	0	0	0	0	0	2.0
Open Water	0	0	0	0	0	0	0	0	3.8	0	3.8	0	3.8	7.3
Agriculture	0	0	0	0	0	0	0	0	0	0	0	0	0	0.7
Ornamental Woodland	0	0	0	0	0	0	0	0	5.2	0	5.2	0	5.2	7.6
Disturbed	1.6	0.3	0	0	0.9	3.7	22.0	0.1	12.6	3.5	14.2	30.5	44.7	165.1
Total	**35.4**	**6.5**	**1.9**	**0.4**	**102.3**	**52.8**	**38.8**	**32.3**	**101.8**	**95.4**	**139.1**	**328.2**	**467.3**	**2,643.9**

Table 2: Permanent and Temporary Impacts to Natural Communities
FERC Staff's Alternative Transmission Alignment

Natural Community	Main Transmission Line Temporary Tower Impacts	Main Transmission Line Permanent Tower Impacts	Loop-Line Temporary Tower Impacts	Loop-Line Permanent Tower Impacts	Reservoir Impacts	Powerhouse Impacts	Northern Substation Impacts	Southern Substation Impacts	Construction Staging Areas	Access Road Impacts	Total Temporary Impacts	Total Permanent Impacts	Total Impacts	Total Survey Area
Non-Native Grassland	3.6	0.7	1.9	0.4	0	0.8	13.2	30.3	27.9	11.5	33.4	56.9	90.3	368.5
Coastal Sage Scrub	0.3	0.1	0	0	0	48.3	3.6	0	4.4	0	4.7	52.0	56.7	68.3
Northern Mixed Chaparral	18.6	3.5	0	0	96.7	0	0	0	47.0	43.7	65.6	143.9	209.5	1,950.5
Coast Live Oak Woodland -	0.2	0.1	0	0	4.7	0	0	1.9	0.9	0.8	1.1	7.5	8.6	120.8
Southern Willow Scrub	0	0	0	0	0	0	0	0	0	0	0	0	0	1.4
Open Water	0	0	0	0	0	0	0	0	3.8	0	0	0	0	7.3
Agriculture	0	0	0	0	0	0	0	0	0	0	0	0	0	0.7
Ornamental Woodland	0	0	0	0	0	0	0	0	5.2	0	5.2	0	5.2	5.2
Disturbed	1.5	0.3	0	0	0.9	3.7	22.0	0.1	12.6	8.4	14.1	35.4	49.5	149.2
Total	**24.2**	**4.7**	**1.9**	**0.4**	**102.3**	**52.8**	**38.8**	**32.3**	**101.8**	**64.4**	**124.1**	**295.7**	**419.8**	**2673.5**

Table 3: Permanent and Temporary Impacts to Critical Habitat to Both Staff's and Co-Applicant's Transmission Line Alignment Alternatives

Natural Community Impacts	Main Transmission Line Temporary Tower Impacts	Main Transmission Line Permanent Tower Impacts	Loop-Line Temporary Tower Impacts	Loop-Line Permanent Tower Impacts	Northern Substation Impacts	Access Road Impacts	Total Impacts	Total Survey Area
California Gnatcatcher Existing	.6	0.1	.6	0.1	0	1.2	2.6	53.2
Quino Checkerspot Butterfly	1.3	0.2	1.3	0.2	0	5.0	8.00	131.7
Stephens' Kangaroo Rat Fee Area	2.3	0.5	1.9	0.4	38.8	6.3	50.2	209.4
Stephens' Kangaroo Rat Core Reserve Area	1.3	0.2	1.3	0.2	0	5.0	8.00	131.7

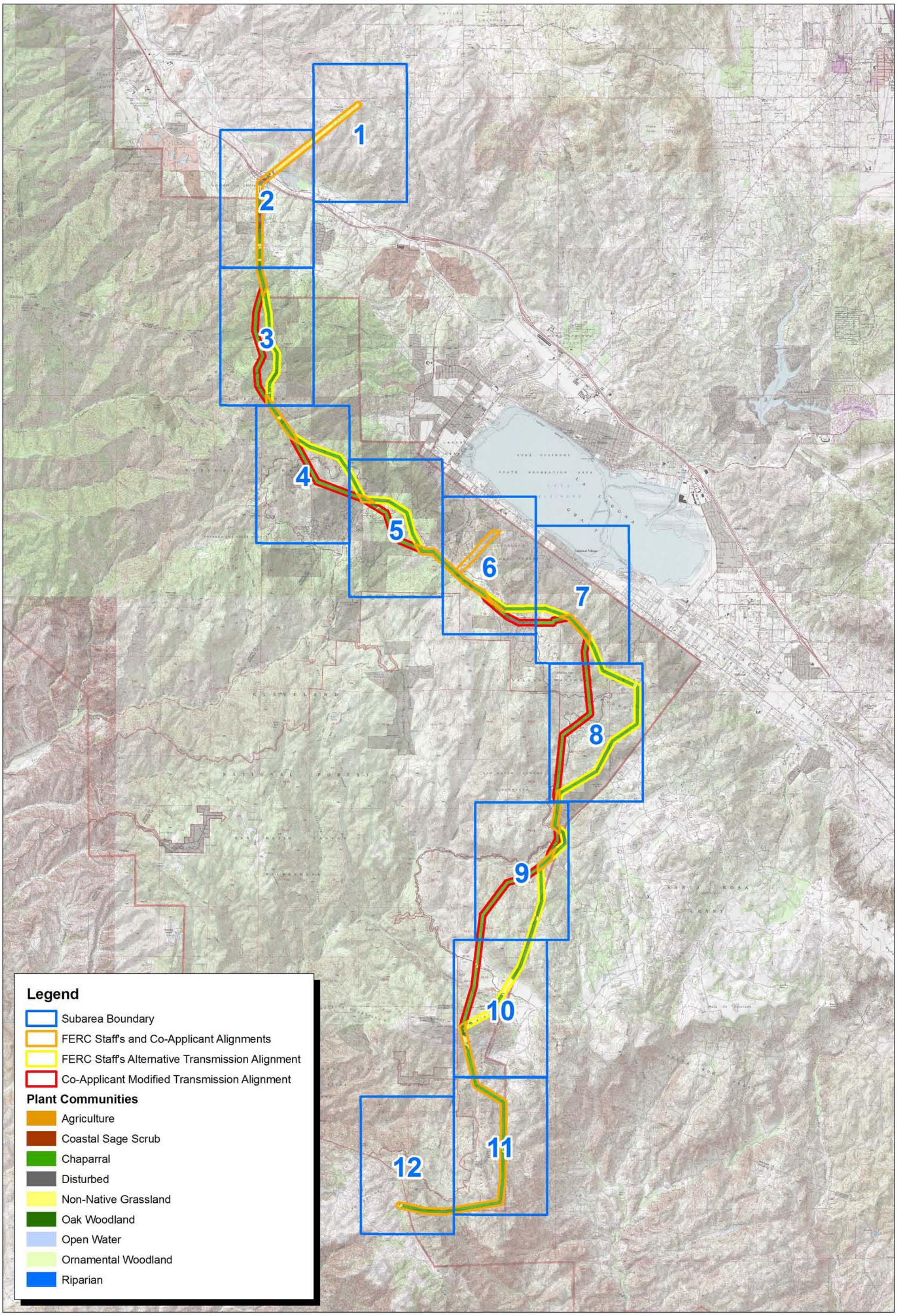
Table 4: Total Impacts Associated with Access Roads for Both Staff's and Co-Applicant's Transmission Line Alignment Alternatives

	Within the Transmission Line ROW			Outside the Transmission Line ROW		
Natural Community	Existing Roads	Improved Roads	New Roads	Existing Roads	Improved roads	New Roads
Non-Native Grassland	0.00	0.67	6.69	1.78	1.43	2.14
Coastal Sage Scrub	0.00	0.00	0.00	0.00	0.00	0.00
Northern Mixed Chaparral	0.05	4.50	58.29	0.68	6.66	36.05
Coast Live Oak Woodland	0.00	0.18	0.72	0.00	0.00	0.00
Southern Willow Scrub	0.00	0.00	0.00	0.00	0.00	0.00
Open Water	0.00	0.00	0.00	0.00	0.00	0.00
Agriculture	0.00	0.00	0.00	0.00	0.00	0.00
Ornamental Woodland	0.00	0.00	0.00	0.00	0.00	0.00
Disturbed	0.51	1.30	0.87	1.83	2.76	1.50
Total	**0.56**	**6.65**	**66.57**	**4.29**	**10.85**	**39.69**

Appendix B: Plant Community Maps

List of Appendix B Exhibits

1	Plant Communities Index Map
1a	Subarea 1 Plant Communities Map -Topographic Base
1b	Subarea 1 Plant Communities Map -Aerial Base
2a	Subarea 2 Plant Communities Map -Topographic Base
2b	Subarea 2 Plant Communities Map -Aerial Base
3a	Subarea 3 Plant Communities Map -Topographic Base
3b	Subarea 3 Plant Communities Map -Aerial Base
4a	Subarea 4 Plant Communities Map -Topographic Base
4b	Subarea 4 Plant Communities Map -Aerial Base
5a	Subarea 5 Plant Communities Map -Topographic Base
5b	Subarea 5 Plant Communities Map -Aerial Base
6a	Subarea 6 Plant Communities Map -Topographic Base
6b	Subarea 6 Plant Communities Map -Aerial Base
7a	Subarea 7 Plant Communities Map -Topographic Base
7b	Subarea 7 Plant Communities Map -Aerial Base
8a	Subarea 8 Plant Communities Map -Topographic Base
8b	Subarea 8 Plant Communities Map -Aerial Base
9a	Subarea 9 Plant Communities Map -Topographic Base
9b	Subarea 9 Plant Communities Map -Aerial Base
10a	Subarea 10 Plant Communities Map -Topographic Base
10b	Subarea 10 Plant Communities Map -Aerial Base
11a	Subarea 11 Plant Communities Map -Topographic Base
11b	Subarea 11 Plant Communities Map -Aerial Base
12a	Subarea 12 Plant Communities Map -Topographic Base
12b	Subarea 12 Plant Communities Map -Aerial Base



Source: TOPO! USGS 7.5' DRG, USFWS, RCIP, and MBA Field Surveys.

Michael Brandman Associates

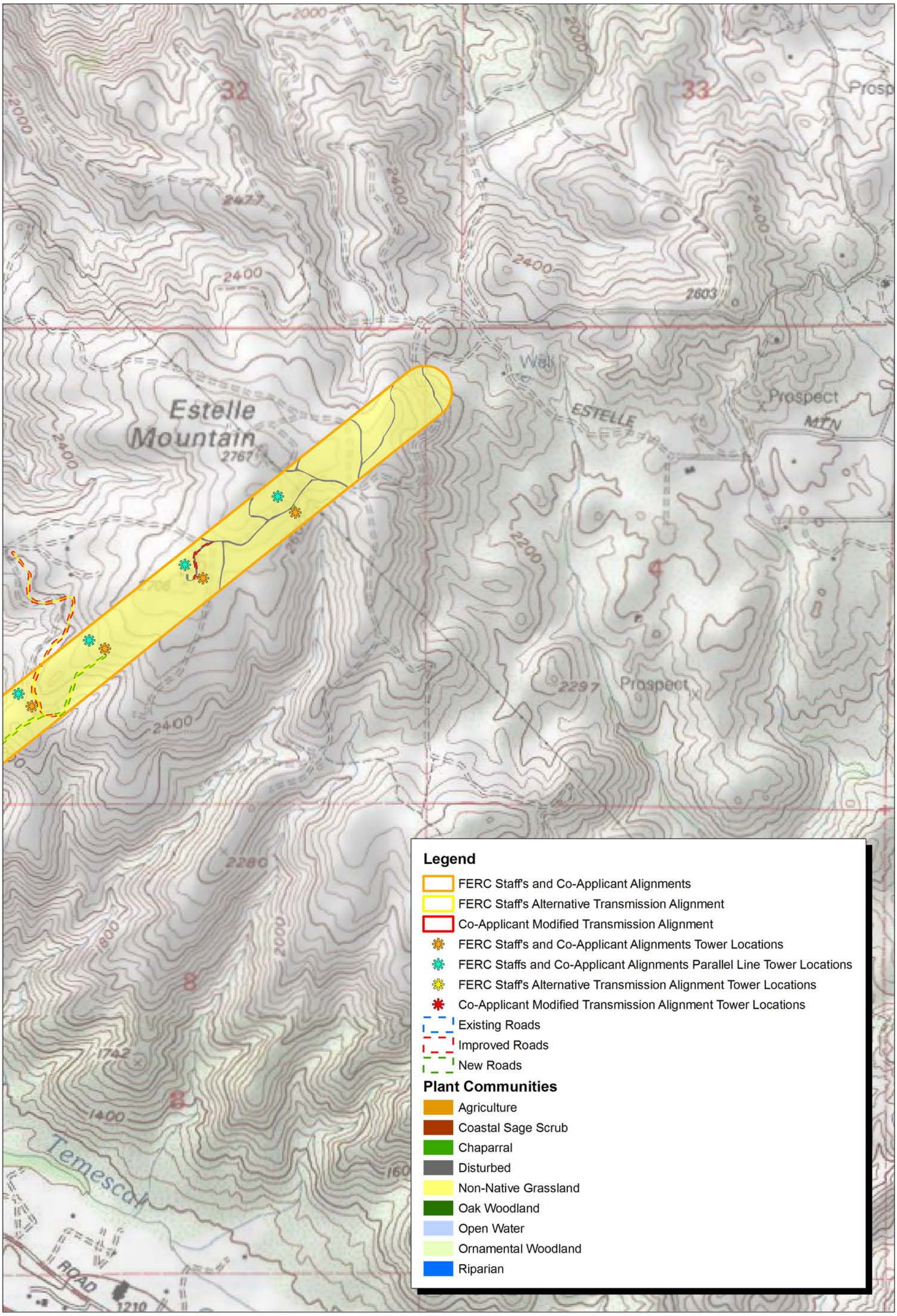
NORTH

1.8 0.9 0 1.8 Miles

27980005 • 08/2007 | 1_plant.mxd

Exhibit 1
Plant Communities Map

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

Michael Brandman Associates

NORTH

1,000 500 0 1,000 Feet

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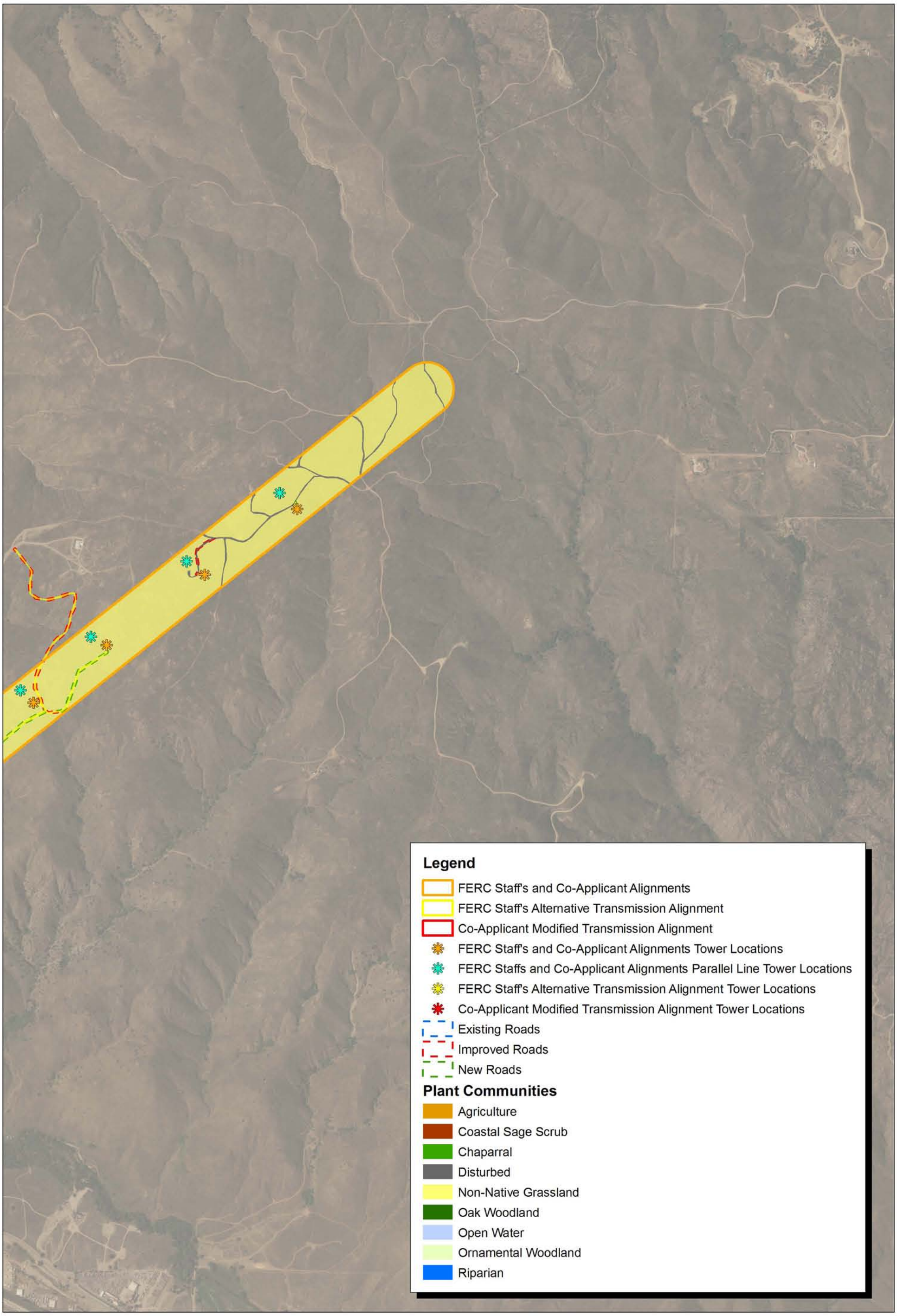
Exhibit 1a
Subarea 1 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

NORTH

1,000 500 0 1,000 Feet

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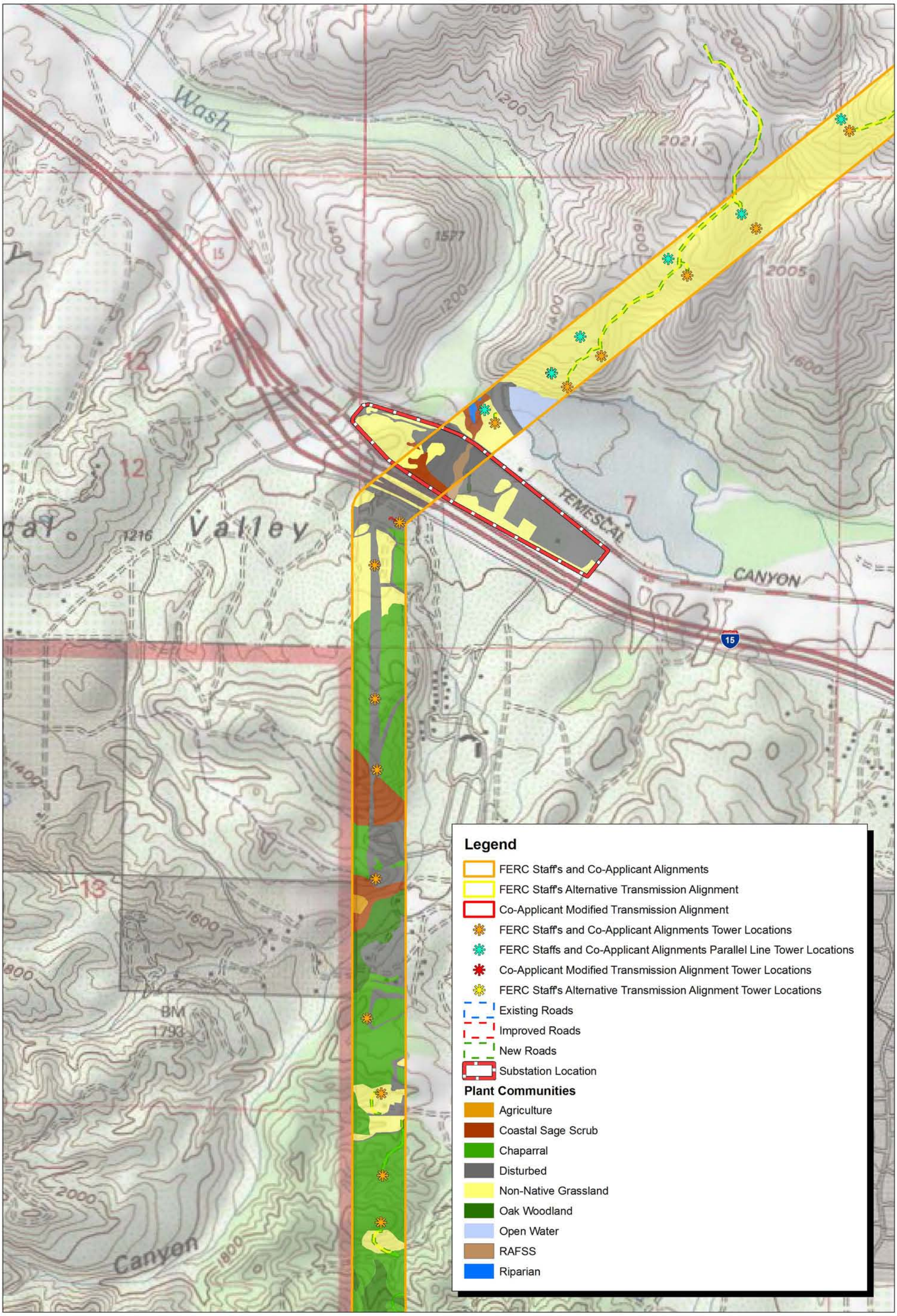
Exhibit 1b
Subarea 1 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

Michael Brandman Associates

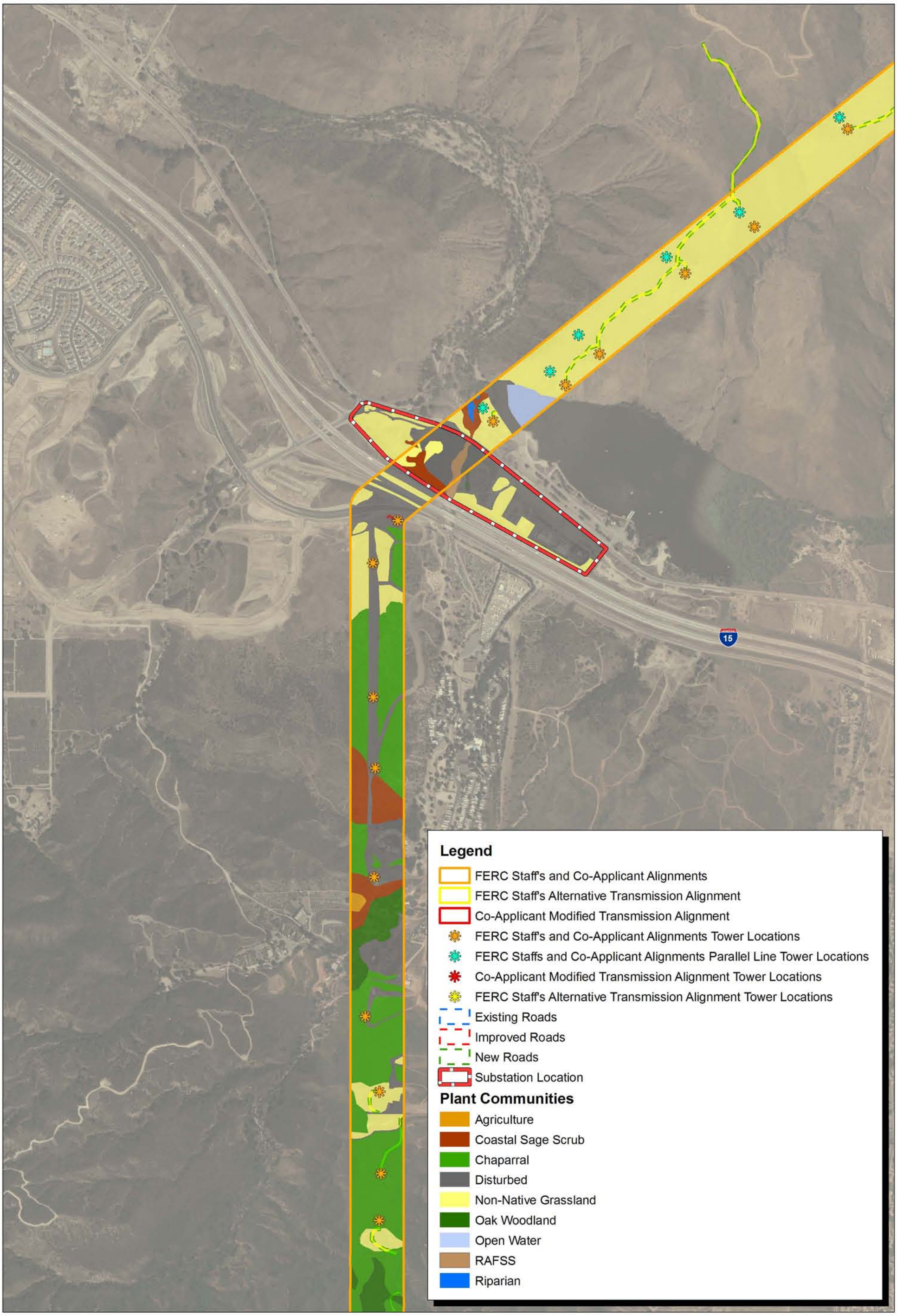
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 2a.mxd

Exhibit 2a
Subarea 2 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

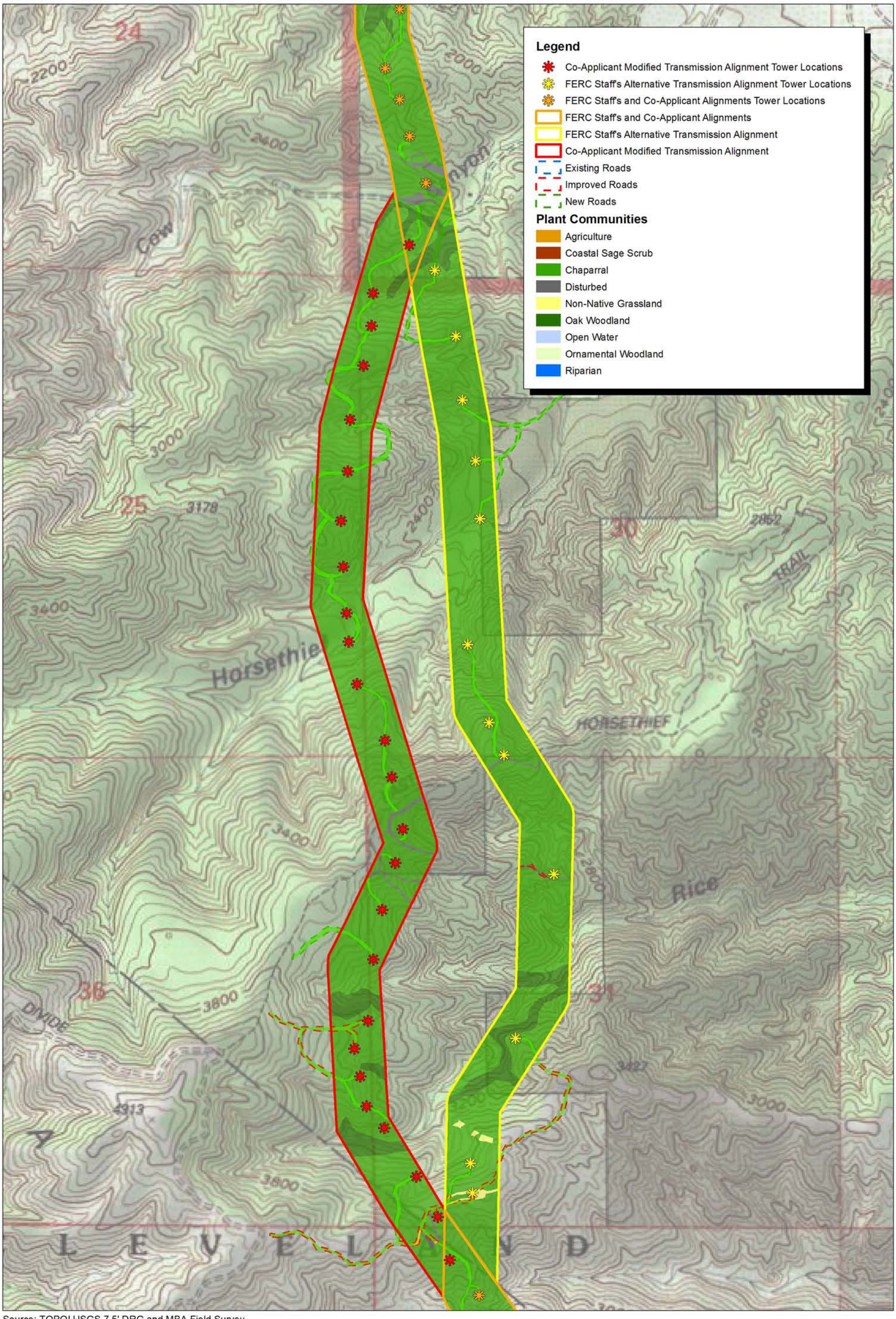
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 2b.mxd

Exhibit 2b
Subarea 2 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

Michael Brandman Associates

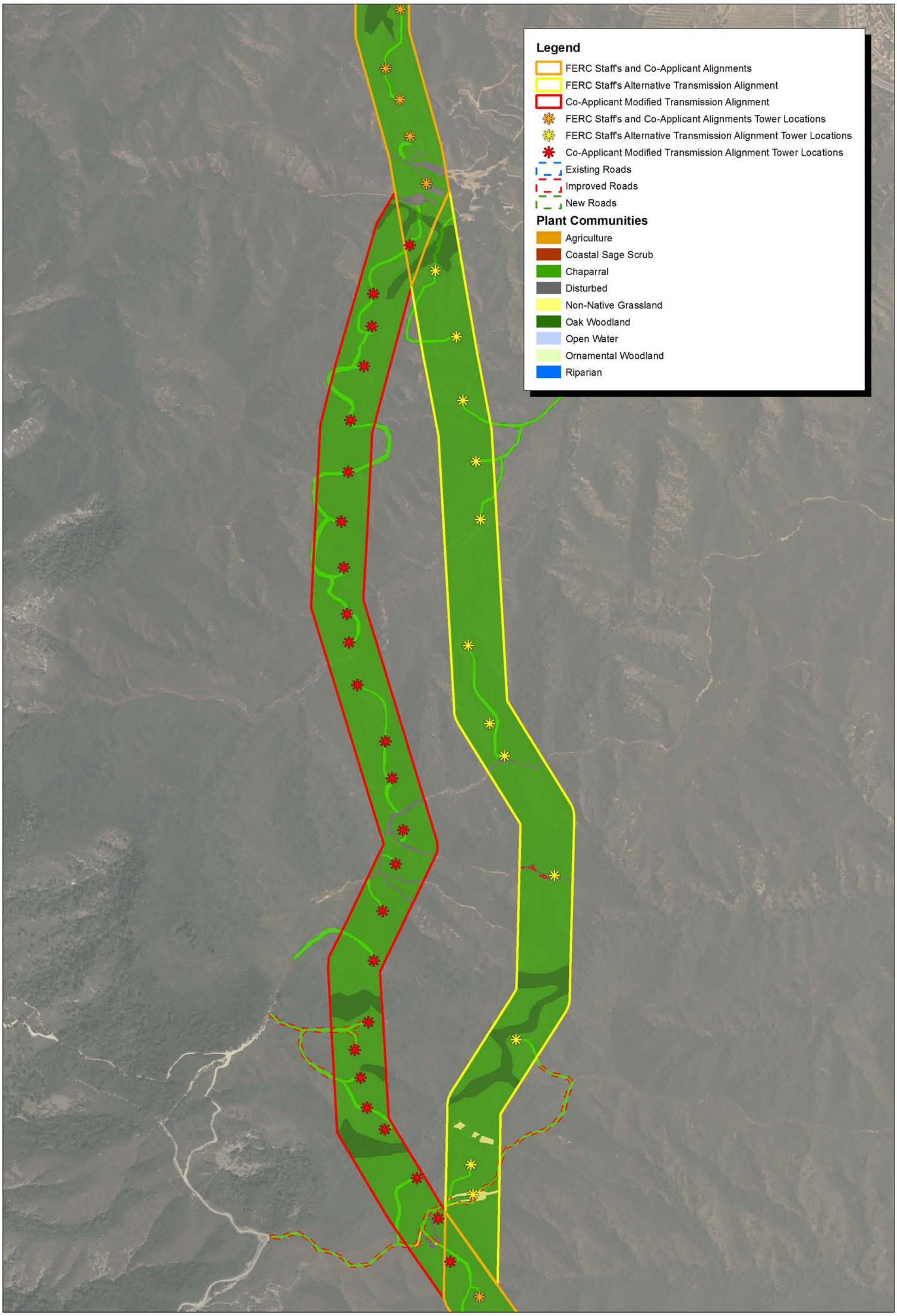
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 3a.mxd

Exhibit 3a
Subarea 3 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

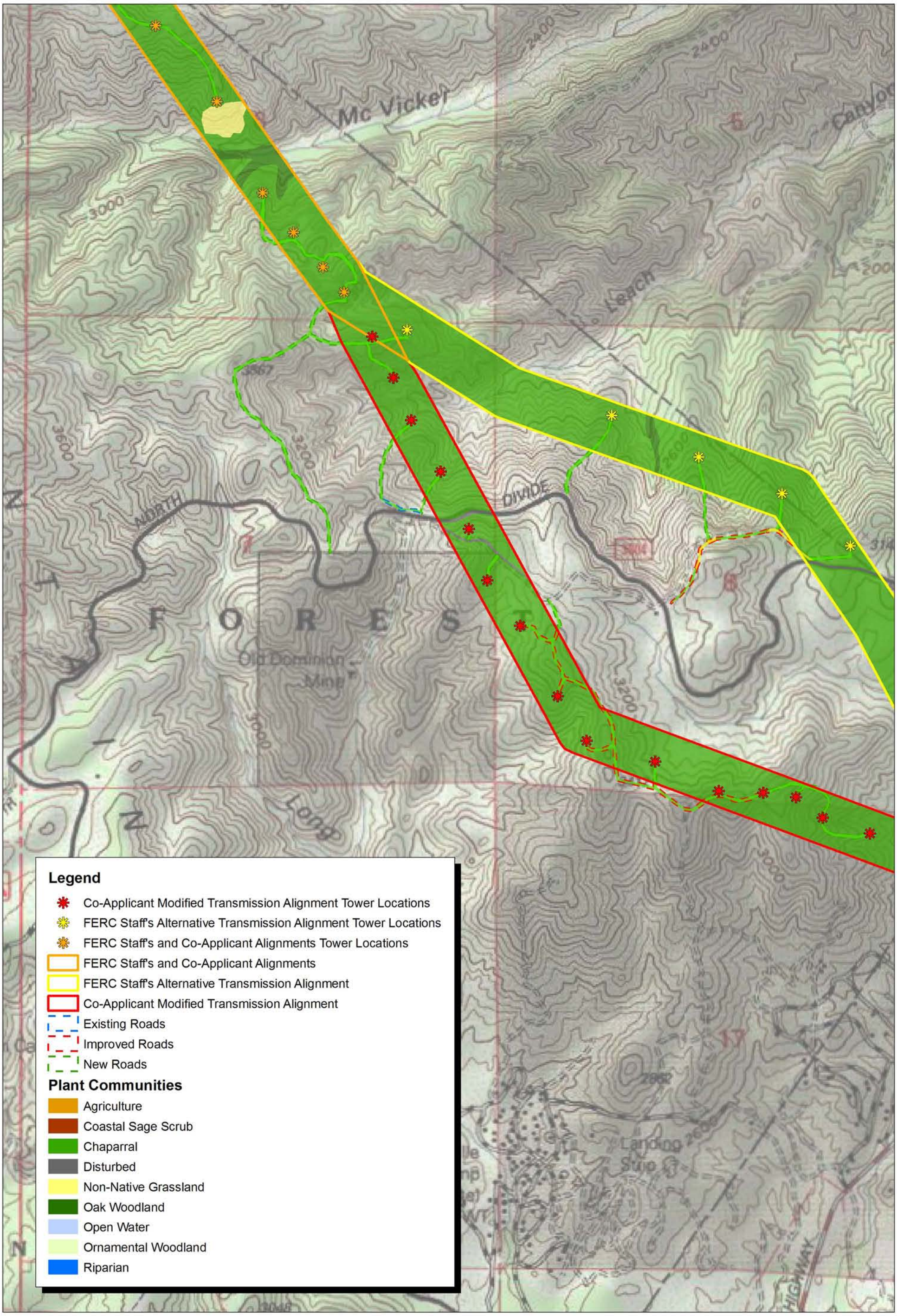
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 3b.mxd

Exhibit 3b
Subarea 3 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

NORTH

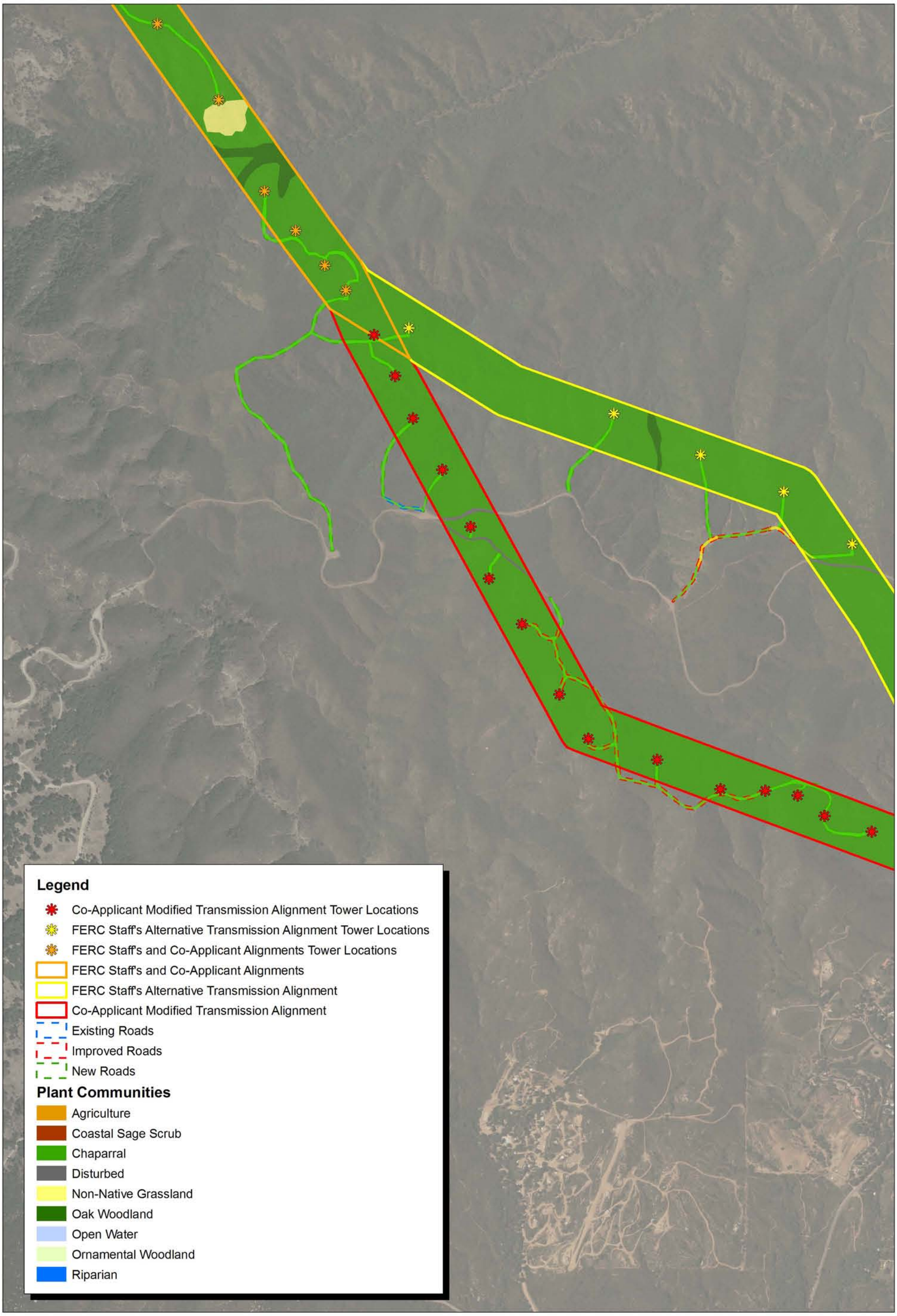
1,000 500 0 1,000 Feet

Michael Brandman Associates

27980005 • 09/2007 | 4a.mxd

Exhibit 4a
Subarea 4 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

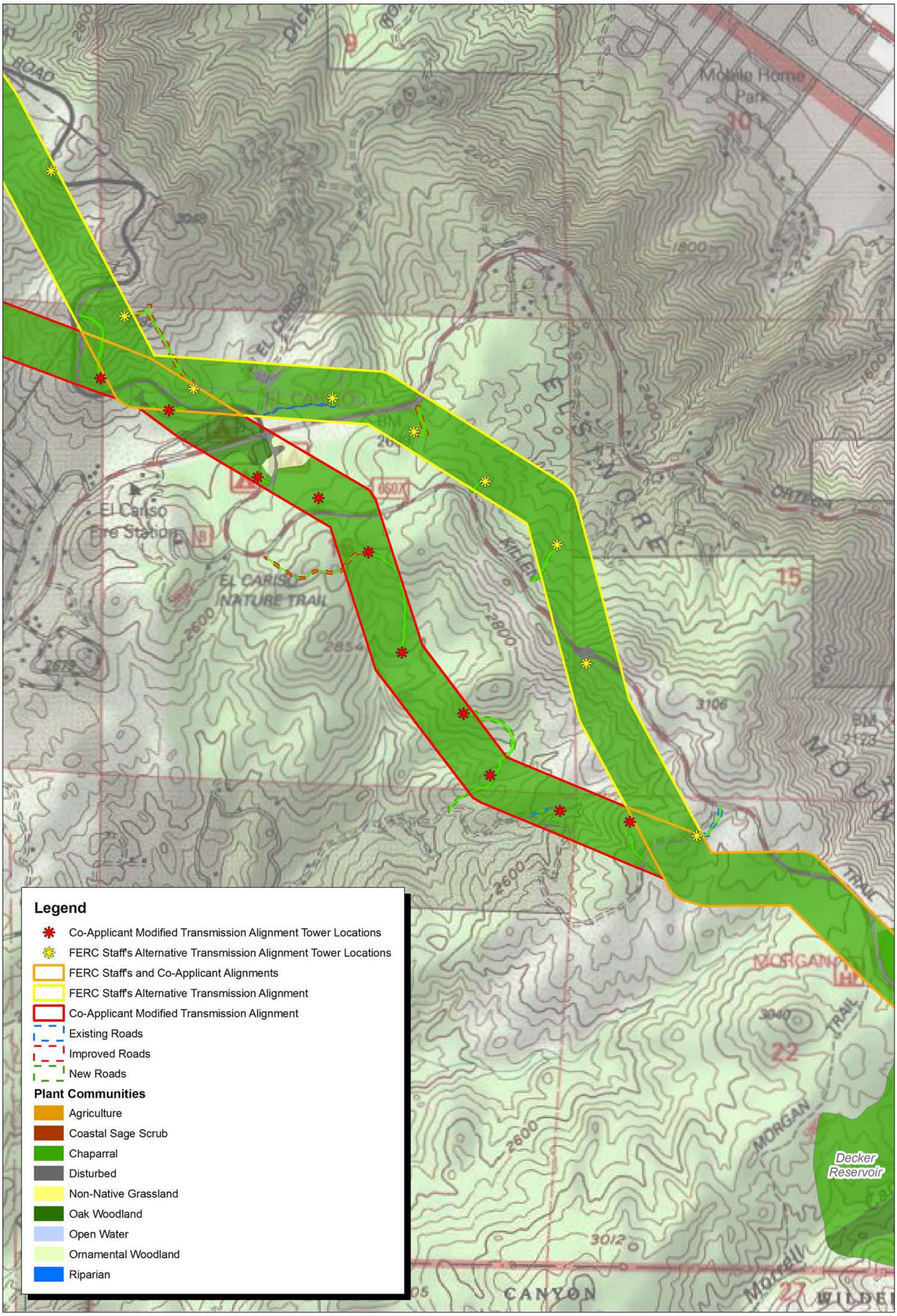
NORTH

1,000 500 0 1,000 Feet

27980005 • 08/2007 | 4b.mxd

Exhibit 4b
Subarea 4 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

Michael Brandman Associates

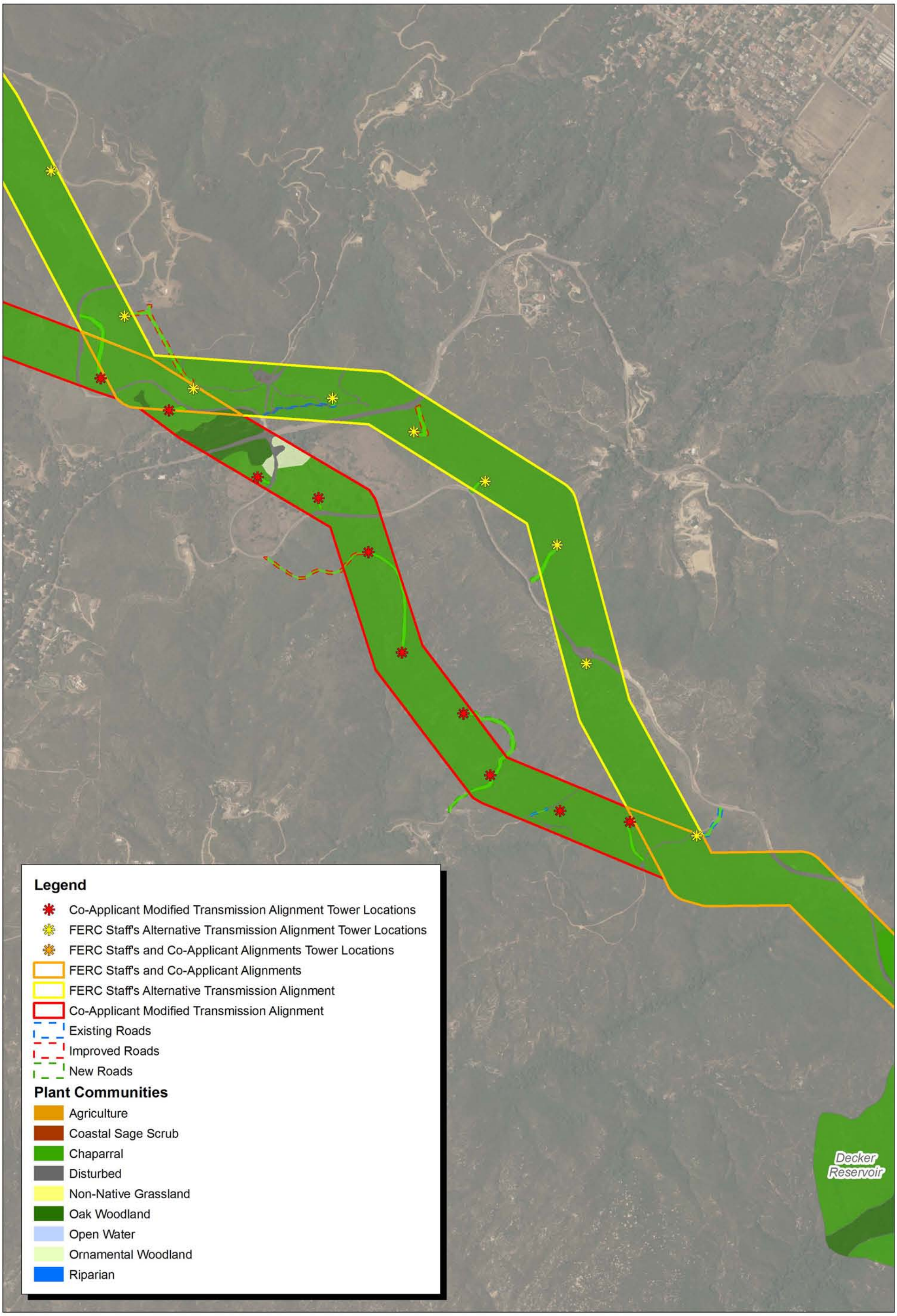
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 5a.mxd

Exhibit 5a
Subarea 5 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

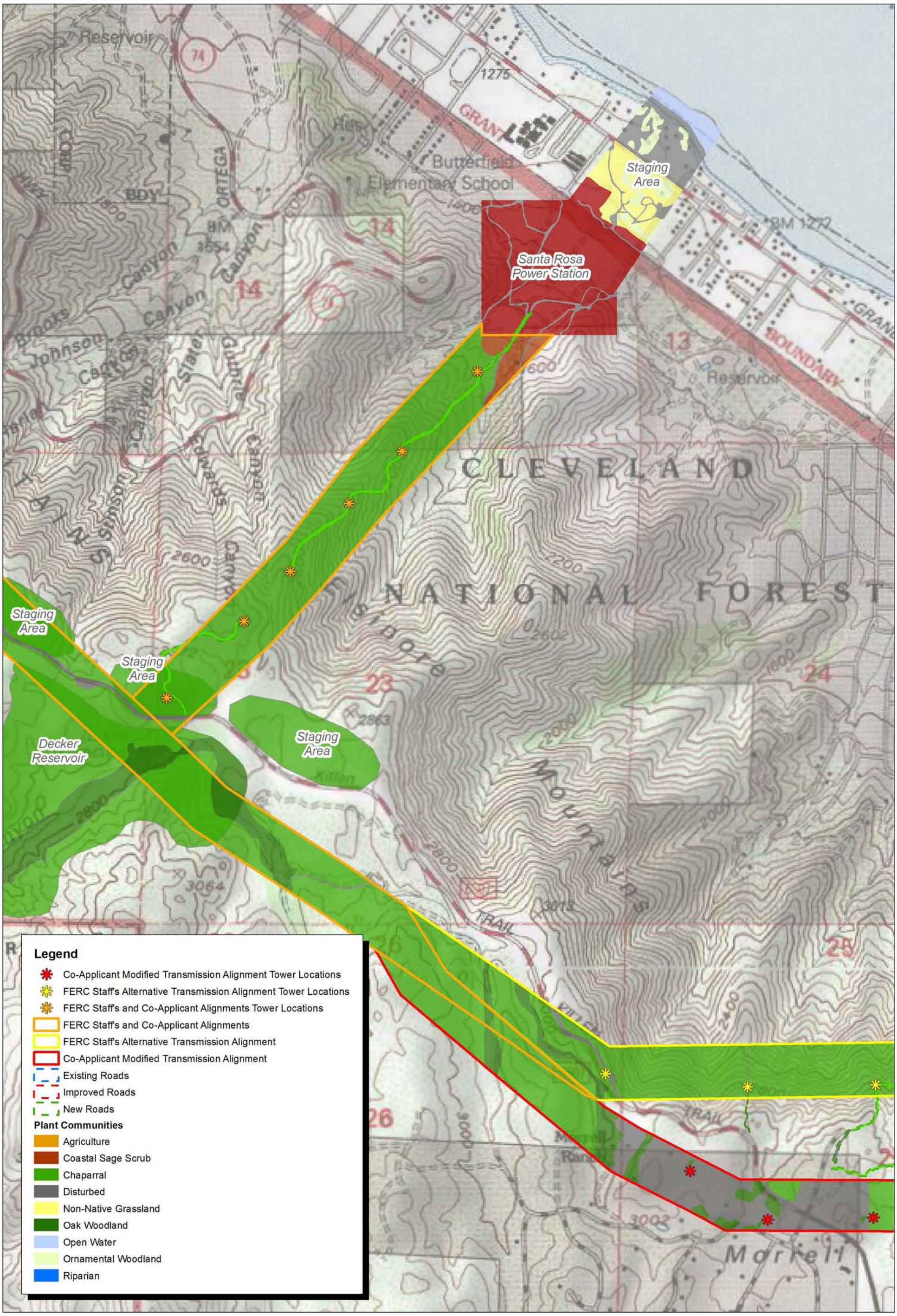
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 5b.mxd

Exhibit 5b
Subarea 5 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

Michael Brandman Associates

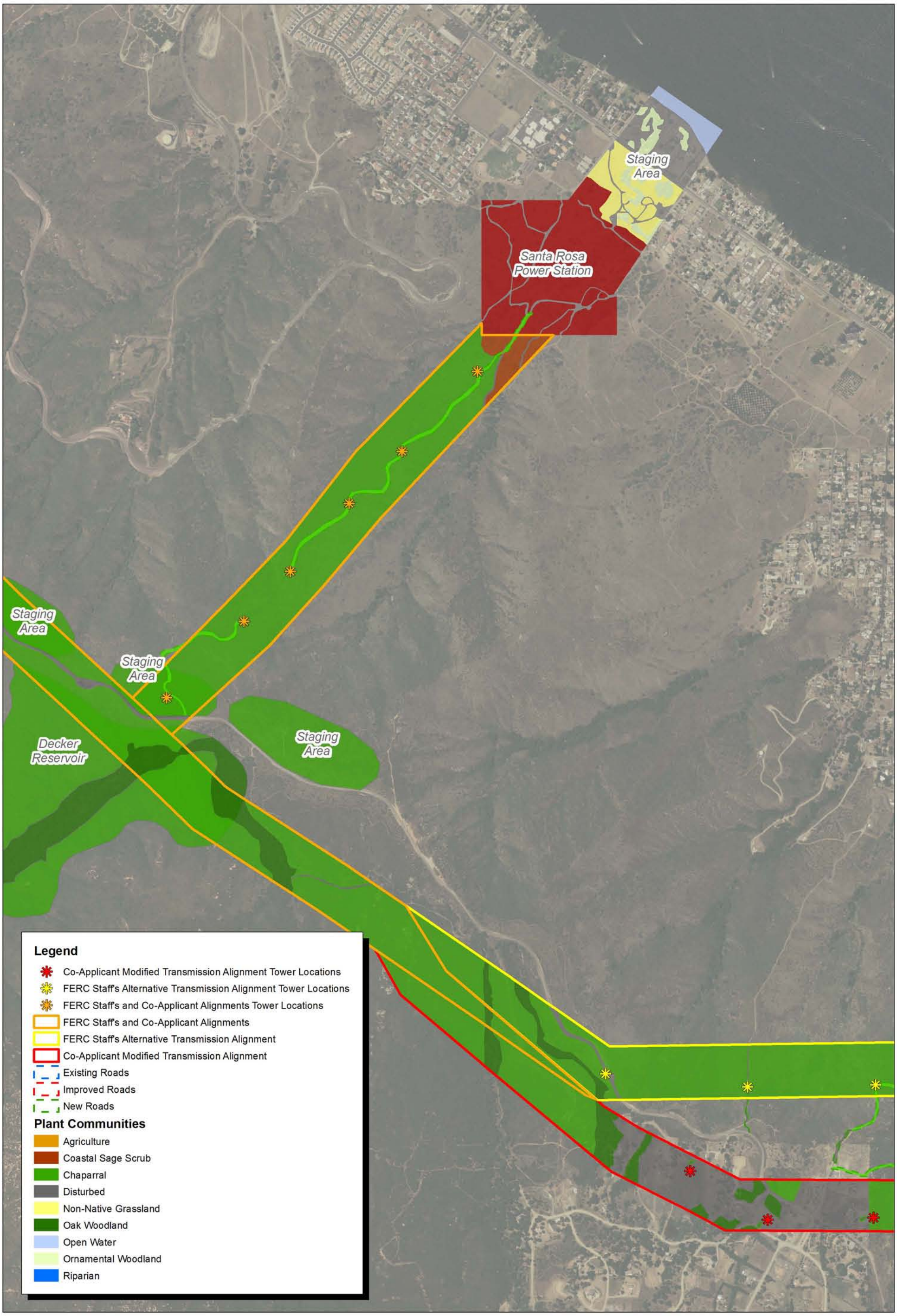
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 6a.mxd

Exhibit 6a
Subarea 6 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

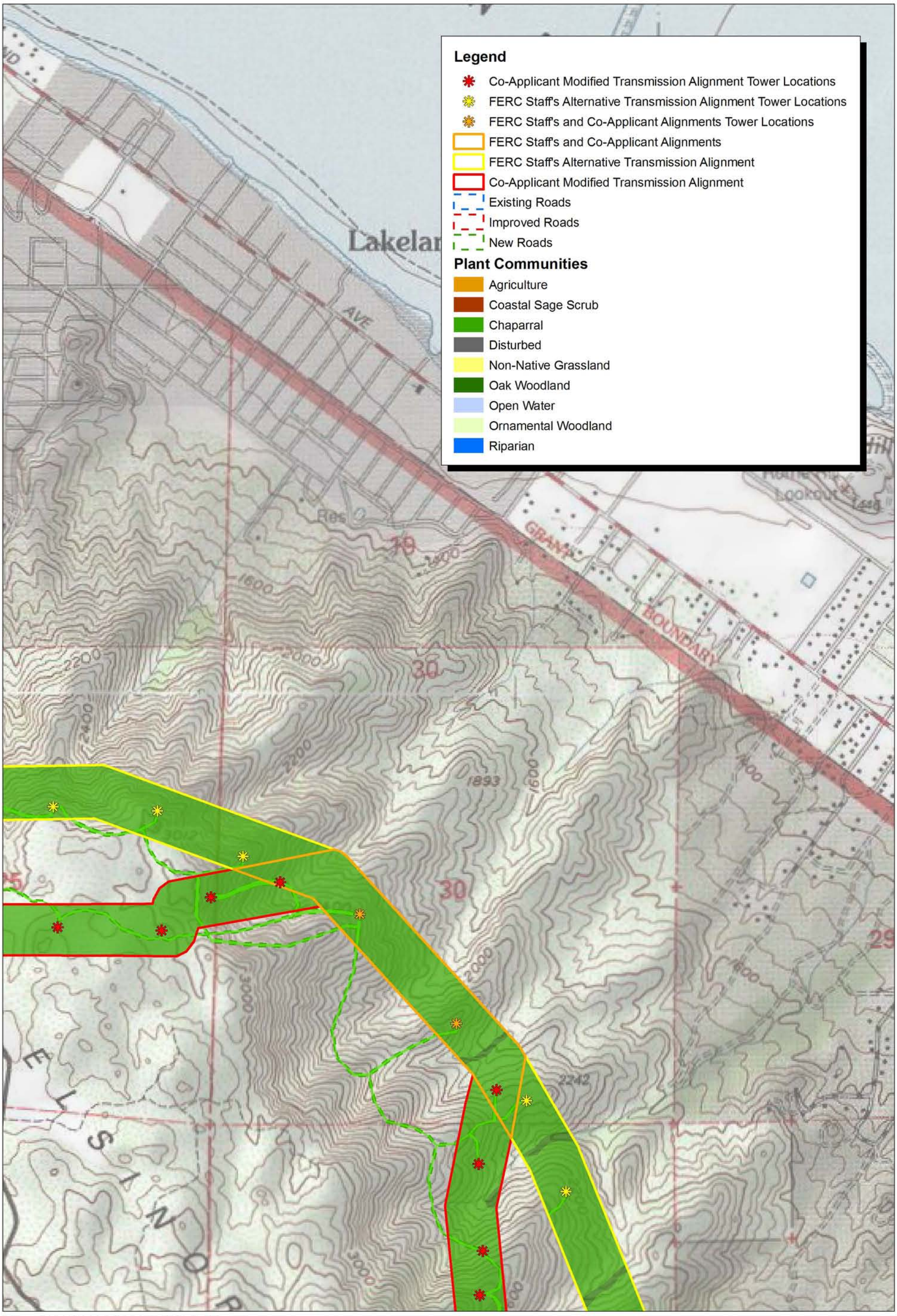
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 6b.mxd

Exhibit 6b
Subarea 6 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



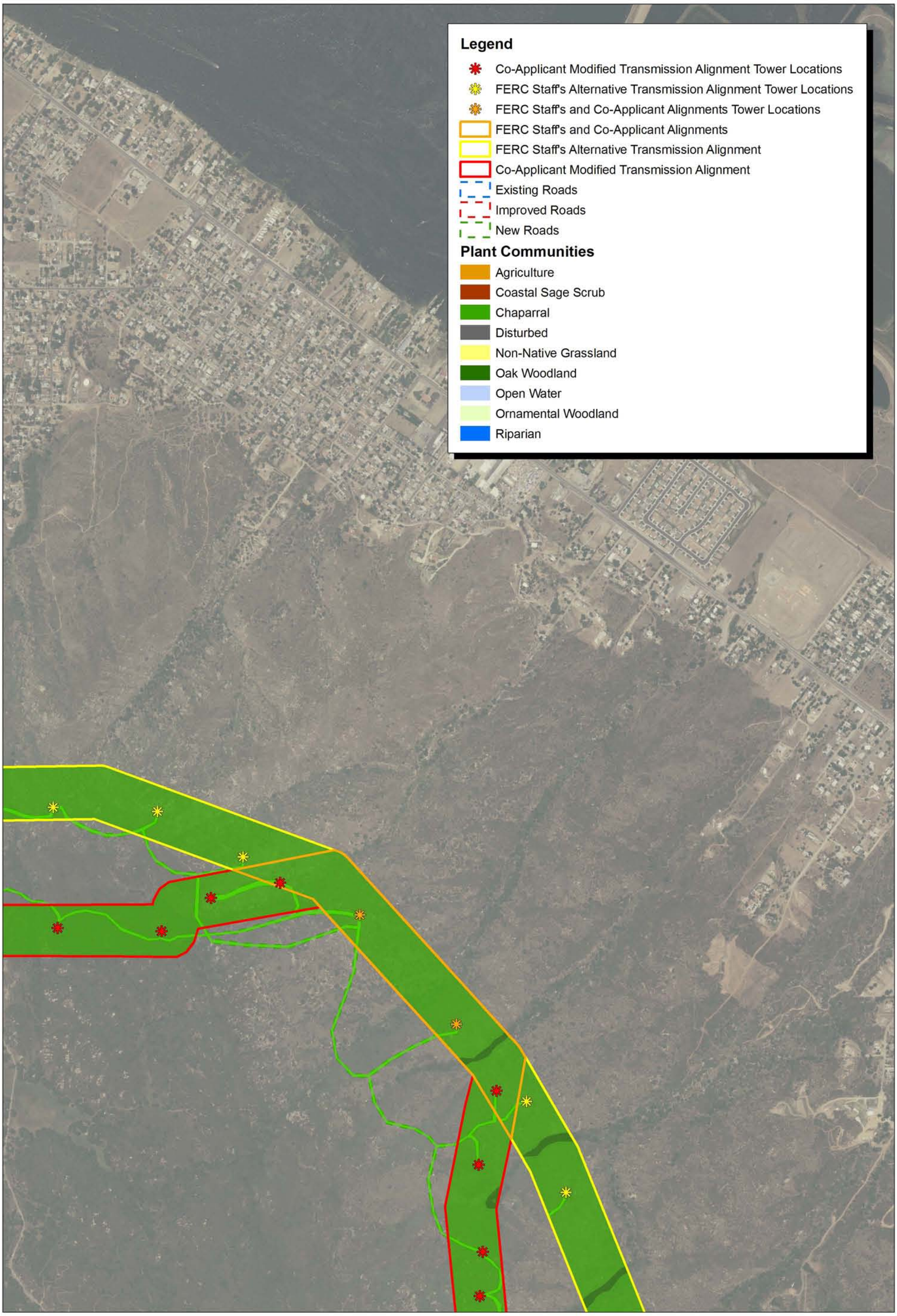
Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

Michael Brandman Associates

27980005 • 09/2007 | 7a.mxd

Exhibit 7a
Subarea 7 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

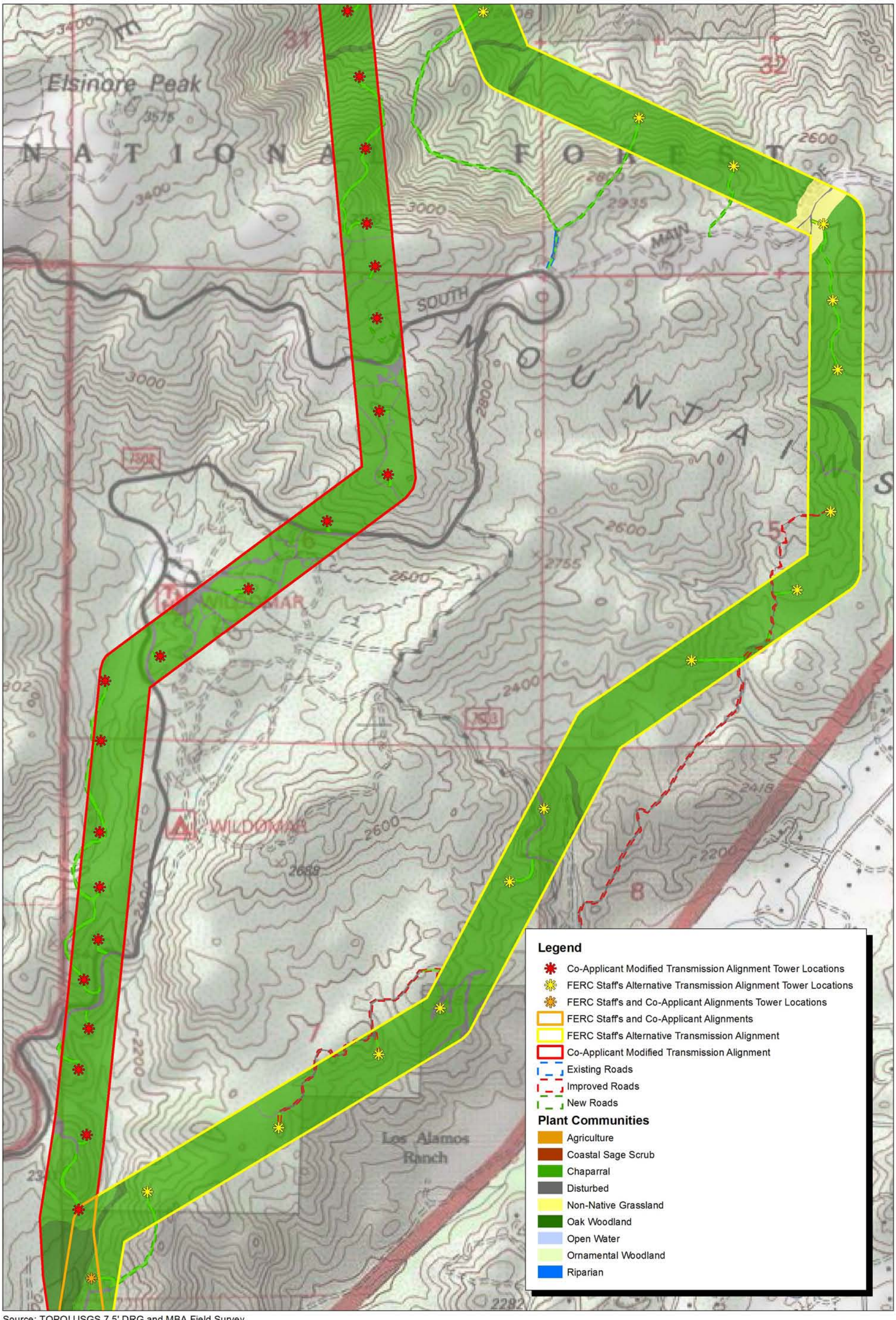
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 7b.mxd

Exhibit 7b
Subarea 7 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

NORTH

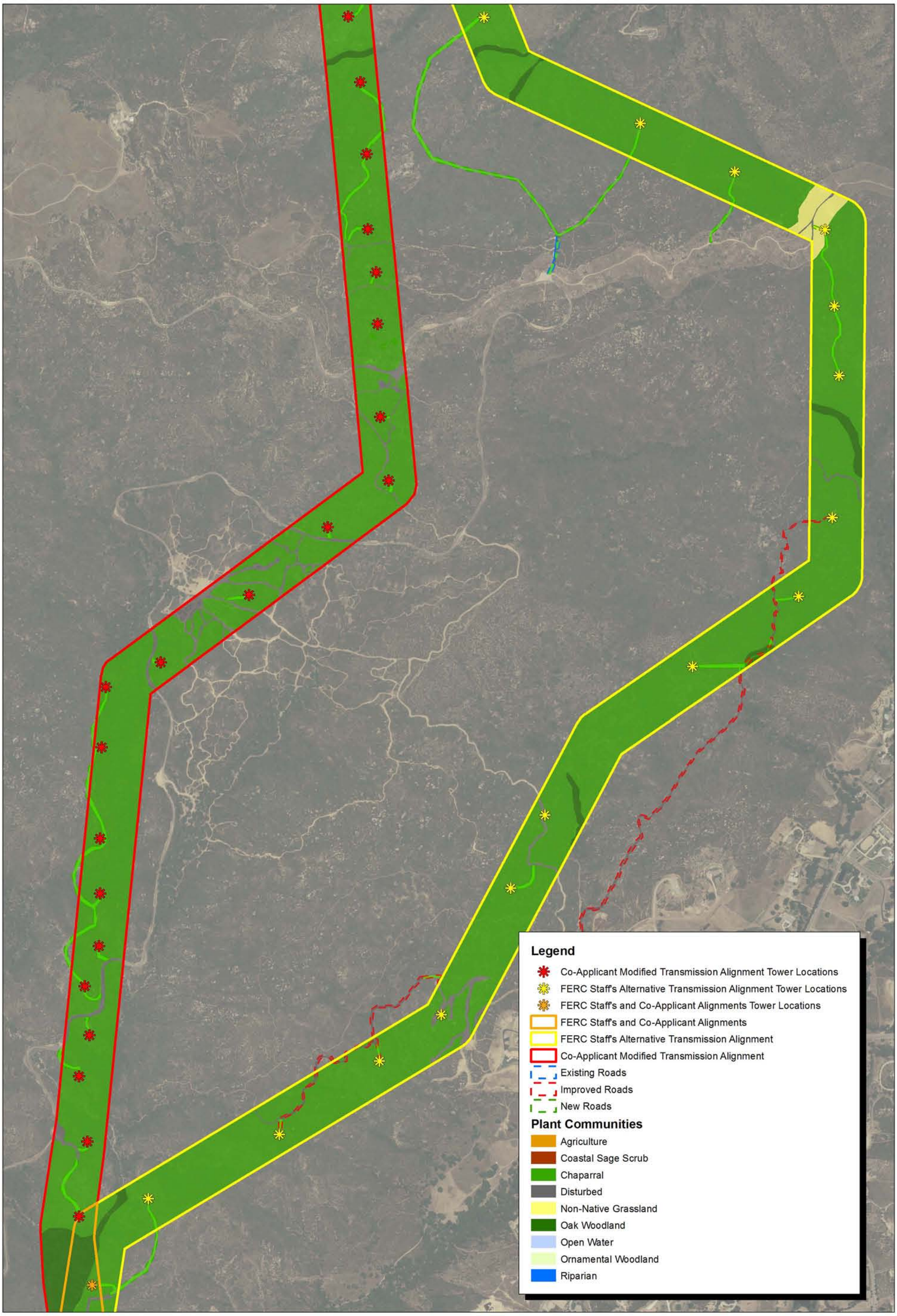
1,000 500 0 1,000 Feet

Michael Brandman Associates

27980005 • 09/2007 | 8a.mxd

Exhibit 8a
Subarea 8 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

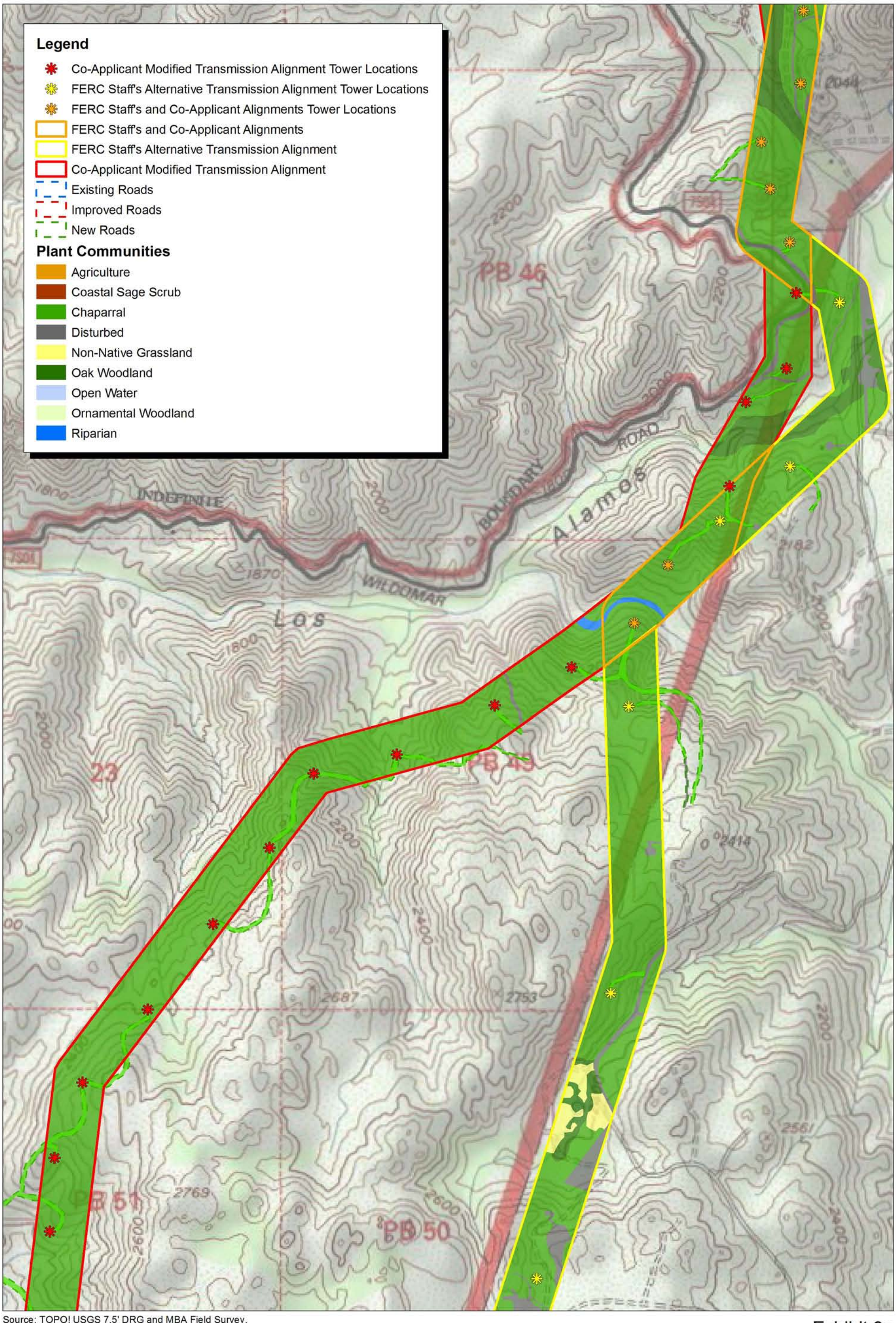
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 8b.mxd

Exhibit 8b
Subarea 8 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

Michael Brandman Associates

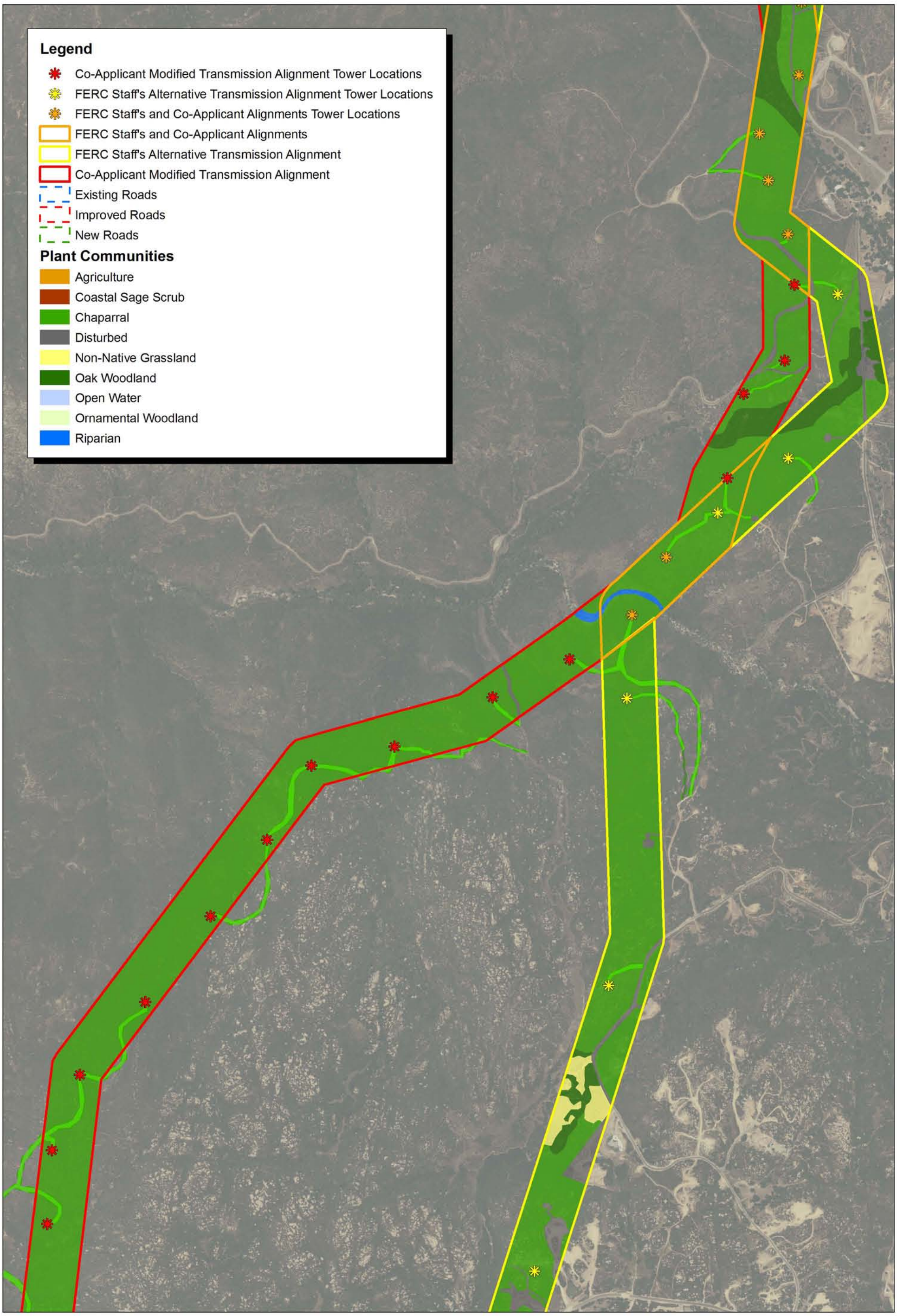
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 9a.mxd

Exhibit 9a
Subarea 9 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

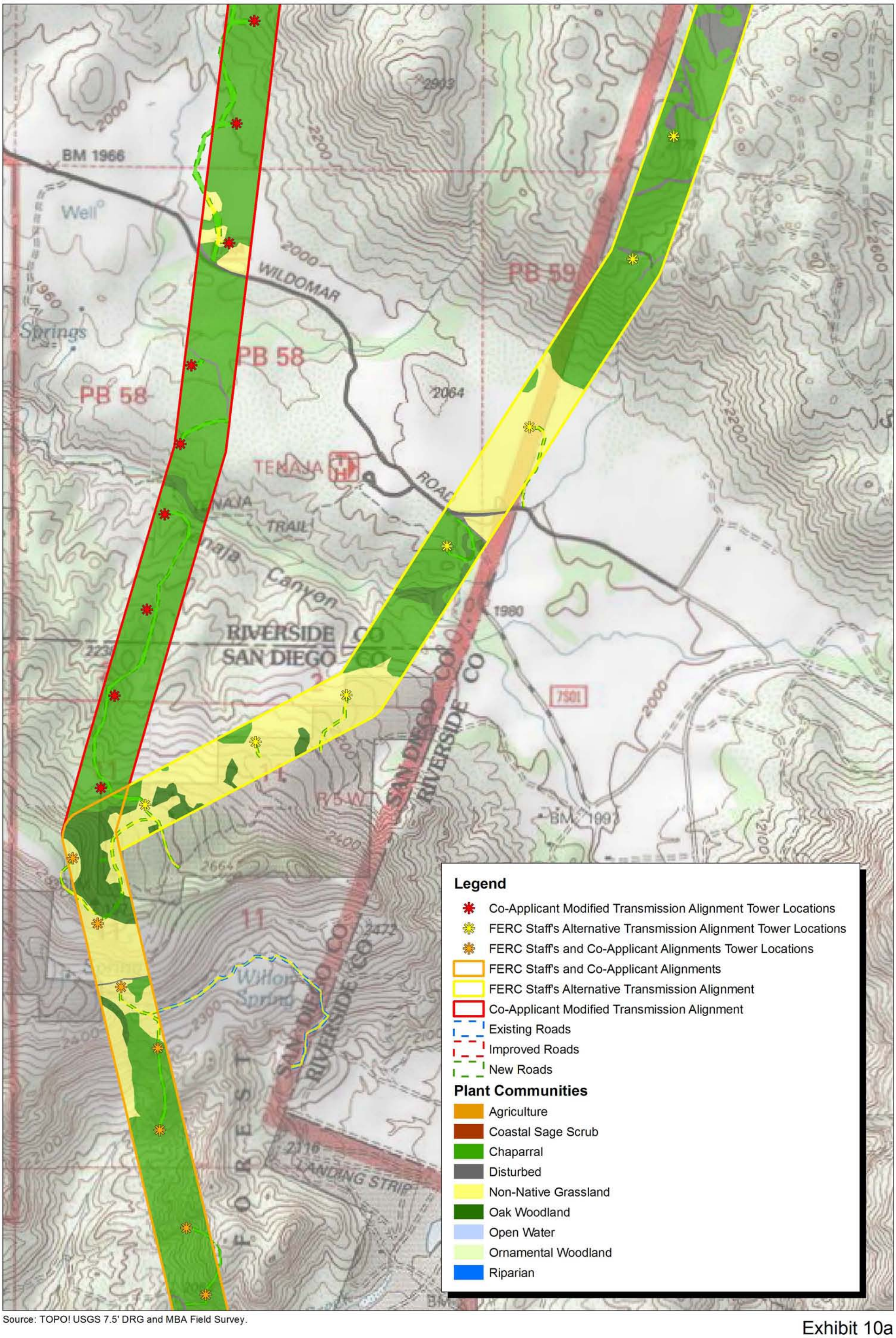
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 9b.mxd

Exhibit 9b
Subarea 9 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

NORTH

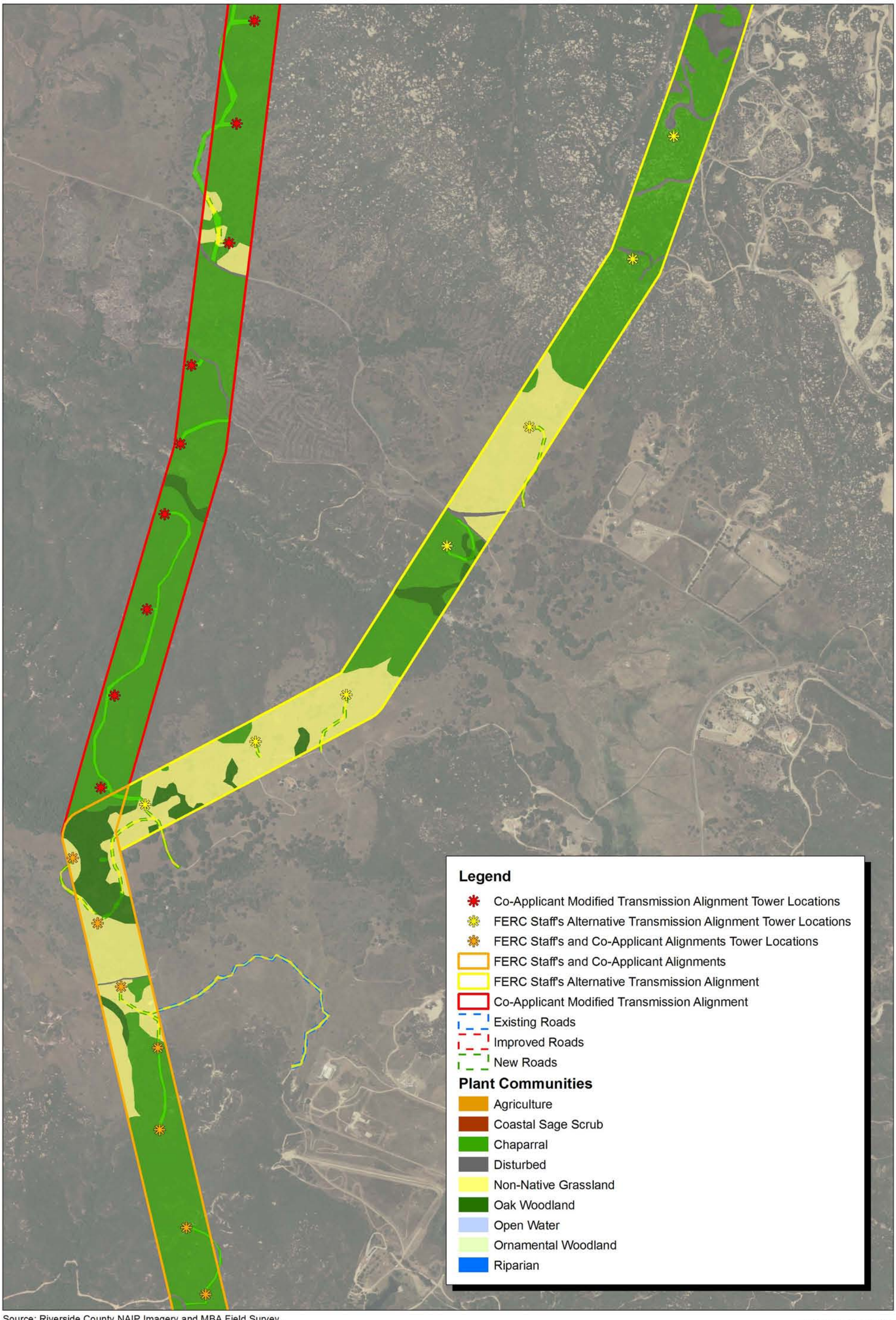
1,000 500 0 1,000 Feet

Michael Brandman Associates

27980005 • 09/2007 | 10a.mxd

Exhibit 10a
Subarea 10 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

NORTH

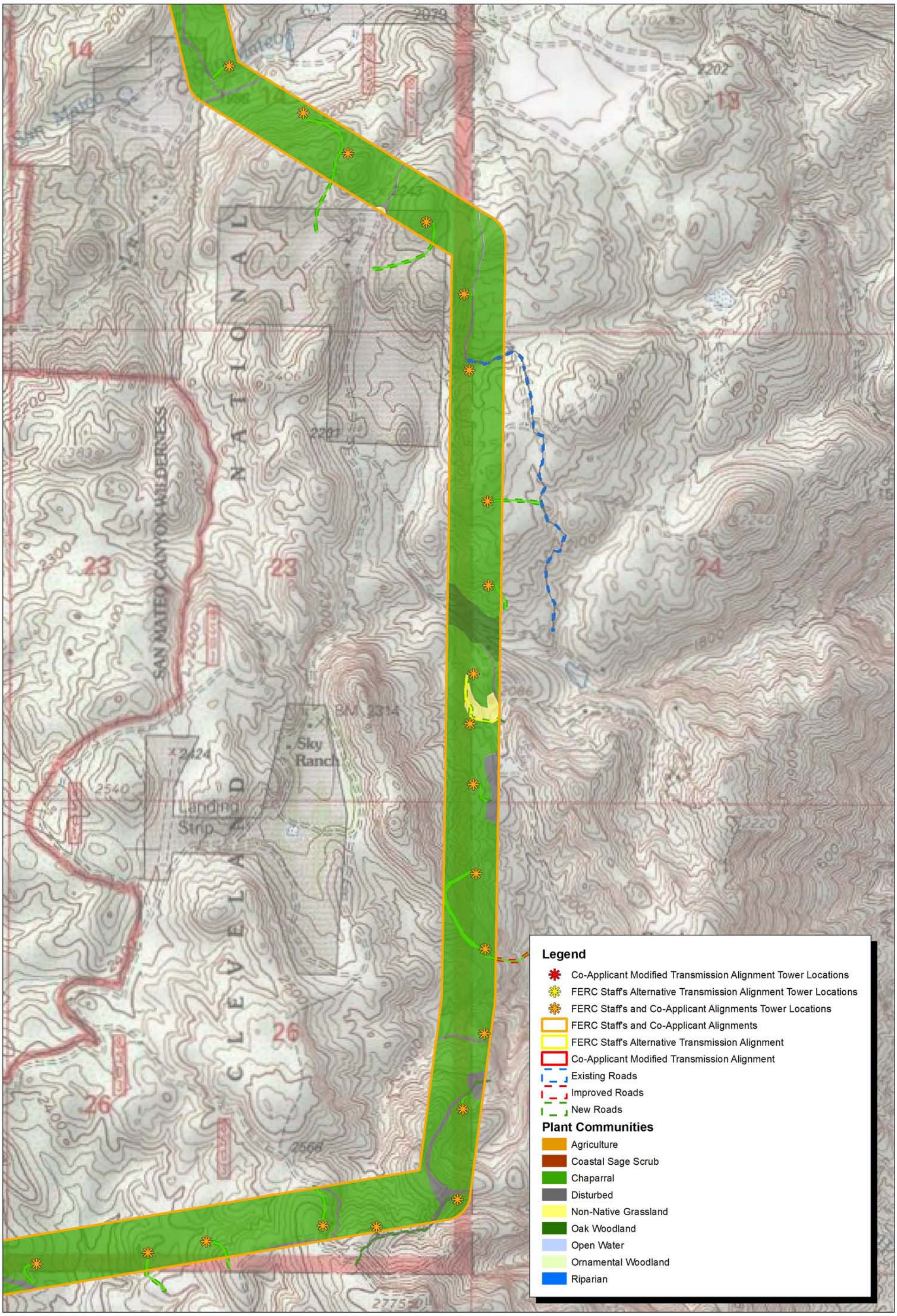
1,000 500 0 1,000 Feet

Michael Brandman Associates

27980005 • 09/2007 | 10b.mxd

Exhibit 10b
Subarea 10 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

Michael Brandman Associates

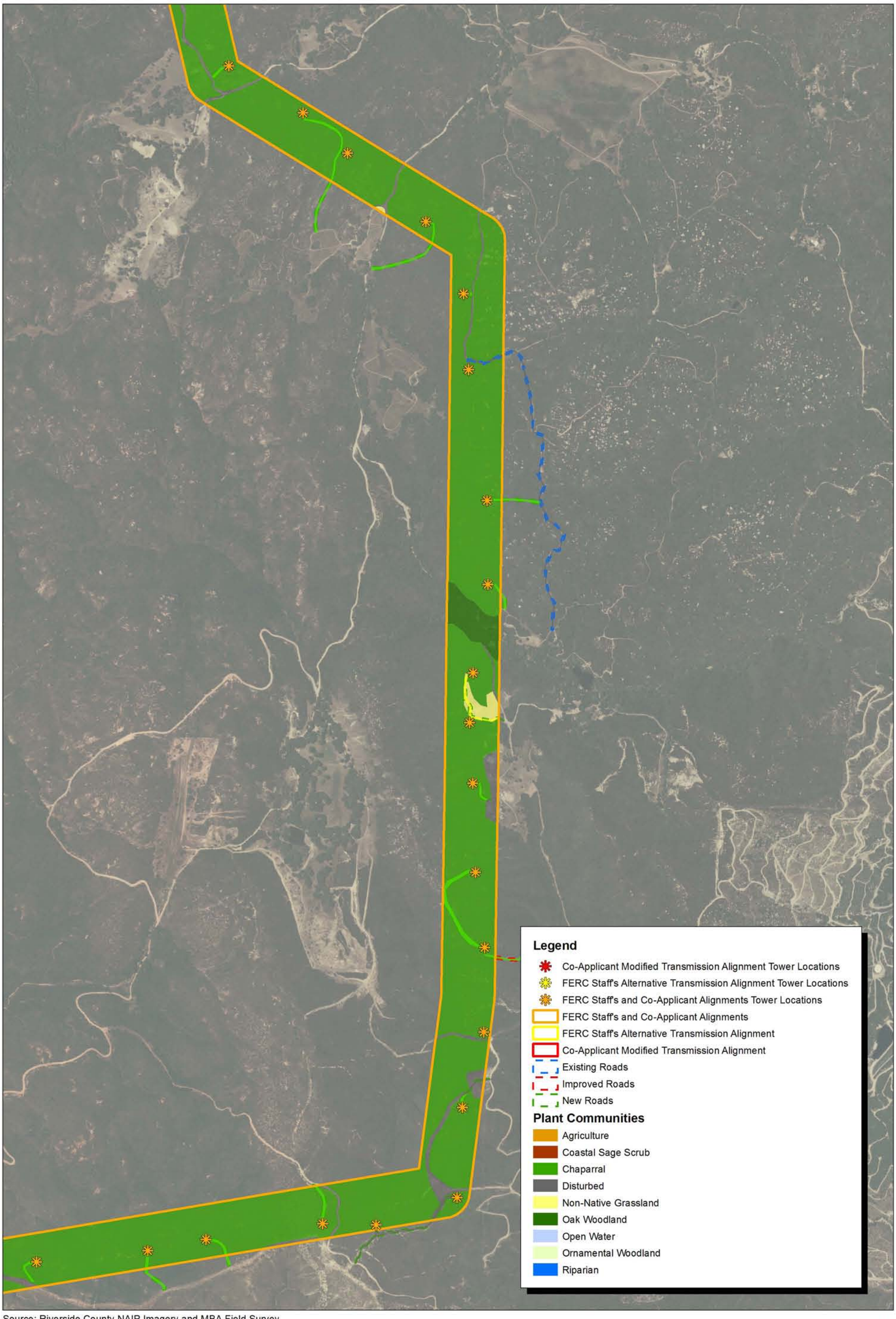
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 11a.mxd

Exhibit 11a
Subarea 11 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

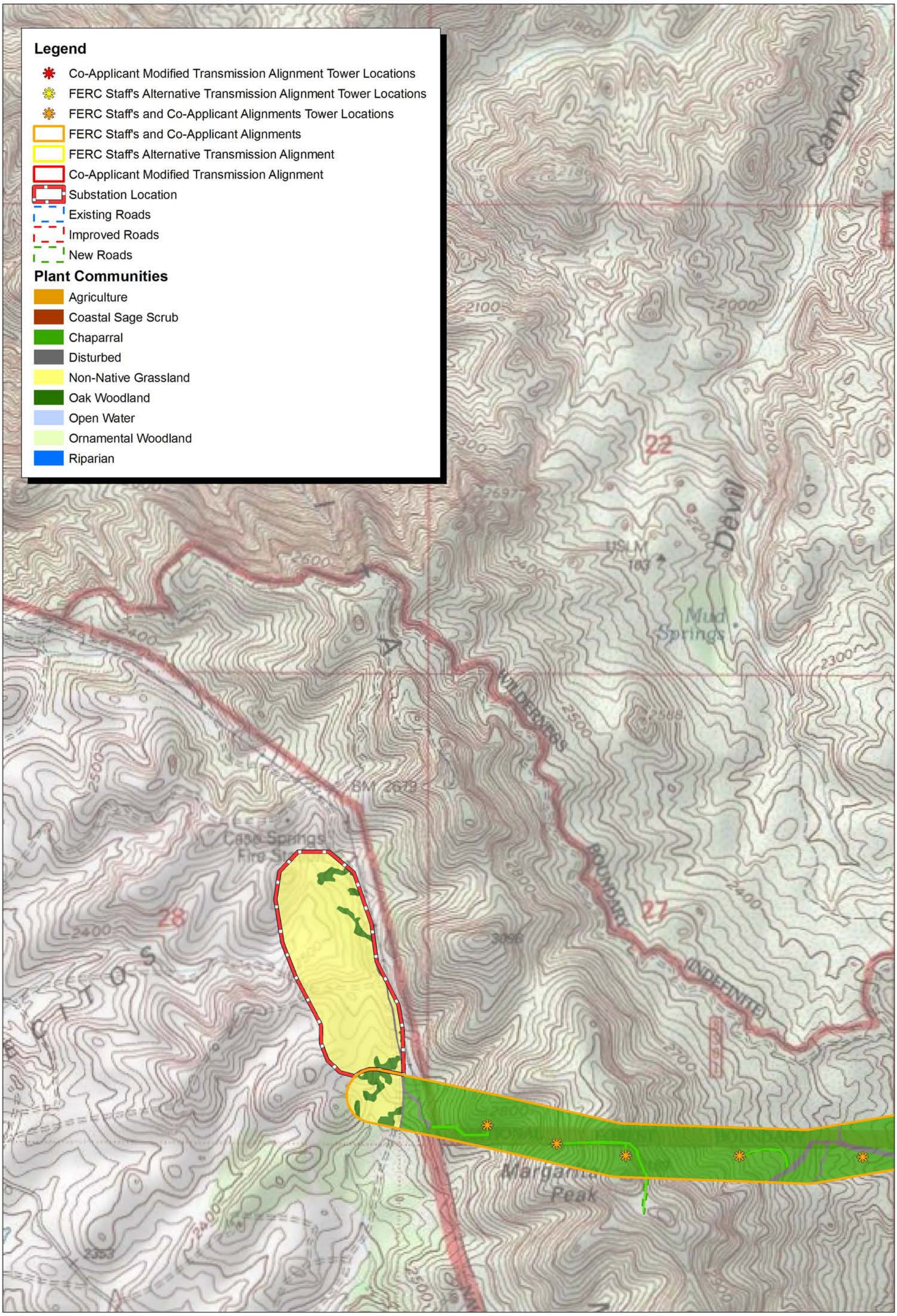
NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 11b.mxd

Exhibit 11b
Subarea 11 Plant Communities Map
Aerial Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG and MBA Field Survey.

NORTH

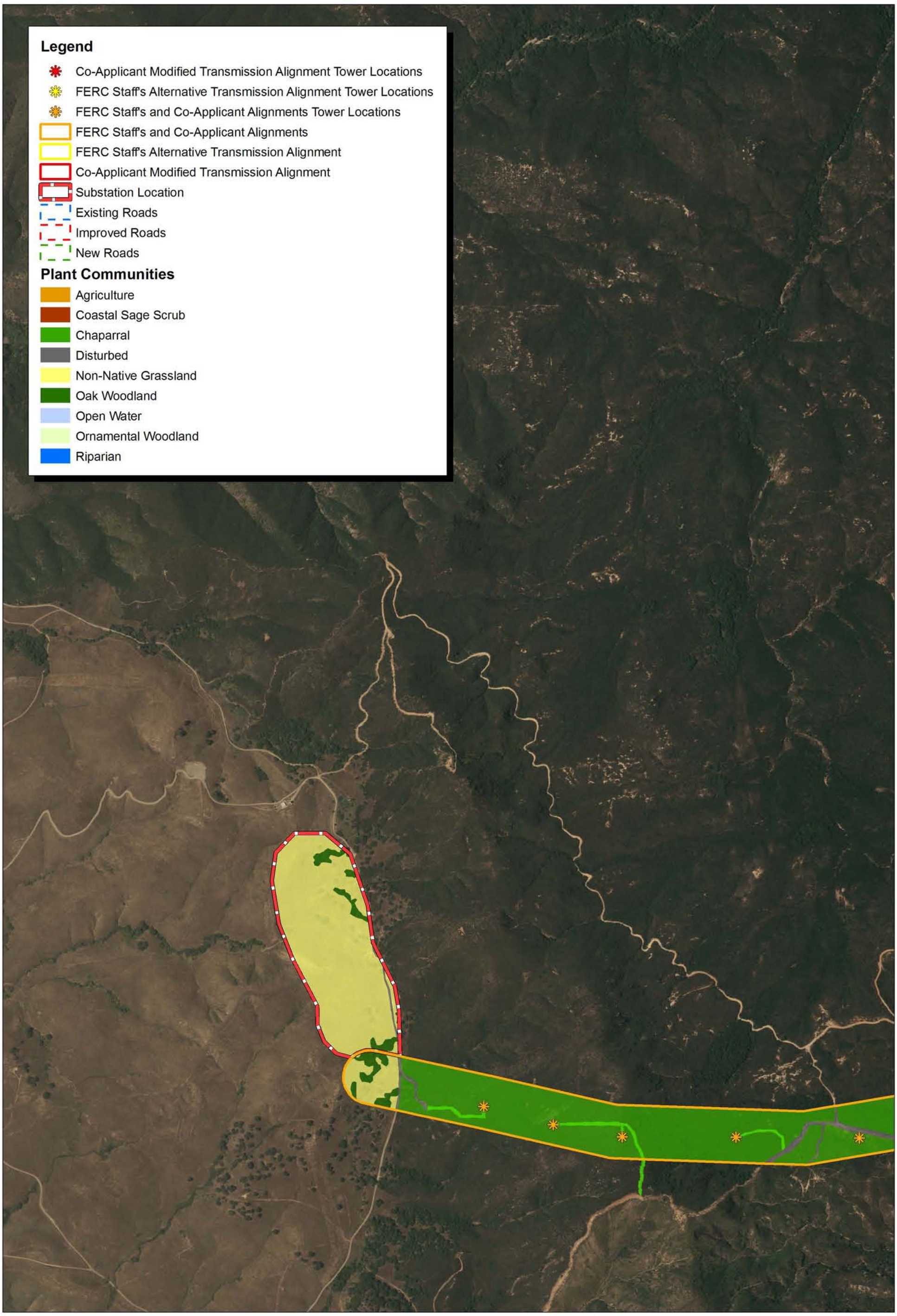
1,000 500 0 1,000 Feet

Michael Brandman Associates

27980005 • 09/2007 | 12a.mxd

Exhibit 12a
Subarea 12 Plant Communities Map
Topographic Base

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: Riverside County NAIP Imagery and MBA Field Survey.

Michael Brandman Associates

NORTH

1,000 500 0 1,000 Feet

27980005 • 09/2007 | 12b.mxd

Exhibit 12b
Subarea 12 Plant Communities Map
Aerial Base

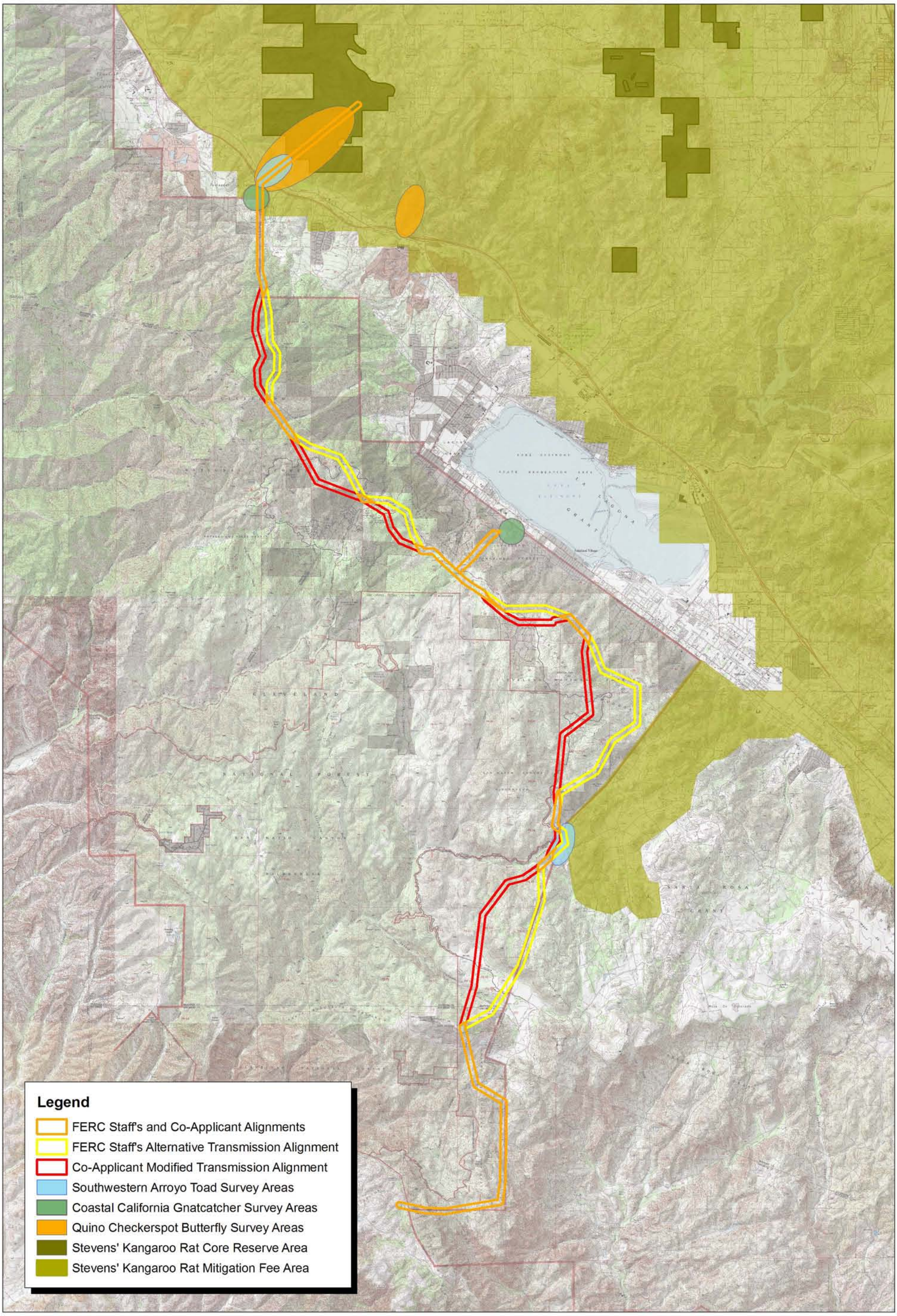
LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT

Appendix C: Sensitive Species Maps

List of Appendix C Exhibits

1 Sensitive Species Survey Areas

2 USFWS Designated Critical Habitat Map



Source: TOPO! USGS 7.5' DRG, USFWS, RCIP, and MBA Field Surveys.

Michael Brandman Associates

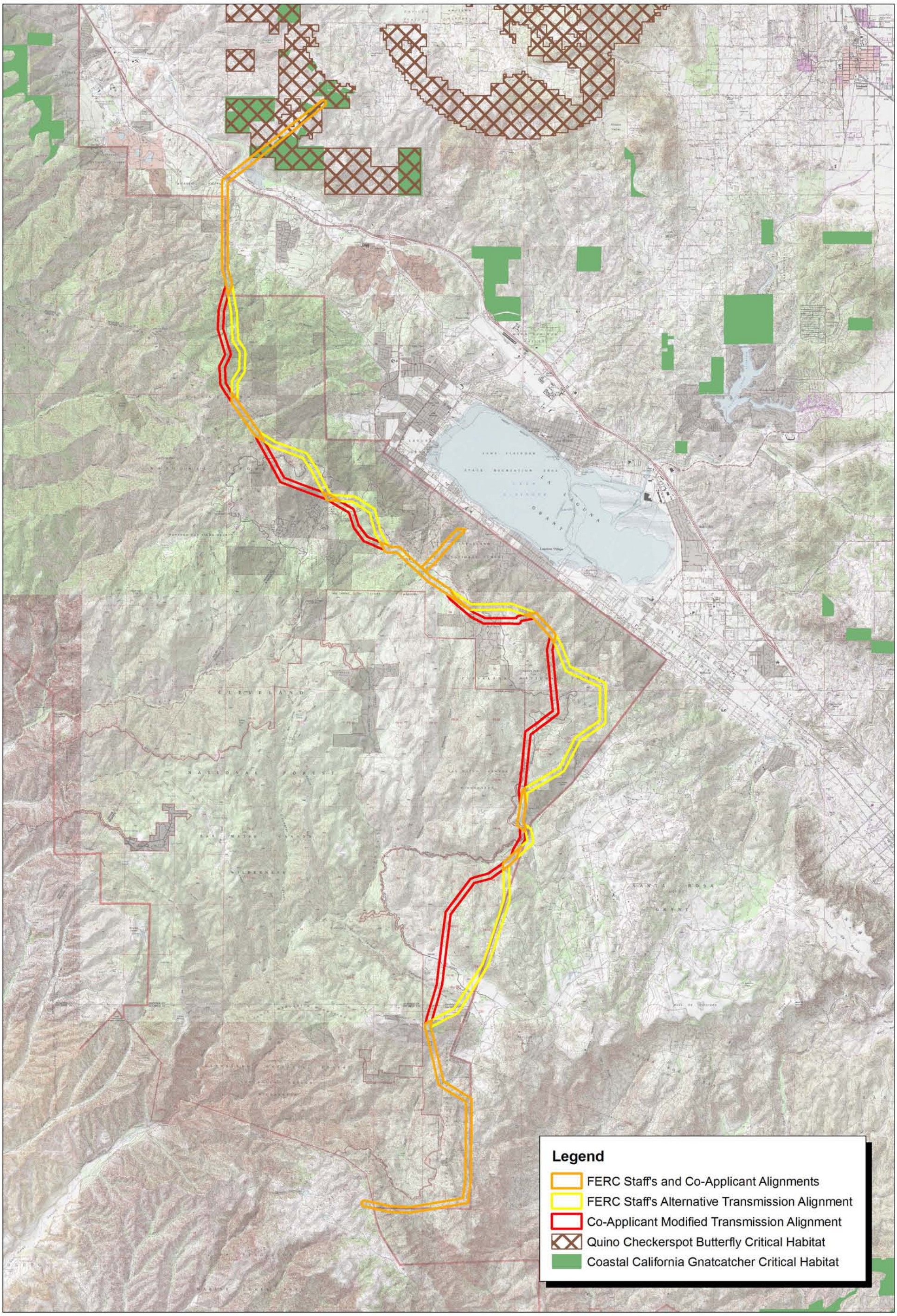
NORTH

1.8 0.9 0 1.8 Miles

Exhibit 1
Sensitive Species Survey Areas

27980005 • 08/2007 | c1_species_areas.mxd

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT



Source: TOPO! USGS 7.5' DRG, USFWS, and MBA Field Surveys.

Michael Brandman Associates

NORTH

1.8 0.9 0 1.8 Miles

27980005 • 01/2008 | c2_critical_habitat.mxd

Exhibit 2
USFWS Designated Critical Habitat Map

LAKE ELSINORE ADVANCED PUMP STORAGE
TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT PROJECT

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ORIGINAL

Docket No: P-11858

Your Name Alan Mitchnick **Phone** - 607Y

Please answer the following questions. **If the answers to all three questions are "yes," then this is a reportable off-the-record communication that should be forwarded to OSEC under Rule 2201.** If any answer is no, Rule 2201 is not implicated.

1. Is this a contested on-the-record proceeding? Yes ☒ No ☐
Has an intervener disputed a material issue, or did the Commission initiate the proceeding on its own motion or in response to a filing?

2. Is the communication relevant to the merits? Yes ☒ No ☐
Is it capable of affecting the outcome of a proceeding or influencing or providing the opportunity to influence a decision on an issue in the proceeding?

3. **Was the communication made off-the-record?** Yes ☒ No ☐
If written, not filed with the OSEC and, if a participant (party (including applicant, respondent or intervener), or trial staff), not served on the official service list.
If oral, made without reasonable prior notice to the parties and without opportunities for the parties to be present.

If answers to questions 1-3 above are all "yes," then this is a prohibited off-the-record communication unless it falls within one of the following exemptions. Refer to the new rule itself for more detail on each exemption.

i	**Expressly permitted by rule or order?**	☐
ii	**Related to emergencies?**	☐
iii	**Agreed to by the parties?**	☐
iv	**From non-party elected official?**	☐
v	**With non-party Federal, state, local or tribal official?**	☐
vi	**Related to NEPA documentation, and prior to FEIS/EA?**	☐
vii	**Communication with non-party landowner?**	☐

Please forward this form and the communication itself (whether prohibited or exempted) to OSEC.

Unofficial FERC-Generated PDF of 20070719-0013 Received by FERC OSEC 07/03/2007 in Docket#: P-11858-000

ORIGINAL

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Ecological Services
Carlsbad Fish and Wildlife Office
6010 Hidden Valley Road
Carlsbad, California 92011

FILED
OFFICE OF THE
SECRETARY
2007 JUL -3 P 3:16
FEDERAL ENERGY
REGULATORY COMMISSION

In Reply Refer To:
FWS-WRIV-2104.9

JUN 26 2007

Timothy J. Welch
Chief Hydro West Group 2
Federal Energy Regulatory Commission
888 First Street N.E.
Washington D.C. 20426

Subj: Formal Section 7 Consultation for the Lake Elsinore Advanced Pumped Storage Project (P-11858), Riverside County, California

Dear Mr. Welch:

This letter concerns the formal section 7 consultation under the Endangered Species Act of 1973 (Act), as amended (16 U.S.C. 1531 *et seq.*) for the above referenced project. The consultation concerns the possible effects of the proposed Lake Elsinore Advanced Pumped Storage Project (P-11858) on the federally endangered arroyo toad (*Bufo californicus*), Stephens' kangaroo rat (*Dipodomys stephensi*), and Quino checkerspot butterfly (*Euphydryas editha quino*), and the federally threatened coastal California gnatcatcher (*Polioptila californica californica*).

On May 11, 2006, we responded that the consultation was initiated upon receipt of your March 1, 2006, request, but that additional information may be requested upon review of the Draft Environmental Impact Statement (DEIS). On June 9, 2006, we requested that additional information be provided to us in order to complete the consultation. On February 7, 2007, we received a response letter from your agency; however, we still had not received all of the information necessary to complete formal consultation on the proposed action as documented in our March 15, 2007, response letter.

On May 23, 2007, we received another response from your agency indicating that the request for consultation was narrowed to four species and providing some additional information. The May 23, 2007, letter also indicates that consultation would only occur for the reservoir portion of the project for the arroyo toad and that the consultation for the powerlines and access roads would occur later for this species. The specific location of the powerlines and access roads has not yet been determined. The May 23, 2007, letter indicates that surveys would be done prior to ground disturbing activities for the powerlines and access roads and consultation would be initiated, as appropriate.

However, under the regulations implementing the Act (50 CFR § 402.02), the consultation must include an analysis of the effects of the proposed action along with the effects of all interrelated and

TAKE PRIDE IN AMERICA

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interdependent activities. An interrelated activity is an activity that is part of the proposed action and depends on the proposed action for its justification and an interdependent activity is an activity that has no independent utility apart from the action under consultation. Since the powerlines, access roads, and associated vegetation management activities depend upon the reservoir construction for their justification, we are not able to proceed with consultation on just the reservoir construction alone.

Thus, to complete consultation, we still need the following information for the four species mentioned above as documented in our previous letters:

1. The analysis in the FEIS does not include the potential effects of temporary and permanent roads associated with the construction and operation of the project. Please identify the proposed location of the roads, the acreage of habitat affected, any survey results, and an analysis of effects associated with road building, use and maintenance on federally-listed species.

2. The FEIS indicates that intensive vegetation management will occur surrounding the proposed structures and transmission lines, but the potential effects of the vegetation management activities do not appear to be fully described. Please identify the acreage of habitat affected, any survey results, and an analysis regarding vegetation management and effects to federally-listed species.

3. Please specify what noxious weed control measures will be implemented in areas with threatened or endangered species habitats.

4. Please provide a focused discussion regarding the potential effects of the proposed project on habitat conditions and the distribution of federally-listed species for the whole project area. In addition to the lack of complete habitat assessment/survey information for roads and vegetation management activities described above, the FEIS indicates on page 3-137 that "Surveys were not conducted in areas where the co-applicants' proposed alignment or staff alternative transmission alignment differ from the original alternatives, or at the southern substation that is currently included in both the co-applicants proposal and the staff." In order to address the missing information documented above for roads, vegetation management, and the proposed facilities, we recommend the completion of habitat assessments and appropriate presence/absence surveys for areas where these studies have not been done.

5. The May 23, 2007, letter provides additional information regarding the potential for release of Lake Elsinore water into the San Juan watershed. Your letter indicates that water from Lake Elsinore would primarily be released into the San Juan watershed during flood events. Please estimate how often these releases could potentially occur, the magnitude of the potential releases, and the nature of the effects to the water quality. Also, the FEIS indicates that remediation measures will be implemented upon the release of non-native species into San Juan Creek. Please specify what measures would be implemented. Finally, the proposed project indicates that transmission towers would be located outside of riparian areas to avoid

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adverse effects to riparian vegetation and stream habitat. Please specify how far transmission towers will be located from drainages where arroyo toads occur and what erosion control measures will be implemented.

In addition, we previously requested in our letter dated June 9, 2006, and in our letter dated March 15, 2007, that you specify whether or not the proposed transmission lines impact the Habitat Conservation Plan for the Stephens' Kangaroo Rat Core Reserve lands and identify the extent of the effects within these areas. We also requested specific information regarding any proposed off-setting measures. The May 23, 2007, letter indicates that 37.25 acres of the project is within Core Reserve lands and a minimum 1:1 replacement of habitat types lost to construction might be included as part of the project. Please specify whether or not this off-setting measure is included in the project and the nature and location of the proposed replacement habitat, if included.

Upon development of the above information, we recommend discussions with our agency regarding the inclusion of specific conservation measures to minimize effects to listed species for incorporation into the proposed action. The May 23, 2007, letter indicates that the proposed action is to recommend the development of plans to minimize effects to listed species to the applicant, but does not commit to implementing specific measures. We recommend committing to implementing specific conservation measures as part of the proposed action and including these specific measures in the proposed action. If conservation measures are included, please provide detailed information regarding the proposed measures, especially with regards to the acquisition and dedication of replacement habitat as part of the proposed action.

Please note that upon receipt of the information requested above, we may recommend additional habitat assessments and/or surveys. Also, please note that without receiving the information requested, we will be unable to complete the biological opinion for this project. If you are unable to provide the requested information in a timely manner, we recommend that the consultation be withdrawn. If you have any questions about this consultation or the consultation process in general, please contact Jesse Bennett of my staff at (760) 431-9440.

Sincerely,

for Karen A. Goebel
Assistant Field Supervisor

cc:
Peggy Hernandez, Cleveland National Forest
Keith Fletcher, Cleveland National Forest, Trabuco Ranger District

Appendix B: Plant Community Maps

Appendix B:
List of Exhibits

230kV Line Plant Communities

1 Plant Communities Index Map

1a Transmission Line Vegetation Map (1 of 9) - Topographic Base

1b Transmission Line Vegetation Map (1 of 9) - Aerial Base

2a Transmission Line Vegetation Map (2 of 9) - Topographic Base

2b Transmission Line Vegetation Map (2 of 9) - Aerial Base

3a Transmission Line Vegetation Map (3 of 9) - Topographic Base

3b Transmission Line Vegetation Map (3 of 9) - Aerial Base

4a Transmission Line Vegetation Map (4 of 9) - Topographic Base

4b Transmission Line Vegetation Map (4 of 9)- Aerial Base

5a Transmission Line Vegetation Map (5 of 9) - Topographic Base

5b Transmission Line Vegetation Map (5 of 9) - Aerial Base

6a Transmission Line Vegetation Map (6 of 9) - Topographic Base

6b Transmission Line Vegetation Map (6 of 9) - Aerial Base

7a Transmission Line Vegetation Map (7 of 9) - Topographic Base

7b Transmission Line Vegetation Map (7 of 9) - Aerial Base

8a Transmission Line Vegetation Map (8 of 9) - Topographic Base

8b Transmission Line Vegetation Map (8 of 9) - Aerial Base

9a Transmission Line Vegetation Map (9 of 9) - Topographic Base

9b Transmission Line Vegetation Map (9 of 9) - Aerial Base

69kV Line Plant Communities

10 7.8 Mile Alternate Transmission Line Plant Communities Index Map

10a 7.8 Mile Alternate Transmission Line Vegetation Map (1 of 5) - Topographic Base

10b 7.8 Mile Alternate Transmission Line Vegetation Map (1 of 5) - Aerial Base

11a 7.8 Mile Alternate Transmission Line Vegetation Map (2 of 5) - Topographic Base

11b 7.8 Mile Alternate Transmission Line Vegetation Map (2 of 5) - Aerial Base

12a 7.8 Mile Alternate Transmission Line Vegetation Map (3 of 5) - Topographic Base

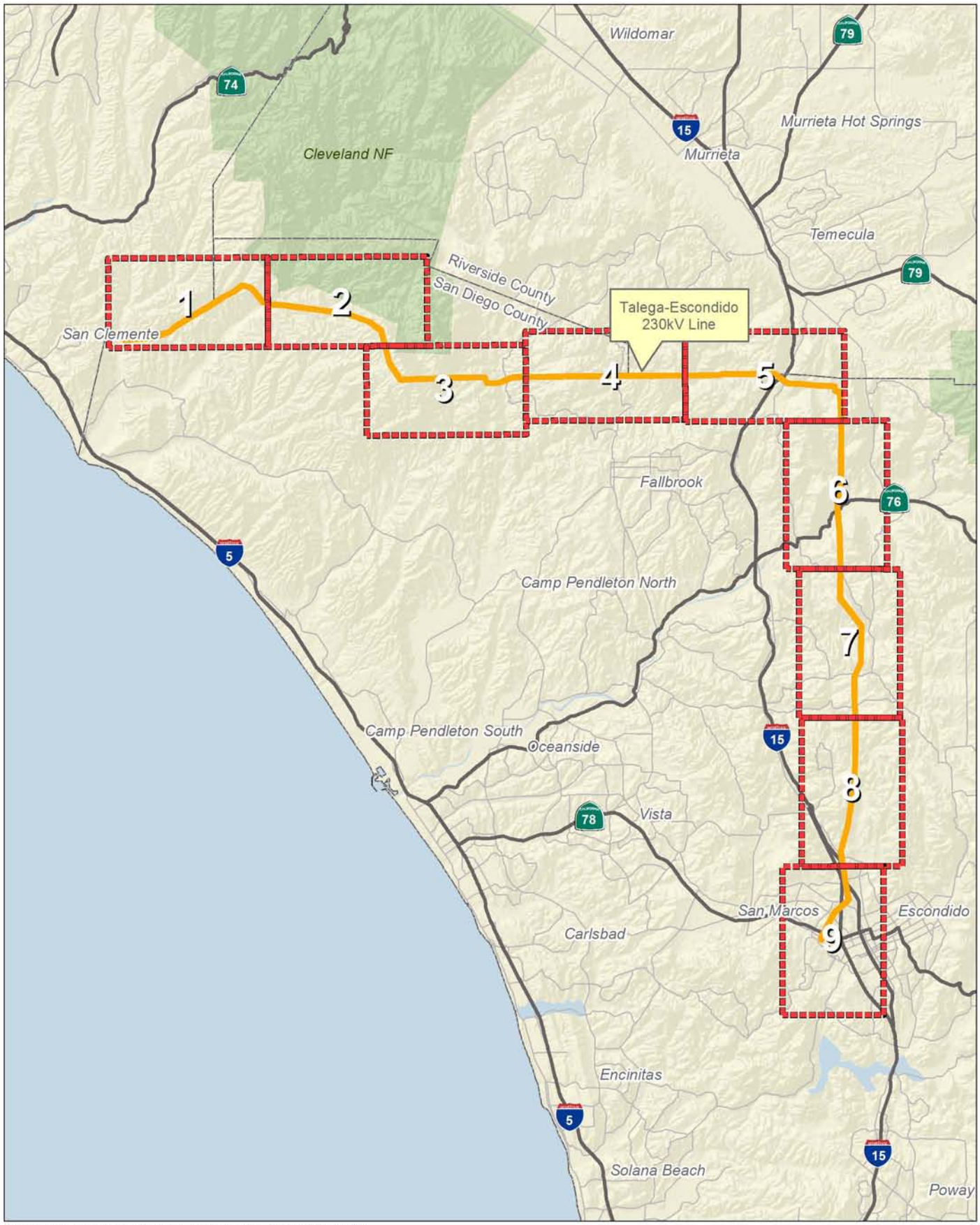
12b 7.8 Mile Alternate Transmission Line Vegetation Map (3 of 5) - Aerial Base

13a 7.8 Mile Alternate Transmission Line Vegetation Map (4 of 5) - Topographic Base

13b 7.8 Mile Alternate Transmission Line Vegetation Map (4 of 5) - Aerial Base

14a 7.8 Mile Alternate Transmission Line Vegetation Map (5 of 5) - Topographic Base

14b 7.8 Mile Alternate Transmission Line Vegetation Map (5 of 5) - Aerial Base



Source: Census 2000 Data, The CaSIL, MBA GIS 2009.

Michael Brandman Associates

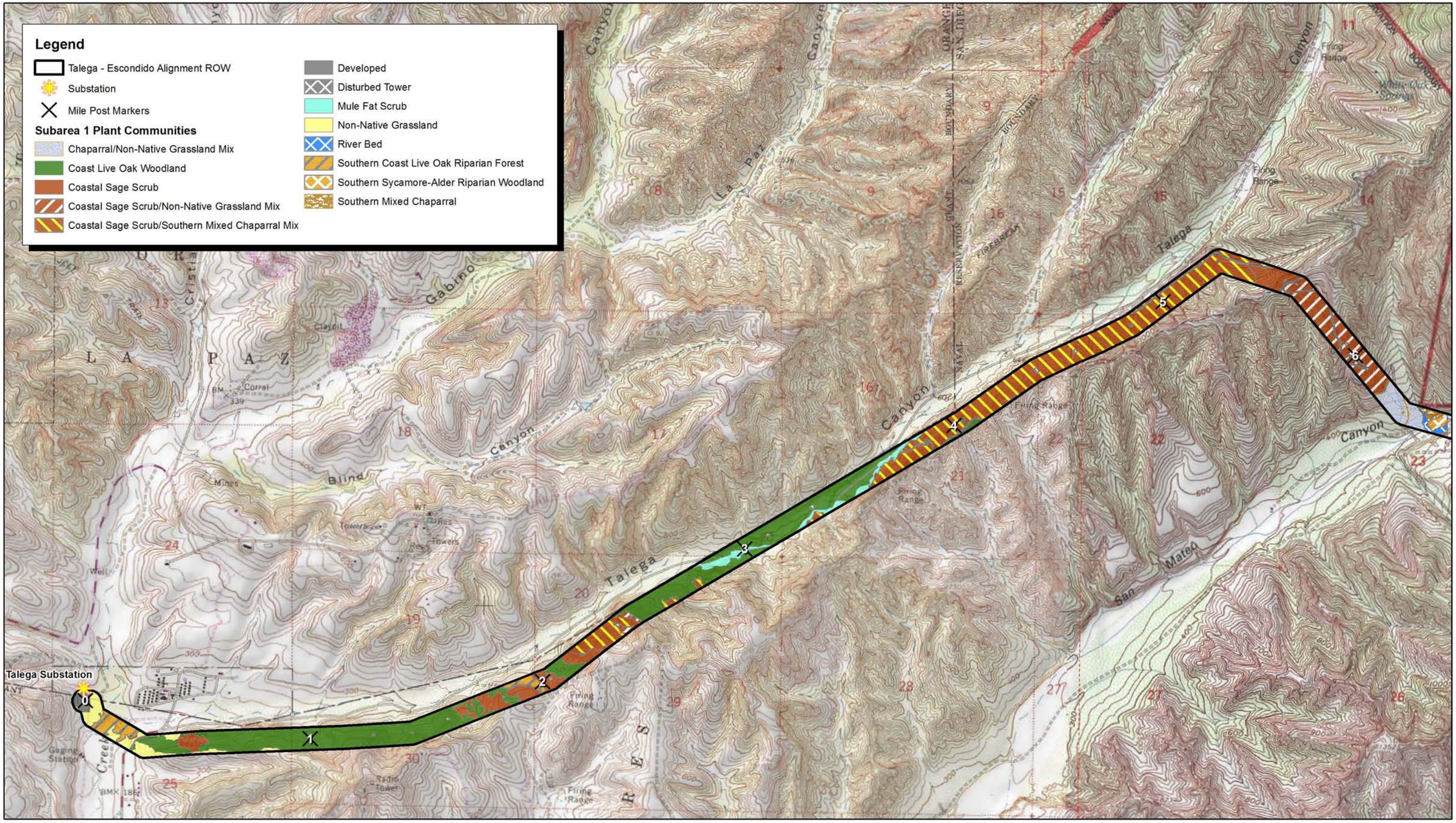
NORTH

5 2.5 0 5 Miles

Exhibit 1
Plant Communities Index Map

27980011 • 01/2009 | 1_index.mxd

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

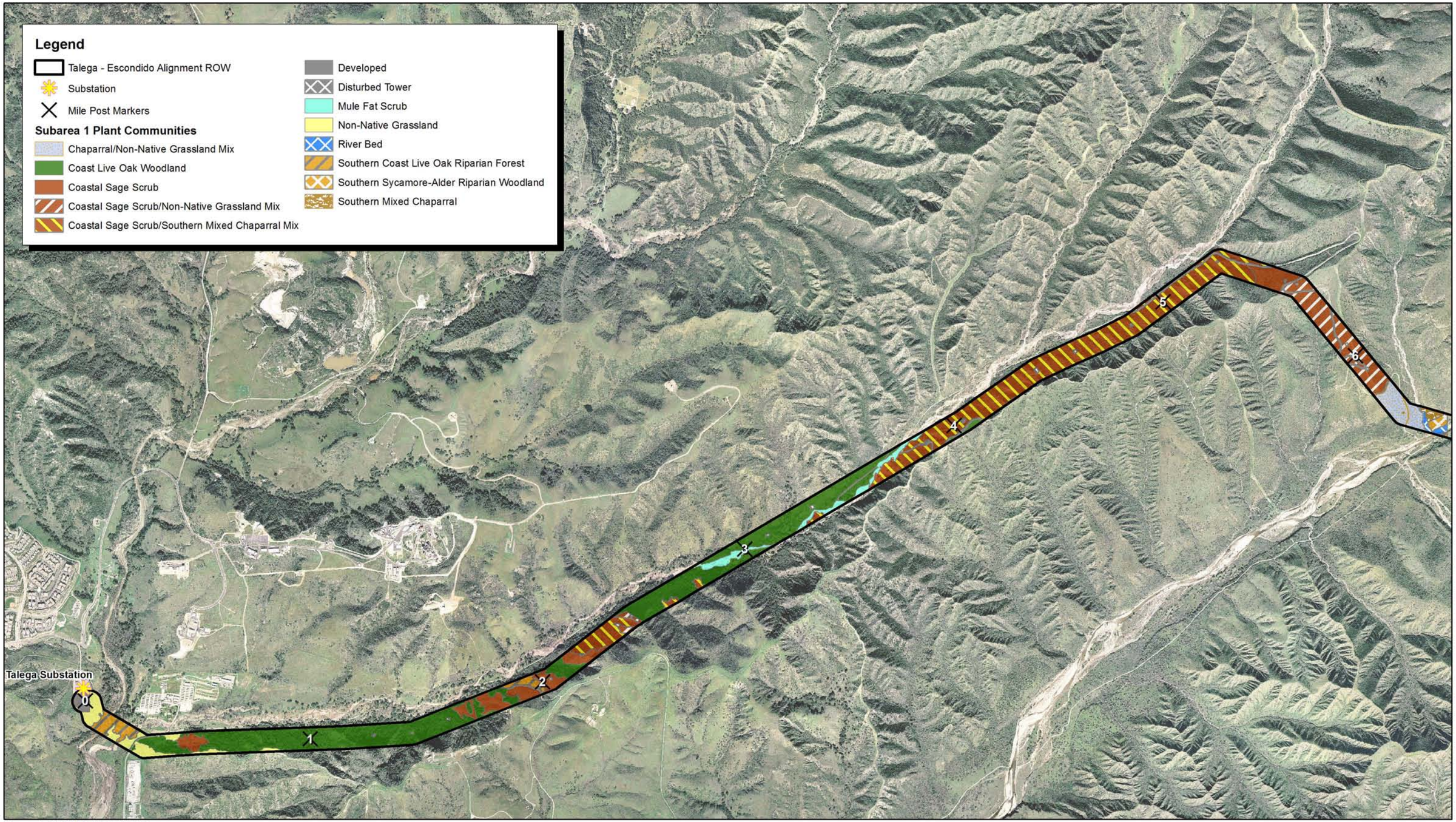
NORTH

2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 1a_subarea1_veg_topo.mxd

Exhibit 1a
Transmission Line Vegetation Map (1 of 9)
Topographic Base



Source: TOPO! USGS 7.5' DRG.

NORTH

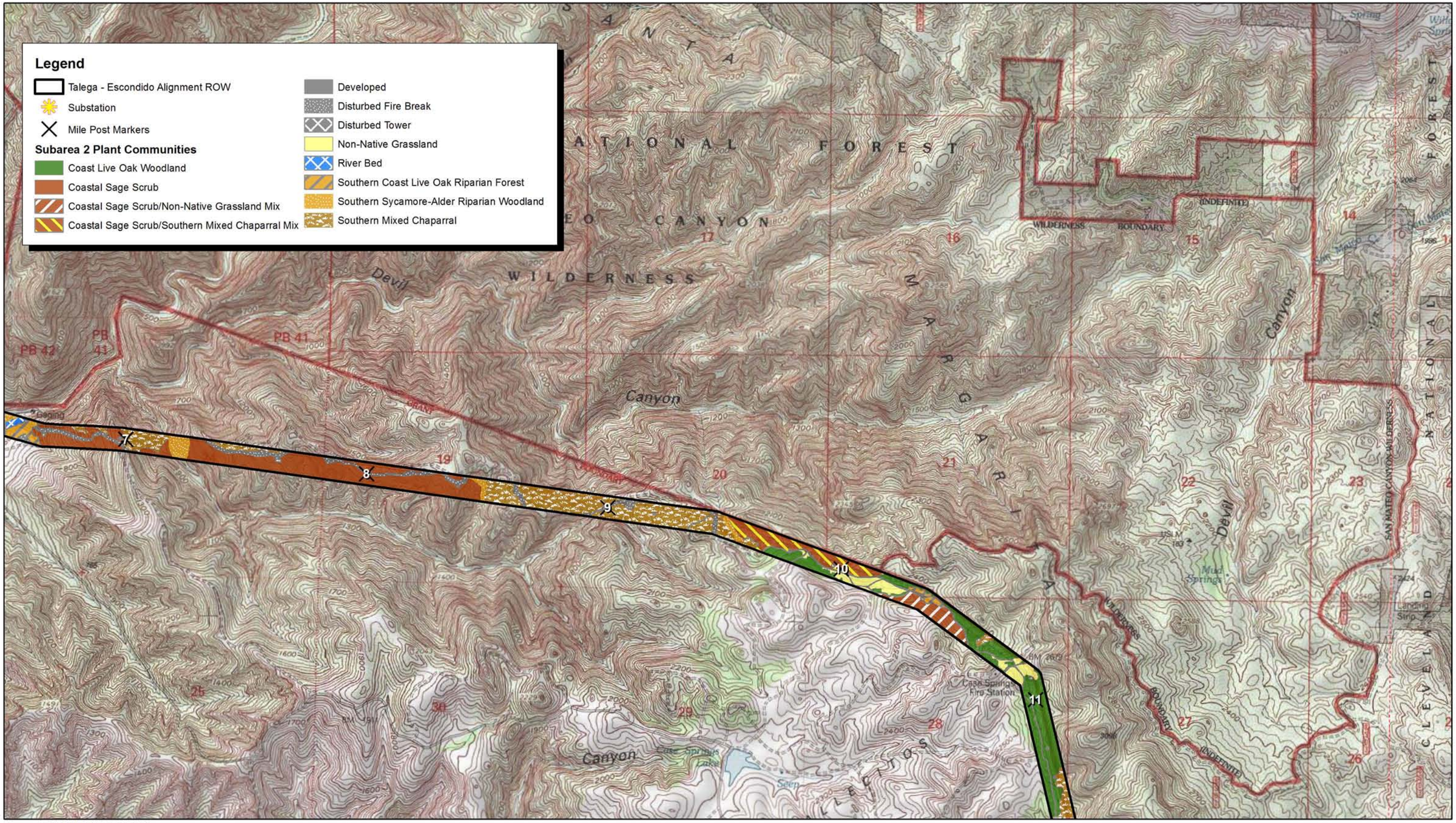
2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 1b_subarea1_veg_aerial.mxd

Exhibit 1b
Transmission Line Vegetation Map (1 of 9)
Aerial Base

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

NORTH

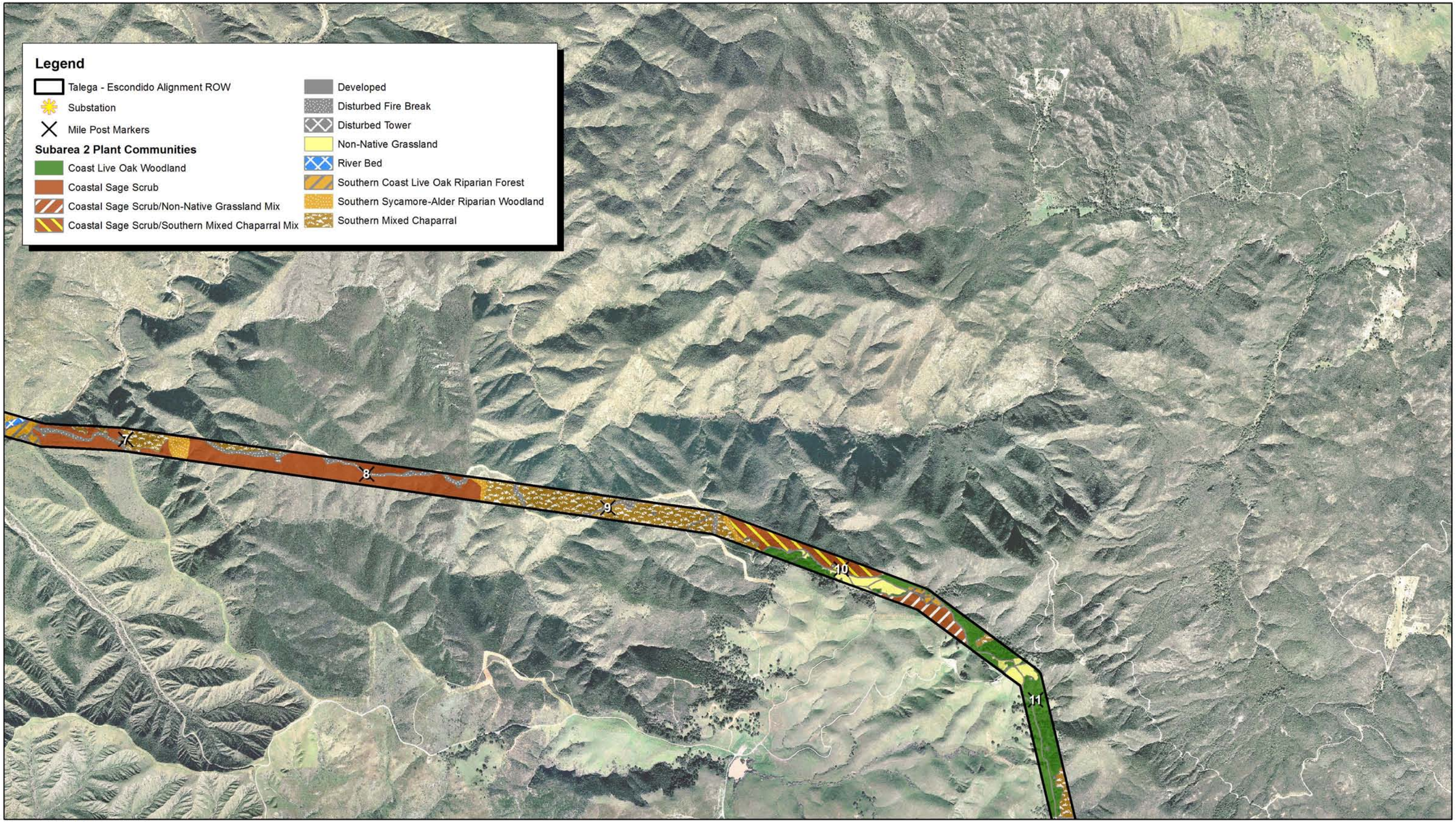
2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 2a_subarea1_veg_topo.mxd

Exhibit 2a
Transmission Line Vegetation Map (2 of 9)
Topographic Base

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

NORTH

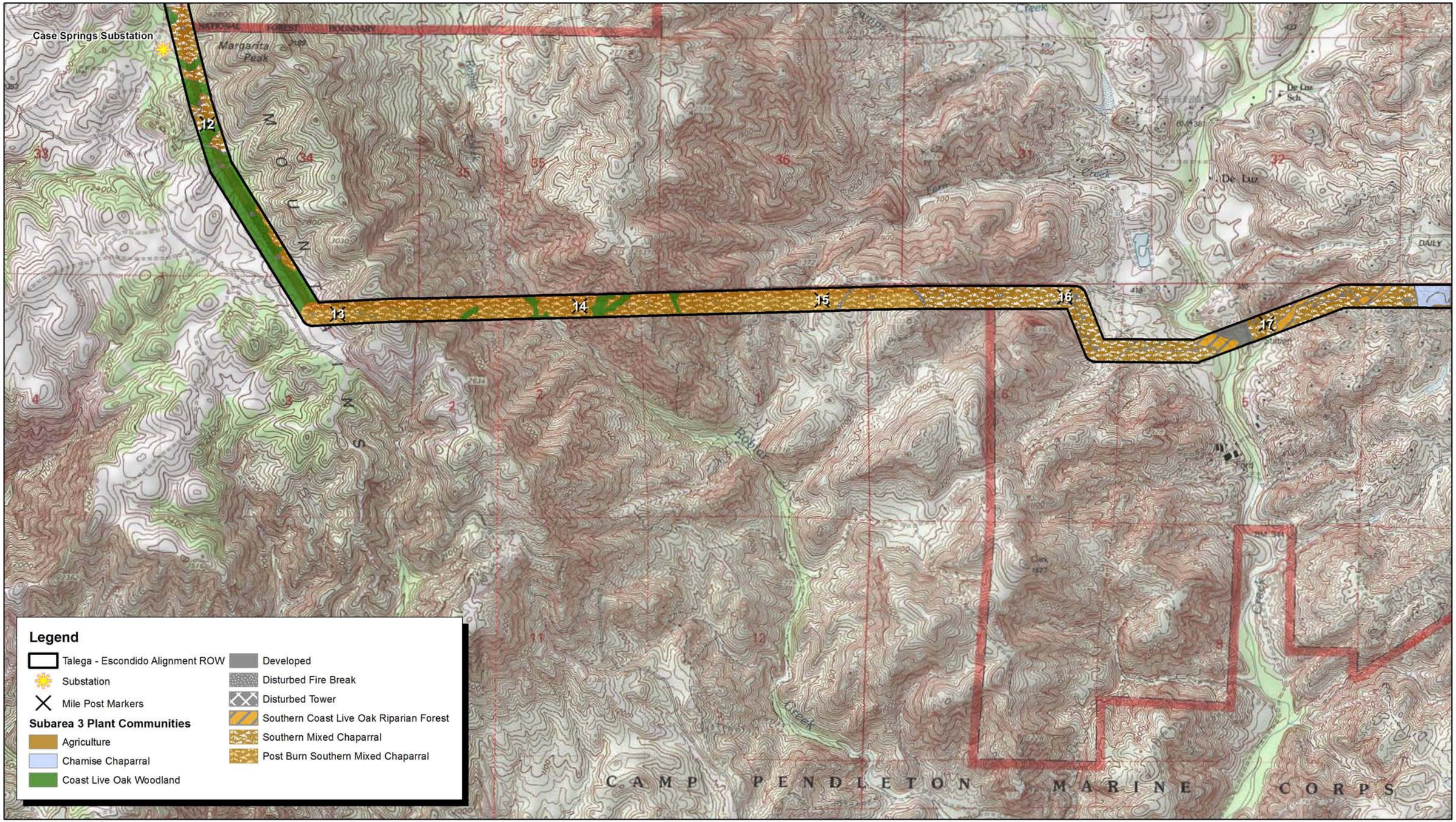
2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 2b_subarea1_veg_aerial.mxd

Exhibit 2b
Transmission Line Vegetation Map (2 of 9)
Aerial Base

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

NORTH

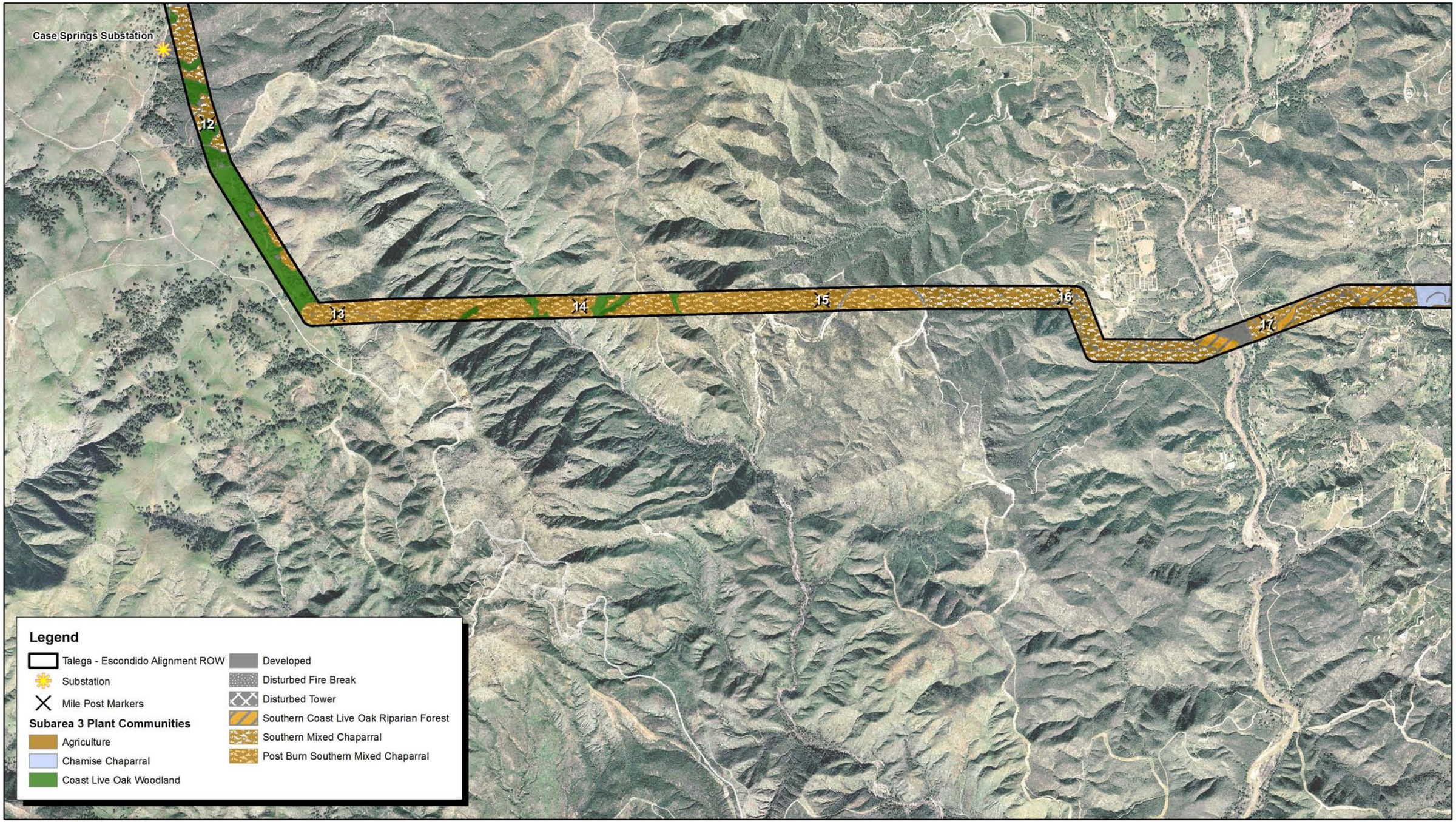
2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 3a_subarea3_veg_topo.mxd

Exhibit 3a
Transmission Line Vegetation Map (3 of 9)
Topographic Base

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

NORTH

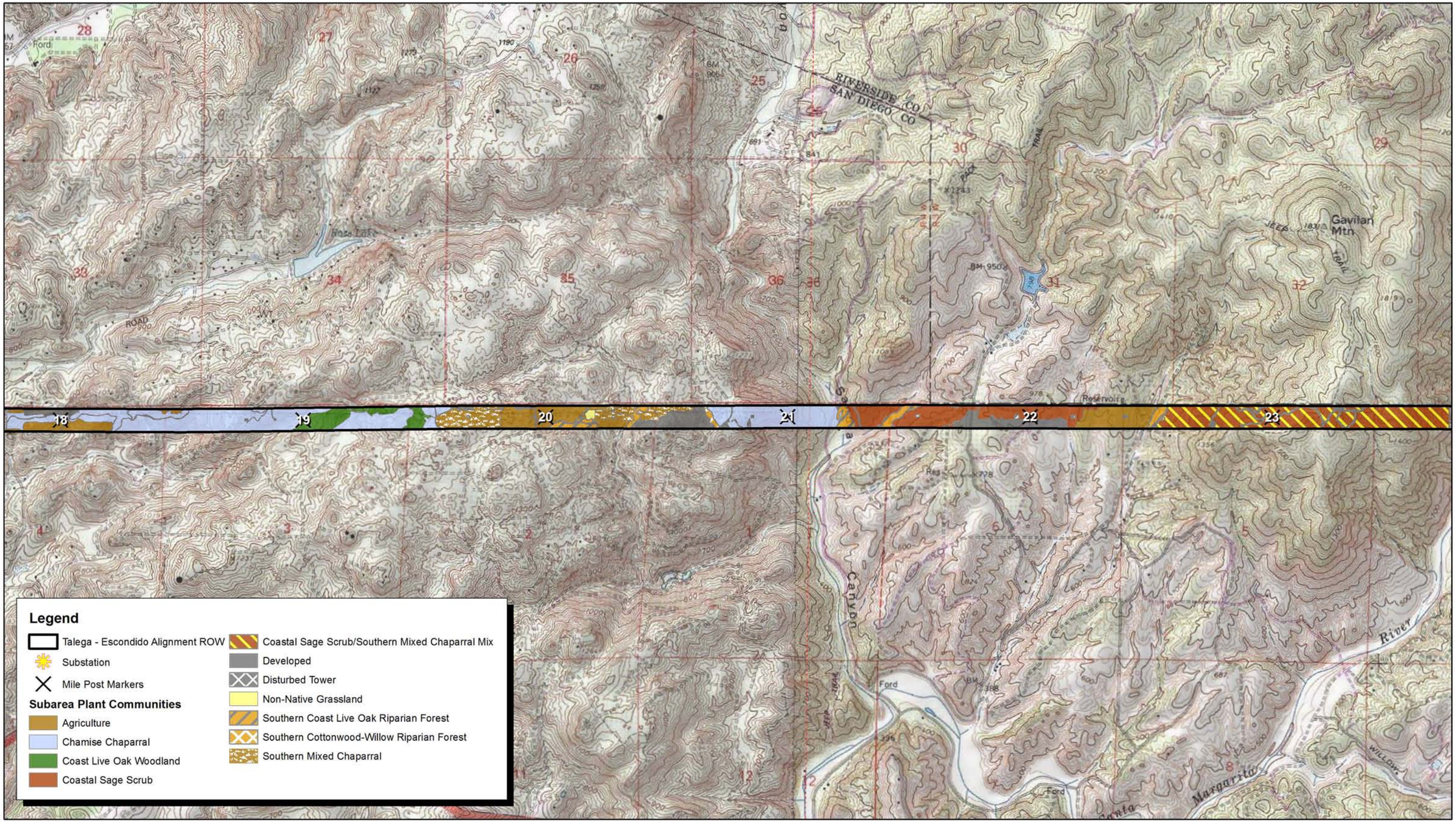
2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 3b_subarea3_veg_aerial.mxd

Exhibit 3b
Transmission Line Vegetation Map (3 of 9)
Aerial Base

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

Michael Brandman Associates

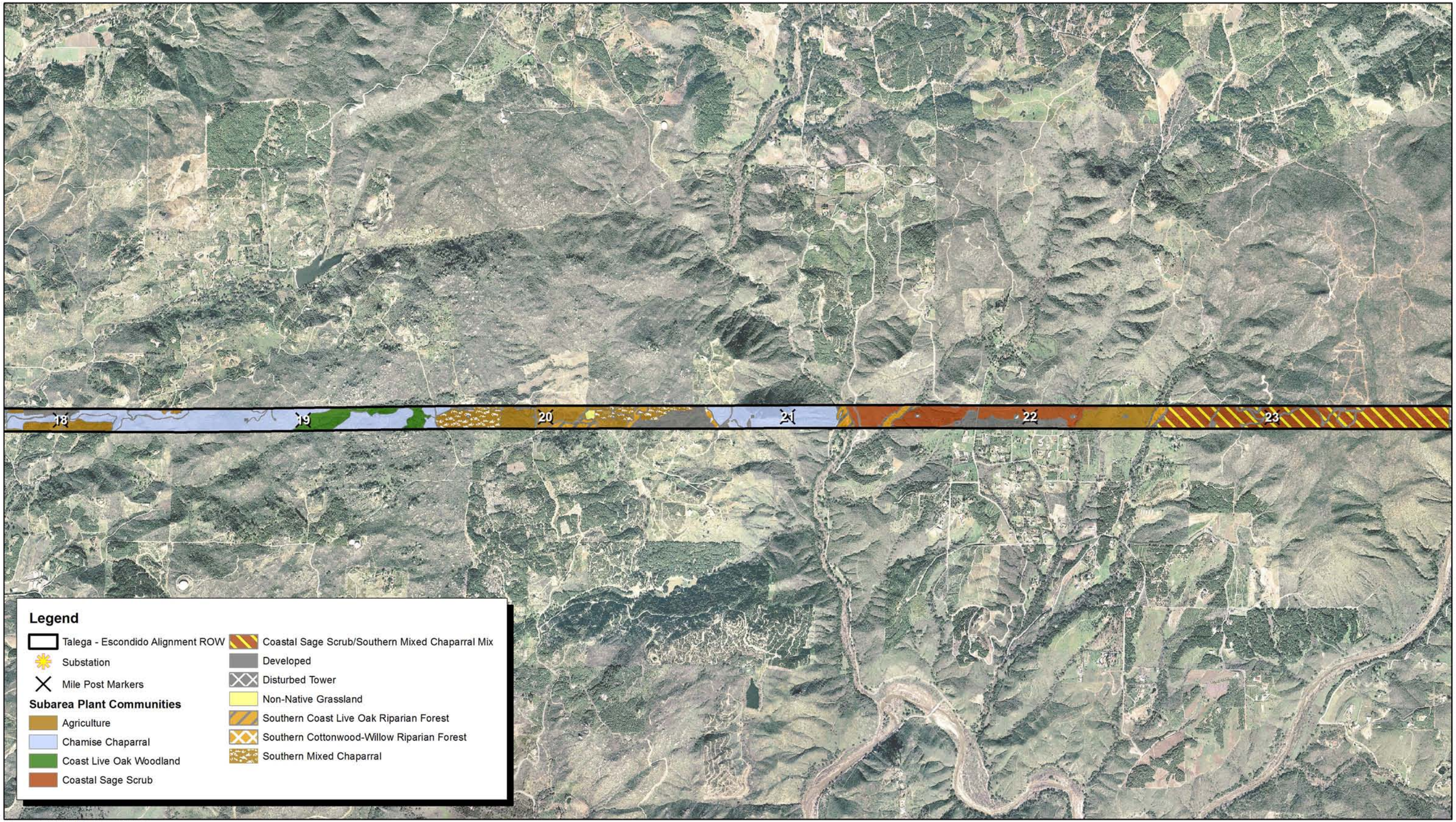
NORTH

2,000 1,000 0 2,000 Feet

27980011 • 01/2009 | 4a_subarea4_veg_topo.mxd

Exhibit 4a
Transmission Line Vegetation Map (4 of 9)
Topographic Base

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

NORTH

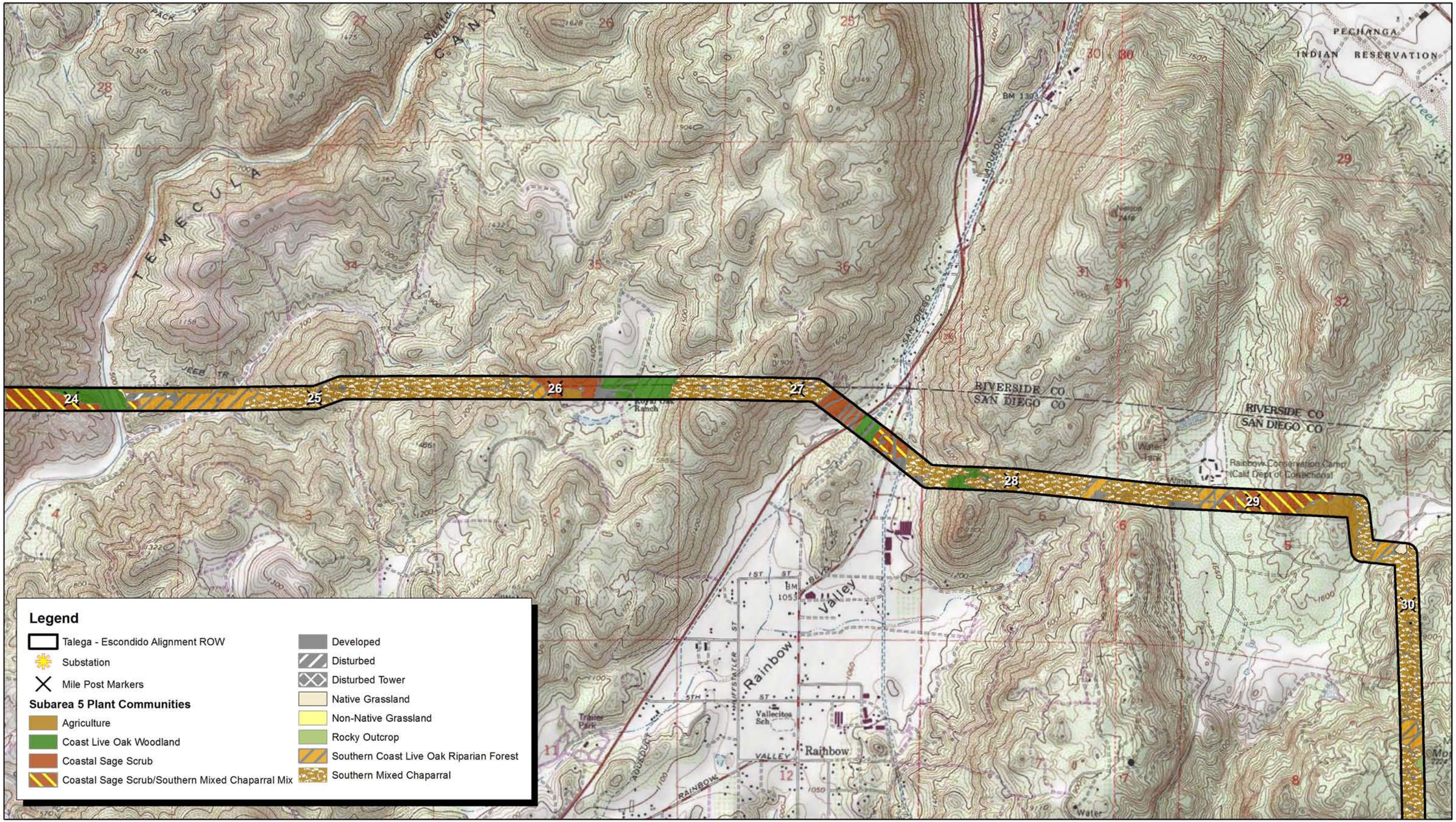
2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 4b_subarea4_veg_aerial.mxd

Exhibit 4b
Transmission Line Vegetation Map (4 of 9)
Aerial Base

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

NORTH

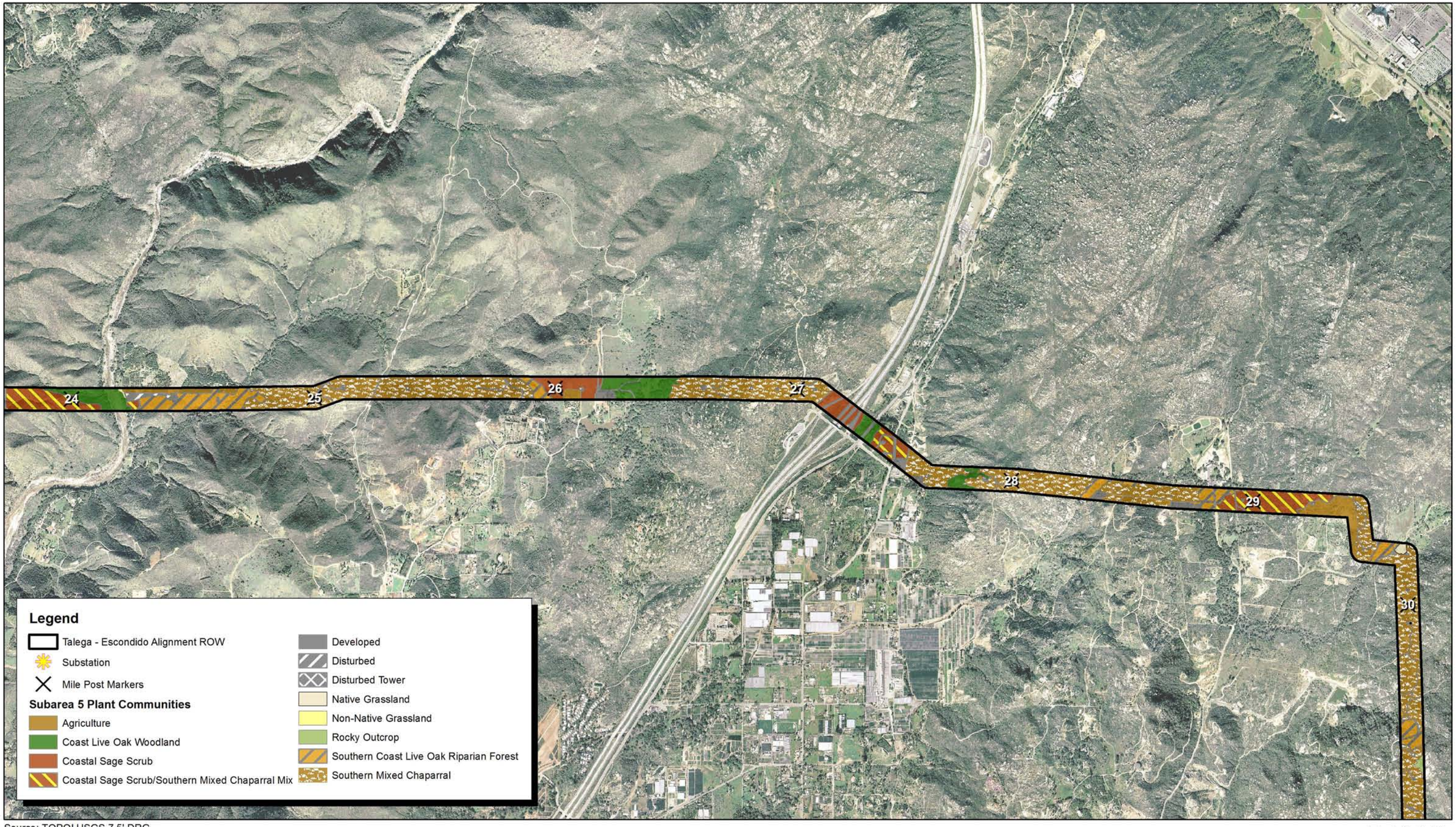
2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 5a_subarea5_veg_topo.mxd

Exhibit 5a
Transmission Line Vegetation Map (5 of 9)
Topographic Base

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

NORTH

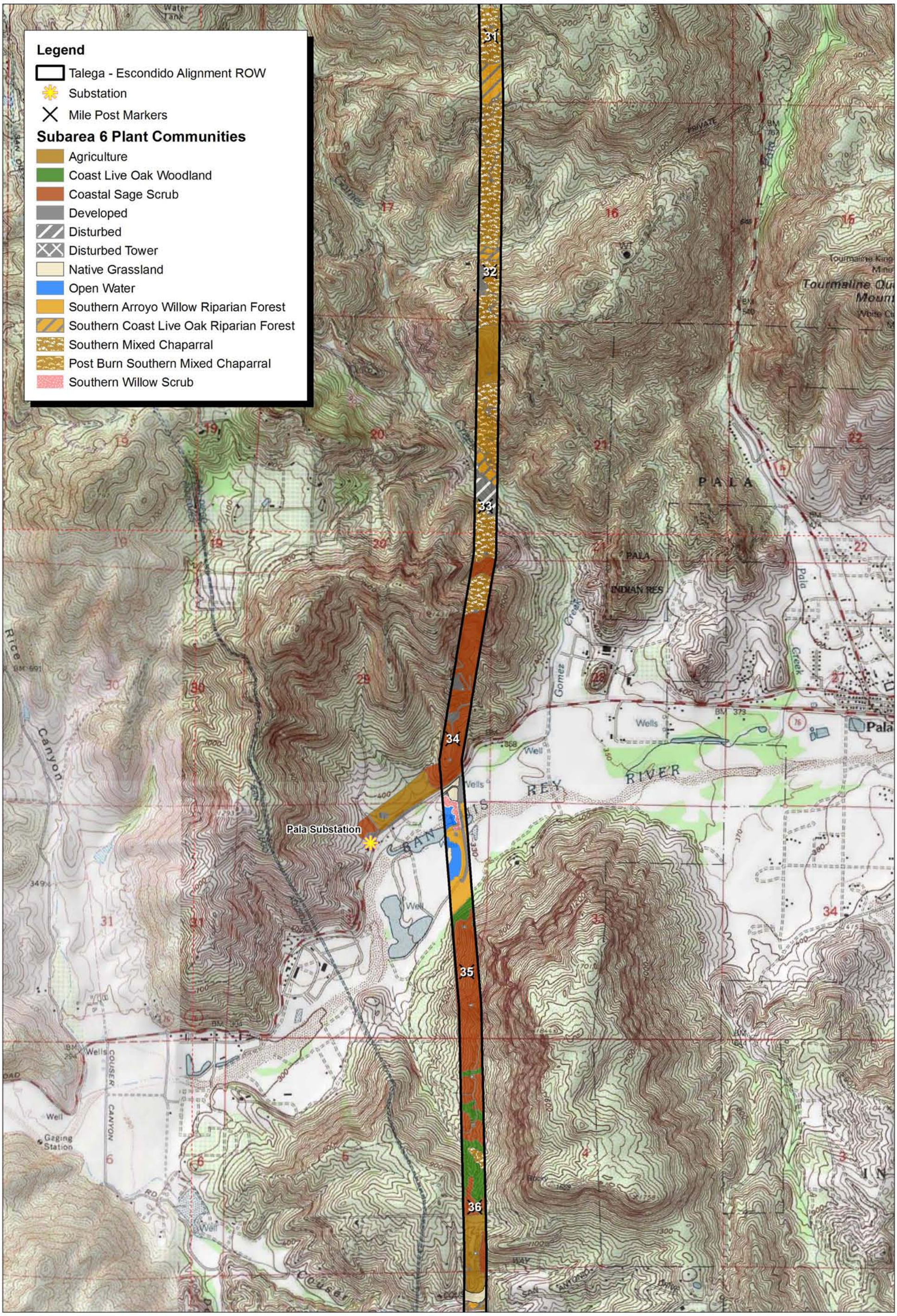
2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 5b_subarea5_veg_aerial.mxd

Exhibit 5b
Transmission Line Vegetation Map (5 of 9)
Aerial Base

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

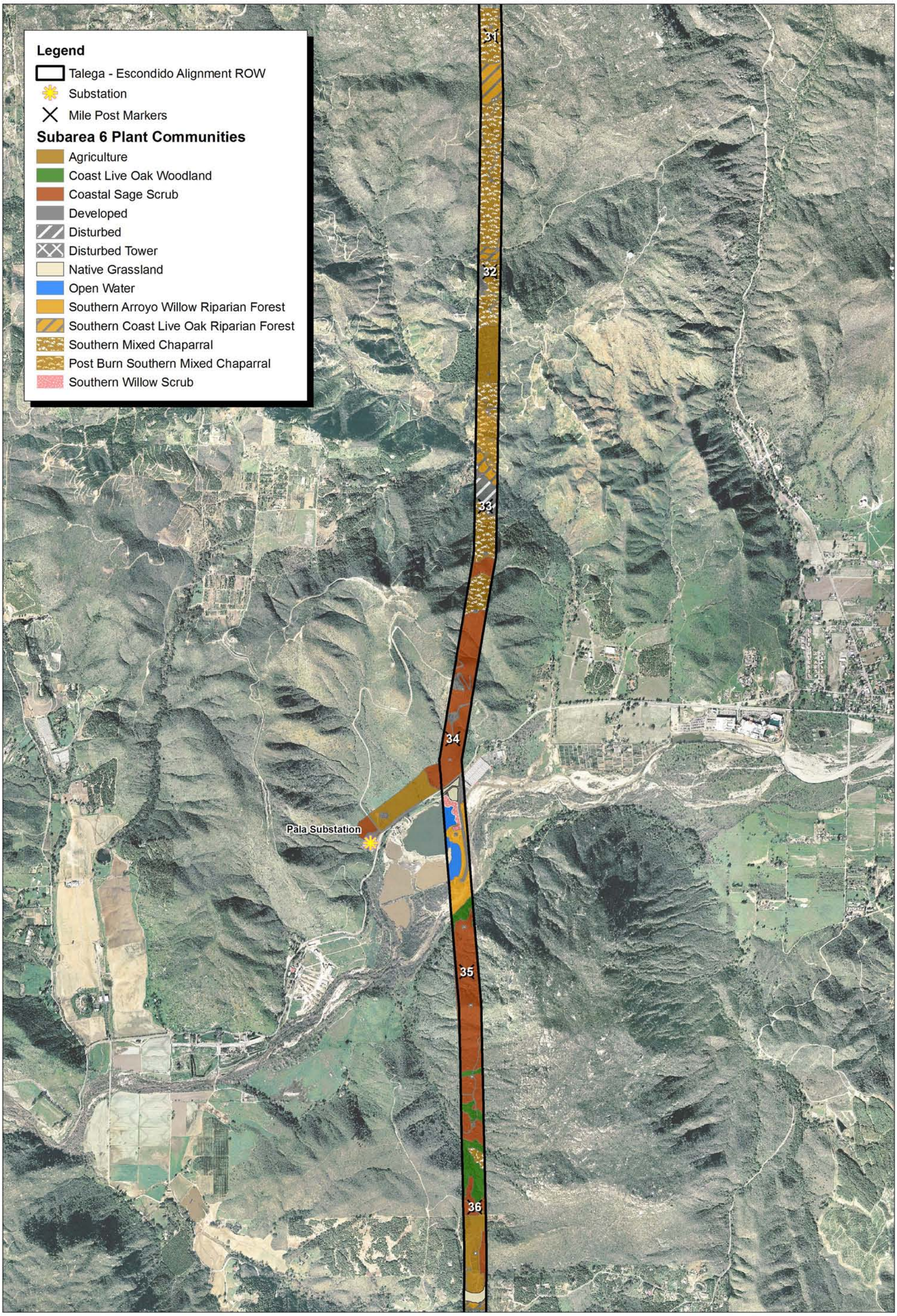
NORTH

2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 6a_subarea6_veg_topo.mxd

Exhibit 6a
Transmission Line Vegetation Map (6 of 9)
Topographic Base



Source: TOPO! USGS 7.5' DRG.

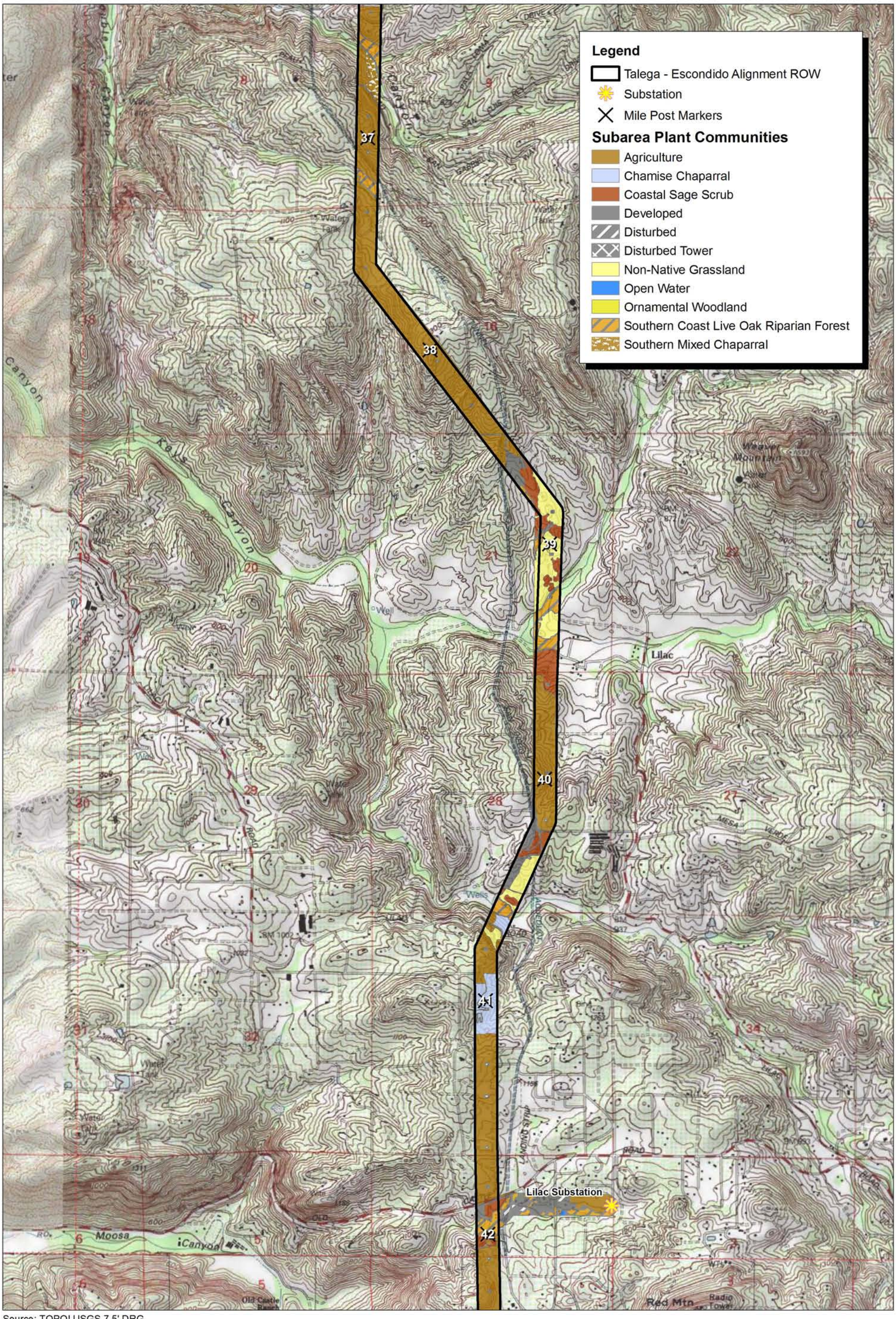
NORTH

2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 6b_subarea6_veg_aerial.mxd

Exhibit 6b
Transmission Line Vegetation Map (6 of 9)
Aerial Base



Source: TOPO! USGS 7.5' DRG.

NORTH

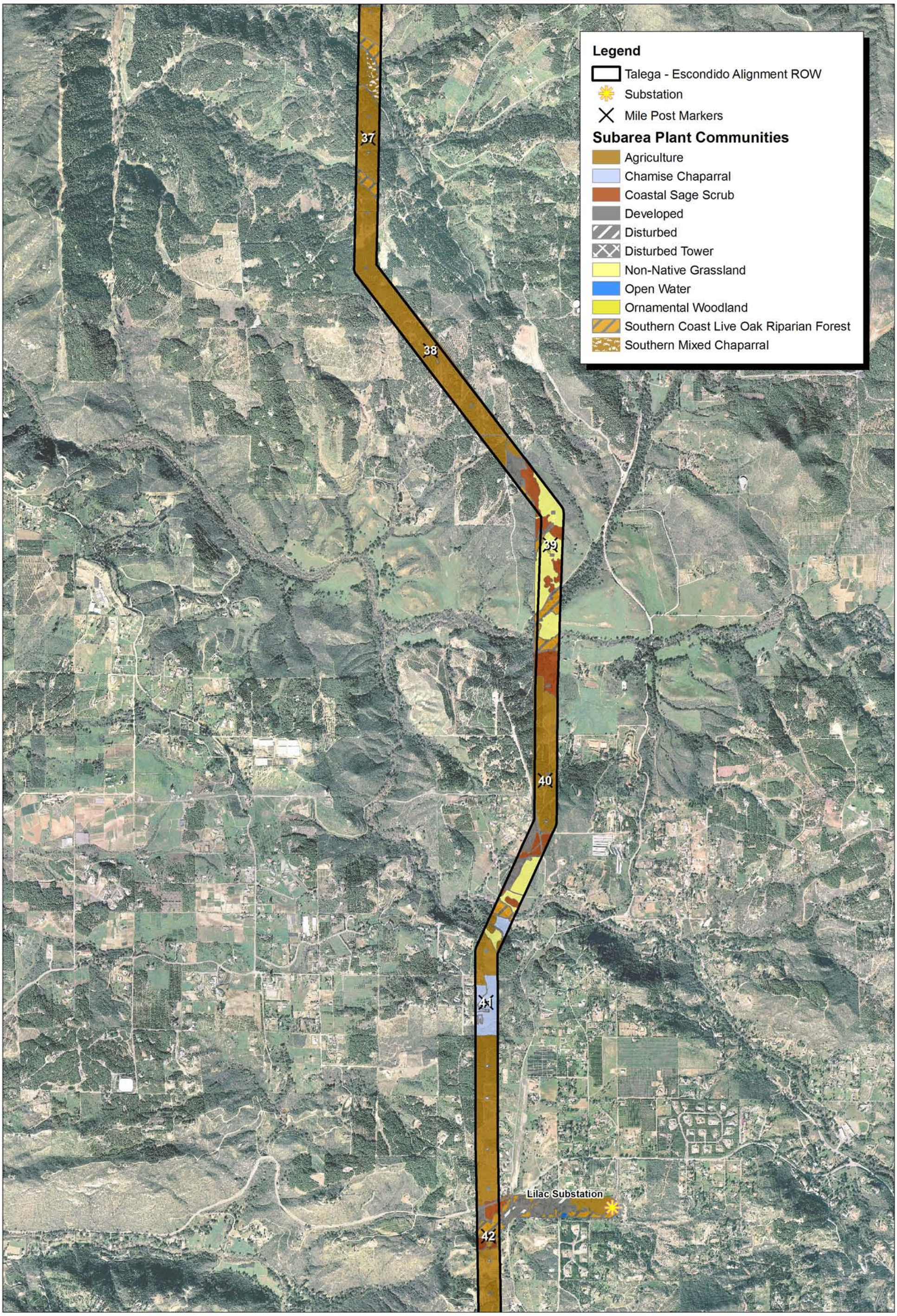
2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 7a_subarea7_veg_topo.mxd

Exhibit 7a
Transmission Line Vegetation Map (7 of 9)
Topographic Base

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

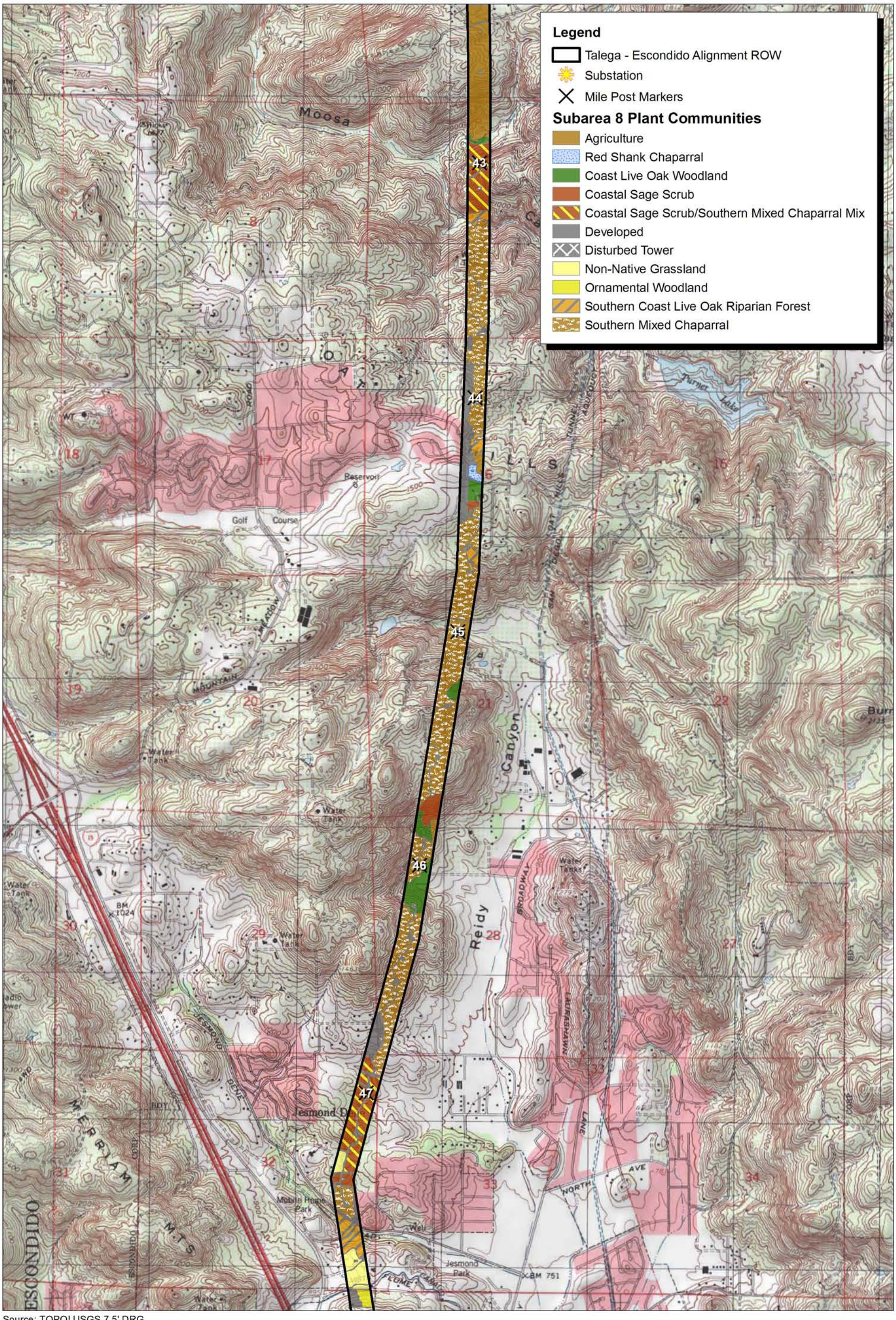
NORTH

2,000 1,000 0 2,000 Feet

Michael Brandman Associates

27980011 • 01/2009 | 7b_subarea7_veg_aerial.mxd

Exhibit 7b
Transmission Line Vegetation Map (7 of 9)
Aerial Base



Source: TOPO! USGS 7.5' DRG.

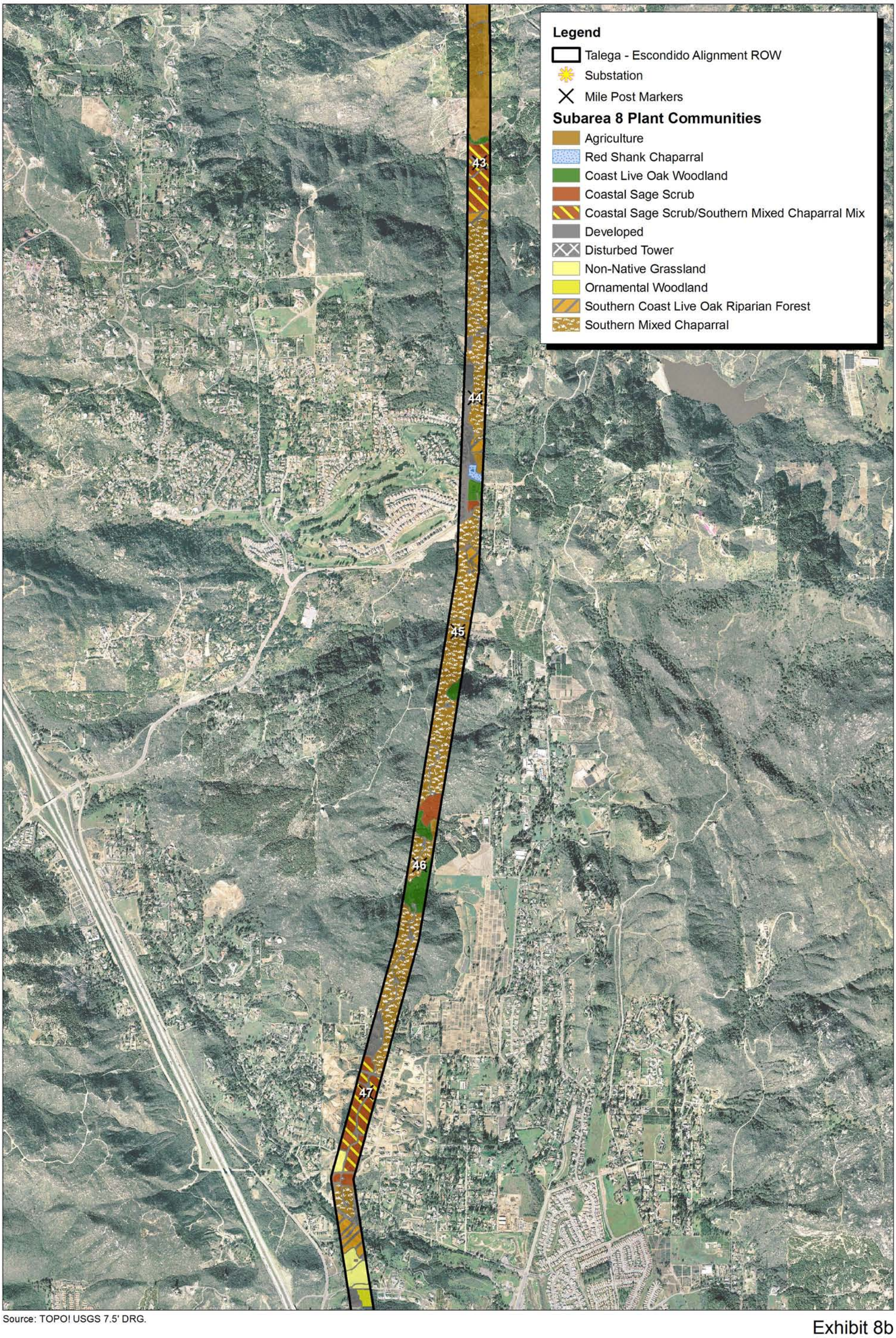
Michael Brandman Associates

NORTH

2,000 1,000 0 2,000 Feet

Exhibit 8a
Transmission Line Vegetation Map (8 of 9)
Topographic Base

27980011 • 01/2009 | 8a_subarea8_veg_topo.mxd



Source: TOPO! USGS 7.5' DRG.

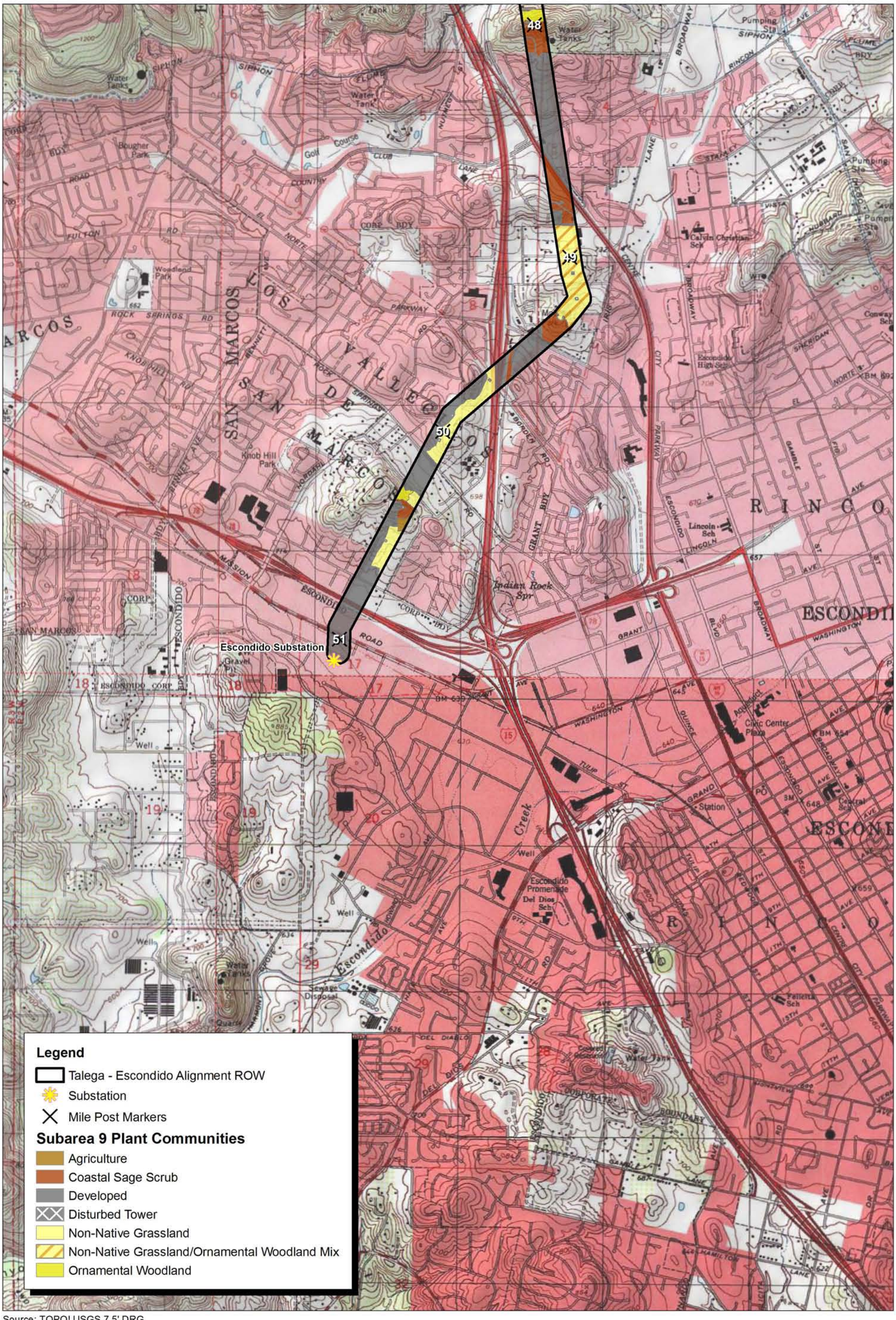
Michael Brandman Associates

NORTH

2,000 1,000 0 2,000 Feet

Exhibit 8b
Transmission Line Vegetation Map (8 of 9)
Aerial Base

27980011 • 01/2009 | 8b_subarea8_veg_aerial.mxd



Source: TOPO! USGS 7.5' DRG.

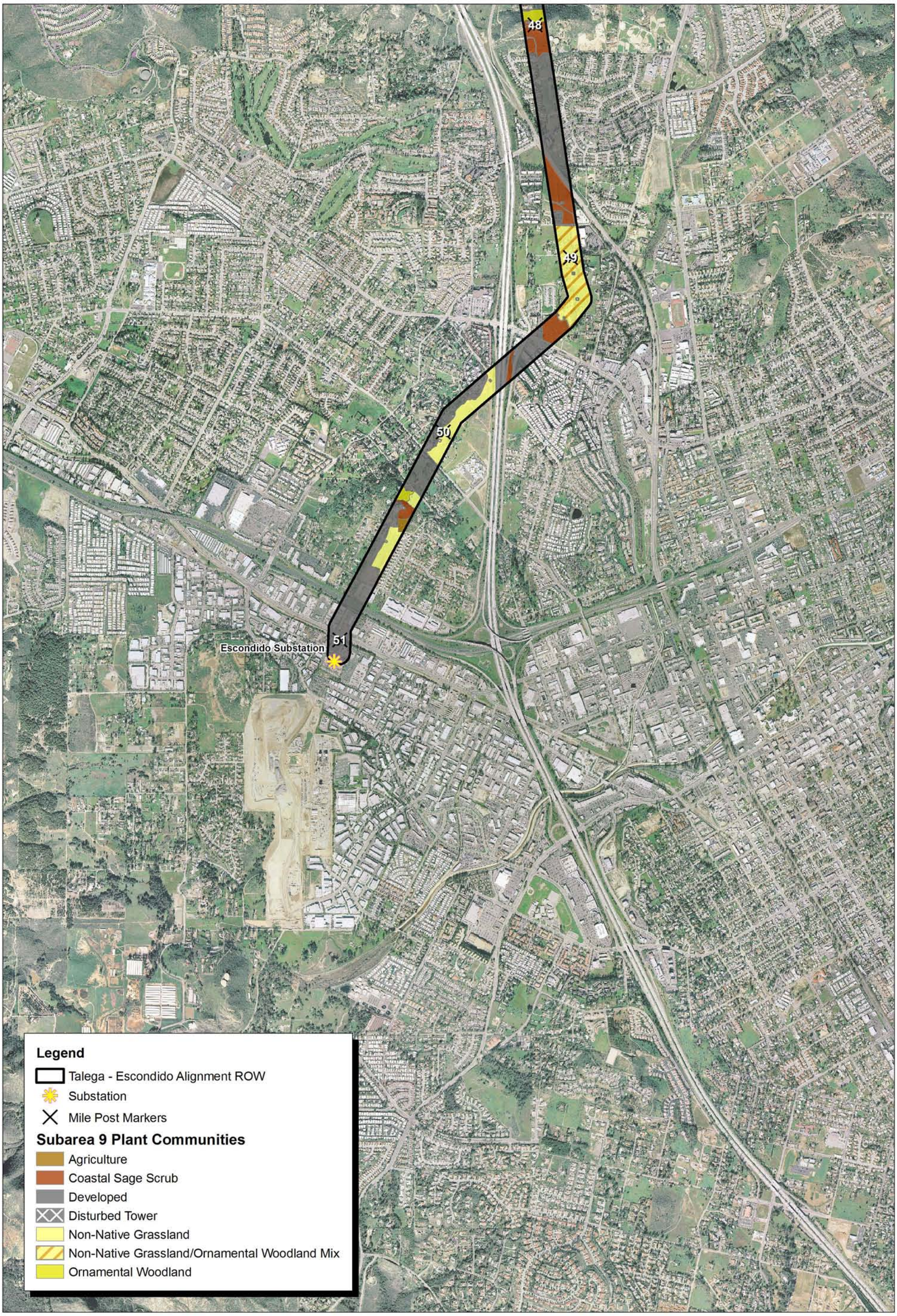
Michael Brandman Associates

NORTH

2,000 1,000 0 2,000 Feet

27980011 • 01/2009 | 9a_subarea9_veg_topo.mxd

Exhibit 9a
Transmission Line Vegetation Map (9 of 9)
Topographic Base



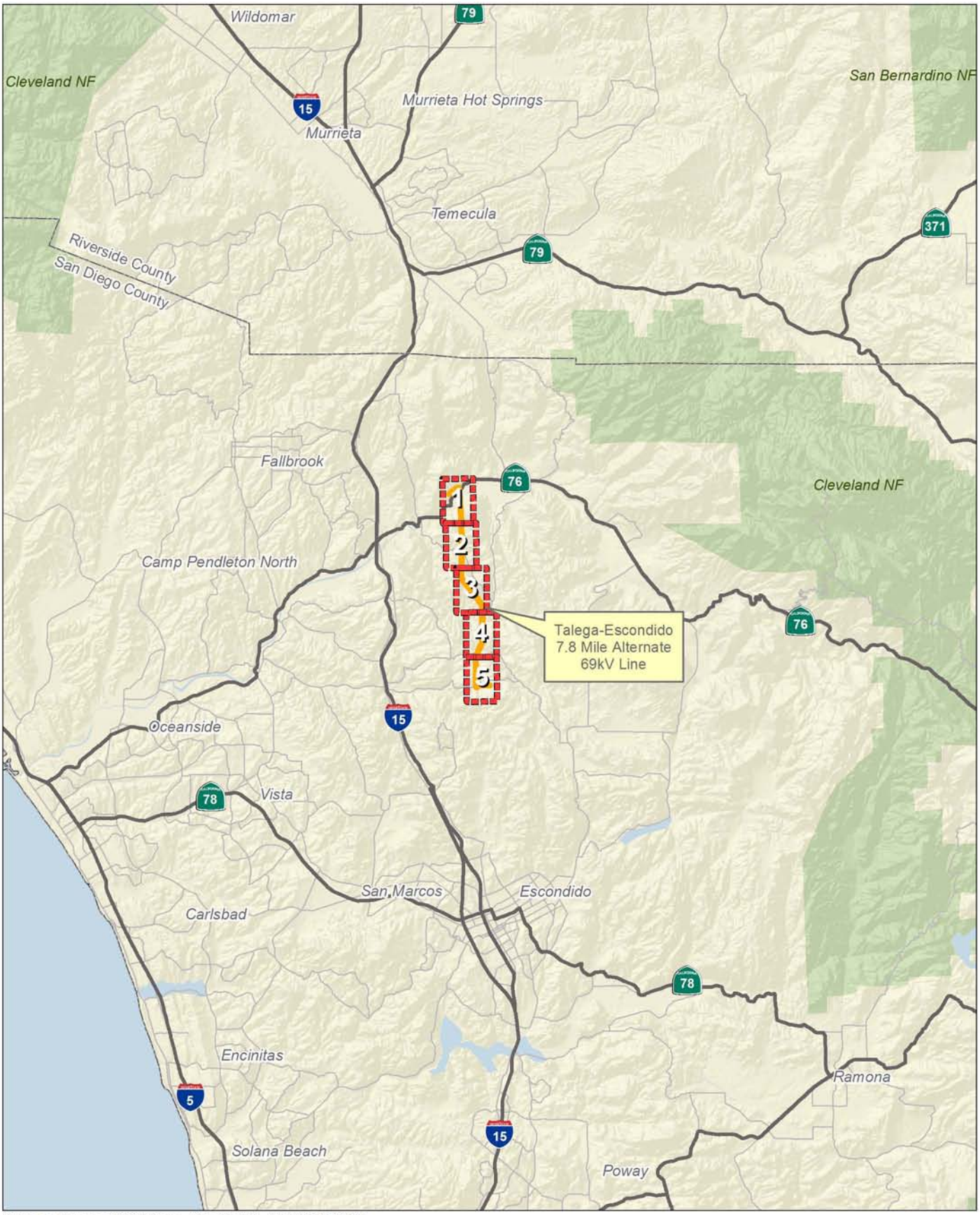
Source: TOPO! USGS 7.5' DRG.

NORTH

2,000 1,000 0 2,000 Feet

Michael Brandman Associates

Exhibit 9b
Transmission Line Vegetation Map (9 of 9)
Aerial Base



Source: Census 2000 Data, The CaSIL, MBA GIS 2009.

Exhibit 10

7.8 Mile Alternate Transmission Line
Plant Communities Index Map

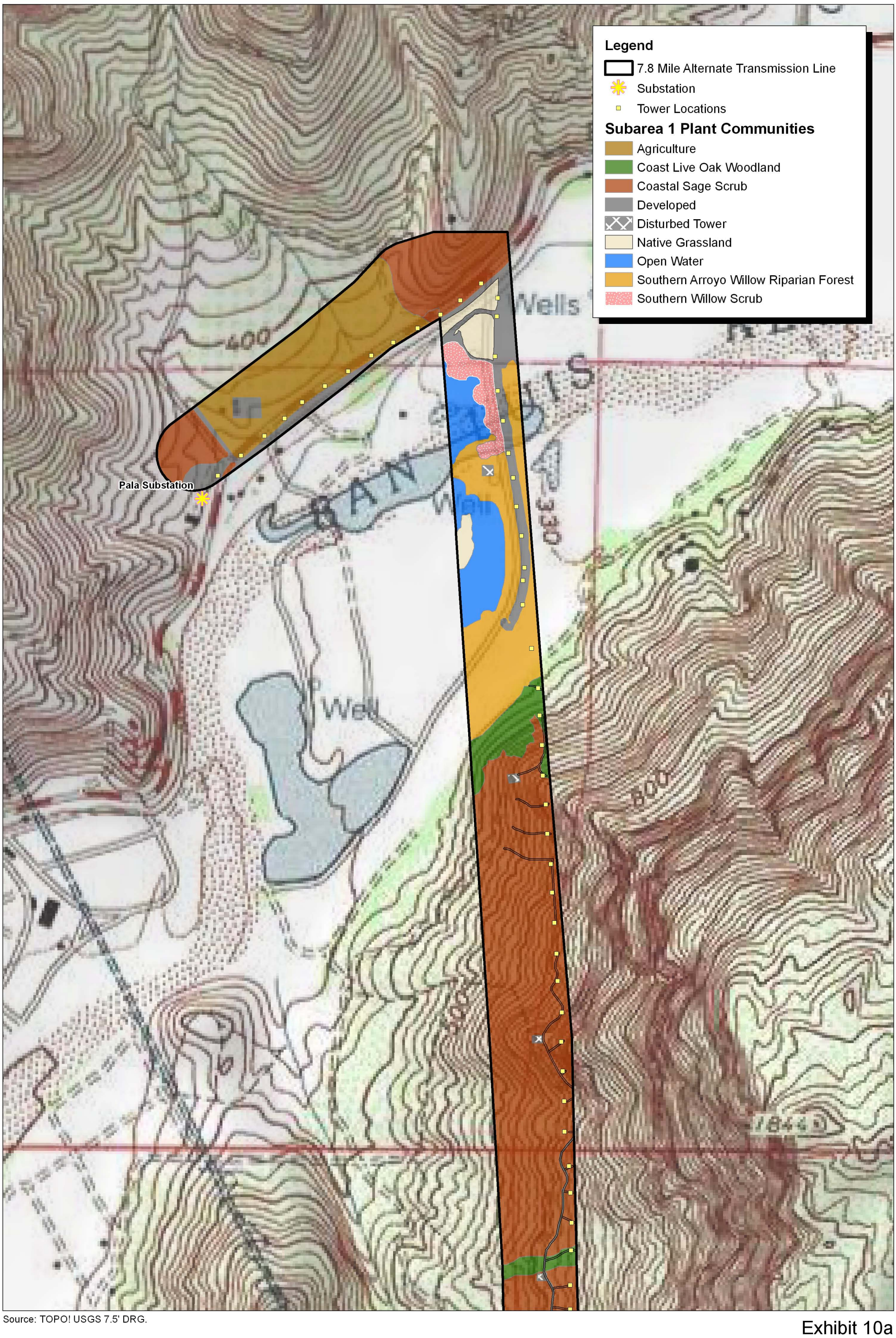
NORTH

5 2.5 0 5 Miles

Michael Brandman Associates

27980011 • 02/2009 | 10_index.mxd

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

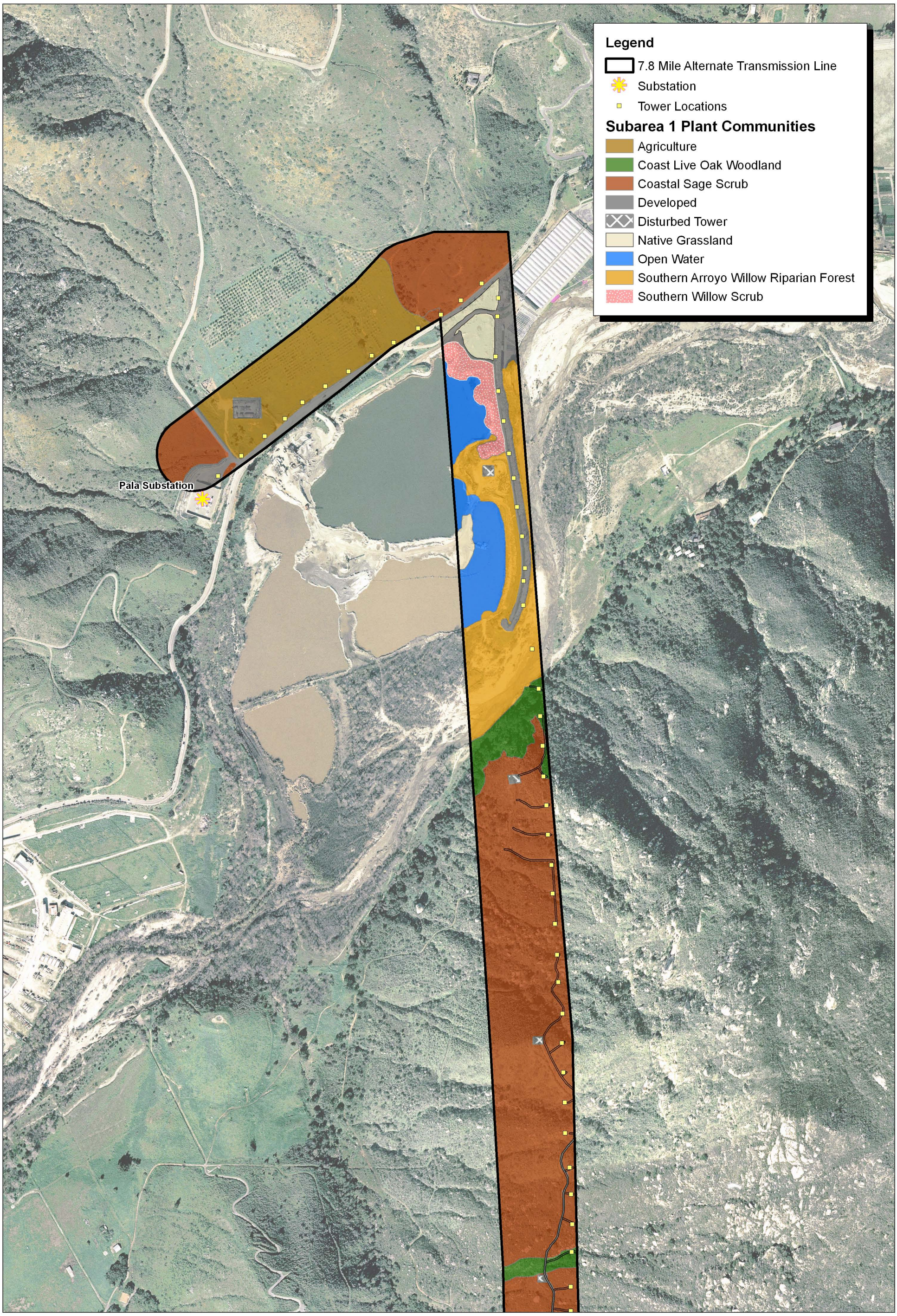
Michael Brandman Associates

NORTH

600 300 0 600 Feet

Exhibit 10a
7.8 Mile Alternate Transmission Line
Vegetation Map (1 of 5) - Topographic Base

27980011 • 02/2009 | 10a_subarea1_veg_topo.mxd



Source: TOPO! USGS 7.5' DRG.

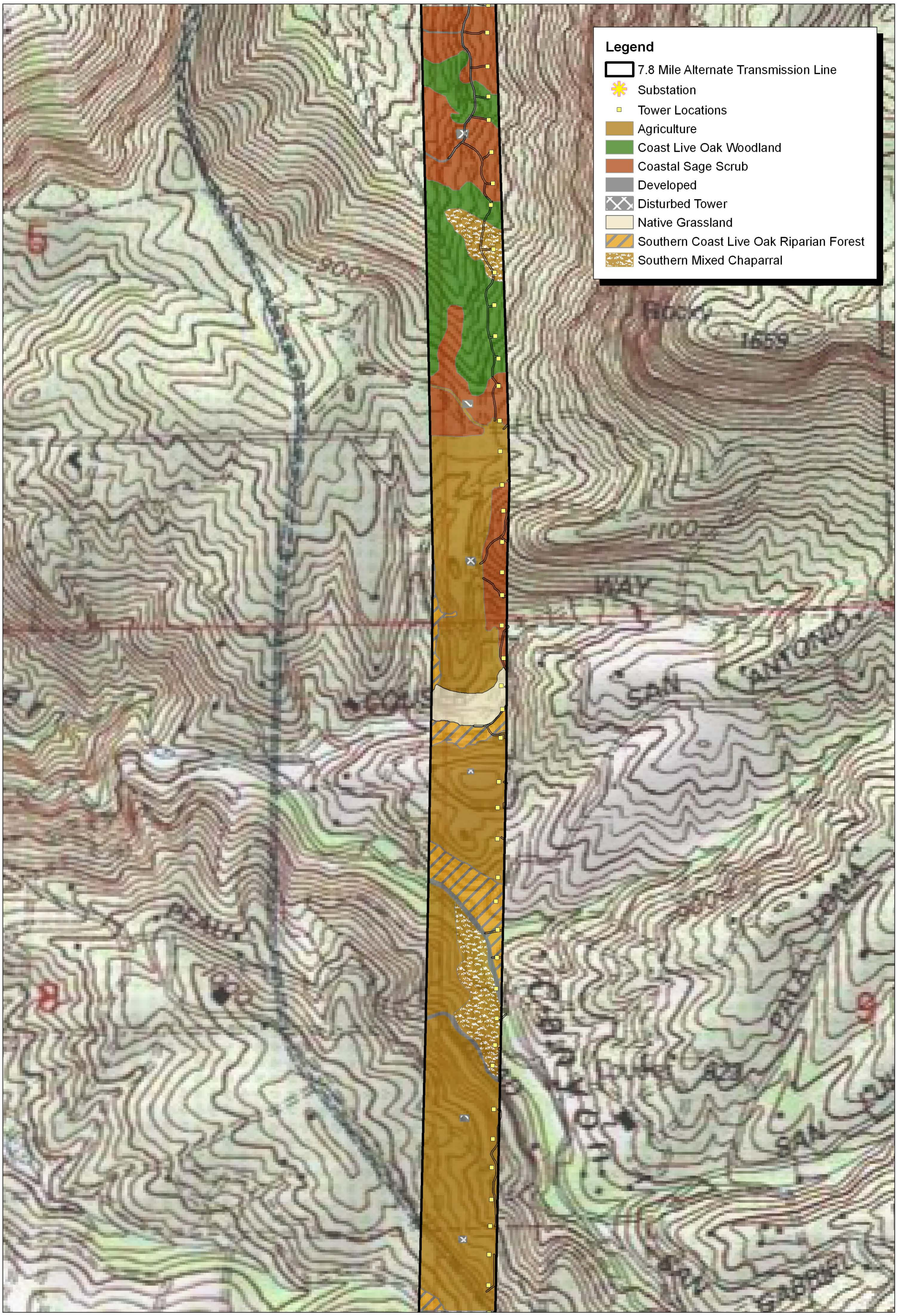
Michael Brandman Associates

NORTH

600 300 0 600 Feet

27980011 • 02/2009 | 10b_subarea1_veg_aerial.mxd

Exhibit 10b
7.8 Mile Alternate Transmission Line
Vegetation Map (1 of 5) - Aerial Base



Source: TOPO! USGS 7.5' DRG.

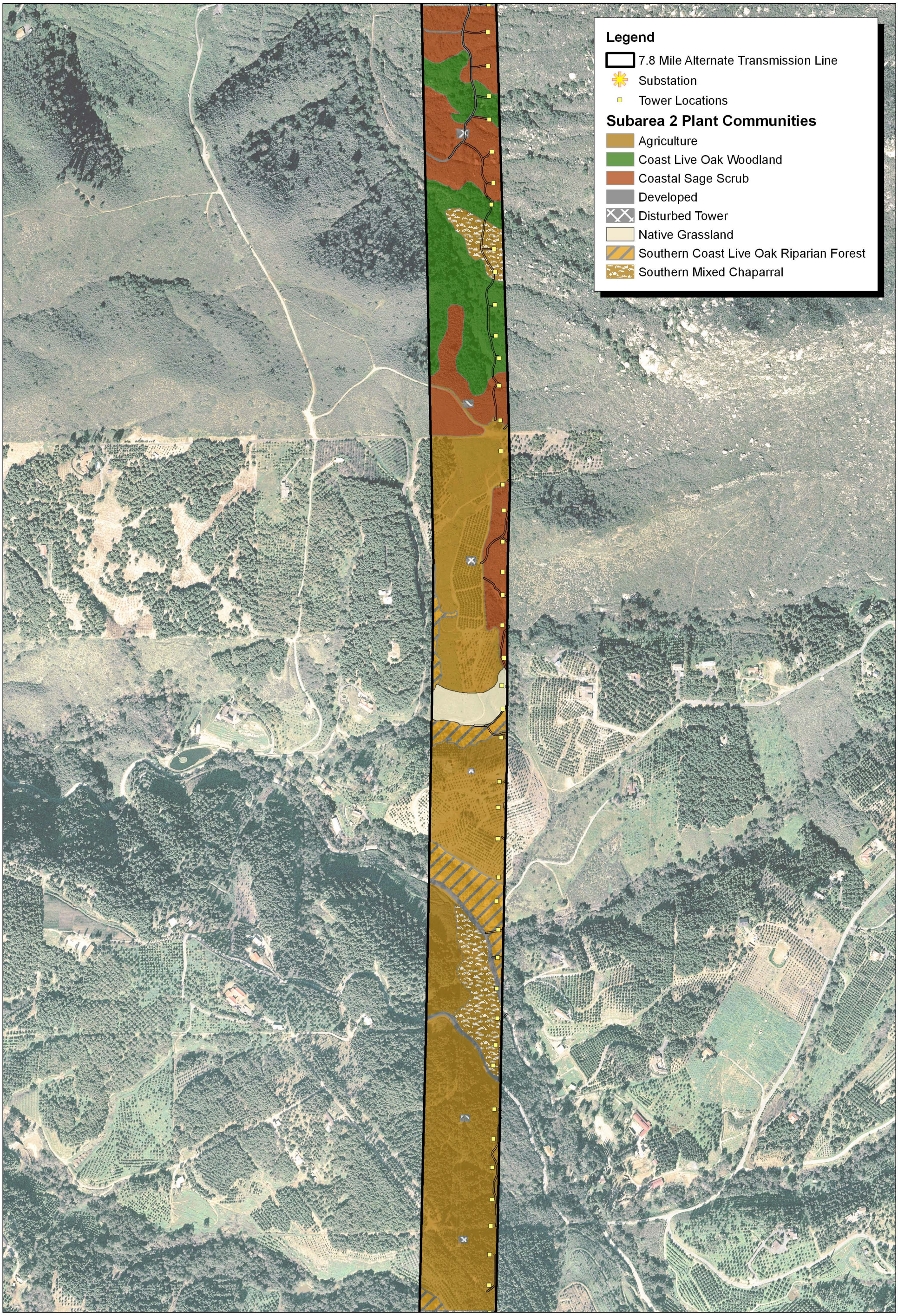
Michael Brandman Associates

NORTH

600 300 0 600 Feet

Exhibit 11a
7.8 Mile Alternate Transmission Line
Vegetation Map (2 of 5) - Topographic Base

27980011 • 02/2009 | 11a_subarea2_veg_topo.mxd



Source: TOPO! USGS 7.5' DRG.

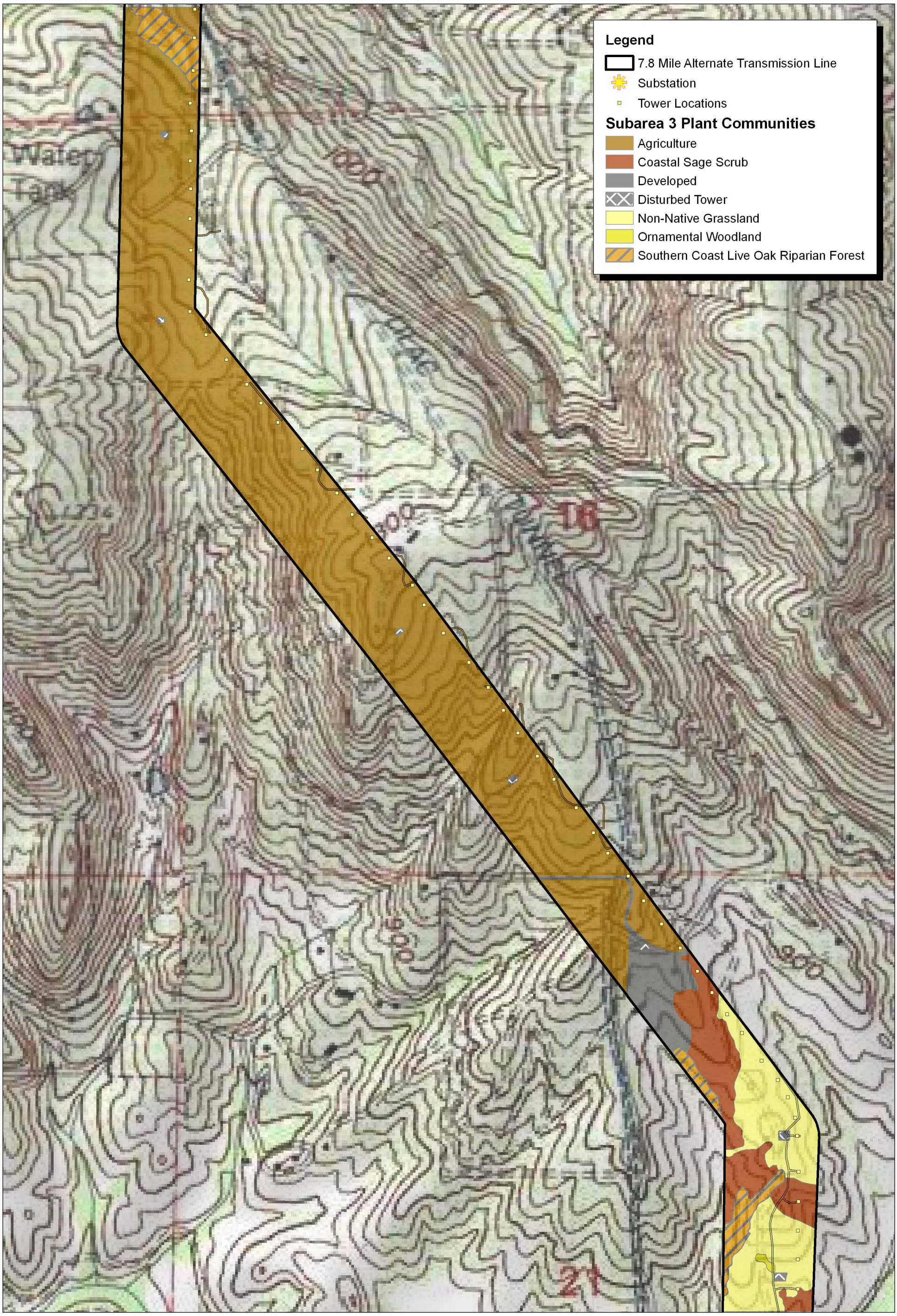
NORTH

600 300 0 600 Feet

Michael Brandman Associates

27980011 • 02/2009 | 11b_subarea2_veg_aerial.mxd

Exhibit 11b
7.8 Mile Alternate Transmission Line
Vegetation Map (2 of 5) - Aerial Base



Source: TOPO! USGS 7.5' DRG.

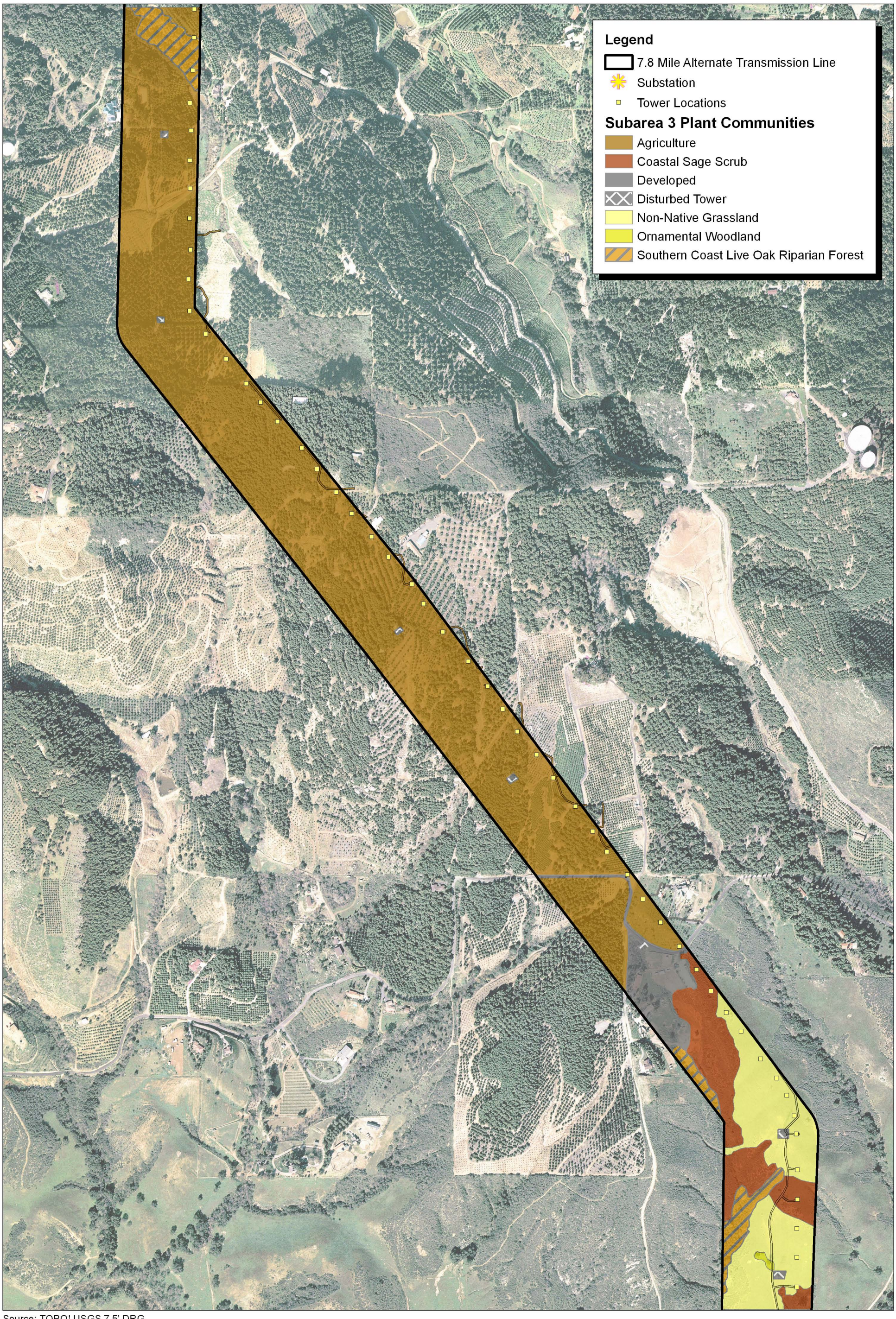
Michael Brandman Associates

NORTH

600 300 0 600 Feet

Exhibit 12a
7.8 Mile Alternate Transmission Line Vegetation Map (3 of 5) - Topographic Base

27980011 • 02/2009 | 12a_subarea3_veg_topo.mxd



Source: TOPO! USGS 7.5' DRG.

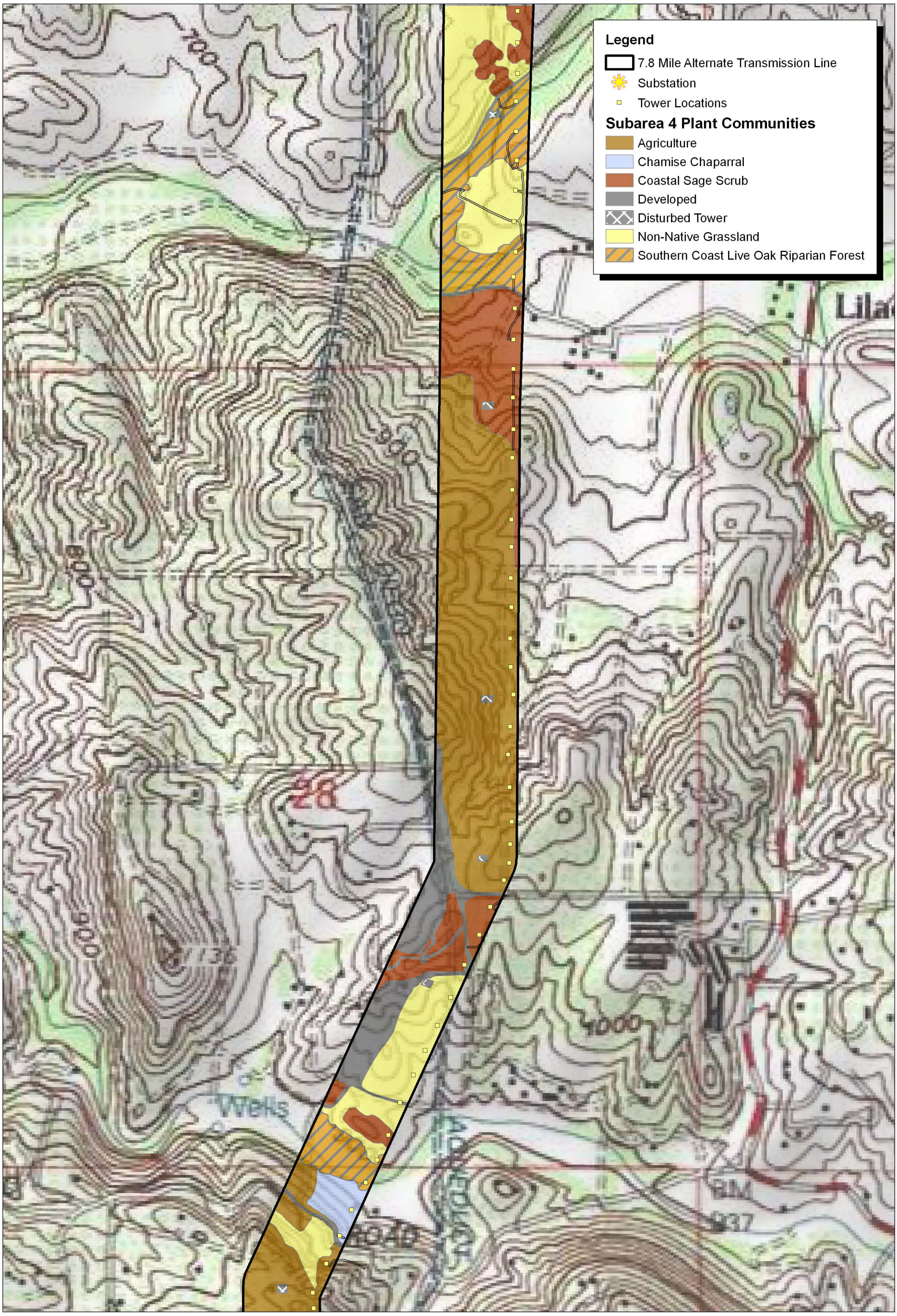
Michael Brandman Associates

NORTH

600 300 0 600 Feet

27980011 • 02/2009 | 12b_subarea3_veg_aerial.mxd

Exhibit 12b
7.8 Mile Alternate Transmission Line
Vegetation Map (3 of 5) - Aerial Base



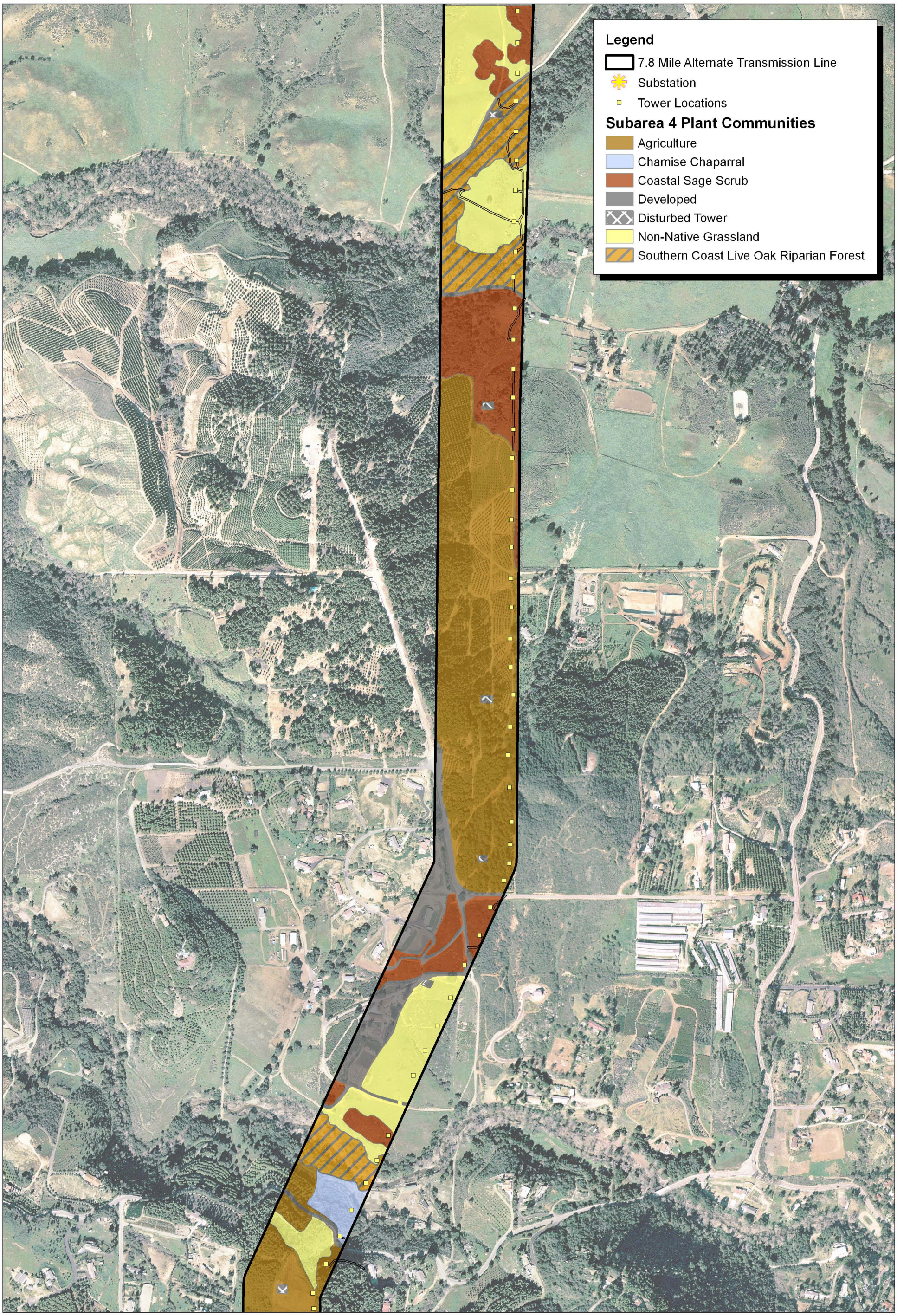
Source: TOPO! USGS 7.5' DRG.

Exhibit 13a
7.8 Mile Alternate Transmission Line
Vegetation Map (4 of 5) - Topographic Base

Michael Brandman Associates

27980011 • 02/2009 | 13a_subarea4_veg_topo.mxd

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

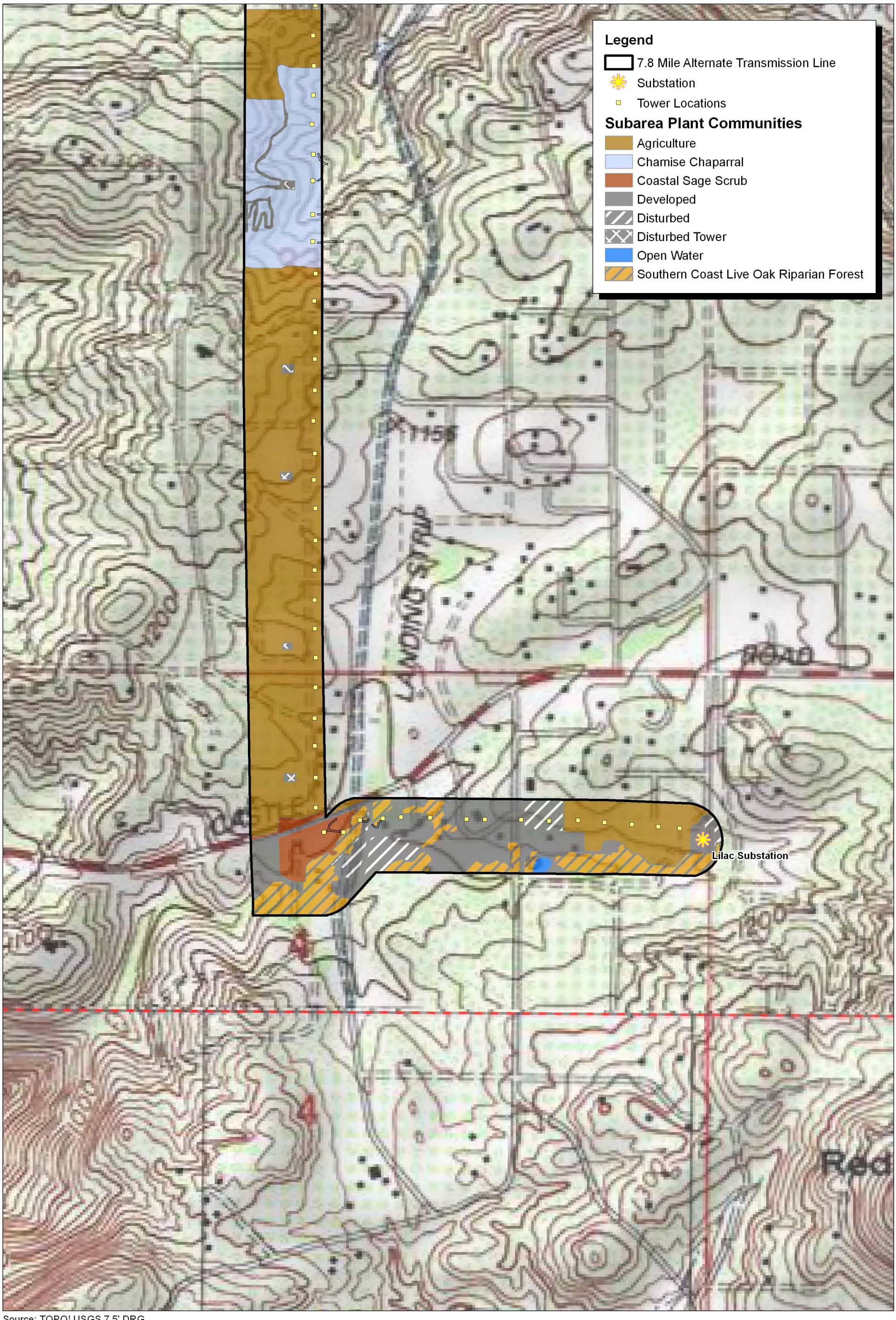
Michael Brandman Associates

NORTH

600 300 0 600 Feet

Exhibit 13b
7.8 Mile Alternate Transmission Line
Vegetation Map (4 of 5) - Aerial Base

27980011 • 02/2009 | 13b_subarea4_veg_aerial.mxd



Source: TOPO! USGS 7.5' DRG.

Michael Brandman Associates

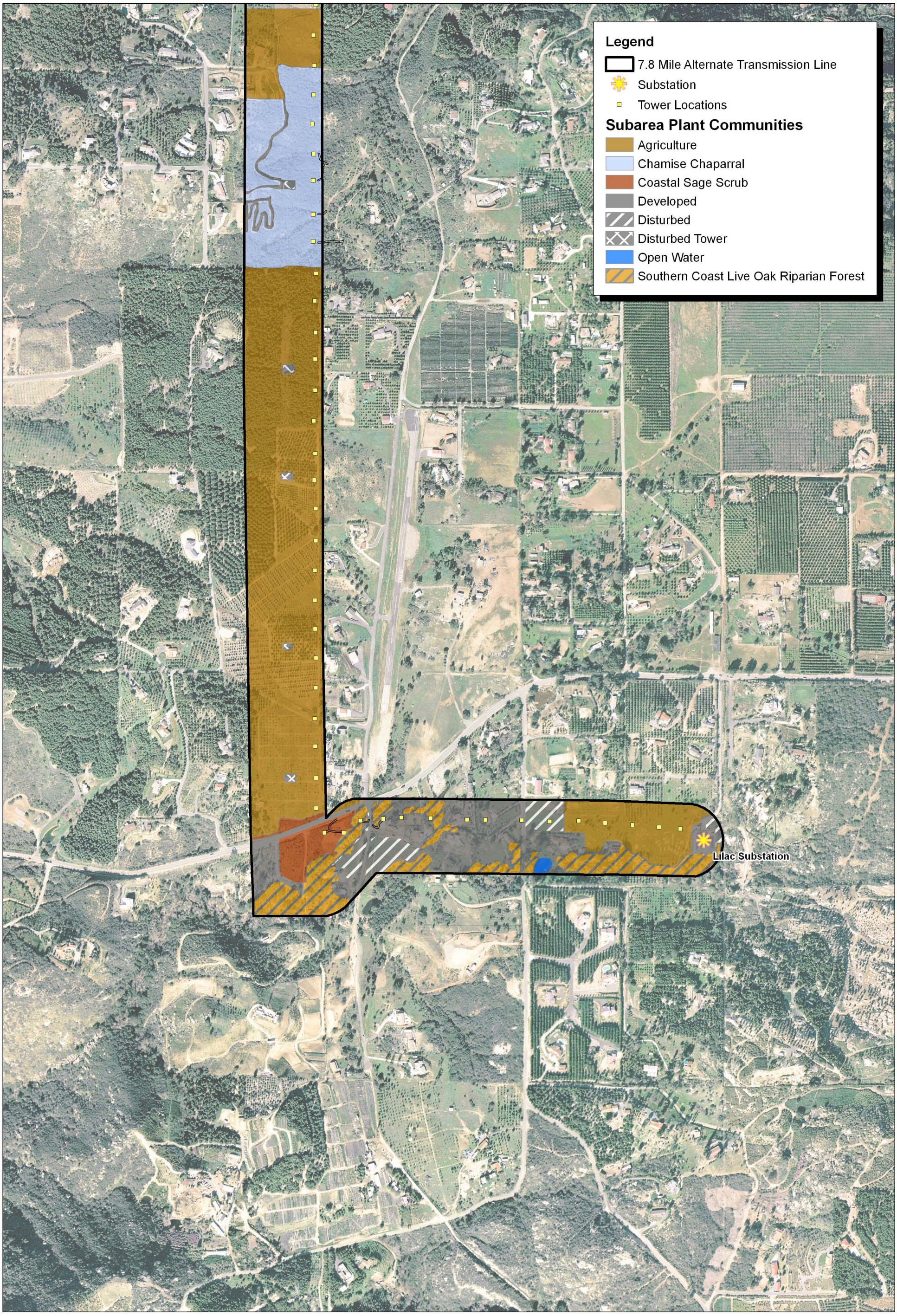
NORTH

600 300 0 600 Feet

Exhibit 14a
7.8 Mile Alternate Transmission Line
Vegetation Map (5 of 5) - Topographic Base

27980011 • 02/2009 | 14a_subarea5_veg_topo.mxd

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: TOPO! USGS 7.5' DRG.

NORTH

600 300 0 600 Feet

Michael Brandman Associates

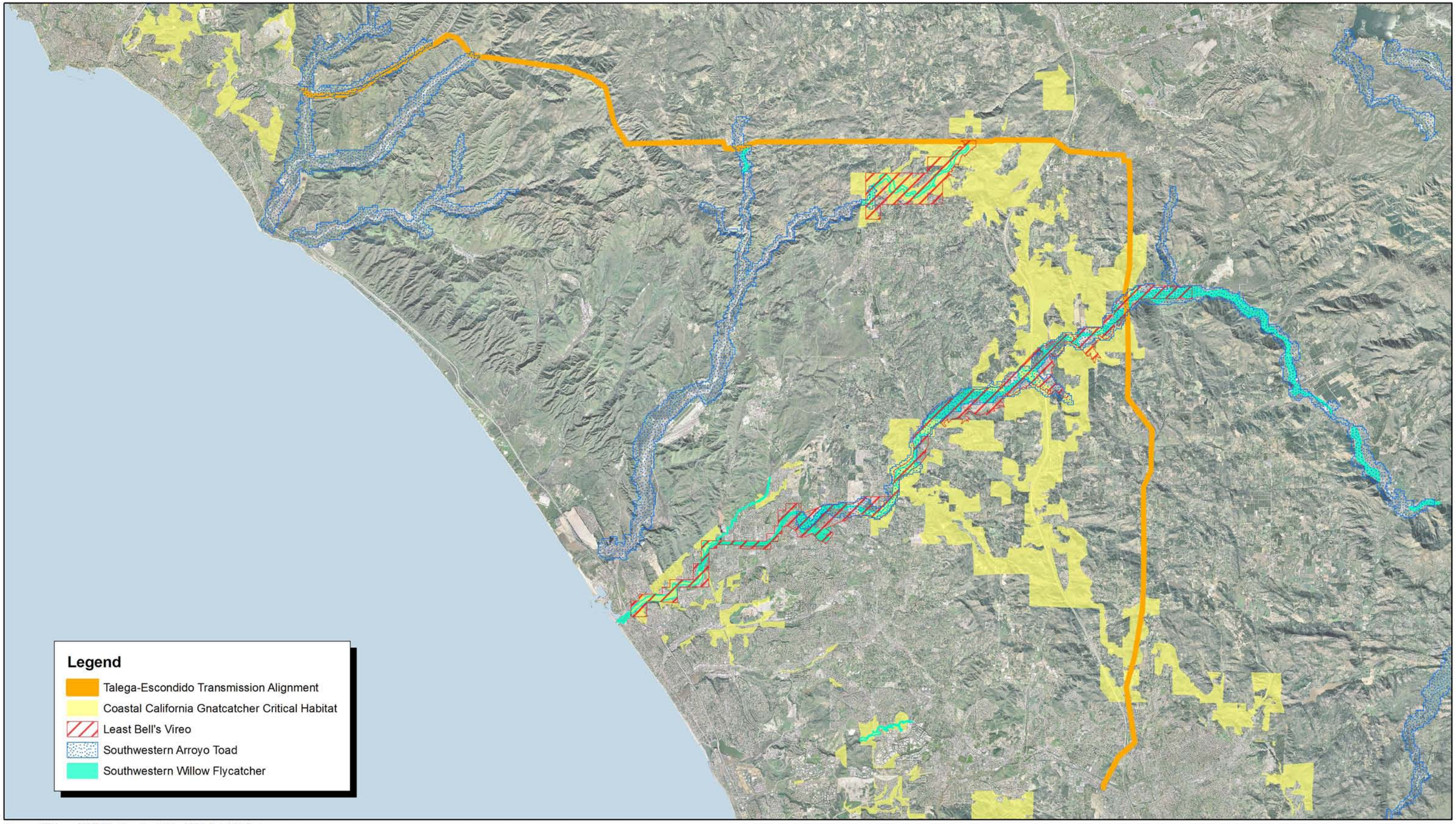
27980011 • 02/2009 | 14b_subarea5_veg_aerial.mxd

Exhibit 14b
7.8 Mile Alternate Transmission Line
Vegetation Map (5 of 5) - Aerial Base

Appendix C: Sensitive Species Maps

Appendix C:
List of Exhibits

1	Critical Habitat Map
2	Sensitive Species Survey Map
3a	CNDDB-Recorded Occurrences of Special-Status Species Map
3b	CNDDB-Recorded Occurrences of Special-Status Species Map
3c	CNDDB-Recorded Occurrences of Special-Status Species Map
3d	CNDDB-Recorded Occurrences of Special-Status Species Map
4a	Occurrence Information for Multiple Species within Carlsbad FWS Jurisdiction
4b	Occurrence Information for Multiple Species within Carlsbad FWS Jurisdiction
4c	Occurrence Information for Multiple Species within Carlsbad FWS Jurisdiction
4d	Occurrence Information for Multiple Species within Carlsbad FWS Jurisdiction



Source: Fish and Wildlife Service Critical Habitat GIS Data.

NORTH

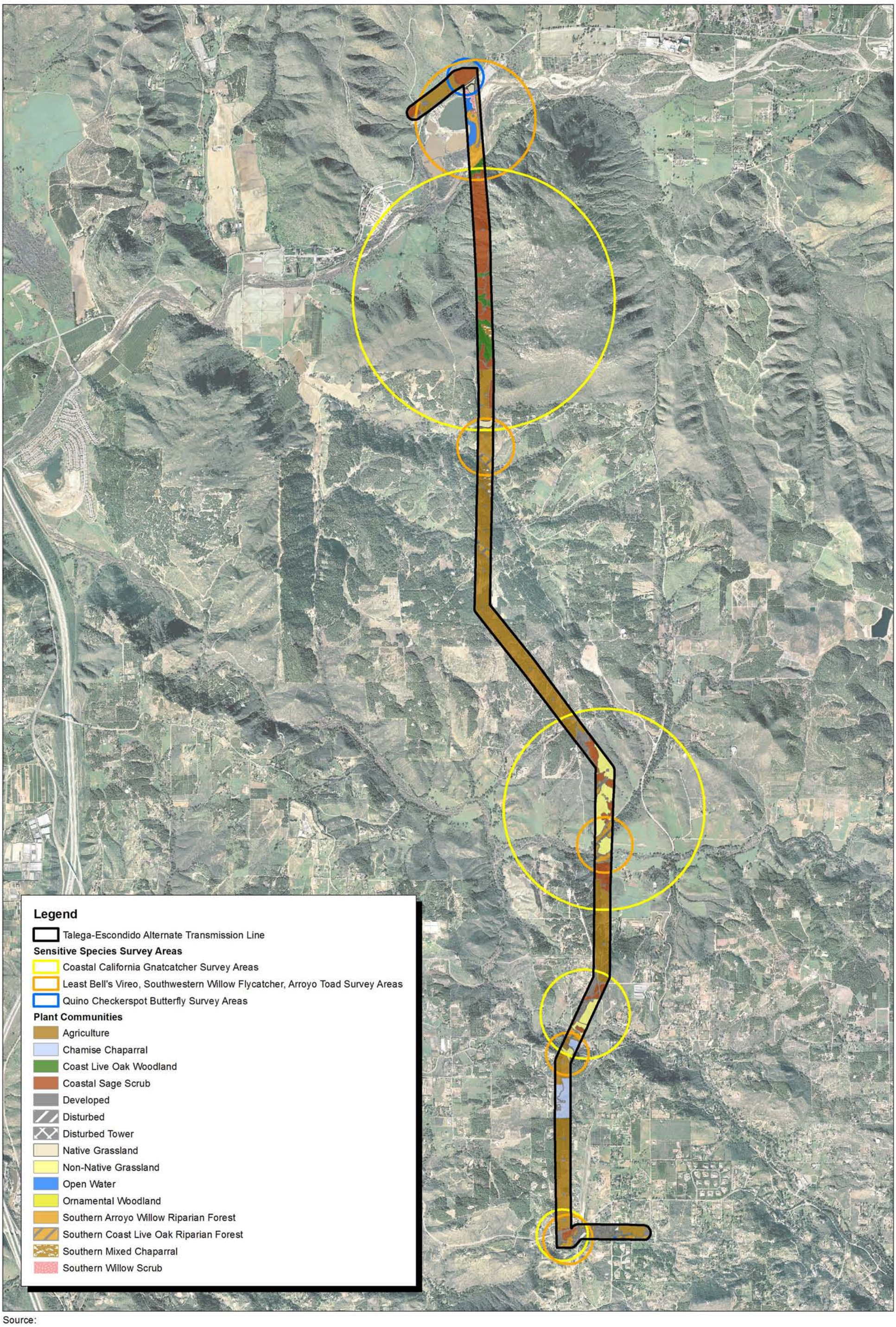
3 1.5 0 3 Miles

Michael Brandman Associates

27980011 • 02/2009 | 1_critical_habitat.mxt

Exhibit 1
Critical Habitat Map

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



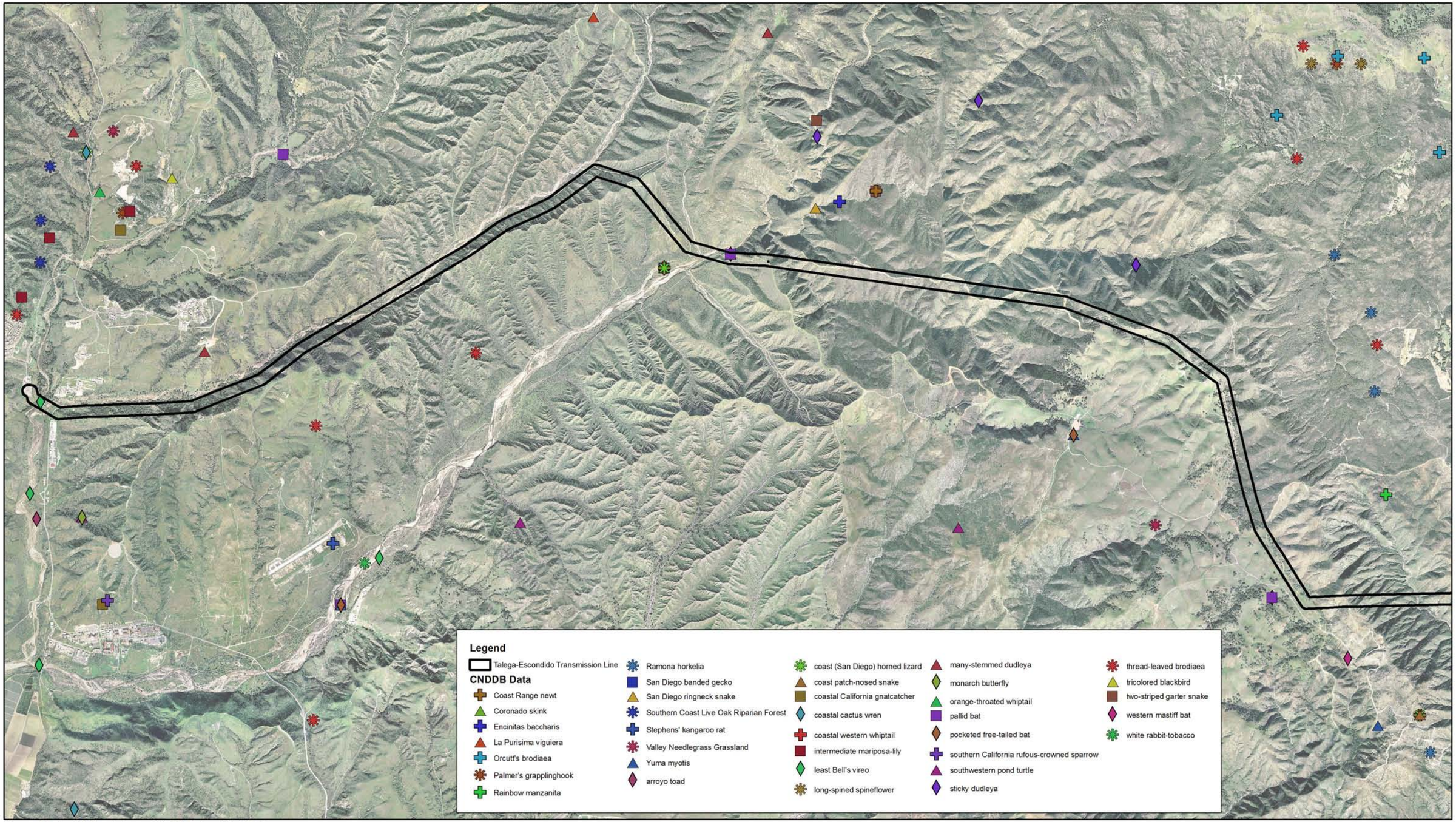
Source:

NORTH

3,000 1,500 0 3,000 Feet

Michael Brandman Associates

Exhibit 2
Sensitive Species Survey Map



Source: Dept of Fish and Game CNDDB Data. Feb. 2009.

NORTH

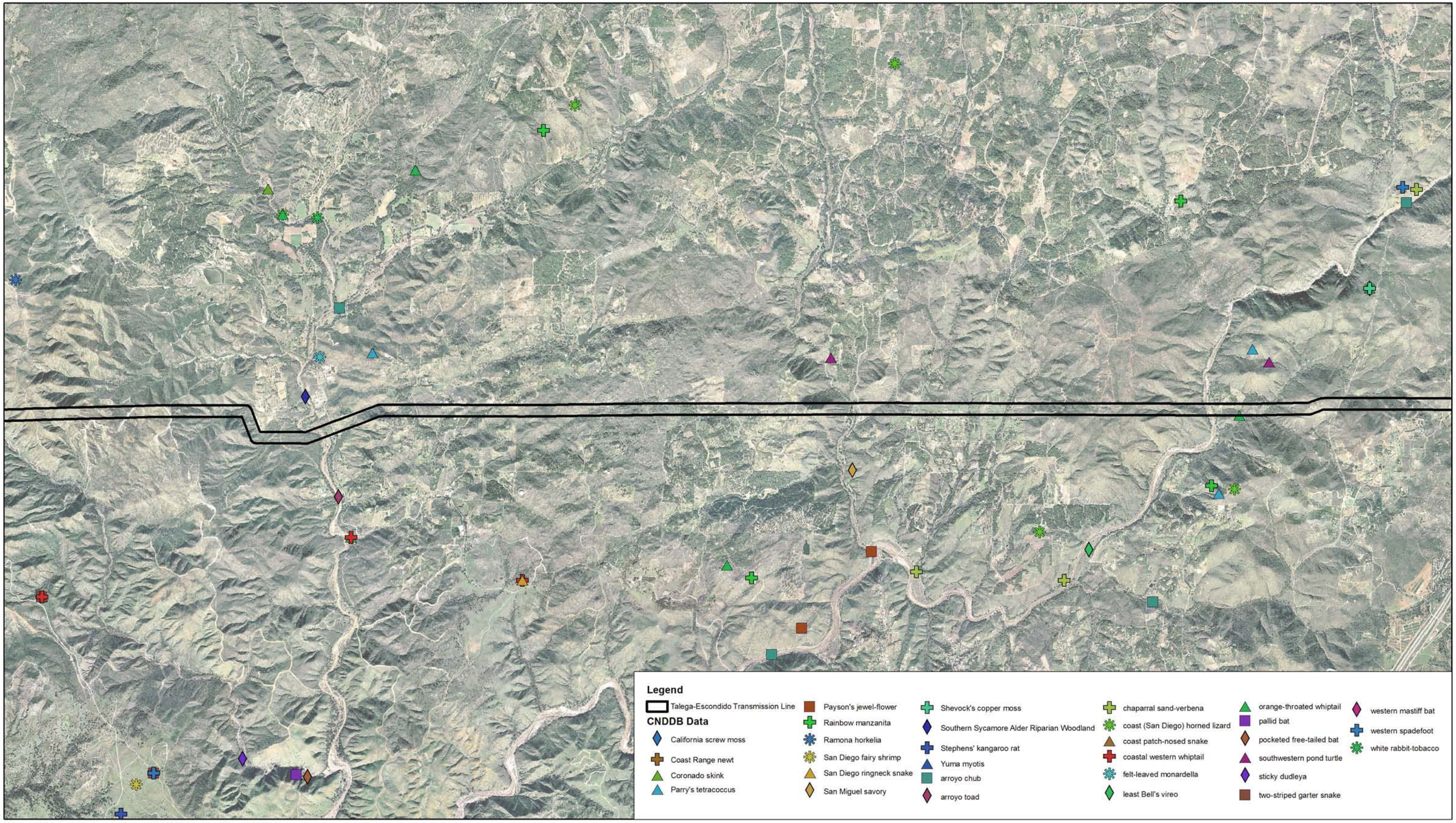
4,000 2,000 0 4,000 Feet

Michael Brandman Associates

27980011 • 02/2009 | 3a_cnddb.mxd

Exhibit 3a
CNDDB-Recorded Occurrences
of Special-Status Species Map

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: Dept of Fish and Game CNDDB Data. Feb. 2009.

NORTH

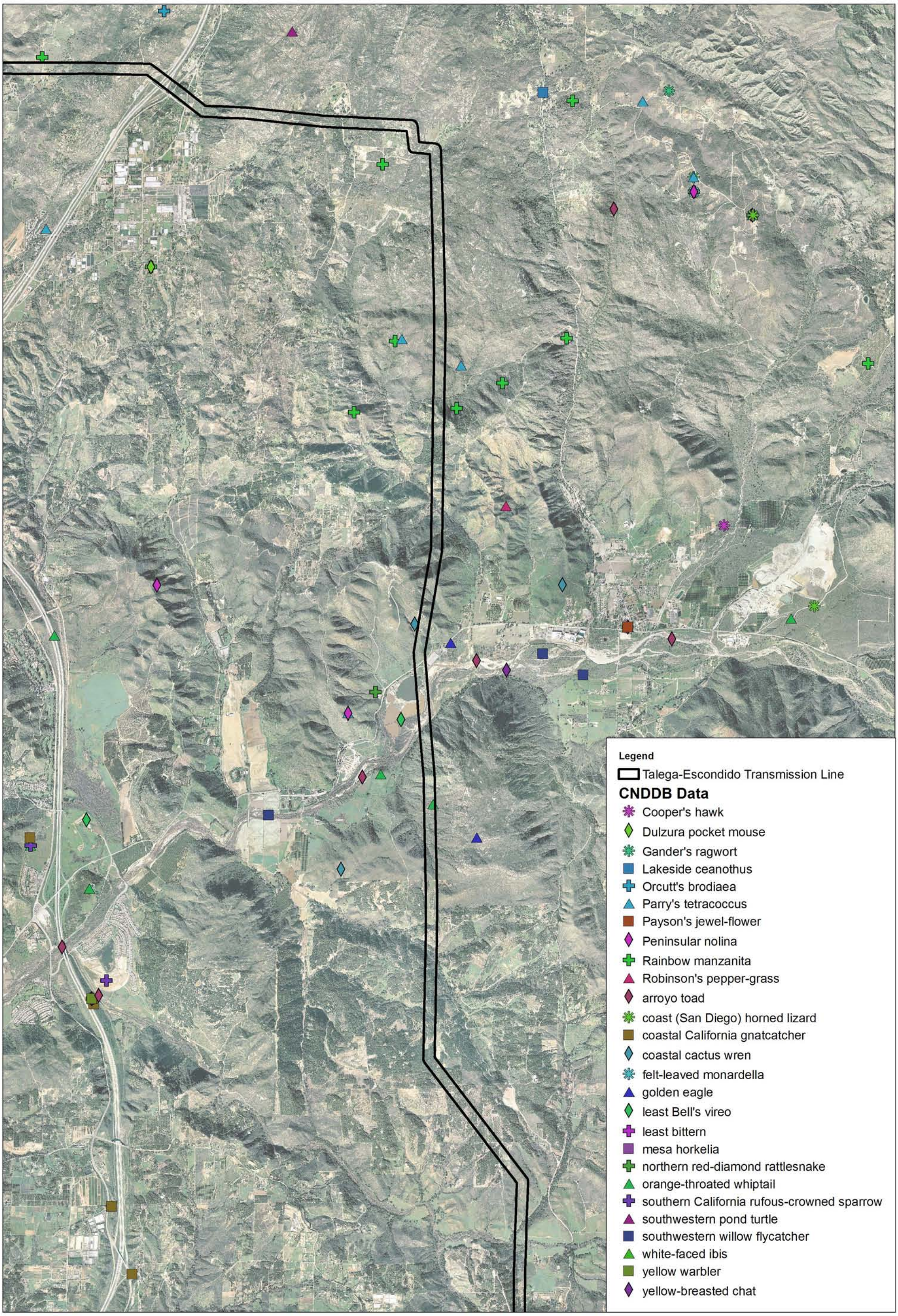
4,000 2,000 0 4,000 Feet

Michael Brandman Associates

27980011 • 02/2009 | 3b_cnddb.mxd

Exhibit 3b
CNDDB-Recorded Occurrences
of Special-Status Species Map

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



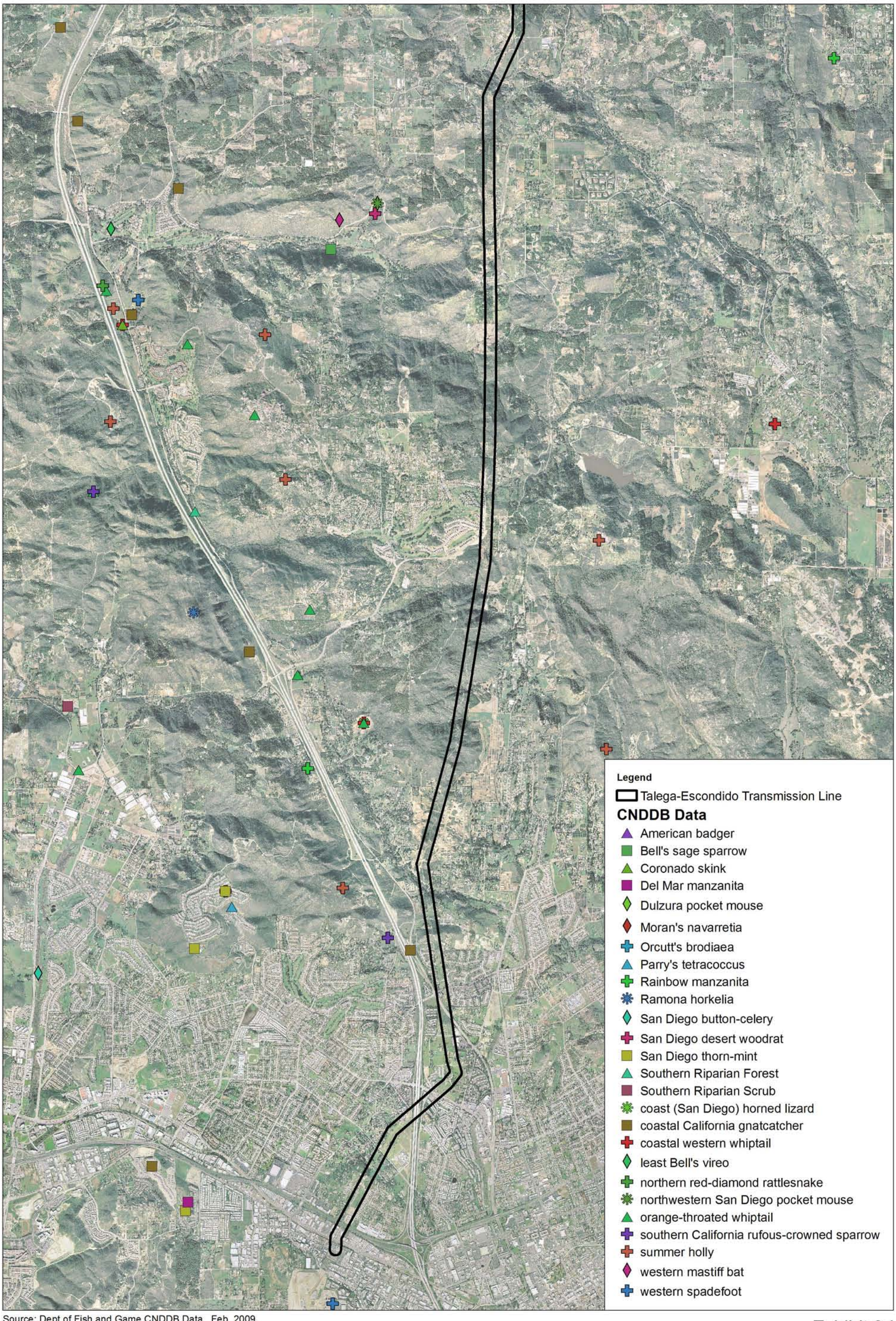
Source: Dept of Fish and Game CNDDB Data. Feb. 2009.

Michael Brandman Associates

NORTH

4,000 2,000 0 4,000 Feet

Exhibit 3c
CNDDB-Recorded Occurrences of Special-Status Species Map



Source: Dept of Fish and Game CNDDB Data. Feb. 2009.

Michael Brandman Associates

NORTH

4,000 2,000 0 4,000 Feet

Exhibit 3d
CNDDB-Recorded Occurrences of Special-Status Species Map

27980011 • 02/2009 | 3d_cnddb.mxd

Source: Fish and Wildlife Service, Feb. 2009.

NORTH

4,000 2,000 0 4,000 Feet

Michael Brandman Associates

27980011 • 02/2009 | 4a_fws_species.mxd

Exhibit 4a

Occurrence Information for Multiple Species within Carlsbad FWS Jurisdiction

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT

Source: Fish and Wildlife Service, Feb. 2009.

NORTH

4,000 2,000 0 4,000 Feet

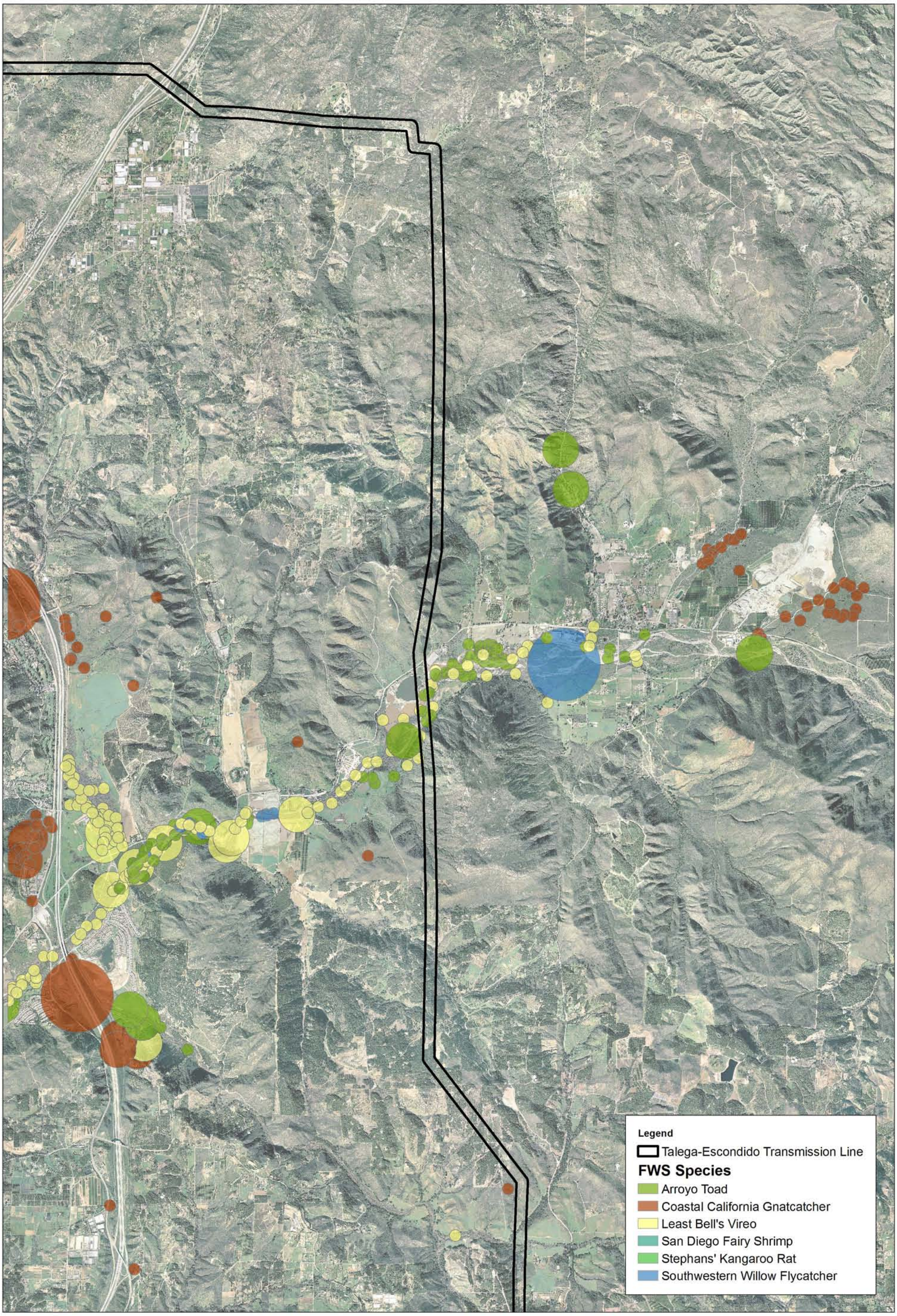
Michael Brandman Associates

27980011 • 02/2009 | 4b_fws_species.mxd

Exhibit 4b

Occurrence Information for Multiple Species within Carlsbad FWS Jurisdiction

TALEGA-ESCONDIDO / VALLEY-SERRANO INTERCONNECT 500 KV PROJECT
BIOLOGICAL RESOURCES LETTER REPORT



Source: Fish and Wildlife Service, Feb. 2009.

NORTH

4,000 2,000 0 4,000 Feet

Michael Brandman Associates

27980011 • 02/2009 | 4c_fws_species.mxd

Exhibit 4c
Occurrence Information for Multiple Species within Carlsbad FWS Jurisdiction

Legend

Talega-Escondido Transmission Line

FWS Species

- Arroyo Toad
- Coastal California Gnatcatcher
- Least Bell's Vireo
- San Diego Fairy Shrimp
- Stephans' Kangaroo Rat
- Southwestern Willow Flycatcher

Source: Fish and Wildlife Service, Feb. 2009.

Michael Brandman Associates

NORTH

4,000 2,000 0 4,000 Feet

27980011 • 02/2009 | 4d_fws_species.mxd

Exhibit 4d

Occurrence Information for Multiple Species within Carlsbad FWS Jurisdiction

Appendix D: Project Impact Tables

Table D-1: Permanent and Temporary Impacts to Natural Communities for the 230 kV Transmission Line Alignment

Vegetation Community	Permanent Impact Area Sq Ft (Acres)	Temporary Impact Area Sq Ft (acres)	Total Impacts Sq Ft (acres)
Coastal Sage Scrub	4,330.2 (0.10)	55,629.7 (1.3)	59,959.9 (1.4)
Chaparral	918.3 (0.02)	7,927.1 (0.2)	8,845.4 (0.2)
Chaparral Chamise Mix	75.6 (< 0.01)	5,355.4 (0.1)	5,431.0 (0.1)
Grassland	50.6 (< 0.01)	0.0	50.6 (< 0.01)
Oak Woodland	354.5 (0.01)	18,758.2 (0.4)	19,112.7 (0.4)
Non-native Grassland	2,028.9 (0.05)	72,699.7 (1.7)	74,728.6 (1.7)
Willow Riparian Forest Arroyo	142.1 (< 0.01)	0.0	142.1 (< 0.01)
Oak Sycamore Riparian Woodland	489.9 (0.01)	4,817.3 (0.1)	5,307.2 (0.1)
Oak Sycamore Woodland	192.8 (< 0.01)	878.9 (< 0.1)	1071.7 (< 0.1)
Oak Riparian Woodland	922.4 (0.02)	0.0	922.4 (< 0.1)
Developed	100.4 (< 0.01)	4,4787.3 (1.0)	44,887.7 (1.0)
Agriculture	401.7 (0.01)	54,237.6 (1.2)	54,639.3 (1.3)
Disturbed	50.2 (< 0.01)	11,822.0 (0.3)	11,872.2 (0.3)
Total	10,057.4 (0.23)	276,913.3 (6.4)	266,970.7 (6.6)

Table D-2: Permanent and Temporary Impacts to Critical Habitat

Listed Species Critical Habitat	69kV ROW Temporary Road Impacts Sq Ft (Acres)	69kV ROW Permanent Tower Impacts Sq Ft (Acres)	Total Impacts Sq Ft (Acres)	Total Suitable Habitat Impacts Sq Ft (Acres)	Total Survey Area (Acres)
California Gnatcatcher	40,946.4 (0.94)	922.4 (0.02)	41,868.8 (0.96)	43.56 (< 0.1)	54.20
Arroyo Toad	2,613.6 (0.06)	1,306.8 (0.03)	3,920.4 (0.09)	3,441.2 (.08)	52.10
Least Bell's Vireo	922.4 (0.02)	696.9 (< 0.1)	1,619.4 (0.04)	1568.2 (0.04)	32.80
Southwestern Willow Flycatcher	174.2 (< 0.1)	43.56 (< 0.1)	217.8 (< 0.1)	230.3 (< 0.1)	10.32

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February 12, 2009

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

Subject: **Augment Response to USFWS Comment Letter Regarding Formal Section 7 Consultation for the Lake Elsinore Advanced Pump Storage and Talega-Escondido/Valley-Serrano 500-kV Interconnect Projects, FERC No. 11858 and Docket Nos. ER06-278-000 through 006 and CPUC No. 07-10-005**

Dear Ms. Bose:

This letter serves as an augment to the previous Response to USFWS Comment Letter dated January 14, 2008 submitted to the Federal Energy Regulatory Commission (FERC or Commission) regarding additional information necessary to complete Formal Section 7 Consultation for the above described projects. This letter report contains project specific impact information requested by the United States Fish and Wildlife Service (USFWS or Service) in order to complete the Formal Section 7 Consultation for the Lake Elsinore Advanced Pump Storage Project (LEAPS) and the Talega-Escondido/Valley-Serrano 500-kV Interconnect Project (TEVS) with regard to the complete range of project-related facilities. Because LEAPS/TEVS (Project) will require federal entitlements from the Commission, the United States Forest Service (USFS), and the United States Department of the Navy/United States Marine Corps (USMC), a federal nexus exists necessitating consultation under Section 7 of the Federal Endangered Species Act.

For the purpose of this response, MBA and The Nevada Hydro Company (Nevada Hydro or Applicant) sought to augment the analysis of project-related impacts on biological resources described in the Commission's "Final Environmental Impact Statement for the Lake Elsinore Advanced Pumped Storage Project, FERC/EIS 0191F" (FERC FEIS) and as presented in Nevada Hydro's "Proponent's Environmental Assessment" (Applicant's PEA), as submitted to the California Public Utilities Commission (CPUC) in July 2008 (Revised February 2009), and the CPUC's and Bureau of Land Management's "Final Environmental Impact Report/Environmental Impact Statement and Draft Land Use Plan Amendment for the San Diego Gas & Electric Company's (SDG&E) Sunrise Powerlink Project" (CPUC/BLM FEIR/FEIS), as certified by the CPUC in December 2008.

The Project includes numerous transmission facilities, including, but not necessarily limited to, a new 500-kV transmission line connecting the proposed hydropower facility to the regional transmission grid, an additional 230-kV transmission line to be upgraded with a new circuit on the existing SDG&E Talega/Escondido Transmission Line, new transitional towers connecting the Applicant's facilities to SDG&E's existing Talega/Escondido Transmission Line, and new utility poles and a subtransmission circuit to relocate an existing 69-kV subtransmission line generally extending between State Route 76 and Old Castle Road. A 500-foot wide study area was surveyed for biological resources potentially affected by Project construction, hereafter referred to as the Project site. The Project also includes, or potentially includes, upgrades to numerous Southern California Edison (SCE) substations (Valley, Serrano, San Bernardino, Vista, Mira Loma, and Etiwanda Substations), SDG&E substations (Talega, Escondido, Peñasquitos, Pala, and Lilac Substations), and a communication facility. Those facility sites are discussed separately below because these are completely developed existing facilities and any Project-related improvements and upgrades thereto would occur within the existing "fence line" of those facilities.

As part of the Pre-Certification Process, FERC has requested that Nevada Hydro coordinate with the USFWS office in order to assist in the preparation of the Final Biological Opinion. MBA prepared a previous report regarding the potential impacts of the proposed hydropower facility and its associated ancillary facilities, including the proposed transmission component (Appendix A). This 2009 letter report, submitted to the Commission on behalf of the Applicant, includes all associated facility upgrades and improvements related both directly and indirectly with the Project and is intended to facilitate the completion of the consultation process requested by FERC. MBA has addressed all USFWS comments contained in the Service's June 26, 2007 comment letter (Appendix A). Individual comments, if applicable, are quoted with their corresponding response in the Response to USFWS Comments of June 26, 2007 section below.

Introduction

MBA, operating under contract of Nevada Hydro, completed a habitat assessment and reviewed existing documentation on the potential for listed species such as Quino checkerspot butterfly (*Euphydryas editha quino*), arroyo toad (*Bufo californicus*), coastal California gnatcatcher (*Polioptila californica californica*), least Bell's vireo (*Vireo bellii pusillus*), southwestern willow flycatcher (*Empidonax traillii extimus*), and Stevens' kangaroo rat (*Dipodomys stephensi*) to occur within any suitable habitat areas within the upgraded facilities. Focused surveys for Quino checkerspot butterfly and sensitive plant species were conducted in 2008 by Helix Environmental Planning (Helix) as part of the environmental studies for the CPUC/BLM FEIR/FEIS. Additional focused survey data was obtained from the USFWS GIS species account (August 2008).

The Project includes, but is not necessarily limited to, a new 230-kV transmission line to be hung on the existing SDG&E Talega/Escondido Transmission Line, a 69-kV replacement line to be hung on new wood/steel poles, and several existing SDG&E and SCE substation upgrades (Appendix B).

Methods

The impact assessment began with a thorough review of existing biological documentation including, but not limited to, general biological resource studies, focused surveys for sensitive plant and wildlife species, the Applicant's PEA, the CPUC/BLM FEIS/FEIR, NCCP/HCP for SDG&E transmission line,

Biological Resources Technical Report for SDG&E's Valley Rainbow 500-kV Interconnect Project (CPUC Application No. 01-03-036, filed on March 23, 2001), and additional focused survey reports for the SDG&E transmission line.

The right-of-way (ROW) of the existing 230-kV transmission line was over-laid onto an aerial photograph and USGS 7.5-minute topographic quadrangle maps from information provided by Nevada Hydro. New and transitional tower sites were identified by Nevada Hydro. Also over-laid was the location of the 69-kV replacement line and the upgraded substations.

For the 69-kV replacement line, Nevada Hydro provided MBA with an estimated tower footprint area and an average length between towers. MBA used this information within the confines of the 500-foot study area to identify the location of the proposed poles. Based on field studies, these tower/pole locations were refined to identify more specific tower locations based on vegetation community, close association to existing access roads, and location of existing drainage features. This information was compared with the estimated impact calculations from SDG&E's previous Biological Resources Technical Report (KEA Environmental, Inc., Biological Resources Technical Report for the Valley Rainbow 500-kV Interconnect Project, March 16, 2001) for consistency.

Once the estimated tower/pole locations were selected, a more refined assessment of tower/pole location habitat was conducted. The proposed tower/pole locations were over-laid on a 3-dimensional topographic map using an elevational modeling software program. The software provides the ability to place proposed tower/pole locations along ridgelines and gentle slopes, while avoiding steep slopes and canyon bottoms. The 3-dimensionality of the program also allows for accurate placement of towers so that topography would not interfere with transmission lines height requirements or locations.

The vegetation associated with each tower/pole was determined based on the existing plant community data collected by MBA during field surveys conducted in 2008 and verified in 2009. This information was compared with the previous vegetation mapping conducted for the CPUC/BLM FEIR/FEIS. Differences in naming convention are generally based on biologist's preference and typically do not have any affect on determining suitable habitat for sensitive plant and wildlife species.

After the tower/pole locations were identified, potential new access roads were designed to minimize impacts to sensitive habitat areas. Existing access roads were not included in the assessment unless it was determined, based on field surveys, that road widening or other improvements might be needed that would potentially create additional impacts to roadside areas. Access roads were placed in areas for ease of access to each tower/pole site as well as to minimize impacts to potentially sensitive plant and wildlife habitat.

All Project-related layers were entered into a Geographical Information System (GIS) database for analysis. Information used during the analysis included the following layers, but was not limited to: topographic maps, recent aerial photographs, soils, USFWS critical habitat, California Natural Diversity Data Base (CNDDB), USFWS GIS data (August 2008), and blue-line drainage crossings.

Project Description

In addition to those hydropower facilities previously examined, the proposed Project has three main elements: the Talega/Escondido 230-kV Transmission Line second circuit, the Pala/Lilac 69-kV

Subtransmission Line upgrade, and upgrades to existing SDG&E and SCE substations. The following describes each component and the types of construction activity required for installation and operation.

Talega/Escondido 230-kV Study Corridor

The portion of the study corridor located within USMC Camp Pendleton (Milepost 0 to 16) is primarily native shrubs (Southern Mixed Chaparral and Coastal Sage Scrub) along the steep slopes, and Coast Live Oak Woodland and Southern Sycamore-Alder Riparian Forest in the valleys and drainages. Approximately three miles of this section is dominated by Native Grassland interspersed with scattered Engelmann oaks. The 22-mile segment from the eastern edge of Camp Pendleton to Pala Road is predominantly native scrubs interspersed with groves and orchards along the hillsides. The eight miles south of Pala Road to Old Castle Road is covered mostly with orchards, small patches of native shrubs, and residential areas. The southernmost four miles of the study area in the City of Escondido is primarily developed and residential with small patches of native vegetation.

Based on the data sources used for this analyses (CNDDB, MHCP, USFWS, Applicant PEA, and CPUC/BLM FEIR/FEIS), several sensitive species are known to occur within or immediately adjacent to the 500-foot-wide Project site. The sensitive plants that occur along the Project site include: San Diego County viguiera (*Viguiera laciniata*, CNPS list 4); Fish's milkwort (*Polygala cornuta* ssp. *fishiae*, CNPS list 4); sticky dudleya (*Dudleya viscida*, CNPS list 1B); and prostrate spineflower (*Chorizanthe procumbens*, CNPS list 4).

The sensitive wildlife species known to occur within the Project site include the scrub associated orange-throated whiptail (*Aspidoscelis hyperthrus beldingi*), San Diego horned lizard (*Phrynosoma coronatum blainvillei*), southern California rufous-crowned sparrow (*Aimophila ruficeps canescens*), coastal cactus wren (*Campylorhynchus brunneicapillus cousei*), the federally listed threatened coastal California gnatcatcher, and the federally listed endangered arroyo toad. The riparian-dependent least Bell's vireo, southwestern willow flycatcher, as well as the great blue heron (*Ardea herodias*) has been documented along the Project site. Two sensitive raptors, the federally protected golden eagle (*Aquila chrysaetos*) and the turkey vulture (*Cathartes aura*), have been observed foraging throughout the region, and presumably utilize the biological resources along the Project site to some extent.

Additionally, there are areas of designated critical habitat for several federally listed threatened or endangered species throughout the Project site. Along this alignment, critical habitat occurs for the federally listed endangered least Bell's vireo, southwestern willow flycatcher, and the threatened coastal California gnatcatcher. Designated critical habitat for the arroyo toad occurs in and adjacent to several drainages that cross the existing 230-kV alignment. The proposed critical habitat is crossed by the Project on the east half of the 230-kV alignment. On the west half of the 230-kV alignment, on UMCB Camp Pendleton, the Project is proposed to cross drainages immediately adjacent to arroyo toad critical habitat at two segments. The adjacent areas of critical habitat are located north of the UMCB Camp Pendleton boundary and the Project is not expected to adversely affect critical habitat (Appendix C). There are no permanent impacts associated with the installation of the 230kV line. Construction related impacts associated with pull-sties include a minimal amount of temporary impacts associated with transmission line stringing and are not sufficient to be considered a significant impact to the habitat. Most critical habitat areas within the 230kV line alignment are avoided.

Although suitable habitat occurs, no documented occurrences of Stephens' kangaroo rat are known along the 230-kV alignment and none were observed during field studies conducted by MBA or Helix.

Pala Lilac 69-kV Subtransmission Line

The 500-foot-wide 69-kV relocation portion of the Project encompasses approximately 560 acres, of which 50 percent is covered in groves, agriculture, residential and developed land (304.3 acres); approximately 23 percent (130 acres) is native scrub (Coastal Sage Scrub and Chaparral), 8 percent grasslands (45.5 acres), 3.5 percent Coast Live Oak Woodland (20 acres), and 12 percent riparian habitats (66.4 acres). This portion of the line is between Mileposts 34 and 42.

The habitats along the 69-kV line support a similar variety of wildlife species as those associated with the rest of the Project site, as these lines run parallel and in close proximity to one another for the majority of the distance of the 69-kV line. Sensitive species observations within the 69-kV portion of the Project site include several animals (e.g., orange-throated whiptail, turkey vulture, great blue heron, and coastal cactus wren). No sensitive plants have been recorded along this segment from existing databases and none were observed during field surveys. Critical habitats designated at various points along the 69-kV line include those for the arroyo toad, coastal California gnatcatcher, and least Bell's vireo.

As discussed for the 230-kV alignment, there are designated critical habitats for several federally listed threatened or endangered species along the 69-kV portion of the Project site. Along this alignment, critical habitat occurs for the federally listed endangered least Bell's vireo, coastal California gnatcatcher, and arroyo toad.

Existing Substation Upgrades

In addition to the Lake Switchyard and Santa Rosa and Case Springs Substations to be constructed by the Applicant, there are a number of existing substations that will or may require upgrade and improvement as a result of the electrical flows associated with the Project. Those existing facilities where upgrades/improvements are proposed to support the Project include:

- SCE's existing Etiwanda (8996 Etiwanda Avenue, City of Rancho Cucamonga), San Bernardino (San Bernardino Avenue east of Mountain View Avenue, City of Redlands), Mira Loma (13568 Milliken Avenue, City of Ontario), and Vista (22200 Newport Avenue, City of Grand Terrace) Substations in San Bernardino County; Serrano (East Carver Lane, Orange), and Talega (33000 Avenida Pico, San Clemente) Substations in Orange County; Valley (Menifee Road and Highway 74, Romoland) Substation in Riverside County.
- SDG&E's existing Pala (State Route 76 near Pala del Norte Road, Pala), Lilac (Lilac Road, North of Escondido, Valley-Center), Escondido (2037 Mission Avenue, City of Escondido), and Peñasquitos (Southeast of Interstate 5 and Highway 56, Carmel Valley, City of San Diego) Substations in San Diego County.
- Additional Project-related improvements have been identified to the existing Santiago Peak Communication Facility in Orange County.

All existing substation and communication facilities are within a previously disturbed area surrounded by a perimeter fence. No activities associated with the upgrades/improvements would occur outside of the existing fence lines on previously undisturbed sites. In several instances,

sensitive plant and wildlife species are known to occur in the general areas surrounding the existing substation. However, due to the disturbed nature of the existing facility, no suitable habitat for any sensitive plant or wildlife species occurs within each facility's existing footprint. The existing substations are completely developed and included approximately 261.6 acres. Since Project-related impacts would be *de minimis*, the amount of disturbed acreage should be viewed an approximation since the precise nature of each upgrade/improvement was not considered in this evaluation.

Three new facilities (Lake Switchyard and Santa Rosa and Case Springs Substations) have been evaluated and are covered under the previously submitted documentation (Appendix A).

Discussion

All vegetation communities within the 230-kV portion of the Project site are identified in Table 1 and are described below. These descriptions, as well as the major categories of vegetation, correspond to Holland 1986 classification system and as modified by Oberbauer (1996) for San Diego County. There are also numerous ecotone communities, which are combinations of two distinct vegetation communities with equal amounts of dominant vegetation. Some vegetation communities have elements of more than two vegetation communities. In these cases, the most dominant vegetation community was chosen to be the representative community. All vegetation community mapping, and other cover types, are depicted in Appendix B.

Wildlife habitat in an area determines the suitability of the site for use by certain animal species. Factors such as vegetation height, soil type, cover availability, and food and water sources influence which animal species will inhabit a specific vegetation association. These factors can be independent of the vegetation community that is present in any given area. In the following descriptions of the vegetation communities present within the Project area, the wildlife species commonly associated with each type of wildlife habitat are included.

Based on the site visits, two areas contained evidence of recent burns. A portion of the ROW between Mileposts 12.5 and 15.5 burned in 2003 during the Roblar Fire. The vegetation is naturally regenerating, but evidence of the burn is still evident. In addition, a small area just north of Milepost 33 also has evidence of a recent burn. This area was likely part of a small isolated roadside fire and is not part of the Rice Fire that burned in 2007. The closest portion of the ROW to the Rice Fire boundary occurs a quarter mile south of Milepost 24.

Table 1: Plant Communities - Approximate Acreage in Existing SDG&E 230 kV Line Study Area

Vegetation Community	230-kV Line (acres)	69-kV Line (acres)	Substations (acres)	Total Area (acres)
Scrub and Chaparral	**(1,732.2)**	**130.6**	**0**	**(1,732.2)**
Coastal Sage Scrub	360.1	107.2	0	360.1
Southern Mixed Chaparral	729.8	7.0	0	729.8
Chamise Chaparral	128.0	16.4	0	128.0
Red Shank Chaparral	1.7	0	0	1.7
Coastal Sage Scrub/Chaparral Mix	298.2	0	0	298.2
Coastal Sage Scrub/Non-native Grassland Mix	48.3	0	0	48.3
Post Burn Southern Mixed Chaparral*	153.9	0	0	153.9
Southern Mixed Chaparral/Non-Native Grassland Mix	12.2	0	0	12.2
Riverine, Wetlands, and Waters	**(212.0)**	**59.5**	**0**	**(212.0)**
Mulefat Scrub	10.9	0	0	10.9
Southern Willow Scrub	2.7	2.7	0	2.7
Southern Arroyo Willow Riparian Forest	13.9	13.9	0	13.9
Southern Coast Live Oak Riparian Forest	161.4	35.0	0	161.4
Southern Cottonwood-Willow Riparian Forest	1.3	0	0	1.3
Southern Sycamore-Alder Riparian Forest	10.5	0	0	10.5
Open Water	7.9	7.9	0	7.9
Unvegetated River Bed	3.7	0	0	3.7
Grasslands and Herb-Dominated Communities	**(138.4)**	**45.5**	**0**	**(138.4)**
Native Grassland	7.0	5.6	0	7.0
Non-native Grassland	105.1	39.9	0	105.1
Non-native Grassland/Ornamental Woodland Mix	26.3	0	0	26.3
Woodland and Forests	**(366.1)**	**20.1**	**0**	**(366.1)**
Coast Live Oak Woodland	358.8	19.9	0	358.8
Ornamental Woodland	7.3	0.2	0	7.3
Disturbed/Developed/Unvegetated Landform	**(737.9)**	**304.3**	**261.6**	**(999.5)**
Developed	281.1	40.3	261.6	542.7
Disturbed	15.1	6.1	0	15.1
Disturbed Fire Break	21.3	0	0	21.3
Agriculture	404.1	257.9	0	404.1
Rocks	1.2	0	0	1.2
Tower	15.1	0	0	15.1
Total	**3,186.6**	**560.0**	**261.6**	**3,448.2**

Scrub and Chaparral Communities

The dominant vegetation communities within the SDG&E 230kV transmission line study area consist of Coastal Sage Scrub, Chaparral, and an ecotone with a combination of the two. Scrub and Chaparral Communities make up approximately 54 percent of all vegetation communities within the 500-foot wide study area (approximately 1,732.2 acres).

Wildlife species often associated with the Coastal Sage Scrub and chaparral habitats include several upland bird species, such as California towhee (*Pipilo crissalis*), Lawrence's goldfinch (*Carduelis lawrencei*), Bewick's wren (*Thryomanes bewickii*), and scrub jay (*Aphelocoma coerulescens*). Scrub habitats on site also provide cover and forage for mammal species, including California ground squirrel (*Spermophilus beecheyi*) and desert cottontail (*Sylvilagus audubonii*), side-blotched lizard (*Uta stansburiana*) and western fence lizard (*Sceloporus occidentalis*).

Coastal Sage Scrub

Coastal Sage Scrub consists of low-growing, drought-deciduous and evergreen shrubs that occur on steep and gentle slopes throughout southern California south into Baja California below 3,000 feet in elevation. For the purpose of this assessment, habitats containing 70 percent or higher dominance by sage scrub species are considered Coastal Sage Scrub. The dominant plants mainly consisted of California buckwheat (*Eriogonum fasciculatum*), bush penstemon (*Keckiella antirrhinoides*), brittle-bush (*Encelia farinosa*), white sage (*Salvia apiana*), black sage (*Salvia mellifera*), and California sagebrush (*Artemisia californica*).

The Coastal Sage Scrub is scattered throughout the study area, with the greatest amount at the northern extent of Camp Pendleton and on both the north and south sides of State Route 76.

Southern Mixed Chaparral

Southern mixed chaparral consists of broad-leaved sclerophyllous shrubs, 2-4 meters tall, forming dense, often nearly impenetrable vegetation dominated by scrub oak (*Quercus dumosa*), toyon (*Adenostoma fasciculatum*), and any one of several taxa in Arctostaphylos or Ceanothus family. This plant community is typically deep-rooted and usually contains little or no understory vegetation; often with a considerable accumulation of leaf litter. Growth may occur throughout the year but is highest in spring and much reduced during the late summer/fall dry season or during the winter at higher elevations. Flowering season extends from late winter to early summer. This community is adapted to repeated fires, to which many species respond by stump sprouting. A dense cover of annual herbs may appear during the first growing season after a fire, followed in subsequent years by perennial herbs, short-lived shrubs and re-establishment of dominance by the original shrub species.

Chaparral is concentrated in the central portion of the study area, with an extension cover of chaparral east of the interconnect with the Project, as well as a portion in the southern extent of the study area

Portions of the southern mixed chaparral community were sub-divided even further into smaller associations that contain a single dominant species including Chamise Chaparral and Red Shank Chaparral. In addition, several ecotones are described as having elements of Coastal Sage Scrub or

Chaparral. Common ecotones associated with scrub and chaparral communities include pairings with Non-Native Grasslands and Oak Woodlands.

Riverine, Wetlands and Water

Several riparian vegetation communities have been mapped for the Project site including a Mule Fat Scrub, Southern Arroyo Willow Riparian Forest, Southern Coast Live Oak Riparian Forest, Southern Cottonwood-Willow Riparian Forest, Southern Sycamore-Alder Riparian Forest, Southern Willow Scrub, Open Water, and Unvegetated River Bed.

Riverine vegetation communities and other wetlands comprise 212 acres, which is less than 7 percent of the entire study area. Most of the riparian wetlands (including marshes) occur along the main creeks that cross the study area. The major rivers, creeks and streams crossing through the study area include Cristianitos Creek (Milepost 0.2), Talega Creek (Milepost 3.0), San Mateo Creek (Milepost 6.5), Roblar Creek (Milepost 13.9), De Luz Creek (Milepost 16.8), Sandia Canyon Creek (Milepost 21.3), Santa Margarita River (Milepost 24.2), Gomez Creek (Milepost 32.9), San Luis Rey River (Milepost 34.5), Couser Canyon Stream (Milepost 36.7), Keys Creek (Milepost 39.4), and Moosa Canyon Stream (Milepost 43.2).

Birds typically associated with riparian habitats include black phoebe *(Sayornis nigricans*), yellow warbler (*Dendroica petechia morcomi*), and common yellow-throat (*Geothlypis trichas*). The open areas at the fringe of these habitats also provide cover for reptile species such as the coastal western whiptail *(Cnemidophorus tigris multiscutatus*) and side-blotched lizard. Riparian areas also typically support a variety of small mammal species, including deer mouse (*Peromyscus maniculatus*) and house mouse (*Mus musculus*).

Mule Fat Scrub

Mule Fat Scrub occurs in small patches and narrow ribbons along streambeds and washes that tend to dry out quickly after storm events. This riparian habitat type consists primarily of mule fat (*Baccharis salicifolia*), with scattered willows *(Salix* spp.), and coyote bush (*Baccharis pilularis*), along with occasional Mexican elderberry (*Sambucus mexicana*) forming the shrub canopy. In most areas, the understory contains upland grasses and forbs like wild oats (*Avena* spp.) and mustard (e.g., *Brassica, Hirschfeldia, Rapa* spp.). In areas where mule fat is particularly dense or where substantial scouring has occurred, the understory component of this habitat may be sparsely vegetated or absent.

Patches of Mule Fat Scrub occur within Talega Canyon Creek, located in the northern portion of Camp Pendleton, east of Cristianitos Road. The vegetation is associated with an ephemeral drainage feature that drains from east to west along the coastal foothills.

Southern Willow Scrub

Southern Willow Scrub is a dense, broad-leafed, winter-deciduous riparian thicket dominated by several Salix species, with scattered emergent Fremont's cottonwood and western sycamore. Most stands are too dense to allow much understory development. Loose, sandy, or fine gravelly alluvium is typically deposited near the active stream channel during severe flood events causing erosion and scouring, which greatly impacts associated vegetation. This plant community typically requires repeated flooding to prevent succession to Southern Cottonwood-Sycamore Riparian Forest.

Formerly, this vegetation community was extensive along the major rivers of coastal southern California. But now it is much reduced by urban expansion, flood control, and channel "improvements." A single occurrence of this vegetation community is located near the Pala Substation, just south of State Route 76, just east of Pala del Norte Road.

Southern Arroyo Willow Riparian Forest

Southern Arroyo Willow Riparian Forest vegetation occurs in association with intermittent to perennial watercourses and water bodies. The representative plant species are typically well adapted to a hydrological regime ranging from semi-permanent inundation to occasional soil saturation on or near the surface during at least a portion of the growing season. This community typically consists of a relatively dense tangle of broad-leaved, winter-deciduous riparian thickets typically dominated by arroyo willows *(Salix lasiolepis*). A stand of this community occurs east of the Pala Substation, south of State Route 76.

Southern Coast Live Oak Riparian Forest

Southern Coast Live Oak Riparian Forest is dominated by coast live oak (*Quercus agrifolia*) trees along drainages and stream channels and may also have other tree species as minor components such as western sycamore (*Platanus racemosa*) and Fremont's cottonwood (*Populus fremontii*).

Three distinct patches of Southern Coast Live Oak Riparian Forest occur within the study area. These areas are generally located along the northern portion of the transmission line, just east of Interstate 15, along the central portion of the transmission line, just north of Lila Road, and in the southern portion of the study area, just south of Jesmond Dene Road.

Southern Cottonwood-Willow Riparian Forest

Fremont's cottonwood and tall willows (*Salix gooddingii, S. lasiandra, S. lasiolepis*) generally greater than 20-feet high dominate this open canopy, broad-leafed winter-deciduous riparian forests. The understory consist of shrubby willows, mule fat, and mugwort (*Artemisia douglasiana*) that occupy relatively broad drainages and flood plains supporting perennially wet streams and sub-irrigated and frequently overflowed lands along rivers and streams. The dominant species require moist, bare mineral soil for germination and establishment. This is provided after flood waters recede, leading to uniform-aged stands in this seral type. Along perennially wet stream reaches of the Transverse and Peninsular ranges, from Santa Barbara County south to Baja California Norte and east to the edge of the deserts.

There is a single stand of this vegetation community within the northern portion of the study area, just west of Sandia Creek Drive and southeast of Ross Lake.

Southern Sycamore - Alder Riparian Woodland

Western sycamore as well as alder (*Alnus rhombifolia*) dominates the Southern Sycamore-Alder Riparian Woodland, which is also a tall, open, broad-leafed, winter-deciduous streamside woodland. These stands seldom form closed canopy forests, and even may appear as trees scattered in a shrubby thicket of sclerophyllous and deciduous species. Understory species include blackberry (*Rubus ursinus*) and poison oak (*Toxicodendron diversilobum*). Very rocky streambeds within this riparian area are subject to seasonally high-intensity flooding. Alders increase in abundance within

more perennial streams, while sycamores favor more intermittent hydrographs. This plant community ranges from the Transverse and Peninsular ranges from Point Conception south into Baja California Norte.

This vegetation community occurs in the western portion of the study area along the northern boundary of Camp Pendleton between Devil's Canyon and Case Springs. The transmission line ROW comes in close contact with several drainage features in the undisturbed rolling canyons.

Open Water

Open water bodies within the Project site provide important habitat for a variety of aquatic organisms and water fowl. Open water bodies include lakes, reservoirs, bays, flowing water within a river channel and small ponds along stream courses. Two areas of open water occur within the 230 kV line ROW. The first area is located immediately adjacent to the Southern Willow Scrub habitat mentioned above, just south of State Route 76. The second area is located near the Lilac Substation, south of Old Castle Road.

Un-vegetated River Bed

An un-vegetated River Bed is described as a frequently scoured drainage feature with little to no vegetation. Typically, this community contains large boulders and rocks with small pockets of deposited sand. All vegetation is frequently removed during large storm events, leaving bare rock. This community is located in the western portion of the study area at the mouth of Devil's Canyon.

Grasslands and Herb-Dominated Communities

Grasslands and herb-dominated communities comprise 138.4 acres of the Project area, which is approximately 4 percent of the study area. Most of the vegetation communities associated with grasslands includes non-native grassland, which typically border chaparral or scrub. It is likely that the non-native grassland areas were, at one time, chaparral and scrub and then were cleared for agricultural use in the early twentieth century and subsequently abandoned.

Avian wildlife species typically associated with grassland communities include western meadowlark (*Sturnella neglecta*), northern harrier (*Circus cyaneus*), lesser nighthawk (*Chordeiles acutipennis*), savannah sparrow (*Passerculus sandwichensis*), grasshopper sparrow (*Ammodramus savannarum*), and lark sparrow (*Chondestes grammacus*). A variety of raptor species, such as white-tailed kite (*Elanus leucurus majusculus*) often forage across grasslands. The northern harrier also nests in grasslands. Other potential inhabitants of grassland habitats include the federally listed endangered (state listed threatened) Stephens' kangaroo rat (*Dipodomys stephensi*), as well as reptile species such as western fence lizard and gopher snake (*Pituophis melanoleucus*).

Native Grasslands

Native grasslands are dominated by perennial bunchgrasses such as needlegrass (*Nassella* spp. and *Achnatherum* spp.), plumed beard grass (*Bothriochloa barbinodis*), wild rye (*Elymus* spp.), and deergrass (*Muhlenbergia* spp.). The degree of habitat quality in native grasslands varies greatly, depending on the history of grazing, cultivation, or other disturbance factors. In addition to purple needlegrass, indicator species include blue-eyed grass (*Sisyrinchium bellum*), mariposa lily (*Calochortus* spp.), and clarkia (*Clarkia* spp.), among others. Approximately 7 acres of native

grassland coincides with the study area and is generally located in three separate areas including the area immediately south of Rainbow Heights Road, south of State Route 76, and north of Couser Canyon Road. No native grasslands were mapped elsewhere for the Project site.

Non-native Grassland

Non-native grassland consists of non-native, annual grasses often associated with native annual forbs. These grasses begin to germinate with the fall rains, grow during the winter and spring, and wither in the early summer. This community is often found on clay soils (Holland 1986). Species observed in this plant community include wild oats (*Avena* spp.), Italian wild rye (*Lolium multiflorum*), bromes (*Bromus* spp.) and weedy herbs such as mustard (*Brassica* spp.) and yellow star-thistle (*Centaurea monspeliensis*).

Woodland and Forests

Woodlands and forests are dominated by upland tree species such as oaks (*Quercus* sp.) and pines (*Pinus* sp.). These communities typically occur on north-facing slopes or canyon bottoms, which provides more available moisture for plant growth. This additional moisture allows for larger tree growth. Typically, woodland and forest areas have nearly a complete canopy with little to no understory and dense leaf litter.

Woodland avian species likely to inhabit these vegetation communities include Cooper's hawk (*Accipiter cooperi*), northern flicker (*Colaptes auratus*), and some woodpecker species (*Picoides* spp.). The moist ground conditions often associated with woodlands provides habitat for numerous reptile and amphibian species such as Coronado skink (*Eumeces skiltonianus interparietalis*), Monterey salamander (*Ensatina eschscholtzii eschscholtzii*), and Pacific treefrog (*Pseudacris regilla*). Mammals such as coyote (*Canis latrans*), raccoon (*Procyon lotor*), and mule deer (*Odocoileus hemionus*) typically utilize woodlands for protective cover and movement corridors.

Coast Live Oak Woodland

Coast live oak woodland is an open to dense tree community with coast live oak (*Quercus agrifolia*) as the dominant overstory species and Engelmann oak (*Quercus engelmannii*) as an occasional associate. This community can occur on mesic north-facing slopes and in canyon bottoms. This community is well represented in the cismontane, interior valleys and foothills of the Peninsular Ranges. The shrub understory of this community is poorly developed but may include: Mexican elderberry, gooseberry (*Ribes* sp.), poison oak, and toyon.

Coast live oak woodland occurs in approximately 359 acres of the project site, usually in canyons surrounded by chaparral. The majority of this habitat is in the western portion of the Project site, within Camp Pendleton; however, small patches also occur in the eastern and southern portions of the Project site.

Ornamental Woodland

Ornamental woodlands typically consist of ornamental species or species not known to occur in southern California that are used for landscaping or agricultural purposes. The vegetation in these areas is often artificially irrigated and likely planted several decades ago. The ornamental woodland

areas are limited to the residential areas in the eastern portion of the Project site. There are 7.3 acres of this plant community within the Project area.

Common species found in this natural community include eucalyptus sp., Oregon ash (*Fraxinus oregona*), and Peruvian peppertree (*Schinus molle*).

Wildlife species observed in this natural community are typical of wildlife species that have adapted to urban development. These species include western fence lizard (*Sceloporus occidentalis*), house finch (*Carpodacus mexicanus*), European starling (*Sturnus vulgaris*), mourning dove, and common raven (*Corvus corax*).

Disturbed/Developed/Unvegetated Landforms

The disturbed/developed/unvegetated landform areas are not typically described as vegetation communities because they are often unvegetated or are extremely poor quality habitat dominated by non-native invasive weedy species. These area provide no suitable habitat for listed species.

Disturbed

Disturbed areas are commonly associated with areas that have been recently disturbed with little to no vegetation present. Over time, these areas will likely revert to a non-native grassland, but currently provide little to no habitat for plant or wildlife species. These areas may include agricultural areas, and fire breaks.

Developed

Developed areas include all areas that have been paved or otherwise built to eliminate any natural revegetation. These areas often include residential developments, commercial developments, electrical facilities and other infrastructure, and other areas that prohibit or restrict vegetation growth. Typically these areas will not allow any future vegetation growth, unless the development is removed.

Unvegetated Areas

These areas are typically associated with a recent disturbance, such as a river bottom, which is completely unvegetated. These areas are routinely impacted, reducing the potential for revegetation. These areas may include routine maintenance beneath existing lattice towers, unvegetated river bottoms, and rocky outcrops.

Federally and State Listed Species

Quino Checkerspot Butterfly

The Quino checkerspot butterfly (*Euphydryas editha quino*) was listed in 1997 as an endangered species by the federal government. Currently, Quino checkerspot butterfly (QCB) is known only from scattered locations in San Diego and western Riverside counties, and northwestern Baja California, Mexico. The species' historic range includes areas of southern California and Baja California, and portions of San Diego, Orange, Los Angeles, and western Riverside counties. This species is

threatened by one or more of the following factors: habitat loss and fragmentation due to urban development, over collection and other human disturbances, drought, fire, or other weather extremes, and by the displacement of the primary larval food plant by non-native grasses and other weedy annuals.

The larvae of the QCB feed primarily on dwarf plantain (*Plantago erecta*), but also utilize owl's clover (*Orthocarpus purpurescens*), Chinese houses (*Collinsia heterophylla*), birds beak (*Cordylanthus rigidus*), and woolly plantain (*Plantago ovata*). Plantain is often found growing in openings in grasslands and Coastal Sage Scrub where cryptogamic crusts and clay soils deter the establishment of invasive non-native grasses. QCB adults are active primarily during March and April (depending on rainfall) when nectar at numerous native annual plants is available.

Host and nectar plants are typically annuals, which die back in the summer and the larvae thus have a period of summer diapauses during which they do not feed. In the late winter and early spring, as the plants appear again, the larvae commence feeding again and then enter a short pupal phase. Because of their dependence on annual host plants that dry up and senesce, pre-diapauses larvae are the stage most susceptible to mortality. It is vital that newly hatched larvae locate a host plant rapidly.

After the food plants germinate following fall or winter rains, the larvae pupate into adults. The larvae may remain dormant for one or more seasons, which is dependent how quickly rain facilitates the sprouting of food plant seeds. In approximately a two-week period, the adults emerge, feed, disperse, reproduce, and then die.

Adult QCB live from 4 to 8 weeks, during which time they mate and lay eggs. Courtship behavior consists of male butterflies hill topping on open or sparsely vegetated rounded hilltops, ridgelines, and rocky outcrops. Adults sun themselves at the base of hills and have been observed flying through areas of unsuitable habitat, most likely dispersing to sites with the appropriate food plants. After mating, adults lay eggs, which hatch in about 10 days. The larvae feed on the food plants for about two weeks,

On April 15, 2002, the USFWS designated final critical habitat for QCB in four Units in Riverside and San Diego Counties. The nearest QCB critical habitat area to the 230 kV line study area is 7.5 miles to the northeast. On January 17, 2008, the USFWS published a proposed rule to revise the designated critical habitat to consider excluding 1,684 acres of land within the City of Chula Vista's MSCP Subarea Plan and 37,245 acres of non-federal land within the Western Riverside County Multiple Species Habitat Conservation Plan (MSHCP) area. Specifically, this proposal to revise critical habitat focuses on areas known to contain core occurrence complexes of the species. This proposed revision to critical habitat also includes addition of a newly identified core complex in San Diego County within and adjacent to the La Posta and Campo Indian Reservations.

QCB Survey Areas include the portion of the 230-kV study area within Camp Pendleton (Milepost 2 to Milepost 10) as well as a 3-mile long section near State Route 76 (Milepost 33 to Milepost 36). The closest recorded occurrence of QCB to the Project ROW is 5 miles to the northeast of Milepost 29 and 2 miles south of Milepost 51. There is extensive suitable habitat along the ROW within Camp Pendleton and an area of potentially suitable habitat immediately north of State Route 76 of Milepost 30.

Helix conducted habitat assessments/focused surveys for QCB in 2008, based on the approved USFWS protocol. All surveys were conducted within suitable habitat within the USFWS recommended QCB Survey Area (between Milepost 27 and Milepost 34), excluding the portion of the study area with the Camp Pendleton area (Shelby Allen pers. comm.). No QCB were observed and the habitat is considered unoccupied.

Arroyo Toad

The arroyo toad (*Bufo californicus*) was listed as endangered by the federal government in 1994 and is a California Species of Special Concern. This species is often found near rivers with sandy banks, willows, cottonwoods, and sycamores in valley-foothill and desert riparian habitats. The arroyo toad may be found in loose gravelly areas of streams in drier portions of its range. Eggs are laid on the bottom of quiet parts of clear streams or shallow ponds, among leaves, gravel, or sticks (Stebbins 1954, 1985).

The arroyo toad historically ranged from the upper Salinas River in San Luis Obispo County through the streams of southern California into northwestern Baja California, Mexico (Jennings and Hayes 1994). Threats to the species include habitat degradation, drought, and small population size. Unlike the common western toad, it is shy and secretive and is vulnerable to disturbance.

Arroyo toads have very specific habitat requirements. Arroyo toads occur in and breed in pools with a depth of 12 inches or less, with extensive gravel beds (Sweet 1991). The arroyo toad breeds along large streams with persistent in-channel pools from late March through mid-June. Larvae have very specific habitat requirements: very shallow water, usually less than four inches deep, with slight currents; a substrate of gravel or fine cobble that supports filamentous algae; emergent vegetation is usually absent; and the stream terrace pools are usually in full sunlight. After metamorphosis, juveniles remain on nearby gravel bars associated with large riparian trees and shrubs in areas lacking grass or herbaceous ground cover present.

Critical habitat was originally designated for arroyo toad in 2005. The ROW crosses critical habitat at four locations: Cristianitos Creek/Talega Canyon Creek (Mileposts 0.5 to 5.0), San Mateo Creek (Milepost 6.5), De Luz Creek (Milepost 16.8), and San Luis Rey River (Milepost 34.5). Suitable habitat for arroyo toad occurs within riparian habitats scattered along the study area.

Potentially suitable habitat for arroyo toads occurs within the major river systems that cross the ROW including Cristianitos Creek, Talega Creek, San Mateo Creek, Roblar Creek, De Luz Creek, Sandia Canyon Creek, Santa Margarita River, Gomez Creek, San Luis Rey River, Couser Canyon Creek, Keys Creek, and Moosa Canyon Creek.

Arroyo toads are known to occur within Cristianitos Creek, San Mateo Creek, De Luz Creek, and San Luis Rey River. This species is known to occur within the drainage feature between Milepost 0 and Milepost 5. Suitable habitat occurs within Santa Margarita River, Gomez Creek, and Keys Creek, but no occurrences have been recorded within the vicinity of the project site. These drainage features are considered potentially occupied. Habitat within the remaining streams including Roblar Creek, Sandia Canyon Creek, Couser Canyon Creek, and Moosa Canyon Creek, are not likely to be considered occupied.

Coastal California Gnatcatcher

Coastal California gnatcatcher (*Polioptila californica californica*) was listed as threatened by the federal government in 1993 and is a CDFG Species of Special Concern. Coastal California gnatcatcher (CAGN) is most numerous in low, dense coastal scrub habitat in arid washes, on mesas, and on slopes of coastal hills. California buckwheat, coastal sage, and patches of prickly pear are particularly favored. Shrubs provide roosting and nesting cover. This species weaves a small, deep cup from hemp-like fibers, leaves, plant down, spider silk, in a shrub 0.6 to 0.9 meter (2 to 3 feet) above ground.

The CAGN is a species with restricted habitat requirements, being an obligate resident of coastal sage scrub habitats that are dominated by coastal sagebrush and generally occur below 750 feet elevation in coastal regions and below 1500 feet above mean sea level (AMSL) inland. It ranges from Ventura County south to San Diego County and northern Baja California. It is less common in coastal sage scrub with a high percentage of tall shrubs such as laurel sumac, preferring habitat with more low-growing vegetation. CAGN breed between mid-February and the end of August, with the peak of activity from mid-March to mid-May. Declines of this species are attributed to loss of coastal sage scrub habitat through development, and there is some evidence of cowbird nest parasitism.

Coastal Sage Scrub communities dominated by California sagebrush, California buckwheat, white sage, and black sage are preferred by this species. Loss and fragmentation of suitable habitat due to expanding development have been major factors in the decline of this bird in southern California. Critical habitat was originally designated for this species in 2000 and was recently revised in 2007. The ROW crosses critical habitat at three main areas including: the area west of Interstate 15 along the Riverside County/San Diego County border, an area two miles north and two miles south of San Luis Rey River, and an area from Jesmond Dene Road, north for approximately 3 miles.

There are approximately 15 areas of suitable CAGN habitat within the ROW. Four of these areas are located in the northern portion of Camp Pendleton and range in elevation from 300 to 1600 feet AMSL between Milepost 0.5 and Milepost 7.5. Previously recorded occurrences of CAGN are within one mile of the western most patch of suitable habitat on Camp Pendleton. It is likely that these areas are presumed occupied.

The next major patch of suitable habitat occurs along the Riverside/San Diego County border near Milepost 22. The area is located immediately east of Sandia Canyon Drive. The elevation ranges from approximately 600 to 800 feet AMSL. The closest recorded occurrence is approximately five miles to the south. There are several patches of Coastal Sage Scrub immediately west of Interstate 15 at an elevation of 1,300 to 1,600 feet. AMSL at Milepost 40. This habitat is near the upper end of the elevation limit for this species.

Four main areas within the Project site are potentially occupied habitat. The area between Mileposts 0 and Milepost 1 is within the immediate vicinity of occupied CAGN habitat. Also, there is a large population of CAGN located south of Milepost 51. There are two small habitat patches located south of State Route 76 at Mileposts 36 and Mileposts 39. The closest recorded occurrence is approximately 130 feet west of the study area at Milepost 39. This species is likely present within some portions of the study area.

Stephens' Kangaroo Rat

Stephens' kangaroo rat (*Dipodomys stephensi*) was listed as endangered by the federal government in 1988 and is a California Department of Fish and Game (CDFG) threatened species. The Stephens' kangaroo rat (SKR) prefers open areas with sparse perennial cover. This species occurs in areas of loose soil where the soil depth is at least 0.5 meter. SKR will also inhabit disturbed areas such as fallow fields by using the burrows of other rodents, including Botta's pocket gophers (*Thomomys bottae*) and the California ground squirrel (*Spermophilus beecheyi*).

Like all kangaroo rats, SKR is primarily a seedeater, feeding on the seeds of both annual and shrub species. It also feeds on green vegetation and insects when available. Being primarily a dry biome species, SKR obtain nearly all of their water from the food they eat, and can subsist indefinitely on water extracted from dry seeds. They forage in open ground and underneath shrubs. Burrows are dug in loose soil.

The Dulzura kangaroo rat (*Dipodomys simulans*) (DKR) and the SKR have overlapping ranges in the project area. DKR are known to occasionally inhabit open grasslands more characteristic of SKR. SKR are infrequently known to inhabit areas of denser vegetation common to DKR. Therefore, trapping is often the only definitive method of confirming the absence or presence, distribution, and abundance of SKR in areas where they are sympatric with other kangaroo rat species, or where trace sign is found.

There is designated critical habitat for SKR, and, this species is included as a covered species in the proposed North County MSCP for San Diego County. However, the MSCP has not been approved.

Suitable habitat for SKR is found within gentle rolling hills within Camp Pendleton between Milepost 0 and Milepost 1 and between Milepost 10 and Milepost 11. The closest recorded occurrence of SKR is approximately 1.5 miles southeast of suitable habitat within the western portion of the study area within Camp Pendleton. Another large habitat patch occurs within the southern portion of the study area between Milepost 39 and Milepost 40 as well as between Milepost 49 and Milepost 51. Outside of Camp Pendleton, the closest recorded occurrence is over 7 miles from the closest suitable habitat. The study area has scattered suitable habitat, but only the western portion of the ROW within Camp Pendleton is close to known occupied habitat. The remaining study area contains low quality habitat or is isolated from known populations of SKR. Based on previous survey data from USFWS, this species is not likely to occur within the Project site.

Southwestern Willow Flycatcher

Southwestern willow flycatcher (*Empidonax traillii extimus*) was listed as endangered by the federal government in 1995 and all subspecies of willow flycatchers in California are listed as state-endangered. Dense willow thickets are required for nesting and roosting and low, exposed branches are used for singing posts and hunting perches.

The endangered southwestern willow flycatcher (SWF) is a small, insectivorous songbird, which is drab olive-brown above with a white throat and a pale yellow belly. It is one of four subspecies of willow flycatchers recognized in North America, and is distinguished by subtle differences in color and morphology. Although the subspecies occupy distinct breeding ranges, northern subspecies *(E t. brewsteri* and *E. t. adastus*) do pass through southern California during migration.

SWF breed in riparian habitats along rivers, streams, or other wetlands characterized by dense willows and shrubs in woodlands with standing water. Willow flycatcher subspecies winter in Mexico and Central America, and typically arrive at breeding sites in the southwest in mid-May and remain until late August.

Historically, SWF were abundant in riparian habitats throughout southern California, Arizona, New Mexico, southwestern Colorado, southern Nevada and Utah, western Texas, and extreme northern Mexico. SWF currently occupies a small fraction of its former range. The decline has been attributed to widespread destruction and degradation of riparian habitats and brood-parasitism by the brown-headed cowbird. As a result, the SWF was listed by CDFG as an endangered species in 1991 and was federally listed as endangered in 1995. Currently, less than 100 breeding pairs are known in southern California. Most are located at Prado Dam in Riverside County, the Kern Valley Nature Reserve in Kern County, the San Luis Rey River and Camp Pendleton Marine Corps Base in San Diego County, and the San Ynez River in Santa Barbara County. Critical habitat was originally designated for this species in 1997 and was most recently revised in 2005. The ROW crosses critical habitat at three main areas including: De Luz Creek, Santa Margarita River, and San Luis Rey River.

Similar to arroyo toad, potentially suitable habitat for SWF occurs within most of the major river systems that cross the ROW including Cristianitos Creek, Talega Creek, San Mateo Creek, Roblar Creek, De Luz Creek, Sandia Canyon Creek, Santa Margarita River, Gomez Creek, San Luis Rey River, Couser Canyon Creek, Keys Creek, and Moosa Canyon Creek. SWF is known to occur within the San Luis Rey River and Santa Margarita River. This species is likely present within these portions of the ROW.

Least Bell's Vireo

Least Bell's vireo (*Vireo bellii pusillus*) is listed as endangered by the federal government in 1986 and is also state listed as endangered. It is now a rare, local, summer resident below about 2,000 ft in willows and other low, dense valley foothill riparian habitat and lower portions of canyons mostly in San Benito and Monterey Counties; in coastal southern California from Santa Barbara County south; and along the western edge of the deserts in desert riparian habitat. .

Least Bell's vireo (LBV) inhabits low, dense riparian growth along water or along dry parts of intermittent streams typically associated with willow, cottonwood, baccharis, wild blackberry, or mesquite in desert localities. LBV winter in southern Baja California, Mexico, and typically migrate between mid March and early April to southern California and northwestern Baja California, where they remain until late September.

The LBV builds an open-cup nest of pieces of bark, fine grasses, plant down, horse hair. The nests are often placed on slender branches of willow, other shrub, mesquite, or other small tree, usually 0.6 to 0.9 m (2 to 3 ft), but sometimes 0.3 to 3.0 m (1 to 10 ft), above ground. Historically, LBV was abundant in riparian habitats throughout the central valley, coastal southern California, and in scattered oases and canyons in California deserts. Populations have declined dramatically this century owing to widespread destruction and degradation of riparian habitats and brood-parasitism by the brown-headed cowbird (*Molothrus ater*). The USFWS listed the LBV as an endangered species in 1986.

The largest LBV populations in southern California are currently located at the Prado Basin in Riverside County, and along the Tijuana River, the San Luis Rey River, the San Diego River, the Santa Margarita River and other drainages on Camp Pendleton in San Diego County. Habitat restoration has also provided additional habitat areas for this species, contributing to its recovery. Critical habitat was originally designated for this species in 1994.

The ROW crosses critical habitat at two areas including: Santa Margarita River (Milepost 24) and San Luis Rey River (Milepost 34.5). Similar to SWF and arroyo toad, potentially suitable habitat for LBV occurs within most of the major river systems that cross the study area including Cristianitos Creek, Talega Creek, San Mateo Creek, Roblar Creek, De Luz Creek, Sandia Canyon Creek, Santa Margarita River, Gomez Creek, San Luis Rey River, Couser Canyon Creek, Keys Creek, and Moosa Canyon Creek. LBV is known to occur within the Cristianitos Creek, Talega Creek, San Mateo Creek, De Luz Creek, Santa Margarita River, San Luis Rey River, and Keys Creek. This species is likely present within some portions of the study area.

Sensitive Plants

Focused surveys were conducted within suitable habitat and accessible areas within the ROW during the appropriate blooming period for each target species. Sensitive plant species observed onsite include Ramona horkelia (*Horkelia truncata*), San Diego County viguiera (*Viguiera laciniata*), Parry's tetracoccus (*Tetracoccus dioicus)*, and rainbow manzanita (*Arctostaphylos rainbowensis)*, These plant species are listed as sensitive by the California Native Plant Society, but are not federally or state listed as threatened of endangered.

Impacts

The removal of common plant communities such as Non-Native Grasslands, Chaparral, Ornamental Woodlands, Disturbed Areas, Open Water, and Agricultural Areas do not require mitigation measures under California Environmental Quality Act (CEQA) Guidelines. Removal of Coastal Sage Scrub, Southern Willow Scrub, and Oak Woodland habitat may be considered adverse with respect to potential impacts to QCB, arroyo toad, CAGN, SKR, LBV, and SWF as these habitats have the potential to support these species.

As shown in Table D-1, Project impacts will result in the removal of eleven distinct plant communities and two geographic features including open water and disturbed areas (Appendix B, Plant Community Maps). The vegetation trimming impacts associated with the vegetation management areas will occur within the temporary workspace surrounding the permanent tower impact area and is included in the impact calculations in Table D-1. Based on the CPUC/BLM FEIR/FEIS, impacts to Coastal Sage Scrub will be replaced at a 2:1 ratio. Final plant community impacts will be calculated once a final plan has been designed. Although impact amounts are anticipated to be less than indicated in the CPUC/BLM FEIS/FEIR, the mitigation ratio will remain the same. A Restoration Mitigation Plan will be prepared to restore suitable habitat areas impacted by Project installation for the federally listed threatened and endangered species mentioned above.

Access roads, if not existing, will be tracked in with no direct vegetation removal. These roads are temporary access roads and vegetation will be crushed by construction vehicles and allowed to naturally revegetate. There are no new permanent access roads designed for this project. Total temporary impacts associated with access road construction are also shown in Table D-1. Where

possible, access roads will be contained within the 500-foot wide buffer area surrounding the transmission route centerline. The buffer area has been surveyed to determine presence/absence of sensitive wildlife species for the Sunrise Powerlink Project. Access roads that are located outside of the buffer area were not surveyed at the same amount of effort as the transmission line ROW, but have recently been evaluated for suitable habitat concerning federal and/or state listed species.

Portions of the 230 kV line transmission alignment occur within designated critical habitat for CAGN, arroyo toad, SWF, as well as LBV.

The following information is based on the project facilities presented in the CPUC/BLM FEIS/FEIR. All areas have been surveyed and assessed and are included in the impact calculations provided in this letter report.

For the purpose of this letter report, the discussion of potential Project-related impacts has been divided into three separate construction related activities including the installation of the 230-kV transmission line, the new 69-kV subtransmission line, and the substation and communication facilities upgrades. The majority of the project site occurs within the existing SDG&E right-of-way. The majority of the ROW was not accessible for focused surveys because of private property access issues, including Camp Pendleton. In addition, SDG&E has not yet provided access to the applicant for the entire ROW. Once the proposed Project has been certified and land access granted, focused surveys will be conducted within suitable habitat areas to confirm presence/absence of the federally and state listed threatened and endangered species mention above.

230-kV Transmission Line

The majority of the ground disturbance related impacts associated with the 230 kV Talega/Escondido transmission line are avoided or minimized due to the presence of existing towers and access roads that may be used with no upgrade or additional impacts. With the exception of new transition towers linking the Applicant's new (Lake-Case Springs) transmission line with SDG&E's existing Talega-Escondido transmission line, no permanent new structures would be required and previous pull-sites locations may be re-used to install the second 230-kV circuit. Some previous pull-site locations may have revegetated since previous tower installation, There may be some minor unforeseen temporary vegetation impacts during the line stringing activities.

Through incorporation of a biological monitor, limiting construction activities to outside of the nesting season near riparian habitats, and adherence to applicable and relevant federal, state and regional policies, the potential impacts to sensitive biological resources along the 230-kV line would be expected to be reduced to a level of insignificance.

69-kV Subtransmission Line

Based on the ground disturbance model described above for the 69-kV transmission line, permanent and temporary impacts (acres) associated with development of the line were calculated. As mentioned above, the ground disturbance model averaged the presumed potential impact in square feet (acres) for ground disturbance over all vegetation communities potentially impacted by tower footings. However, application of best management practices, specific siting of the poles and access roads, and site-specific engineering design refinements to this line would certainly allow a reduction in the estimated area of impacts.

Adherence to applicable and relevant federal, state and regional policies, and compliance with any avoidance and mitigation measures required by the applicable resource agencies having jurisdiction, the potential impacts to sensitive biological resources along the 69-kV line would be expected to be reduced to a level of insignificance. In addition, the amount of suitable habitat that will be permanently impacted as part of the Project installation is approximately 0.23 acres across an approximate 8-mile section of the 230 kV line ROW, or approximately 0.03 acres/mile. The amount of vegetation loss will not significantly reduce the amount of habitat for any listed species to a less than self-sustaining level. Therefore, habitat removal will not be considered a direct take for any sensitive plant or wildlife species.

Prior to project construction, federal and state resource agencies will require focused surveys for all previously inaccessible impacted areas to fully assess potential impacts and to develop any necessary avoidance and mitigation measures. Focused biological surveys for the 69-kV portion of the Project site, to be conducted when and in a manner as determined through consultation with the USFWS and CDFG, would more precisely identify the locations of habitat and those portions of such habitat actually occupied by sensitive species, facilitating final engineering design along the relocated 69-kV line and adjustments of final pole sites, and the effective implementation of best management practices.

Focused surveys will be conducted after permitting as pre-activity surveys coupled within programmatic avoidance and mitigation protocols, depending on the requirements of the applicable resource agency. Focused surveys and the effective implementation of best management practices (including any actions required by the resource agencies) would minimize the area of potential project impacts and reduce the level of impact. In addition, where impacts are unavoidable, mitigation measures required by applicable federal and state resource agencies will reduce the residual impact to less than a significant level.

Without the implementation of best management practices to minimize and reduce potential impacts within the 69-kV portion of the Project site; impacts to the biological resources discussed above as being common to the Project area, have the potential to be significant. Relocation of the 69-kV line has the potential to permanently impact 0.1 acre of Coastal Sage Scrub.

This potential permanent loss of Coastal Sage Scrub may require compensatory mitigation by the applicable resource agencies, if the habitat is occupied by CAGN. Approximately 0.1 acres of suitable habitat will likely be permanently impacted in addition to 1.3 acres of temporary impacts disbursed throughout the 69kV line ROW. The small areas of riparian habitat and wetlands have the potential to support resident riparian-dependent wildlife; in particular, the arroyo toad, LBV, and SWF. Recorded occurrences of all three species have been documented along the northern portion of the 69-kV ROW. Approximately 0.03 acres of suitable habitat will likely be permanently impacted in addition to .01 acres of temporary impacts.

A small portion of the 69-kV route is within the USFWS and County of San Diego-designated QCB survey area. Development of this line could permanently impact less than 0.01 acres and temporarily impact approximately 0.1 acres of vegetation communities (potentially open scrub and non-native grasslands) that, per the USFWS protocol survey requirements, have the potential to support this endangered species. Habitat that has the potential to support QCB coincides with this line in numerous locations (exclusive of the grove and developed areas). All suitable habitats would need to be surveyed per the current USFWS protocol, if construction activity is scheduled to occur

within the QCB flight season. Construction activity outside of the flight season will have no significant impact due to the minor amount of temporary and permanent impacts.

The 69-kV corridor crosses habitats that are potentially suitable for SKR, including patches of disturbed grassland habitat with a high proportion of herbaceous annuals and sparse to no shrub cover, on gentle slopes. Within the proposed corridor, there are approximately 1.75 acres of grasslands that have the potential to be impacted (0.05 acre permanent and 1.70 acres temporary) by this portion of the Project (Appendix C). Following the refinement of site-specific engineering design and focused survey data as needed for the 69-kV line, any avoidance and mitigation measures required by the federal and state resource agencies would be incorporated into applicable best management practices.

Implementation of the best management practices would effectively minimize the areas of potential impact to biological resources along the 69-kV line and are expected to reduce the potentially significant impacts to sensitive native uplands, riverine, wetlands, and waters, arroyo toad, QCB, and SKR to less than significant levels. If focused surveys identify a listed species as occurring within the proposed construction footprint, habitat replacement at a 2:1 ratio will be required as compensatory mitigation.

Based on the recent biological assessment, approximately 230 square feet of suitable habitat for southwestern willow flycatcher will be removed as part of the impacts associated with the 69kV line relocation. In addition 1600 square feet of LBV habitat, 3,440 square feet of arroyo toad habitat, and 70 square feet of California gnatcatcher critical habitat will also be impacted as part of the project construction activities. The removal of such small patches of suitable habitat will not have a short or long-term affect on these species.

Substation and Communication Facilities Upgrade

Upgrades/improvements to existing SCE substations (Valley, Serrano, San Bernardino, Vista, Mira Loma, and Etiwanda Substations), existing SDG&E substations (Talega, Escondido, Peñasquitos, Pala, and Lilac Substations), and existing Santiago Peak Communication Facility will occur within existing facilities' footprints and are completely disturbed with no natural habitat or suitable habitat for any sensitive plant and wildlife species. Upgrades to the existing substation and communication facilities would result in no impacts to natural resources.

Results

Based on the habitat assessment and previous presence/absence surveys conducted within the Project site in 2007 and 2008, MBA has determined that it is unlikely that QCB occurs within any of the proposed impact areas within the Project site. Although we cannot completely rule out the possibility that these species may occupy the habitat onsite in the future, the likelihood of these species establishing significant populations in the near future is unlikely. It is highly likely that CAGN, LBV, SWF, and arroyo toad occupy at least some portion of the survey area between Milepost 34 and Milepost 39 due to the close recorded occurrence adjacent to the Project site and the presence of suitable habitat. However, implementation of best management practices, habitat and breeding season avoidance, and a biological monitor, will likely reduced the potential for a take to a level that

is not considered significant. The proposed project has a no "may affect" with regard to impacts to critical habitat and federally and state listed species

The information presented above and verified with a habitat assessment, coupled with comprehensive reviews of the existing literature and vegetation communities and potentials for these communities to support sensitive species under consideration, provides the foundation for response to USFWS requests listed below.

Response to USFWS Comments of June 26, 2007

MBA has prepared the following responses to the specific USFWS requests, as stated in the Service's June 26, 2007 letter. These responses are intended to clarify circumstances regarding impacts to the five federally listed species currently under consideration for the Final Biological Opinion: CAGN, LBV, SWF, SKR, and arroyo toad.

> **Comment 1.** "The analysis in the FEIS does not include the potential effects of temporary and permanent roads associated with the construction and operation of the project. Please identify the proposed location of the roads, the acreage of habitat affected, any survey results, and an analysis of effects associated with road building, use and maintenance on federally-listed species."
>
> > **Response to Comment 1**. Included as Appendix D, the Project Impact Tables include all Project-related impacts as assessed under the FERC FEIS transmission line alignments, approximately 8-miles of new 69-kV pole locations, and temporary access roads with regard to plant community and suitable habitat for federally listed species. Appendix B includes maps indicating the specific location of the transmission line alignments, proposed access roads, new pole locations, substations, and the plant communities associated with them (Appendix B). Appendix C includes maps of the Project site illustrating recommended focused survey areas (Exhibit 1), designated critical habitat areas (Exhibit 2), and sensitive species known recorded occurrence Map (Exhibit 3). Impacts to designated critical habitat are in Table D-2. (Appendix D.)
> >
> > The incremental loss of a few hundred to a few thousand square feet of suitable habitat is not considered a significant impact due to the small size of the impact compared to the size of the project. The loss of vegetation associated with the project site will not fragment the existing habitat or in anyway alter the existing suitable habitat. Temporarily disturbed areas may provide suitable habitat for non-native weedy and/or invasive plant species. For a more detailed explanation of weed control measures, please see response to comment 3 below.
>
> **Comment 2**. "The FEIS indicates that intensive vegetation management will occur surrounding the proposed structures and transmission lines, but the potential effects of the vegetation management activities do not appear to be fully described. Please

identify the acreage of habitat affected, any survey results, and an analysis regarding vegetation management and effects to federally-listed species."

Response to Comment 2. It is likely that some vegetation trimming may be required at each transmission line tower/pole; these areas are referred to as vegetation management areas. A vegetation and road management plan will be required prior to initiation of construction activities. The plan will cover issues such as erosion control, Migratory Bird Treaty Act issues, restoration activities, and biological monitors. The plan will be designed as a working document for construction foreman to assist construction crews in avoiding significant biological resources during construction activities. An initial educational program and periodic updates on sensitive species issues will be required for construction workers prior to working on the Project. Information necessary for minimizing impacts includes the identification of suitable habitat, species activity periods, species identification, and construction equipment requirements, such as vehicle speed and noise levels.

The vegetation trimming associated with the vegetation management areas will occur within the temporary workspace surrounding the permanent pole impact area and is included in the impact calculations in Table 1. A 4-foot wide footing is required for each post. Following construction of the poles, this 4-foot wide area will be cleared of vegetation for routine maintenance activities. Currently, there are no plans to go beyond the limits of temporary work space. In the event that additional vegetation trimming is required outside of the temporary workspace area, resource agencies will be contacted to discuss the appropriate action prior to implementation if suitable habitat for listed species will be impacted. All suitable habitat impacted during construction activity will be replaced at a 2:1 ratio of similar habitat.

Comment 3. "Please specify what noxious weed control measures will be implemented in areas with threatened or endangered species habitats."

Response to Comment 3**.** The Applicant proposes to design and implement an integrated pest management plan to prevent the introduction of weeds during construction and to control any populations of weeds that are identified near construction sites during project implementation. USFS Revised Preliminary 4(e) Condition No. 33 is very similar, specifying that the Applicant consult with the USFS to develop and implement a plan to monitor and control noxious weeds and non-native invasive species, but the USFS specifies this plan should be continued through any license period. Nevada Hydro has agreed to fulfill these requests not only on USFS lands, but on all Project facilities and transmission and subtransmission line alignments.

USFS also indicates that the vegetation and invasive weed management plan should be consistent with guidance provided in the Cleveland National Forest Land Management Plan, including consulting with USFS to design and

conduct an invasive non-native plant and noxious weed risk assessment, using weed lists that are current at the time of survey. Implementation of USFS Revised Preliminary 4(e) Condition No. 29, which provides for annual employee awareness training, would apply to noxious weeds and invasive non-native plants, as well as to special status plants, as described above.

Although the Applicant may not propose to construct any new Project features during the license period beyond those specified by FERC, the USFS, and the CPUC, routine Project maintenance could cause ground disturbance at Project facilities, and Project-related traffic could pose a risk of introducing and spreading weeds. Public use of any access roads would have an especially high potential for adverse effects because it would likely be difficult to control. Implementation of a noxious weed management plan throughout the term of any new license for both USFS and non-USFS lands within the project boundary would reduce these risks and help to protect native plant communities and wildlife habitat values. This approach would minimize planning costs and would provide coverage for weeds and invasive exotic plants throughout the Project area, as a whole.

Comment 4. "Please provide a focused discussion regarding the potential effects of the proposed project on habitat conditions and the distribution of federally-listed species for the whole project area. In addition to the lack of complete habitat assessment/survey information for roads and vegetation management activities described above, the FEIS indicates on page 3-137 that "Surveys were not conducted in areas where the co-applicants' proposed alignment or staff alternative transmission alignment differ from the original alternatives, or at the southern substation that is currently included in both the co-applicants proposal and the staff." In order to address the missing information documented above for roads, vegetation management, and the proposed facilities, we recommend the completion of habitat assessments and appropriate presence/absence surveys for areas where these studies have not been done."

Response to Comment 4. This portion of the 69/230-kV transmission line alignment was not included in the focused surveys conducted for the new transmission facilities associated with the LEAPS project. Based on information obtained during the 2008 field surveys, focused surveys were being conducted on this portion of the Project as on-going surveys for the existing SDG&E ROW. In an attempt to reduce habitat-related impacts due to multiple survey efforts, MBA did not conduct duplicate surveys on the 230 kV line portion of the Project site, but relied on the survey efforts of other to document the presence/absence of sensitive species within the Project site. A habitat assessment was conducted on the 230 kV line study area, including the additional new 69 kV line pole construction, access roads, and substation facilities with respect to the presence/absence of suitable habitat to support federally or state listed threatened or endangered species.

In some cases, private property prohibited surveys from being conducted at suitable habitat locations within the study area. These areas have been mapped and will either be avoided during project installation, or focused surveys will be conducted prior to construction activities to determine presence/absence. If listed species are present during construction activities, a resource management plan will be prepared in order to proceed with project implementation. The resource management plan will contain specific construction related avoidance, minimization, and habitat replacement measures to reduce the likelihood of any take.

Comment 5. "The May 23, 2007, letter provides additional information regarding the potential for release of Lake Elsinore water into the San Juan watershed. Your letter indicates that water from Lake Elsinore would primarily be released into the San Juan watershed during flood events. Please estimate how often these releases could potentially occur, the magnitude of the potential releases, and the nature of the effects to the water quality. Also, the FEIS indicates that remediation measures will be implemented upon the release of non-native species into San Juan Creek. Please specify what measures would be implemented. Finally, the proposed project indicates that transmission towers would be located outside of riparian areas to avoid adverse effects to riparian vegetation and stream habitat. Please specify how far transmission towers will be located from drainages where arroyo toads occur and what erosion control measures will be implemented."

Response to Comment 5. This comment was addressed adequately in the previous response letter and is not applicable to SDG&E's existing 230 kV Talega-Escondido Transmission Line ROW.

However, no release of waters from the Santa Ana watershed are planned or proposed to the San Juan Creek watershed. Waters would only be released in the unlikely event of an upset condition affecting the proposed upper reservoir. Since that reservoir will be designed and maintained in accordance with applicable federal and state dam safety requirements, no such event is anticipated to occur over the license period.

Comment 6. "Specify whether or not the proposed transmission lines impact the Habitat Conservation Plan for the Stephens' Kangaroo Rat Core Reserve lands and identify the extent of the effects within these area. We also requested specific information regarding any proposed off-setting measures."

Response to Comment 6. This comment was addressed adequately in the previous response letter and is not applicable to the existing 230 kV Talega-Escondido Transmission Line ROW. However, suitable habitat does occur within selective portion of the Project study area and focused trapping efforts may be required prior to the commencement of Project construction.

Comment 7. "Upon development of the above information, we recommend discussions with our agency regarding the inclusion of specific conservation

measures to minimize effects to listed species for incorporation into the proposed action. The May 23, 2007, letter indicates that the proposed action is to recommend the development of plans to minimize effects to listed species to the applicant, but does not commit to implementing specific measures. We recommend committing to implementing specific conservation measures as part of the proposed action and including these specific measures in the proposed action. If conservation measures are included, please provide detailed information regarding the proposed measures, especially with regards to the acquisition and dedication of replacement habitat as part of the proposed action."

Response to Comment 7. MBA and Nevada Hydro have ongoing informal consultation with USFWS to assist in providing additional information necessary to complete a Final Biological Opinion for the Lake Elsinore Advanced Pump Storage and Talega-Escondido/Valley-Serrano 500-kV Interconnect Projects. Nevada Hydro has agreed to commit to all recommended measures in the FERC FEIS as part of the proposed action and includes these specific measures in an Impact Assessment Letter Report prepared for USFWS in July 2007. Please refer to the EIS report for detailed information regarding the proposed measures. Furthermore, Nevada Hydro agrees to all of the USFS conditions as stated in the Revised Forest Service Preliminary Section 4(e) Conditions, submitted in 2006 and, where appropriate, will implement these conditions throughout the Project area for all Project components. In addition, all BMPs in the Cleveland National Forest Land Management Plan will also be reviewed and implemented where appropriate. All mitigation measures required for this Project will be implemented prior to or during ground disturbance activities.

Thank you for reviewing these responses to the USFWS comments. If you have further questions, please feel free to call me at 714.508.4100.

Sincerely,

Scott Crawford, M.A.
Section Manager of Natural Resources
Michael Brandman Associates
220 Commerce, Suite 200
Irvine, CA 92602

Enclosures: Appendix A: Previous Report and USFWS Comment Letter
Appendix B: Plant Community Maps
Appendix C: Sensitive Species Maps
Appendix D: Project Impact Tables

cc: Peter Lewandowski, The Nevada Hydro Company
James Fargo, FERC

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THE HYDRO COMPANY, INC.
DBA THE NEVADA HYDRO COMPANY, INC.

January 7, 2009

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

Subject: Lake Elsinore Advanced Pumped Storage Project, FERC PN 11858-002

Dear Madam Secretary:

The Nevada Hydro Company, Inc. (TNHC) remains aware that the United States Fish and Wildlife Service (Service) has yet to issue a final biological opinion (final BO) for the Lake Elsinore Advanced Pumped Storage Project (LEAPS). This letter outlines the actions being taken by TNHC to provide the Federal Energy Regulatory Commission (Commission) with supplemental information to facilitate continuing formal Section 7 consultation between the Commission and the Service in accordance with the Endangered Species Act of 1973.

On March 19, 2008, the Service filed with the Commission correspondence (Subject: Formal Section 7 Consultation for the Lake Elsinore Advanced Pumped Storage Project, Riverside County, California) stating, in pertinent part, that the Service's letter "concludes formal consultation on the proposed project." In separate correspondence filed with the Commission, TNHC has accepted and has agreed to implement and/or to work cooperatively with the Commission to implement all of the "terms and conditions" and "conservation recommendations" which have been identified by the Service.

Although the project description summarized in their March 2008 letter included "appurtenant facilities," it is TNHC's current understanding that the Service may not have fully considered potential biological resource impacts associated with other related system improvements and upgrades predicated by the construction and operation of LEAPS and its associated applicant-proposed transmission facilities. Those improvements and electrically-required upgrades include, but may not be limited to, an approximately 52-mile second 230-kV circuit (Talega-Escondido No. 2) along existing support structures (already containing one existing 230-kV circuit) connecting San Diego Gas and Electric Company's (SDG&E) existing Talega and Escondido substations. In order to accommodate an additional 230-kV conductor on existing lattice steel towers, it is necessary to rebuild an approximately 7.8-mile section (generally extending between SDG&E's existing Pala and Lilac substations) of SDG&E's existing 69-kV subtransmission circuit on new 69-kV steel poles to be erected

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within the existing 230-kV transmission right-of-way. Other related improvements include associated upgrades to SDG&E's existing Talega, Escondido, and Peñasquitos substations and Southern California Edison Company's (SCE) existing Valley, Serrano, San Bernardino, Vista, and Mira Loma substations.

TNHC has continued to work diligently to ensure that all biological resource studies remain current and accurately assess and effectively mitigate the potential impacts of the proposed project, including performance of additional general and focused species-specific surveys during 2008. Those studies are currently being assembled into a consolidated report by our consulting biologists, Michael Brandman Associates (MBA).

Because a substantial portion of the project is located within the Cleveland National Forest – Trabuco Ranger District, finalization of the consolidated report was delayed as a result of on-going discussions with the United States Department of Agriculture - United States Forest Service (USFS). In separate correspondence from Mr. William Metz, Forest Supervisor, dated December 18, 2008, a copy of which was filed with the Commission on December 19, 2008, with the exception of southernmost tower sites whose location needs to be coordinated with the United States Department of the Navy – United States Marine Corps (USMC), concurrence has been reached with regards to the precise placement of all transmission towers, access roads, pull-sites, and staging areas on National Forest System lands. The siting of the four southern towers is not an environmental concern but one of coordination between federal agencies.

With the USFS' concurrence, MBA's final report is anticipated by February 15, 2009 and will be forwarded to the Commission upon receipt. Because MBA has been coordinating its multi-year field efforts with the Service, TNHC anticipates that courtesy copies will be concurrently sent to the Service and to the National Marine Fisheries Service (NMFS). To ensure transparency, representatives of MBA remain available to meet and confer with federal agencies concerning any findings and/or recommendations presented in that report.

Because the applicant-proposed Pendleton substation is located within the USMC's Camp Joseph H. Pendleton, TNHC would further welcome discussions between the Commission, the USMC, and the USFS to ensure that any siting concerns within those federal reservations, including National Environmental Policy Act (NEPA) documentation, have been fully addressed.

Sincerely,

David Kates
Project Manager

SDG&E 2007 TRANSMISSION RELIABILITY ASSESSMENT

FINAL REPORT

A Sempra Energy utility℠

November 14, 2007

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I. Executive Summary

San Diego Gas and Electric (SDG&E) is a part of Sempra Energy Utilities, a Sempra Energy regulated business unit. Sempra Energy (NYSE: SRE) is a Fortune 500 energy services holding company based in San Diego. SDG&E is a regulated public utility that provides energy service to 3.4 million consumers through 1.4 million electric meters and more than 830,000 natural gas meters in San Diego and southern Orange counties. The utility's area encompasses 4,100 square miles.

In accordance with the California ISO (CAISO) FERC Electric Tariff, section 3.2.2.1, SDG&E is required to annually develop a transmission expansion plan, coordinating with the CAISO and other market participants. This report documents SDG&E's electric transmission plan for the years 2008 through 2012 and provides a screening for the year 2017.

The primary objective of this report is to present the SDG&E 2007 Transmission Plan of Service to the participating stakeholders and specifically to the CAISO for review and approval. In addition, this report highlights significant developments made in 2007 related to projects addressing congestion, generation development, and expansion of the SDG&E bulk power system.

SDG&E continually looks for ways to maintain a reliable transmission system to meet the load growth by developing and constructing cost effective projects.

The most significant project in this study period is the proposed 500 kV Sunrise Powerlink, which will be the largest upgrade to the SDG&E system in over two decades. This project will help ensure reliability in San Diego while lowering energy costs and providing economic access to the renewable energy needed to comply with state law. The Sunrise Powerlink will also significantly increase SDG&E's import capability to provide the needed resources to meet the load demand. Details of this import capability increase are discussed in the body of the report.

Major project milestones achieved in 2007 include the completion of the Miguel-Old Town portion of the Otay Metro Powerloop. Also, documentation of compliance with NERC mandatory transmission planning standards was completed.

The following table summarizes the plan of service for the 2007 Grid Assessment Study.

Table ES-1: SDG&E 2007 Transmission Expansion Plan of Service

Project Number	Project Title	CAISO Approval Status	ISD
Proposed Projects Requiring CAISO Approval			
P07XXX	Reconductor TL6915, TL6924: Pomerado-Sycamore	Pending	Jun-09
P07XXY	New 230,138 kV Reactive Support: Mission, Sycamore, Telegraph Canyon	Pending	Jun-10
Proposed Projects Requiring CAISO Board Approval			
P06130	Construct 2nd 230 kV line: Encina-Penasquitos	Pending	Jun-09
P06131	Loop-in TL13825: Shadowridge 138 kV Switchyard	Pending	Jun-09
P06133	New 230/138 kV transformer: Miguel Substation	Pending	Jan-10
P06132	Relocate South Bay Substation	Pending	Dec-10
Previously Approved Projects Requiring CAISO Approval for Change in Status, Scope, or In-Service Date			
P00154	Reconductor TL13802B, Shadowridge- Calavera Tap	Approved	Jun-09
P061XY	Reconductor TL13812, Talega-San Mateo	Approved	Jun-09
P03183	Reconductor TL678, Los Coches-Alpine	Approved	Jun-10
Cancelled Projects Requiring CAISO Approval			
P02161	New 69 kV Line: TL6942, Miramar-Sycamore	Approved	Jun-10
Previously Approved Projects with No Proposed Changes			
P06136	Rearrange 230 kV Switchyard: San Luis Rey	Approved	Jun-08
P04195	Lake Hodges Pump Storage Project (Generator Interconnection)	Approved	Sep-08
P99126	Transmission for Otay Mesa Power Generation Project	Approved	Oct-08
P03170	New 230/69 kV Substation: Silvergate	Approved	Dec-08
P01141	Reconductor TL13836, Talega – Pico	Approved	Jun-09
P04137	Construct 2nd 69 kV line: Division-Naval Station Metering	Approved	Jun-09
P05153	Reconductor TL689, Escondido-Felicita Tap	Approved	Jun-09
P06134	Loop-in TL651: Silvergate 69 kV Switchyard	Approved	Jun-09
P00153	Reconductor TL13837, Capistrano-Laguna Niguel	Approved	Jun-10
P061XX	Reconfigure TL13821 & 13822, Carlton Hills Area	Approved	Jun-10
P04138	New 500 kV line: Sunrise Powerlink	Approved	Jun-10
P01142	Reconductor TL683, Lilac-Rincon	Approved	Deferred
Projects Completed in 2007			
P0100	Reconductor TL6916: Sycamore-Scripps (UG only)	Approved	Complete
P03191	New 230 kV lines: Otay Metro Powerloop	Approved	Complete
P05156	Loop-in TL23011C: PEN Switchyard	Approved	Complete
P06126	New 230 kV Capacitors: Miguel Substation	Approved	Complete

II. Introduction

This report describes the study assumptions, methodology, criteria, and results of SDG&E's 2007 Grid Assessment. The report is the product of a stakeholder review process and is submitted to the CAISO for review. SDG&E seeks CAISO approval for the new and revised projects described in this report.

In accordance with the CAISO Tariff, SDG&E performed an annual grid planning study consisting of:

- Development of power flow and stability models
- Assessment of the SDG&E transmission system from 2008 to 2017 to meet CAISO, NERC, and WECC reliability criteria
- Development of mitigation plans including capital expansion projects
- Development of a detailed five-year transmission expansion plan
- Transmission upgrade projects proposed or recommended by stakeholders and the CAISO which were determined to be necessary and/or cost justified

Significant developments during the study year include:

- The completion of the Otay Metro Powerloop
- Documentation of compliance with recent NERC mandatory transmission planning standards

III. 2007 Transmission Planning Projects

The results of the 2007 grid assessment study culminated in the plan of service outlined in the Executive Summary, Table ES-1. Each project will be discussed in this section of the report with a more detailed project description located in Appendix A. This report summarizes the study results of the new proposed projects and the re-evaluation of the need and project scope of the previously approved projects. The project alternatives were also reviewed to ensure that the proposed alternative is the most cost effective alternative within the scope of the 2007 expansion plan.

A. Projects completed in 2007

The following projects from prior year expansion plans were placed in service during 2007 and are reflected in the base cases:

Reconductor TL6916, Sycamore-Scripps (P0100)
This project increased the normal rating of the 69 kV circuit from Sycamore-Scripps.

New 230 kV line: Otay Metro Powerloop (P03191)
This is a reliability-driven project to construct a new 230 kV circuit between Sycamore, Miguel, and Old Town substations. The portion of the project from Miguel-Old Town was placed in service in June 2007.

New 230 kV Capacitors: Miguel (P06126)
This project installed 126 MVAR of 230 kV capacitors at Miguel substation to improve voltage support and stability.

Loop-in TL23011C: PEN Switchyard (P05156)
This project increased operational flexibility and reliability by looping in a 230 kV circuit into the Palomar Energy Center switchyard.

B. Proposed Projects requiring CAISO approval

Reconductor TL6915, 6924: Pomerado-Sycamore (P07XXX)
This project increases the normal rating of these lines by replacing underground cable getaways outside of each substation. It is driven by load growth and is scheduled for an in-service date of June 2009.

New 230, 138 kV Capacitors: Mission, Telegraph Canyon, Sycamore Substations (P07XXY)
These projects will add 239 MVAR of shunt capacitors at strategic locations to support voltage stability of the system. A more detailed description of the project justification is in section V.B. The in-service date is June 2010.

C. Proposed Projects Requiring CAISO Board Approval

Construct 2nd 230 kV line: Encina-Penasquitos (P06130)
This project will construct a second 230 kV line between Encina and Penasquitos Substations. This project is driven by the outage of one of the South of Encina 230 kV lines, which overload the remaining 230 kV lines when the South of SONGS import is scheduled at 2500 MW. Also, the generation dispatch at Palomar could be limited due to an overload on the Penasquitos-Encina 230 kV line for the outage of the Sycamore-PEN 230 kV line. To accommodate this additional 230 kV line, TL13807 will be rebuilt, and TLs 610 and 674 modified. This project would support South of SONGS import and provide operating flexibility for generation dispatch at Encina and Palomar power plants. The in-service date for this project is June 2009. This project is estimated to cost over $20 million and will be submitted to the CAISO as a separate project, since this will require CAISO Board approval.

Loop-in TL13825: Shadowridge 138 kV Switchyard (P06131)
This project will loop in TL13825 into Shadowridge substation. This project is driven by an N-1 overload of TL13825C (Shadowridge-Meadowlark Tap). This project would eliminate the need to upgrade the aging Escondido 138/69 kV transformer and 69 kV line upgrades at Melrose. Also, this project is needed to support the proposed new Ocean Ranch distribution substation in the area. The in-service date for this project is June 2009. This project is estimated to cost over $20 million and will be submitted to the CAISO as a separate project, since this will require CAISO Board approval.

Relocate South Bay Substation (P06132)
This project will construct a new 230/69 kV substation to replace the existing South Bay Substation. This is a project driven by aging infrastructure, an MOU signed with the City of Chula Vista, and South Bay generation retirement. The planned in-service date for this project is December 2010.

New 230/138 kV Transformer: Miguel Substation (P06133)
This is a project to increase import capability at Miguel Substation and support the 138 kV system after retirement of the South Bay Power Plant. A new transformer at Miguel is needed after the 138 kV bus is removed at South Bay, and helps mitigate some 138 kV overloads. The planned in-service date for this project is January 2010.

D. Previously approved projects requiring approval for a change in scope or in-service date

Reconductor TL13802B, Shadowridge-Calavera Tap (P00154)
This project mitigates an N-1 contingency driven by load growth. It has been accelerated from June 2010 to June 2009 in conjunction with the TL13825 loop into Shadowridge (P06131).

Reconductor TL678, Los Coches-Alpine (P03183)
This project will mitigate contingency based overloads due to load growth. The project completion date has been advanced to June 2010.

Reconductor TL13812, Talega-San Mateo (P061XY)
This project relieves an N-1 thermal overload due to a distribution load transfer. The planned in-service date has been advanced to June 2009.

E. Cancelled Projects Requiring ISO Approval

New 69 kV line: TL6942, Miramar-Sycamore (P02161)
The project need has been eliminated due to the completion of projects P0100-Reconductor of TL6916 (Sycamore-Scripps) and the Sycamore 230/138 kV transformer.

F. Previously Approved Projects with No Proposed Changes

Rearrange 230 kV Switchyard: San Luis Rey (P06136)
This project improves system reliability and supports import capability on the South of SONGS path. The planned in-service date for the project is June 2008.

Transmission for Otay Mesa Power Generation Project (P99126)
This project constructs the transmission interconnection requirements for the Otay Mesa Generation Project. TL23040 Miguel-Tijuana will loop into the new Otay Mesa 230 kV switchyard and the Miguel-Otay Mesa 230 kV line will be converted to two bundled circuits with two separate breakers at Otay Mesa switchyard. Due to a modified construction schedule the planned in-service date is October 2008.

Reconductor TL13836: Talega-Pico (P01141)
This project increases the capacity of TL13836, Talega-Pico, by reconductoring a portion of this line. This increased capacity is necessitated by load growth. The in-service date of the project is June 2009.

New 230/69 kV Substation: Silvergate (P03170)
This project will construct a new substation at the former Silvergate generation site, near the existing Main St. Substation, and loop in a portion of Otay Metro Powerloop (Miguel-Old Town 230 kV). This project eliminates the need for Main St. substation. The project includes moving all 69 kV lines presently served via Main Street substation into the nearby Silvergate site. The project will allow elimination of the South Bay-Main Street 138 kV transmission lines. This project is scheduled to be completed by December 2008.

Construct 2nd 69 kV line: Division-Naval Station Metering (P04137)
This project constructs a second line from Division to Naval Station Metering substation. It is driven by load growth and operational flexibility. The in-service date for the project is June 2009.

Loop-in TL651: Silvergate 69 kV Switchyard (P06134)
This project loops in the existing Wabash-Main St. 69 kV tie line into Silvergate. The project will increase the transmission capacity within the downtown area to meet load growth. It also effectively creates a new 69 kV line radiating from the Silvergate bulk power substation. The in-service date is June 2009.

Reconfigure TL13821 & 13822, Carlton Hills Area (P061XX)
This project will rearrange existing 138 kV tie lines between Sycamore, Mission, and Carlton Hills Substations. This project is driven by overloads on the Sycamore-Carlton Hills Tap line under high import conditions. The planned in-service date is June 2010.

New 500 kV Line: Sunrise Powerlink (P04138)
This project is discussed in greater detail in section III.D. The planned in-service date is June 2010.

Lake Hodges Pump Storage Project - Generator Interconnection (P04195)
This is a loop-in of TL616, Olivenhain-Bernardo Tap, to serve a new 40 MW pumped storage facility. The planned in-service date for this project is September 2008.

Reconductor TL689 Escondido-Felicita Tap (P05153)
This project mitigates overloads due to load growth in the area. The planned in-service date for this project is June 2009.

Reconductor TL13837, Capistrano-Laguna Niguel (P00153)
This project mitigates an N-1 contingency driven by a distribution load transfer. The in-service date of the project is June 2010.

Reconductor TL683, Lilac-Rincon (01142)

This project mitigates contingency overloads due to area load growth. It has been deferred past 2012.

G. Deferred Projects

Install third 500/230 kV transformer: Imperial Valley (P06135)
This project proposes to add a second 1120 MVA 500/230 kV transformer at the Imperial Valley switchyard. The ISO economic studies showed that the addition of the third Imperial Valley transformer bank is not economic because it was needed only for congestion; and congestion on the existing transformers occurs only under off-peak conditions. The cost of congestion is lower than the cost of the transformer. However, the project will be needed if the new generation develops in the Imperial Valley area. The addition of the third imperial Valley bank will be considered in the LGIP process.

H. Sunrise Powerlink

This new transmission line will increase SDG&E's import capability, allowing SDG&E to meet the region's increasing demands for electric power. It is also anticipated that this new line will increase SDG&E's economic access to renewable resources (e.g. wind, solar, and geothermal), in order to meet California's renewables mandate. The line will also provide economic benefit by reducing transmission congestion and Reliability Must Run (RMR) contract costs, as well as providing access to other new, low cost power sources. Other benefits of this new transmission line include improved reliability and system operating flexibility.

The scope of this 500 kV Project, as represented in the 2010 base case, includes:

<u>Transmission</u>
- 500 kV Imperial Valley-Central line, 85 -100 miles
- Two 230 kV Central-Sycamore Canyon lines
- One 230 kV Sycamore Canyon-Penasquitos line
- Reconductor of TL639, Sycamore Canyon-Elliott

<u>Substation</u>
- New 500kV/230kV substation (Central Substation)
- Two 500/230 kV transformers at Central substation
- Eight 45 MVAR 12 kV reactors
- 240 MVAR of Static Var Devices (SVDs) located at Central, San Luis Rey, and South Bay substations
- A third 230/69 kV transformer at San Luis Rey substation

<u>Project Status</u>
- SDG&E obtained CAISO approval of the Sunrise Powerlink on August 3, 2006.
- SDG&E filed a project CPCN application on August 4, 2006.
- The CPCN application was deemed complete by the CPUC on September 8th, 2006.
- Phase I of the CPUC hearings was completed on October 4, 2007.

I. Distribution Substation Projects

The table below summarizes the anticipated in-service dates of planned distribution substation projects. The projects are needed to provide capacity to meet load growth and improve system reliability. These substations will be fed by looping-in existing transmission lines, and have been included for informational purposes in this report.

Table III-1: Distribution Substation Projects

Project Number	**Project Name**	**Proposed ISD**
P02246	Grant Hill (formerly named Uptown)	Dec-2007
P04243	Chollas upgrade	Dec-2007
P06251	Otay Substation rebuild	Dec-2009
P05244	New Rancho Mission Viejo Substation	Jun-2010
P03262	New Jamul Substation	Dec-2011
P02252	New Mira Sorrento Substation	Jun-2012
P05253	New Ocean Ranch Substation	Dec-2013
P03269	New Carmel Valley Substation	Dec-2016
P03255	New Otay Ranch Substation	Dec-2017

IV. Study Assumptions

A. NERC Compliance

Recent NERC initiatives stress the need for detailed yearly evaluations of each system. SDG&E's Grid Assessment process has historically followed NERC, WECC and CAISO standards to meet reliability criteria. The process includes yearly and long-term analysis of Category A, B, C, and D conditions, emphasizing critical conditions such as planned outages of transmission or generation, or specific operating scenarios. Coordination with SDG&E's Grid Operations Department ensures that all current and planned Special Protection Systems and other operating practices are included as part of the analysis. This year, an emphasis was placed on documentation of processes, assumptions, and results, specifically with regards to Category C and D conditions. In particular, thermal loading and mitigation measures for Category A-D contingencies are contained in Appendix D.

B. Power Flow Modeling Assumptions

- Power flow models were prepared for each year in the study period in order to simulate the transmission system. These models reflect known or anticipated system conditions, approved new additional facilities, and load forecasts prepared for the entire SDG&E system and for individual substations. The models were developed using the GE PSLF program, version 16. The approved WECC planning cases used to develop the study cases are as follows:

Year	WECC name	Posting Date
2008	07HS3A1P	12/19/06
2009	09HS2SB1P	02/12/07
2010	09HS2SB1P	02/12/07
2011	11HS1B1P	01/19/07
2012	11HS1B1P	01/19/07
2017	16HS1	05/30/06

Sensitivity cases with proposed projects and their alternatives have been studied to meet mandatory reliability standards.

C. Load Forecast Assumptions

When creating the load model for the power flow database, the non-coincident substation peak load forecast generated by the Electric Distribution Planning section was used. The non-coincident load forecast reflects the anticipated peak loads for each individual substation under adverse conditions such as high summer temperatures.

Heavy summer peak conditions were studied with a system 90/10 (1-in-10 year) load forecast. A diversity factor was used to scale down the non-coincident substation load forecast so that the aggregate substation load (including system losses) will match the system 90/10 load forecast.

The Grid Assessment also studied other load scenarios, including area non-coincident area peaking, summer off-peak, light spring, and light autumn scenarios.

Non-Coincident Substation Peak Load Forecast

An updated non-coincident substation peak load forecast (contained in Appendix B) was issued by the Electric Distribution Planning department in early 2007. The forecast, incorporated into the 2007 Grid Assessment study, was based on historical data and specific planned load additions. The table below shows a comparison between the 2006 non-coincident forecast and the 2007 non-coincident forecast.

Table IV-1: Non-Coincident Substation Load forecast

SDG&E N.C. forecast	2008	2009	2010	2011	2012	2017*
07 Adv Smr FC	5064.5	5141.8	5220.7	5293.5	5371.5	5767.5
06 Adv Smr FC	4991.5	5078.6	5171.8	5243.3	5314.7	n/a
% Difference	1.5%	1.2%	0.9%	1.0%	1.1%	n/a

*2017 forecast is estimated based on long-term growth rates.

Coincident System Peak Load Forecast

SDG&E's Electric Demand Forecasting section prepared the system load forecast using econometric methods, plus regional economic forecasts. The 90/10 system load forecast represents adverse weather conditions (e.g., a hot summer) that are expected to occur once every 10 years.

With respect to loads and committed resources, SDG&E's analysis is consistent with the CPUC 2007-2016 Long-Term Procurement Plan.

SDG&E Coincident forecast	2008	2009	2010	2011	2012	2017
90/10 Forecast (MW)	4886	4960	5032	5091	5131	5401

Power Factor

Power flow cases for the 2007 SDG&E Grid Assessment study modeled a load power factor of 0.995 lagging at nearly all load buses. This number was used because SCADA-controlled distribution capacitors are installed at each substation with sufficient capacity to compensate for distribution transformer losses. The .995 lagging value is based on actual system power factor during peak conditions. The exceptions listed below were modeled using power factors indicative of historical values.

- Naval Station Metering (bus 22556): .707 lagging*
- Creelman (bus 22152): .992 leading
- Descanso (bus 22168): .900 leading
- Rincon (bus 22688): Unity
- Loveland (bus 22416) Unity
- Santa Ysabel (bus 22736) Unity
- Warners (bus 22884) Unity

*A 23 MVAR distribution capacitor project at Naval Station Metering will reduce apparent reactive loading by June 2008.

D. In-Basin Generation Capacity Assumption

Existing generation within the SDG&E system is comprised of combustion turbines (CT), qualifying facilities (QF), steam turbines (ST), the combined cycle plant at Palomar Energy (PEN), and one wind farm. The total capacity of existing units is based on the P_{max} number shown in CAISO Procedure G-206. Future generation may include new combustion turbines, combined cycle power plants, and renewable generation technologies such as biomass, solar, and wind. However, only generation under construction or with an interconnection agreement is modeled.

Existing Generation

Encina (Cabrillo I)
All five Encina steam units were assumed to be available during peak loads. A total of 946 MW of generating capacity can be dispatched based on the maximum capacity of each generating unit. This total capacity is based on the P_{max} number shown in CAISO Procedure G-206 for the units at Encina Power Plant. The existing capacity of the Encina plant is assumed in this Grid Assessment study.

South Bay (LS Power)

All four South Bay steam units were assumed to be available during peak loads through 2009. A total of 689 MW of generating capacity can be dispatched based on the maximum capacity of each generating unit. This total capacity is based on the P_{max} number shown in CAISO Procedure G-206. The existing capacity of the South Bay plant is modeled in this Grid Assessment study for the 2008 and 2009 study years. The plant has an expiring lease that will likely result in its retirement by the end of 2009, so the 2010-2017 study years modeled South Bay generation retired.

Combustion Turbines (CTs)

Cabrillo II owns and operates all but two of the small CTs in SDG&E's territory. Of the two not operated by Cabrillo II, Cabrillo I operates one at the Encina plant and the second is operated by LS Power at the South Bay power plant. The CT at South Bay is expected to be in operation through 2009. A total of 200 MW of generating capacity can be dispatched during summer conditions, and the total maximum capacity of these generators is 217 MW. This total capacity is based on the P_{max} number shown in CAISO Procedure G-206.

Qualifying Facilities (QFs)

The total output of the QFs was modeled at 182 MW. Power contract agreements with the QFs do not obligate them to generate reactive power. Therefore, to be conservative, all QF generation explicitly represented in power flow cases were modeled with a unity power factor assumption. This modeling is based on the typical operating practice for generators not to be allowed to draw significant VARS from the system. Typical unit design will allow operation in lagging and leading modes, which are usually used to maintain system voltages at high and low load periods through exciter voltage control.

Calpeak Peakers

Calpeak peakers are located near Escondido (42 MW), Border (42 MW), and El Cajon (42 MW) substations.

Coral Peakers (Larkspur)

Coral's two peaker units are located at the Larkspur site next to Border substation and each have a summer capacity of 46 MW.

MMC Peakers

Two peakers, owned by MMC, are located near Otay (42 MW) and Escondido (49 MW) substations.

SDG&E Peaker (MEF)

SDG&E owns a 46 MW CT located at Miramar substation. The unit began commercial operation late in 2005.

Kumeyaay Wind Farm
The 50 MW Kumeyaay wind farm began commercial operation in December of 2005.

Palomar Energy
This new 541 MW combined cycle generation plant, owned by SDG&E, began commercial operation in April of 2006. The two combustion turbines (CTs) are rated at 155 MW maximum output each, and the steam turbine (ST) is rated at 231 MW maximum output. For summer months, this plant is modeled at a maximum output of 520 MW, to reflect the reduced capacity during high temperature periods.

Table IV-2 summarizes the maximum summer and winter capacity values used in this study for existing generation, as the starting point for the 2007 Grid Assessment Study. These values represent net generation and reflect the capacity assumption at each plant.

Table IV-2: Existing SDG&E In-Basin Generation Capacity

Generator	**Capacity (MW)**	
	Summer	**Winter**
Encina (Cabrillo I)	946	946
South Bay	689	689
GTs	200	217
Peakers	355	355
Palomar Energy	520	541
QFs	182	182
Total Capacity	2892	2930

Future Generation

The following generation projects have interconnection agreements with SDG&E in the years 2008 through 2009, and therefore were added to the base cases.

Otay Mesa Generation Project (2009)
The Otay Mesa Generation Project is a combined cycle power plant (615 MW) planned for commercial operation by May 2009.

San Diego County Water Authority Pumped Storage Project (2008)

The San Diego County Water Authority's Lake Hodges Pumped Storage facility has an anticipated in-service date of September 2008, and will consist of two pump/generator units. This facility will be providing 40 MW of capacity as well as managing water resources. The facility includes two 23 MW pumps.

The future generation capacity modeled in the 2006 Grid Assessment Study is summarized in Table IV-3.

Table IV-3: Future SDG&E In-Basin Generation Capacity

Generator	**Capacity (MW)**	
	Summer	**Winter**
Lake Hodges Pump Storage	40	40
Otay Mesa	561	615
Total Capacity	601	655

E. Dispatch Assumption of In-Basin Generation

SDG&E utilizes a dispatch stack as a guide for determining the dispatch order of in-basin generation. It should be noted that under certain operating modes the dispatch of generation in the SDG&E system would require out-of-sequence dispatch. For example, under certain operating conditions some minimal dispatch of generation at Encina and South Bay must be maintained. Under various sensitivities, and to mitigate congestion associated with various operating modes, out-of-sequence dispatch can be considered. Appendix C contains a description of the dispatch which reflects the study assumptions for future study years.

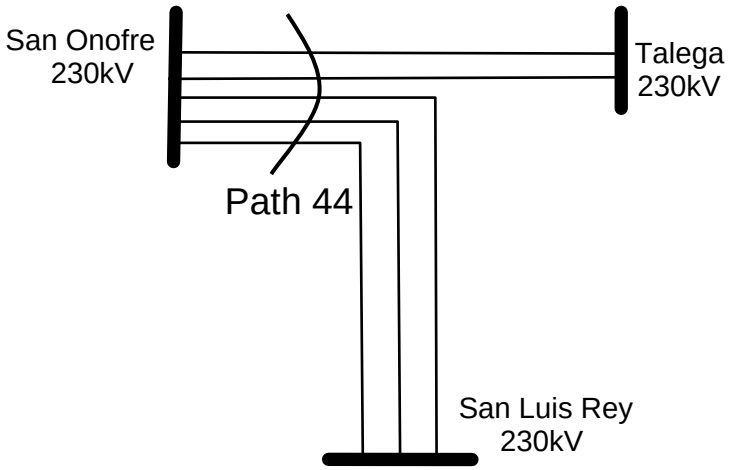
F. Import Assumptions

Based on SDG&E's existing system configuration, two import operating conditions were modeled: simultaneous (SIL) and non-simultaneous import (NSIL) conditions. The 2010-2017 import capabilities assume the new 500 kV Sunrise Powerlink is in service. With the proposed Sunrise Powerlink plan of service, SDG&E's simultaneous import capability will increase from 2850 MW to 4200 MW.

Non-Simultaneous Import Limit (NSIL)

The current NSIL is defined by SDG&E's ability to import power into its system via the five 230 kV lines which comprise the South-of-SONGS (SOS) WECC Path 44. This implies the loss of the Southwest Power Link and no export of power from CFE into SDG&E. The following diagram depicts this graphically:

Figure IV-2: Path 44 Cut Plane



From 2005-2009, the projected maximum SDG&E NSIL is 2500 MW. With the addition of the Sunrise Powerlink, SDG&E's Import Capability Limit (ICL) will increase from 2500 MW to 3500 MW. The ICL is defined as the import limit following the most limiting Category B event (N-1 or G-1*/N-1) with the system readjusted to within continuous ratings and path ratings, such that the system meets Category B perfromance criteria. Operating the system within the ICL will allow for meeting the Reliability Criteria for a subsequent contingency. Prior to the Sunrise Powerlink, the NSIL is used to reference the 2500 MW import limit. With the Sunrise Powerlink, the NSIL definition is no longer applicable and the ICL definition describes the SDG&E import capability.

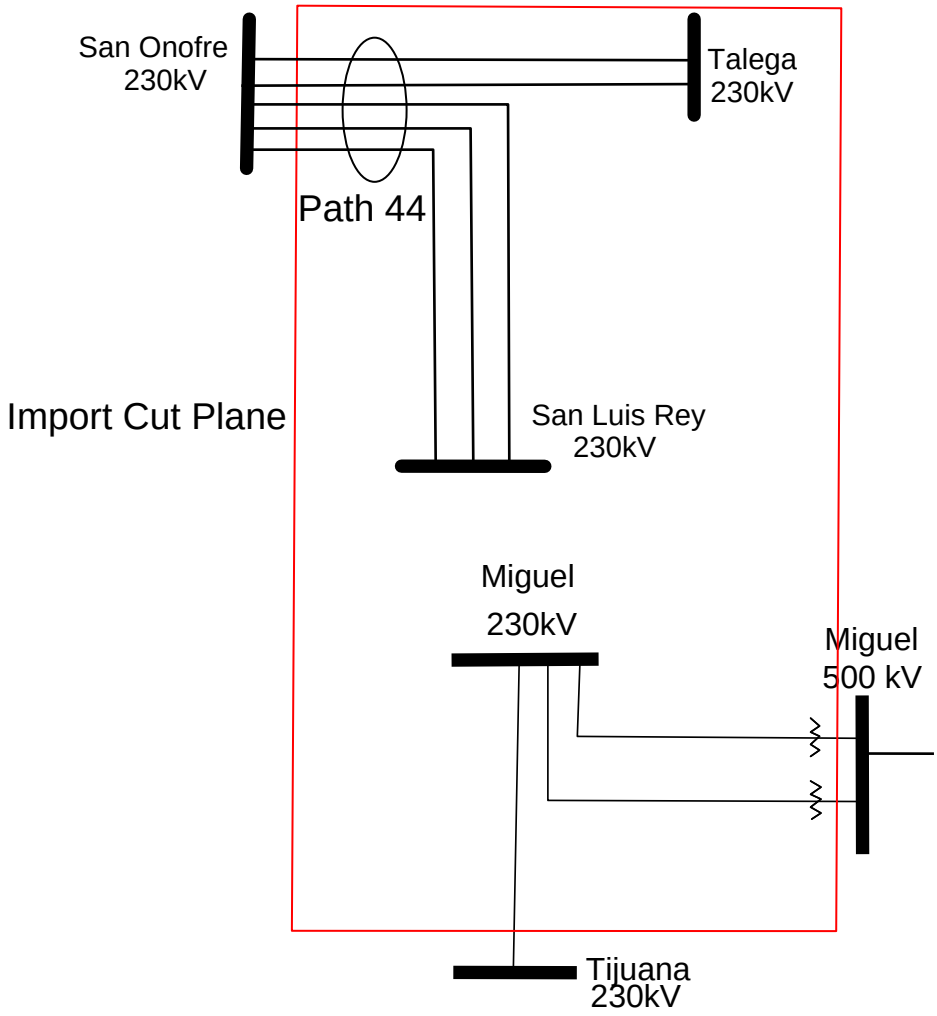
San Onofre Nuclear Generating Station (SONGS)

SDG&E's share of the total capacity of Unit 2 and 3 at SONGS is 430 MW. Although SONGS is located inside SDG&E's service territory, SDG&E's share is modeled as import since it is delivered via the South of SONGS path. In the power flow study, the units are assumed to be normally on-line at maximum capability.

Simultaneous Import Capability

The simultaneous import limit (SIL) is determined by SDG&E's ability to import power into its system via the Miguel 230 kV bus and the five 230 kV lines South-of-SONGS (SOS). The following diagram depicts this graphically:

Figure IV-3: SDG&E Import Cut Plane



From 2007-2009, the projected maximum SDG&E SIL is 2850 MW. Beginning in 2010, with the addition of the Sunrise Powerlink, the projected SIL will rise to 4200 MW. For the purposes of this study, a more conservative number of 4000 MW was modeled.

V. Study Results

A. Thermal Line Loading Study Results

Each existing project was reevaluated to ensure correct scope and in-service date. SDG&E simulated various scenarios, varying dispatch of internal generation, peak and off-peak loading, specific operating modes, etc. to record thermal overloading. Category A (normal conditions), Category B (N-1, N-1/G-1), Category C (N-2, common structure outages), and Category D (Severe contingencies) were simulated. Contingency results are provided in Appendix D.

This year's grid assessment proposes new projects and updates project scopes and/or in-service dates for existing projects. The proposed projects will make efficient use of existing infrastructure wherever possible to eliminate the need for larger and more expensive projects. Through this analysis, no projects were identified that require a lead time of longer than five years. All proposed projects are included in Appendix A.

<u>2017 Screening Analysis</u>

In addition to detailed analysis of 2008-2012 planning years, a screening analysis was performed for the year 2017. The system was modeled with similar upgrades as the 2012 system, with imports from the Sunrise Powerlink allowing reduced dispatch of Encina generation, and Palomar and Otay Mesa power plants acting as baseload units.

By 2017, area load growth will stress numerous 69 kV paths. Study results show that some reconductoring projects that were deferred or cancelled due to higher voltage alternative projects may need to be returned to the plan of service by 2017.

The other major area of concern for 2017 is transformer loading. Bulk power transformers at Miguel, Sycamore, Mission, and other substations incur high loading under many normal and emergency scenarios. Projects to increase transformation at the substation were not specifically identified for this part of the assessment. However, these areas of concern will be taken into account during the evaluation of future assessments.

B. Voltage Stability Study Results

Post Transient Study Results:

This analysis studied the planning years of 2008-2012 to ensure compliance with NERC/WECC reactive margin and voltage stability criteria.

Approximately 192 MVAR of shunt capacitors were found to be needed in 2010 regardless of the construction of the Sunrise Powerlink (SRPL). This group consisted of:

Mission 230 kV:	1x 63 MVAR
Telegraph Canyon 138 kV:	1x 43 MVAR
Sycamore Canyon 138 kV:	2x 43 MVAR

These shunt capacitor installations are in addition to the 239 MVAR being installed at Central 230KV, San Luis Rey 230KV, and South Bay 69KV Substations, which are specifically part of the Sunrise Powerlink project. The shunt capacitors' individual sizes were determined by SDG&E standards. Likewise, the location of the banks were chosen according to available substation space.

For each year, select Category B and Category C contingencies were studied. In addition, some Category D contingencies were studied. The contingencies represent historical and simulated critical conditions for system voltage instability. For each year and scenario the system was tested for positive margin, using system peak load plus 5% (Category B) and plus 2.5% (Category C). The results in Table V-1 confirm that no additional reactive support is needed prior to 2010. In 2010 and beyond, the addition of 192 MVAR of shunt capacitors independent of the Sunrise Powerlink, and an additional 239 MVAR as part of the Sunrise Powerlink, give sufficient margin for post-transient voltage stability for all of the violations shown below.

Table V-1: Post-Transient Voltage Stability Results

Scenario	Cont. category	Load increase	Results	Contingency
2008	B	5%	Positive Margin	
2008	C	2.5%	Positive Margin	
2009	B	5%	Positive Margin	
2009	C	2.5%	Positive Margin	
2010 (w/SRPL)	B	5%	Margin Violation	SWPL6.2
2010 (w/SRPL)	C	2.5%	Positive Margin	
2010G-1 (w/SRPL)	B	5%	Margin Violation	SWPL6.2

2010G-1(no SRPL)*	B	5%	Margin Violation	SWPL6.2
2010G-1(no SRPL) w/ new capacitors**	B	5%	Positive Margin	
2010 (no SRPL)	C	2.5%	Positive Margin	
2011	B	5%	Margin Violation	SWPL6.2
2011	C	2.5%	Positive Margin	
2012	B	5%	Margin Violation	SWPL6.2
2012	C	2.5%	Positive Margin	

*This margin violation shows the need for the reactive additions being proposed independent of the Sunrise Powerlink.
**This result shows that the reactive additions that are needed independent of the Sunrise Powerlink meet the reactive margin criteria.

Voltage Delta Analysis Results:

Voltage delta violations were recorded for each contingency. For category B (C) contingencies, a 0.05 (0.10) P.U. threshold was used. No projects were deemed necessary due to delta voltage analysis.

Contingency Low Voltage Analysis results:

SDG&E's standards are, in general, to keep post-contingency voltages above 0.90 P.U. No projects were deemed necessary due to low voltages.

C. Transient Stability Study Results

Simulations were run for 2009, 2010, and 2012. Scenarios analyzed included critical Category B, C, and D contingencies based on historical and expected operation. No WECC/NERC criteria violations were found. The analysis indicates acceptable transient stability performance for all of the following contingencies:

All faults simulated are 3-phase, 4-cycle duration, Category B outages unless noted.

Imperial Valley-Miguel with CFE cross trip
Sycamore-Central (planned) #1 and #2
Imperial Valley-North Gila
Lugo-Eldorado
Valley-Devers
Hassayampa-North Gila
Valley-Serrano
Palo Verde Generator #2
SONGS Generator #2
Palo Verde-Devers
Miguel-Mission #1 and #2 Category C)
Otay Mesa Northbound 230 kV #1 and #2 (Category C)
Lugo-Mira Loma #2 and #3 (Category C)
SONGS Generators #2 and #3 (Category D)
Palo Verde Generator #1 and #2 (Category D)

D. Short Circuit Study Results

This section documents the results of the short circuit study for the years 2008 through 2012 of San Diego Gas and Electric's transmission system. The short circuit study was performed with Aspen's Oneliner software.

The worst-case fault current duty was identified at each bus and compared to the nameplate breaker rating for all circuit breakers protecting that bus. For generator buses, SDG&E will allow breaker duties to reach 100 percent of the nameplate rating. For non-generator buses SDG&E will allow breaker duties to reach 115 percent of the nameplate rating.

The study indicates breaker duty mitigation is required for the following 69 kV breakers at the following substation:

- San Luis Rey Breakers 34, 35, 680, 693 694, 697, and 6912 (2008)

These circuit breakers are scheduled to be replaced under budget number 1145.

VI. Long Range Studies

A. Orange County Long-term Expansion Plan

The Orange County long term expansion plan is currently under review by SDG&E. This project is being proposed to address load growth and aging infrastructure issues, as well as improve reliability by adding a second 230kV source in Orange County. The Orange County plan will cost more than $20 million and will need CAISO Board approval. SDG&E will submit this project independent of the 2007 Transmission Reliability Assessment. With approval of the Orange County expansion plan, projects P061XY (Reconductor TL-13812 Talega-San Mateo) and P00153 (Recondutor TL 13837, Capistrano-Laguna Niguel) would be able to be canceled.

Business Practice Manual for the Transmission Planning Process

Order 890 Compliance

Version 2.0

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1. Introduction

Welcome to the CAISO's ***BPM for the Transmission Planning Process.*** In this Introduction, you will find the following information:

- The purpose of CAISO BPMs, in general
- What you can expect from this specific CAISO BPM

1.1 Purpose of California ISO Business Practice Manuals

The Business Practice Manuals (BPMs) developed by the CAISO are intended to contain implementation details consistent with, and supported by, the CAISO Tariff —including instructions, rules, procedures, examples and guidelines for the administration, operation, planning, and accounting requirements of the CAISO and the markets. Table 1 lists the currently available CAISO BPMs.

Table 1 CAISO BPMs

Title
BPM for Candidate CRR Holder Registration
BPM for Change Management Process for MRTU BPMs
BPM for Compliance Monitoring
BPM for Congestion Revenue Rights
BPM for Credit Management
BPM for Definitions and Acronyms
BPM for Managing Full Network Model
BPM for Market Instruments
BPM for Market Operations
BPM for Metering
BPM for Outage Management
BPM for Reliability Requirements
BPM for Rules of Conduct Administration
BPM for Scheduling Coordinator Certification and Termination
BPM for Settlements and Billing
BPM For the Transmission Planning Process

1.2 Purpose of this Business Practice Manual

This BPM explains the CAISO Transmission Planning Process, as well as the annual Transmission Plan produced by this process. Additionally, the BPM discusses how other associated processes performed by the CAISO's Planning and Infrastructure Development Department serve to guide the enhancement and expansion of transmission facilities to ensure that the CAISO Controlled Grid can satisfy the needs of a competitive bulk power market in a

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reliable, economically efficient, and environmentally acceptable manner. In so doing, this BPM, together with corresponding CAISO Tariff provisions on the Transmission Planning Process, serve to fulfill the requirements of the Federal Energy Regulatory Commission's (FERC) Final Rule on *Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890* ("Order No. 890").[1] Among other things, this Order requires all transmission providers, including independent system operators, to implement and document, through open access Tariffs and other public postings, a coordinated, open, and transparent transmission planning process that complies with the planning principles and other requirements articulated in Order No. 890.

The provisions of this BPM are intended to be consistent with the CAISO Tariff. If, however, the provisions of this BPM conflict with the CAISO Tariff in any way, the CAISO is bound to operate in accordance with the CAISO Tariff. Any provision of the CAISO Tariff that may have been summarized or repeated in this BPM is only to aid understanding. Even though every effort will be made by the CAISO to update the information contained in this BPM and to notify Market Participants of changes, *it is the responsibility of each Market Participant* to ensure that he or she is using the most recent version of this BPM and to comply with all applicable provisions of the CAISO Tariff.

Any reference in this BPM to the CAISO Tariff, a given agreement, or any other BPM or instrument, is intended to refer to that Tariff, agreement, BPM or instrument as modified, amended, supplemented or restated in the most current version.

The captions and headings in this BPM are intended solely to facilitate reference and not to have any bearing on the meaning of any of the terms and conditions of this BPM.

1.3 Specific Topics Covered by this BPM

In this BPM, the following general topics will be covered:

- Overview of the CAISO Transmission Planning Process that covers the schedules and scope of each stage of the process.
- Roles and responsibilities of Participating Transmission Owners (PTOs) and participants in the CAISO Transmission Planning Process (TPP)
- The "stages" that form the Transmission Planning Process, such as:
  - Development of Unified Planning Assumptions and Study Plans
  - Performance of technical studies and management of the Request Window
  - Project approval process and development of CAISO Transmission Plan
- General calendar and major milestones of the TPP
- A description of the types or categories of transmission upgrades or additions identified through the TPP, including:
  - Reliability transmission projects
  - Economic transmission projects
  - Location Constrained Resource Interconnections Facilities (LCRIF)

[1] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, III FERC Stats. & Regs., Regs. Preambles ¶31,241 (2007).

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  - Long-term Congestion Revenue Rights (Long Term CRRs) Projects
- Other key components related to the Transmission Planning Process include:
  - Request Window, including instructions and requirements for submitting study requests or project proposals to be considered in the CAISO Transmission Plan
  - Project final approval principles
  - Study and approval processes for Large Projects and projects with a capital cost of less than $50 million.
- Information requirements from various participants to facilitate the Transmission Planning Process
- The availability of planning information provided by CAISO and accessibility of that information
- The CAISO's involvement in regional and sub-regional transmission planning with neighboring entities, and sub-regional and regional planning groups

2. Overview of the Transmission Planning Process and Annual Transmission Plan

The continuing development and growth of the CAISO's competitive markets necessarily rest, in significant part, on a foundation of adequate transmission infrastructure. Therefore, a primary function of the CAISO is to plan for, and promote, the enhancement and expansion of transmission capability within its footprint. The CAISO, with cooperation from Participating Transmission Owners (Participating TOs), Market Participants, Load Serving Entities (LSEs), publicly-owned utilities (POUs), neighboring transmission providers, regional and sub-regional planning groups including WECC committees such as TEPPC, state regulatory authorities and other affected customers or entities (collectively referred to as TPP Participants), perform this function through the Transmission Planning Process in accordance with the terms of Section 24 of the CAISO Tariff,[2] as well as the business rules set forth in this BPM. The TPP ensures independent analyses and recommendations, supported by timely and meaningful opportunities for broad TPP Participant input and independent CAISO Board of Governor approval, all of which are ultimately incorporated into an annual CAISO Transmission Plan, project-specific reports, and other specific transmission-dependent resource adequacy studies.

2.1 The CAISO Transmission Planning Process

The CAISO's Transmission Planning Process is an integrated, open, participatory and transparent process that focuses on ensuring reliable, economically efficient, and non-discriminatory use of the transmission system. It accounts for three levels of transmission planning to meet these objectives:

[2] Reference to Section 24 of the CAISO Tariff also constitutes reference to Appendix EE of the CAISO Tariff. Appendix EE includes the majority of the CAISO Tariff provisions governing the Transmission Planning Process prior to the effective date of MRTU. Appendix EE will expire upon the commencement of MRTU and the relevant tariff sections will again be found in Section 24 of the CAISO Tariff. When there is a potential conflict between the pre-MRTU Tariff provisions and the MRTU Tariff provisions, this BPM references the MRTU Tariff provisions.

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- Local planning – Planning for the transmission systems of the CAISO's Participating TOs to meet the needs of LSEs serving Load within the CAISO Control Area. The PTOs planning activities are integrated into the 3-stage TPP that will be described in this BPM. In general, the PTOs will perform their studies using the same study assumptions, tools, and methodologies documented in the Study Plan that will be discussed with TPP Participants during the first stakeholder meeting in Stage 1 of the process. The study results from PTO studies will be presented during the CAISO Transmission Plan stakeholder meeting conducted during Stage 3. In addition, transmission projects proposed by PTOs must go through the Request Window during Stage 2 and will be evaluated by CAISO at the same time as the projects being proposed by other Project Sponsors. Consequently, TPP participants can participate in the local planning activities conducted by the CAISO throughout each stage of the planning process.
- Sub-regional planning – Planning at this level encompasses two components. First, the CAISO itself conducts sub-regional planning by aggregating the assessment of transmission needs of the Participating TOs and LSEs within the CAISO Balancing Authority Area. Second, as part of the foregoing process, the CAISO plans for the needs of the CAISO Balancing Authority Area, through the reciprocal exchange of transmission plans and other information, among the CAISO, Participating TOs and transmission systems neighboring the CAISO Balancing Authority Area (Interconnected Balancing Authority Areas) and/or established sub-regional planning entities. The CAISO believes this type of planning broadly facilitates the consistency of data, identification of efficiencies, and the avoidance of duplication to ensure simultaneous feasibility of local planning outcomes.
- Regional planning – Planning across sub-regions through the WECC, including by means of the CAISO's membership and active participation in WECC committees such as Transmission Expansion Planning Policy Committee (TEPPC).

Further, the implementation of the Transmission Planning Process is generally achieved through three stages below. In addition, the process also relies on the Request Window that will be explained in more detail in section 3.

- Stage 1: Identification of Unified Planning Assumptions and development of the Study Plan.
- Stage 2: Performance of technical analyses, posting of study results, and the proposed mitigation plans.
- Stage 3: Project approval and development of CAISO Transmission Plan.

Finally, there are standards and interrelated planning information that drive the Transmission Planning Process, including, but not limited to:

- NERC/WECC Regional Reliability Council Transmission Planning Standards and Criteria
- CAISO Grid Planning Standards
- CAISO Annual Report on Market Issues and Performance
- Reliability transmission project proposals
- Economic Planning Studies and Economic transmission project proposals, including Merchant Transmission Facilities
- Other alternatives or input CAISO receives from the Request Window
- Sub-regional transmission expansion plans

CAISO Public
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- Local Capacity Area Resource requirements
- Generator Interconnection Requests
- Generation and import deliverability assessments
- Reliability and congestion concerns from CAISO Short-term plan
- Long-term CRR feasibility assessments
- State initiatives, mandates, and policies.

2.1.1 Roles of Participants in the Transmission Planning Process

In order to achieve this multi-tiered[3] planning perspective, the CAISO engages with its TPP Participants. The anticipated roles of respective TPP Participants are summarized in table 2:

[3] Local, sub-regional, and regional planning

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Table 2: Roles and Responsibilities of TPP Participants

No	Participant	Roles and Responsibilities
1	**CAISO**	Leads and manages the CAISO TPP; responsible for coordinated planning of CAISO Controlled Grid; performs NERC's Planning Coordinator functions; conducts transmission planning studies for the CAISO Controlled Grid to identify the need for system reinforcements; proposes potential solutions as part of its study results as needed, and conducts an independent review of all proposed projects and project alternatives received through the Request Window; manages the Request Window for proposing new transmission projects and/or study requests; approves beneficial projects consistent with CAISO Tariff authority; administers LGIP/SGIP processes; participates in regional/sub-regional planning groups; and conducts simultaneous feasibility analyses for Long Term CRRs.
2	**PTOs**	Participate in the CAISO TPP; perform NERC's Transmission Planner functions, including proposal of study assumptions for consideration in the Study Plan, updating of planning base case models, conducting local and bulk transmission planning studies of its service area under the direction of the CAISO for inclusion in the CAISO TPP; develop, propose and submit new transmission project proposals through the Request Window; prepare meaningful cost estimates for proposed and alternative facilities upon CAISO's request; conduct interconnection studies, facility studies, participate in regional/sub-regional planning groups, and construct projects when designated under the CAISO Tariff. The roles and responsibilities of the PTOs and CAISO are described in more detail at *** of this BPM.
3	**Load Serving Entities (LSE)**	Participate in the CAISO TPP; assist in capacity planning and conduct procurement to meet resource adequacy requirements; obtain CRRs, voluntarily provide resource planning information, and propose desired non-wire alternatives.
4	**Publicly Owned Utilities (POU)**	Participate in the CAISO TPP; voluntarily exchange information and coordinate plans with CAISO and PTOs and other regional and sub-regional planning groups.
5	**California Energy Commission (CEC)**	Participates in the CAISO TPP; conducts Integrated Energy Policy Report (IEPR) and other strategic plans; provides data, permitting and approval of new thermal generation.
6	**California Public Utilities Commission (CPUC)**	Participates in the CAISO TPP; issues CPCN/environmental permits for new transmission projects, and administers the resource portfolio requirements of its jurisdictional LSEs, including the Renewable Portfolio Standard (RPS).

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No	Participant	Roles and Responsibilities
7	**Other TPP Participants/Affected Customers or Entities**	Participate in the CAISO TPP; propose new transmission projects; request studies, submit project proposals through the Request Window as needed, and provide relevant information and data.
8	**Regional and Sub-regional Planning Groups, including TEPPC and neighboring transmission providers**	Participate in the CAISO TPP; perform transmission planning studies (including congestion studies) when appropriate; propose new conceptual facilities, along with analyses of alternatives; exchange information toward shaping transmission plans from sub-regional and regional perspectives; and consider CAISO's plans with respect to the larger regional or sub-regional transmission plan.

The integrated and coordinated nature of the Transmission Planning Process is set forth in Figure 1 (see p. 15 of this draft).

2.1.1.2 Coordination of the Meeting, Planning and Study Responsibilities of the PTOs and CAISO.

Tariff §24.2.2.1

The PTOs play an important role in the CAISO TPP as Transmission Planners within the CAISO Balancing Authority Area as defined by the NERC Functional Model. In particular, the PTOs provide key planning data that will be used in each TPP cycle. Consequently, the success of overall transmission planning activities relies on careful coordination between CAISO and the PTOs to ensure the effectiveness of the TPP. The paragraph below summarizes the major tasks, roles, responsibilities, and the timeline for the coordination that occur throughout each TPP cycle that apply to CAISO and its PTOs.

- Planning Data Provided by the PTOs

The PTOs are responsible for providing the following planning data to the CAISO by the due date shown in Attachment 3. The CAISO validates and incorporates planning data and other related information from the PTOs as well as from other sources (such as WECC and appropriate regional planning organizations) to develop the Study Plan during each planning cycle.

- The bus-level load forecast in each local area to be studied as defined in the Study Plan and the written methodology of how to derive these load forecasts if any modifications have been made to the California Energy Commission (CEC) load forecast.
- Contingency files that include all contingencies that will be studied in each scenario identified in the study plan. The contingency file must be provided in a defined electronic format that is readable by GE-PSLF or other power

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system analysis tools, or with detailed documentation as to the format in which it is provided.

- Verified dynamic files in GE-PSLF format (flat responses for all channels under normal conditions) for each scenario transient stability study will be studied.
- Change files or EPC files that include CAISO-approved transmission projects and applicable regulatory approved generation projects to reflect modeling changes that have been made to the previous year base cases.

➢ PTO and CAISO Technical Studies Identified in the Study Plan

The CAISO is responsible for developing the Study Plan that describes the details of all technical studies to be conducted in each planning cycle, including the roles and responsibilities of each entity conducting the studies, consistent with NERC functional responsibilities and with input from the PTOs and other stakeholders. CAISO and PTOs shall conduct the technical studies based on the scope, scenarios, and assumptions delineated in the Study Plan.

➢ NERC Reliability Base Cases Developed by the PTOs

Once the scope and assumptions of each study have been established through the Study Plan, PTOs are responsible for developing the base cases of their systems for NERC compliance assessments, pursuant to the requirements imposed under the applicable NERC requirements. The base cases shall then be submitted to CAISO.

➢ Planning Data Developed by the PTOs and Maintained by CAISO

The CAISO will assimilate the PTO base cases and verify that the modeling in the base cases is consistent with the scope and assumptions defined in the Study Plan. CAISO also is responsible for posting and managing planning data on its Regional Transmission secured website.

➢ PTO Transmission Upgrades and Additions Submitted through the Request Window

The Request Window is a 3.5 month time period wherein Project Sponsors and TPP Participants annually may submit project proposals or certain types of study requests to the CAISO. The PTOs must submit reliability transmission project proposals through the Request Window by October 15th of each year.

➢ NERC Reliability Assessments Performed by CAISO and PTOs

CAISO and the PTOs are each responsible for performing NERC reliability assessments using the base cases developed by the PTOs and integrated into the CAISO Balancing Authority Area-wide base case. These studies should be conducted according to the scope of roles and responsibilities, and according to the time schedule, set forth in Attachments 2 and 3 to this BPM.

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- Technical Studies Conducted by CAISO

As part of its planning responsibilities for the entire Balancing Authority Area, CAISO also conducts studies to identify potential system limitations and congestion issues and may propose mitigation plans to address the needs that arise from other drivers affecting system design and requirements. These studies include the Seams Assessment, the Local Capacity Requirements Study, the Large Generator Interconnection (LGIP) Study, the CAISO Short-Term Plan, the Economic Planning Study, and other special plans (*e.g.,* studies related to the integration of intermittent resources into the state renewable resource portfolio and onto the CAISO-controlled grid) that can vary from year to year. The CAISO will post the results of its studies and any available mitigation proposals on its website in mid-September.

- Detailed Scope of Transmission Projects Developed by CAISO and PTOs

During Stage 2, the CAISO will identify transmission needs, and may propose preliminary solutions to meet applicable standards. Once these transmission needs and preliminary solutions are identified, and at the request of CAISO, the PTOs will be responsible for providing the detailed scope of potential solutions in accordance with NERC Reliability Standards TPL-001 through TPL-004 and identifying the potential projects that would resolve the needs specified by the CAISO. Upon receiving CAISO's requests, the PTOs shall provide in a timely manner the detailed scope of the requested transmission projects such as detailed cost estimate, alternative routes, alternative solutions or any other information related to the proposed transmission projects to the CAISO. The CAISO, in consultation with the PTOs, will establish the time frame in which this information is to be provided based upon a consideration of the complexity of the project and other pertinent factors.

- Coordination of Public Meetings Scheduled by CAISO

The CAISO is responsible for managing the public meetings held throughout the TPP. This includes issuing market notices, posting meeting materials prior to the meeting, providing phone and web-access, leading the meetings, and working with PTOs on the agendas and topics being presented in the public meetings. The PTOs shall participate in the CAISO public meetings, provide meeting materials and present the topics according to the agenda. In addition to public meetings that will be held at the CAISO offices, additional public meetings may be held at local PTO locations to discuss the issues specific to each PTO. Although such meetings will be held locally, the CAISO will be responsible for leading the meetings and ensuring that TPP Participants notify TPP participants through the market notices, posting and distributing meeting materials, similar to public meetings held at CAISO offices.

- Study Reports Provided by CAISO and the PTOs and Development of the Transmission Plan

The CAISO shall publish a preliminary report containing the assumptions, methodology, and study results for its NERC reliability assessment, as well as the results of the other technical studies conducted by the CAISO, by September 15th of each year. By October 15th of each year, the PTOs shall provide the CAISO the final study reports that document their NERC compliance, updates on the status of transmission projects previously approved by CAISO but not yet in-service, and newly proposed transmission additions and upgrades. During Stage 3, CAISO will incorporate relevant planning

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information from these reports into the annual CAISO Transmission Plan, as well as assimilate the studies presented by the PTOs, other TPP Participants and those conducted on its own accord. CAISO may approve projects included in the transmission planning studies prepared by the PTOs, alternative projects proposed by Non-PTOs, or projects identified by the CAISO.

- Appointment of Representatives to Coordinate CAISO/PTO Duties and Responsibilities

Each PTO and the CAISO shall appoint representatives that will be responsible for the coordination of planning activities between CAISO and the PTOs. The general responsibilities of the representatives will be to:

- Ensure that the exchange of information (planning data, study results, report, etc.) or other information will occur according to the schedule identified in the Study Plan
- Represent or delegate other individuals to participate in the CAISO TPP public meetings or other related meetings
- Act as the point of contact for the CAISO's requests to develop detailed transmission projects and provide responses to related questions or comments raised by TPP Participants

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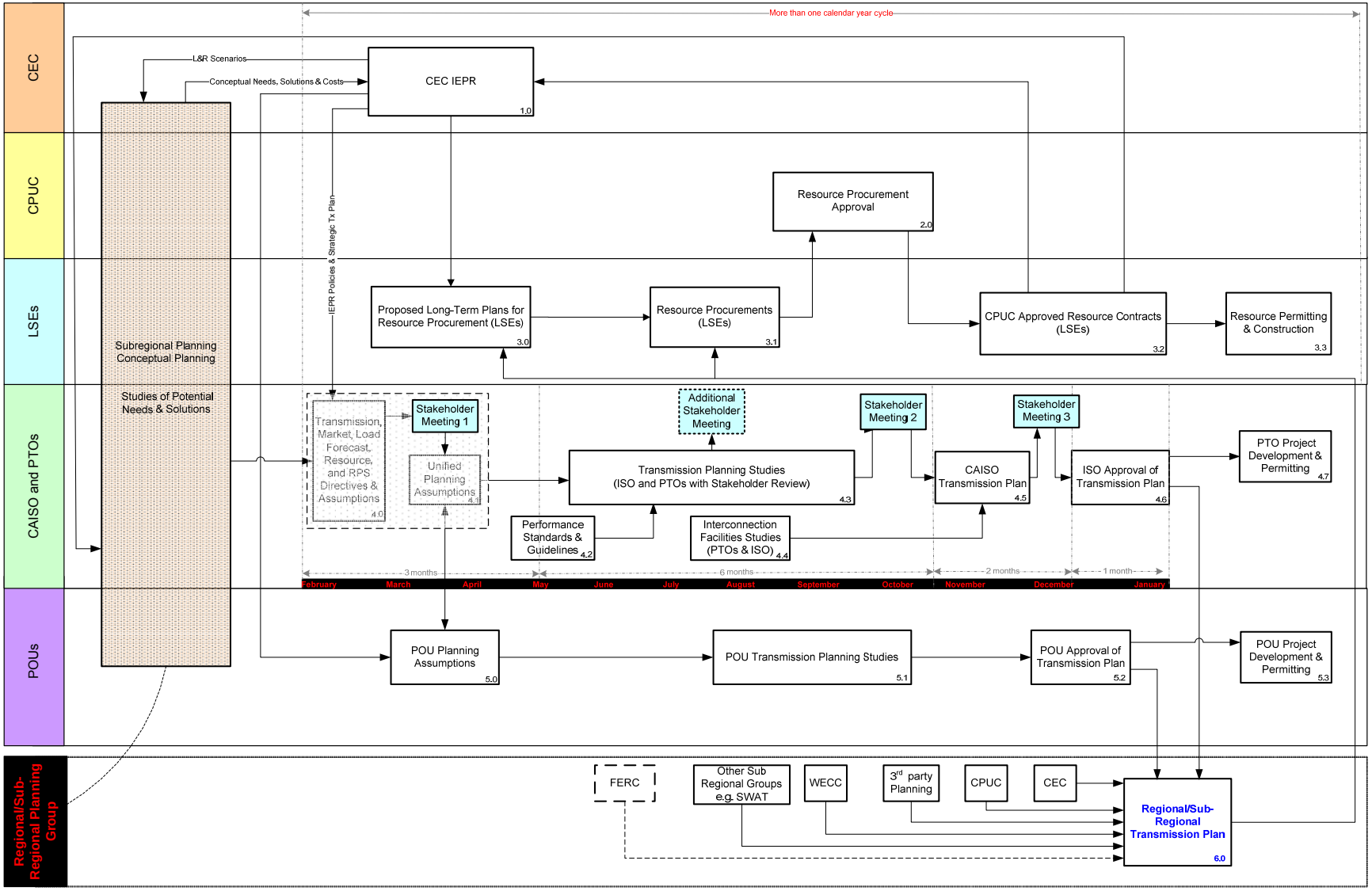

Figure 1: Coordination among Entities Regarding California ISO Transmission Plan

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2.1.2 General Description of TPP Stages

The CAISO conducts the TPP on overlapping cycles of approximately 13 months, beginning in January of Y1 and ending in February of Y2.[4] The cycle is comprised of a Request Window and the three general planning stages described in Section 2.1, as well as several supporting processes that culminate in the CAISO's Transmission Plan and other identified planning reports. The CAISO's planning horizon is a minimum of ten years and its Transmission Plan is presented to the CAISO Governing Board for review in February or March of each year. Figure 2 illustrates the overview of the timeline of Request Window and the three planning stages.

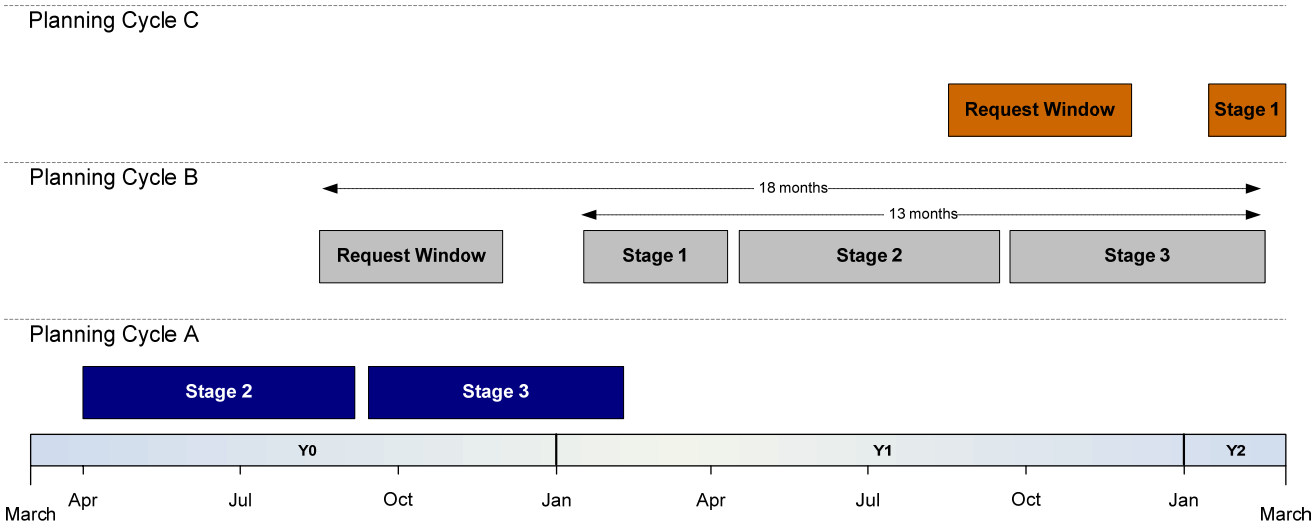

Figure 2: The CAISO TPP Stages and the Request Window

2.1.2.1 Request Window

CAISO Tariff Section 24.2.2

The CAISO's Transmission Planning Process utilizes a Request Window to provide TPP Participants with the opportunity to propose economic or reliability-driven transmission upgrades or additions (projects), requests for Economic Planning Studies, resource alternatives, *i.e.*, Demand management programs or Generation, or otherwise submit additional relevant data to the CAISO for inclusion in the following year's annual Transmission Planning Process. *The Request Window opens August 15th and closes November 30th of each planning cycle.*

All transmission project proposals seeking CAISO approval must be submitted through the Request Window. These include:

- Reliability transmission projects

[4] If the TPP cycle is presumed to begin with the Request Window, which is opened between August 15 through November 30 of Y0 and overlaps the previous planning cycle, the entire duration of the process is 18 months.

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- Economic transmission project proposals, including upgrades or additions proposed to reduce Local Capacity Area Resource requirements, reduce or eliminate Congestion, or Merchant Transmission Facilities to obtain Merchant Transmission Congestion Revenue Rights. Definitions and distinctions between Economic and Reliability transmission projects are defined in section 4.2.1 and 4.2.2 of this BPM.
- Location Constrained Resource Interconnection Facilities
- Transmission upgrades or additions determined to be the appropriate mechanism to maintain the feasibility or allocated Long-term CRRs
- Network Upgrades identified through CAISO Interconnection Studies
- Economic Planning Study requests
- Specific Demand management, Generation, and other resources for potential inclusion in the Transmission Planning Process analyses
- Operating solutions to reduce Local Capacity Requirements
- Alternative solutions to transmission projects proposed during the Request Window.

Besides the planning data, the CAISO will apply "screening criteria" to each submission it receives from the Request Window. Please refer to section 3.3 of this BPM for more information. Upon satisfying the screening criteria, each submission may be included in a different stage of the TPP based upon the nature of each submission. The following are three types of submissions that will likely be received through the Request Window and how these submissions will be integrated into the TPP stages:

- Economic Planning Study Requests[5] will be included in the preparation of the following cycle's Study Plan.
- Project proposals that solve a need either identified by CAISO or with which CAISO concurs, but which require additional technical studies to be conducted as part of the project evaluation process, will be included in the following cycle's Study Plan.
- Project proposals for which all necessary technical studies have been completed will be considered in the approval process (Stage 3) of the CAISO planning process and included in the Transmission Plan for that cycle.

Reliability transmission projects proposed by PTOs shall be submitted by October 15 of each year to allow sufficient time for stakeholders to review these projects. The CAISO will post a summary of valid project proposals and study requests it receives from the Request Window on the CAISO website. The annual CAISO Transmission Plan will also provide a summary of these submissions.

The TPP Participants sponsoring any proposed project shall provide the required information for the projects seeking CAISO approval as further described in this BPM. These include (a) a description of the project's objectives, (b) a list of alternative projects that would accomplish these

[5] These include High Priority Economic Planning Studies that will be performed by CAISO and Non-High Priority Economic Planning Studies that will be performed under CAISO direction by the requesters and at their expense.

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objectives, and (c) any methodological and/or data requirements imposed or suggested by the requesting party's or parties' local regulatory authority(ies).

As further discussed in Section 3.4, the screening process applied by CAISO to Request Window submissions generally assesses proposed transmission projects against three categories of criteria:

(1) whether the submissions are "complete" in that they provide all necessary data or information requested by the CAISO with respect to the particular category of submission;

(2) whether the proposal is or is not functionally duplicative of transmission upgrades or additions that have been previously approved by the CAISO; and

(3) whether the proposal, if a sub-regional or regional project that affects other interconnected Control Areas, has been reviewed by the appropriate sub-regional planning entity and is not inconsistent with any sub-regional planning entity's preferred solution or project.

The CAISO applies separate screening criteria to Economic Planning Study Requests to select which requests will be designated High Priority Economic Planning Studies. High Priority Economic Planning Studies are included in the Study Plan for the upcoming planning cycle and will be performed by the CAISO at its cost. If a requested Economic Planning Study meets the screening criteria for a High Priority Study and is regional or sub-regional in scope, the study shall be submitted to WECC's Transmission Expansion Planning Policy Committee (TEPPC) or applicable sub-regional planning group. If TEPPC or other sub-regional planning group does not select such Economic Planning Study for inclusion in its study scope, the CAISO will retain the responsibility to conduct the study.

Similarly, other Economic Planning Studies not designated as High Priority Economic Planning Studies, but which meet the screening criteria and are regional (and potentially sub-regional) in scope, will be submitted to WECC's Transmission Expansion Planning Policy Committee (TEPPC) as part of its joint coordinated evaluation and prioritization process. The TEPPC process will determine whether the request is performed and by whom. Economic Planning Studies that are neither High Priority Economic Planning Studies nor regional or sub-regional in scope may still be performed at the proponent's expense and submitted to the CAISO for review and potential inclusion in the final Transmission Plan. The CAISO will coordinate with any third party performing its own study to ensure that the study is consistent with the data, assumptions, and methodology employed by the CAISO.

Any proposed transmission upgrades or additions that do not pass the screening process will be subject to the CAISO's alternative dispute resolution (ADR) procedures under Section 13 of the CAISO Tariff.

2.1.2.2 Stage 1: Unified Planning Assumptions of the Study Plan

CAISO Tariff Sections 24.2.3 and 24.2.4

Stage 1 of the Transmission Planning Process involves development of the Study Plan which encompasses the Unified Planning Assumptions[6] for each technical study. The objective of this

[6] The term "Unified Planning Assumptions" means the proposed assumptions of each technical study that stakeholders have reviewed and agree upon, regarding how the studies shall be conducted.

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stage is to determine the goals of, and agree upon assumptions for, the various studies and project evaluations to be performed as part of a TPP cycle. Information from the Request Window conducted in the previous TPP cycle, as well as information from PTOs, neighboring balancing authorities, state agencies, regional and sub-regional planning groups[7] will be integrated into the development of the Study Plan. Input is also expected from the TPP Participants, and the CAISO will consider comments received via email to regionaltransmission@caiso.com. This information forms the basis of the Study Plan produced by the CAISO as shown in Attachment 1. The Study Plan articulates the Unified Planning Assumptions and provides TPP Participants with a coordinated plan for completing all of the required and proposed studies during Stage 2 of the TPP cycle. The Study Plan lists all the studies to be conducted, describes basic planning assumptions and inputs, sources for those assumptions and inputs, how assumptions and inputs will be applied, methodology, tools used, study criteria, (*i.e.* WECC Planning Standards), expected study outputs and assignments for performing specific analyses to PTOs and third parties as determined by the CAISO. Major milestones such as tentative schedules and locations of the meetings, postings of information, dates for the submission of comments and CAISO responses to the comments , along with contact information of subject matter experts (SMEs) are also part of the scope of the study plan. Finally, the Study Plan will document the scope and major milestones for the evaluation of Large[8] Projects.

Generally, the components of the Study Plan are Demand, transmission system topology, generation assumptions, and imports. As mentioned earlier, the information contained in the Study Plan is intended to allow replication of the studies performed during the CAISO's TPP by competent transmission engineers.

The timeframe for Stage 1 development is January through April of each year. The first CAISO TPP stakeholder meeting (public meeting) will be held to present the draft Study Plan to the stakeholders approximately in March of each year.

2.1.2.3 Stage 2: Technical Studies and Presentation of Results

CAISO Tariff Section 24.2.5

Stage 2 of the TPP involves the performance of technical studies to identify the need for system reinforcement and to propose applicable solutions. The initial results of these studies will be presented to TPP participants during this stage. The technical studies will follow the Study Plan using the Unified Planning Assumptions to the maximum extent possible. *The time frame for Stage 2 is May – October of each year*. The CAISO will perform technical studies according to the Study Plan and will post its study results on the CAISO website by mid-September of each year. The CAISO will rely on its study results as the benchmark during the Stage 3 project

[7] By the 2nd week of December of each year, the CAISO will send out data requests to the neighboring balancing authorities, state agencies, regional/sub-regional planning groups, and TPP participants for the information that should be considered in the development of the Study Plan.

[8] Large Projects are defined as a transmission upgrade or addition that exceeds $200 million in capital costs and consists of a proposed transmission line or substation facilities capable of operating at voltage levels greater than 200 kV. A large project may also be a project that does not meet the dollar or voltage level requirement, but in the CAISO's opinion raises significant policy issues warranting a separate planning process.

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approval process. A minimum of one public meeting will be held in October of each year[9] to deliver preliminary study results to TPP Participants for their review and comment. The information presented to the TPP Participants shall include:

- Summary of findings (need identifications)
- Proposed solutions for the selected identified problems, including detailed descriptions of any reliability criteria violations and proposed mitigation solutions
- Findings on High Priority Economic Planning Studies (i.e. feasible upgrades to relieve congestions or bottlenecks) and, if necessary, the scope for needed further analysis

As discussed earlier in this BPM, the PTOs are required to submit reliability transmission projects through the Request Window by October 15 each year. Before Stage 2 is complete, the CAISO will hold, in coordination with the PTOs or other parties, additional public meetings to discuss results of system performance assessment studies conducted by the PTOs and potential solutions to the problems identified in those studies (wire and non-wire). These meetings provide an additional opportunity for TPP Participants to provide input on the transmission alternatives to be considered in the CAISO's Transmission Plan. All meetings will be noticed by the CAISO by Market Notice and will be coordinated with the CAISO's stakeholder calendar.

2.1.2.4 Stage 3: Project Approval and Development of the Expansion Transmission Plan

CAISO Tariff Section 24.2.5

Stage 3 of the TPP involves the approval of projects from the Request Window that meet the CAISO project screening criteria, documentation of the technical study results and information related to the planning activities, and addressing TPP Participant comments and/or concerns. The primary product resulting from this stage is the CAISO Transmission Plan, which will be presented to the CAISO Board of Governors. Also, if consistent with the agreed upon schedule in the Study Plan, the Transmission Plan may include the results of other specific technical studies involving Large Projects or other identified planning evaluations. Otherwise, Large Projects or other identified planning evaluations will be presented independently of the Transmission Plan. Either way, the status of large projects will be documented in the Transmission Plan. *The timeframe for this activity is November – February*.

During this stage, the CAISO develops its draft CAISO Transmission Plan report primarily based on the final study results. The Transmission Plan lists, but is not limited to, the status of the transmission projects subject to CAISO management approval (*i.e.*, those with capital investment < $50 million), along with the basis for the CAISO's decision on such projects, including analyses of other alternatives not recommended by CAISO management. The Transmission Plan also provides the status of projects CAISO previously approved but still under construction, and the status of projects requiring more than $50 million of capital investment that are separately submitted to the CAISO Governing Board for approval. As noted above, the technical studies, reports and recommendations for those separately reviewed transmission projects may be prepared concomitantly with the Transmission Plan or on an alternative schedule.

[9] The CAISO will send market notice to notify TPP participants for the exact dates when its study results will be posted as well as the date for the stakeholder meeting.

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The CAISO will present a draft Transmission Plan report to TPP Participants at a public meeting in accordance with the timeframes set forth in this BPM. As part of this process, the CAISO will explicitly request the participation of representatives from neighboring transmission providers and sub-regional planning organizations, in order to seek input and identify potential improvements for the following year's Transmission Plan. The CAISO also will present its Transmission Plan at relevant regional and sub-regional planning groups. All TPP Participant comments and CAISO responses throughout the development of the Transmission Plan will be posted on the website (http://caiso.com/1f42/1f42d6e628ce0.html) and will be addressed in the final Transmission Plan. The CAISO Transmission Plan will be finalized and scheduled for presentation during the CAISO Governing Board meeting in February or, if necessary, in March.

PTOs and other successful Project Sponsors may move toward the development and permitting of those projects approved by the CAISO Governing Board or management, as applicable. Projects with estimated capital investment of $50 million or less that are included as approved in the final Transmission Plan are deemed formally approved by CAISO management. Figure 3 illustrates the relationship between each stage of the CAISO TPP and the Request Window.

CAISO Public

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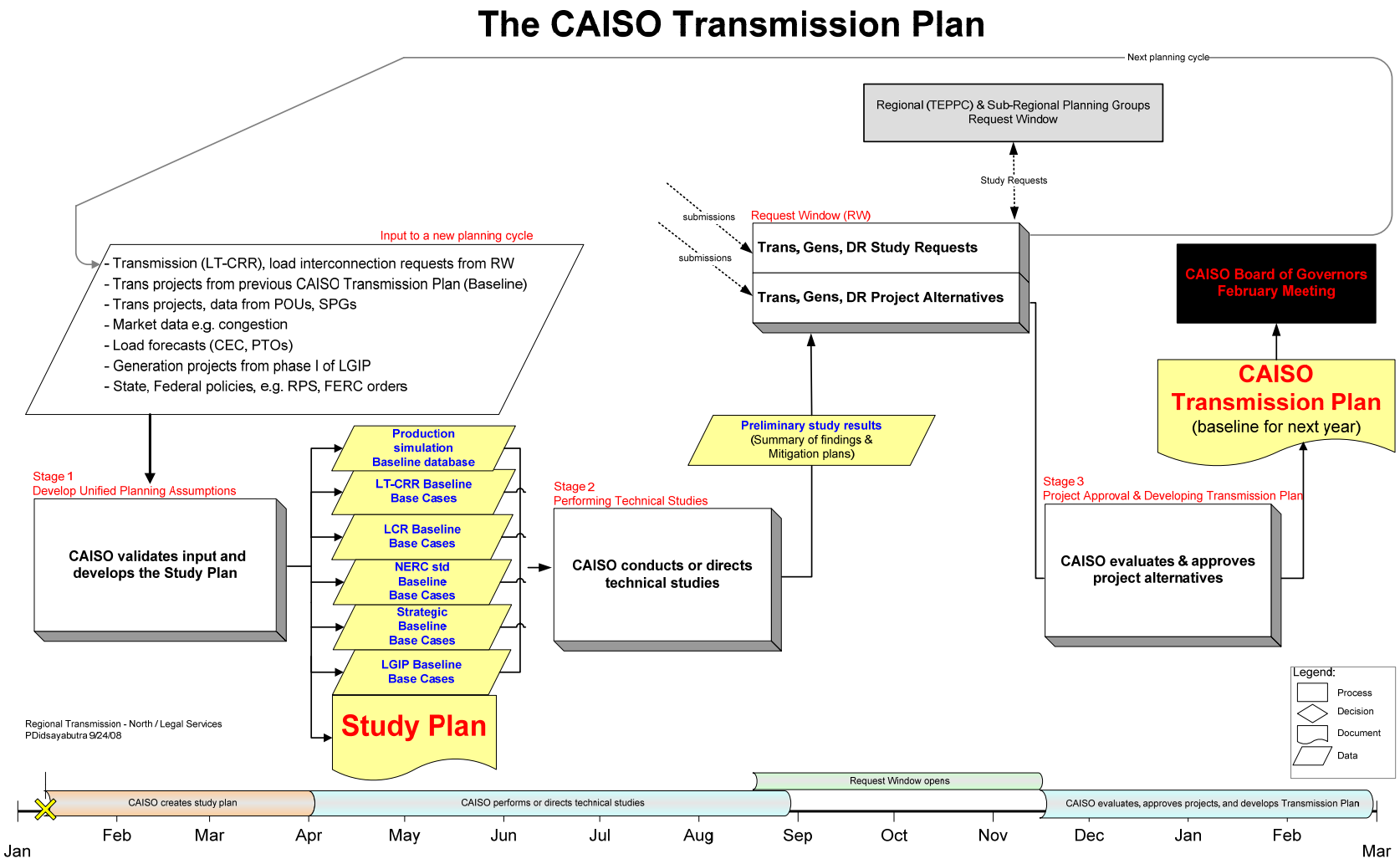

Figure 3: Request Window and three stages in the CAISO Transmission Planning Process

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2.1.3 TPP General Calendar

The following table describes the approximate proposed timelines and milestones for the CAISO TPP:

Transmission Planning Process Schedule

No	Due Date	Activity
1	2nd week of December	CAISO sends a letter to neighboring Balancing Authorities, sub-regional and regional planning groups requesting planning data and other related information to be included in the CAISO Transmission Plan
2	2nd week of January	PTOs, neighboring balancing authorities, regional/sub-regional planning groups, and other TPP participants provide CAISO planning data
3	End of January	If needed, CAISO Planning Standards Committee Meets
4	2nd week of February	CAISO develops the Draft Study Plan and posts it on CAISO website
5	March	**CAISO hosts Stakeholder Meeting #1**
6	Early April	The CAISO finalizes the Study Plan and posts the base cases and other planning data on its secured website
7	End of July	If needed, the CAISO hosts additional stakeholder meetings at the local locations
8	August 15	Request Window Opens
9	September 15	The CAISO posts preliminary study results on its Regional Transmission secure website
10	October 15	PTOs submit reliability project proposals through the Request Window along with their study reports
11	End of October	**CAISO hosts Stakeholder Meeting #2**
12	November 30	Request Window Closes
13	December-January	Projects with capital costs less than $50 million will be submitted to the ELT meetings
14	End of January	The CAISO posts draft Transmission Plan on its website
15	February	**CAISO hosts Stakeholder Meeting #3**
16	February (or March) Board Meeting	CAISO presents Transmission Plan to the Board of Governors

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This reflects the minimum level of activity. As noted, additional TPP Participant meetings may be scheduled as necessary, both for projects to be included in the Transmission Plan and for projects being studied through their own schedules. Should the issuance of the draft Study Plan, the CAISO preliminary study results, the PTO study submissions or the draft Transmission Plan be delayed beyond the approximate dates set forth above, the public meetings shall be accordingly adjusted.

2.1.4 Transmission Projects Identified Through the TPP

The TPP, which encompasses the CAISO's Large and Small Generator Interconnection Procedures (LGIP/SGIP), will identify the following categories of transmission additions or upgrades:

2.1.4.1 Transmission Projects Identified Through the LGIP/SGIP

- Reliability Network Upgrades – The transmission facilities at or beyond the Point of Interconnection necessary to interconnect a Large Generating Facility safely and reliably to the CAISO Controlled Grid, which would not have been necessary without the interconnection of the Large Generating Facility. This includes Network Upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of the Large Generating Facility to the CAISO Controlled Grid. Consistent with WECC practice, Reliability Network Upgrades also include the facilities necessary to mitigate any adverse impact the Large Generating Facility's interconnection may have on a path's WECC rating.
- Delivery Network Upgrades – Transmission facilities at or beyond the Point of Interconnection, other than Reliability Network Upgrades, identified in the Interconnection Studies to relieve constraints on the CAISO Controlled Grid and which the Interconnection Customer or the PTO elects to fund.
- Interconnection Facilities – The PTO's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modifications, additions, or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the CAISO Controlled Grid. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

In accordance with Tariff §7.2 and 7.5 of Appendix GG, the LGIP procedures for interconnection requests a queue cluster window, CAISO will coordinate the Phase II Interconnection Studies with the TPP, to the maximum extent possible, including:

- Consistency between the Interconnection Base Case Data used for the performance of Phase II Interconnection Studies and the Unified Planning Assumptions;
- Consideration of any conceptual transmission plans developed, but not rejected, in the TPP intended to access generation development areas as a means to satisfy the Network Upgrade requirements included in the Phase II Interconnection Study;

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- Performance of sensitivities within the TPP to optimize transmission upgrades developed in the current TPP to achieve System Reliability, economic efficiency and satisfy Network Upgrade requirements;
- Consideration of future generation development potential in transmission upgrade designs pursuant to the criteria developed as part of the Unified Planning Assumptions;
- Consideration of phased development and option value of transmission projects to address uncertainty.

Generation projects entering the Phase II Interconnection Study will also be considered in the Unified Planning Assumptions, as appropriate. Transmission projects proposed through the Phase II Interconnection Study that require Board approval (those with capital costs of over $50 million) will be integrated into the TPP stakeholder process.

2.1.4.2 Transmission facilities originating outside the LGIP/SGIP and deemed "needed" under Section 24.1 of the CAISO Tariff

- Reliability transmission projects – The CAISO obligates PTOs, as NERC Transmission Planners, to identify the need for any transmission additions or upgrades required to ensure System Reliability consistent with Applicable Reliability Criteria and CAISO Planning Standards. This obligation requires that the CAISO Controlled Grid be planned to a level that meets or exceeds transmission system performance criteria established by the WECC, NERC, Local Reliability Criteria, and other CAISO Planning Standards (collectively Reliability Criteria). Reliability transmission projects may also originate from CAISO recommendations from the CAISO's short-term plan based on the past operational experiences. A transmission upgrade or addition will be justified on the basis of reliability where the project is specifically designed to mitigate or prevent identified Reliability Criteria violations.
- Economic transmission projects – These types of upgrades promote economic efficiency. The CAISO Tariff does not define economic efficiency. However, economic efficiency may be demonstrated where (1) the Project Sponsor, other than a PTO, commits to pay the full cost of the construction, maintenance, and operation of the addition or upgrade and rely on the receipt of Merchant Transmission Congestion Revenue Rights to recover such costs; or (2) the economic benefits of the upgrade or addition are expected to exceed its costs. Economically efficient transmission upgrades or additions may serve many objectives, including, but not limited to, lowering a region's Energy production costs, reducing or eliminating Congestion, reducing capacity costs (*i.e*., lowering Local Capacity Requirements for a Local Capacity Area), and efficiently accessing renewable Energy resources.
- LCRIF – A High Voltage Transmission Facility, proposed to connect location constrained resources in designated Energy Resource Areas (ERAs), that has been determined by the CAISO to satisfy, or conditionally satisfy, all of the requirements of Section 24.1.3 of the CAISO Tariff. (*See* Section 4.2.3 for further discussion.)
- Long-term CRR transmission projects – Transmission organizations must incorporate procedures into their Transmission Planning Processes that maintain or ensure the feasibility (but not the value) of allocated or awarded long-term firm transmission rights over their entire term. The terms under which the CAISO satisfies this requirement are

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set forth in Section 24.1.4 of the CAISO Tariff and are further addressed in Section 4.2.6 of this BPM.

2.1.5 Large Project Evaluations

A Large Project is a transmission upgrade or addition that exceeds $200 million in capital costs and consists of a proposed transmission line or substation facilities capable of operating at voltage levels greater than 200 kV. A large project may also be a project that does not meet the dollar and voltage levels described but that, in the CAISO's opinion, raises significant policy issues so as to require a separate planning process. Location Constrained Resource Interconnection Facilities are not included in this definition, regardless of the capital cost or voltage level of the transmission upgrade or addition.

Although the process to evaluate the impact from these projects is part of the CAISO TPP, Large Projects may require comprehensive technical studies to be conducted and it may take more than one planning cycle to complete the evaluation process. Consequently, in addition to the overview of these projects that will be documented in the overall Study Plan, the CAISO may develop individual study plans and public meeting schedules for the evaluation of each Large Project (and alternatives).

In developing the study plan and public process for the evaluation of Large Projects, CAISO may follow the guidelines set forth in Decision 06-11-018 issued by the California Public Utilities Commission on November 9, 2006. These guidelines set forth the requirements that must be met during the CAISO evaluation of a Large Project in order that a CAISO finding of electrical need for the project can be afforded a rebuttable presumption of reasonableness during the CPUC Certificate of Public Convenience and Need (CPCN) process.

Although the Large Project study process may proceed on a separate study and public participation track, the process will be coordinated with the TPP as follows:

- Development of the individual study plan and the schedule for completion of the necessary studies for such Large Projects may be determined through a separate TPP Participant public process involving additional noticed TPP Participant meetings and comment periods, and then published in addition to the Unified Planning Assumptions, if necessary.
- To maximize TPP Participant public participation, this additional meeting addressing study assumptions may be noticed both through CAISO Market Notices and through the media in the area in which the project will be located. Other meetings may also be held near the project's proposed or anticipated location.
- CAISO will attempt to apply the Unified Planning Assumptions to Large Projects to the maximum extent possible. Nonetheless, TPP Participants will be advised at public meetings during Stage 1 if individual study assumptions for Large Projects are being separately considered at other public meetings.
- CAISO will provide access to updates and information regarding Large Project alternatives similar to that provided for studies that will be incorporated into the Transmission Plan. Further, to the extent practical, the CAISO will seek to document, within the Unified Planning Assumptions and Study Plan, any special

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data, assumptions and other inputs tailored specifically for Large Project proposals. Large Project status reports will be documented when CAISO posts its technical study results in mid-September and will also be provided in the annual CAISO Transmission Plan report.

Each Large Project recommended for approval by CAISO management will be presented to the CAISO Governing Board for approval in accordance to the schedule developed for the project.

2.2 CAISO Transmission Plan

The CAISO's Transmission Plan is the primary product of its TPP. Produced annually, it details information on newly proposed transmission projects and alternatives considered within the CAISO Balancing Authority Area, as well as external transmission facilities that will interconnect to the CAISO Controlled Grid. The Transmission Plan also articulates the plans or key activities of other participating entities and contains information on other issues such as Congestion analyses, a long-term projection of Local Capacity Requirements, resource deliverability and operational issues based on experiences learned from real-time operation. The Transmission Plan shall contain information, including, but not limited to, the following:

- Transmission Project Summary – Provides a list and details about transmission projects including:
  - Updates on the status of transmission projects approved by the CAISO during prior Transmission Planning Process cycles
  - Transmission projects that have been proposed to the CAISO for approval and recommendation
  - Transmission projects CAISO management approves in the current transmission plan and the basis of approval i.e. description of the analysis for assessing "need" for the preferred project
  - Alternatives considered and the resulting comparison of these alternatives to the preferred project
  - Transmission project proposals CAISO management does not approve along with the basis of its decisions
  - Transmission projects proposals require approval from CAISO Board of Governors
  - Transmission project proposals that are at a conceptual stage or require additional study that are advanced to mitigate reliability issues or provide economic benefits to the CAISO ratepayers, or for other purposes, including the potential development of Energy Resource Areas (that may also be competitive renewable energy zones (CREZ)) identified through State regulatory processes.
- System Outlook – Provides information on future system conditions to facilitate transmission planning decisions, including, but not limited to:
  - New generation from CAISO Interconnection Queue and CEC licensing process
  - Generation retirement analyses from CEC

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- Load forecast data from CEC
- Other factors, such as state and federal policies impacting transmission planning, economic trends, fuel prices outlook, activities from other entities in the region that should be considered, future technology, impact from climate changes, etc.

➢ System Assessment Results – Results from various technical studies performed by the CAISO or other entities at the direction of the CAISO in accordance with the Study Plan that focus on different perspectives of the system, including, but not limited to:

- Reliability – Studies performed to ensure that system performance can satisfy all NERC/WECC (TPL 001 – TPL 004) reliability and CAISO Planning Standards over both the short-term (up to 5 years) and long-term (10 years or longer)
- Resource Adequacy and Related Issues – Studies support resource adequacy programs such as the Local Capacity Requirement (LCR) Technical Study
- Economic transmission project studies – Studies to determine how a proposed transmission upgrade or addition promotes economic efficiency relative to other alternatives
- Economic Planning Studies – Studies that provide information for Market Participants to independently assess the effects of Congestion in order to facilitate market decisions regarding transmission or other resource additions or upgrades to mitigate the identified Congestion.
- Location Constrained Resource Interconnection Facilities (LCRIFs) – evaluation of proposed LCRIFs from Project Sponsor(s) to connect location constrained resources in designated Energy Resource Areas (ERAs)
- Long-Term Congestion Revenue Rights (CRRs) – Identify simultaneous feasibility of allocated Long Term CRRs
- Other System Planning Studies – Studies that evaluate specific relevant planning topics, including, but not limited to, aging power plants, conceptual Transmission Plans to facilitate Renewable Portfolio Standards, and operational studies to integrate renewable resources
- Short-Term Plan – Summary of recent concerns and recommendations based on system operators' experiences on the grid, including congestions, load, resources, and system performances. This also includes the assessments of near-term system conditions (1-3 years) with consideration of the benefits from future transmission upgrades. This study may recommend system reinforcements or additional actions that are not addressed by other future upgrades.
- Operating Guide – Informational guidelines for CAISO grid operations regarding possible impacts of new transmission projects and the need to revise existing—or develop new—operating procedures
- Scenarios Analysis – Results from specific, periodic studies focusing on opportunities to improve reliability and system performance

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- Conclusions, Visions and Future Plans – Conclusion from the current plan, CAISO's vision on various topics, such as potential concerns, potential grid enhancements, and plans for enhancing future iterations of the Transmission Plan.

The Transmission Plan will be used by CAISO as part of the documentation of compliance with the NERC Reliability Standards applicable to Planning Coordinators.

3. Request Window

The CAISO's Transmission Planning Process utilizes a "Request Window" as a centralized, transparent, and organized method to solicit and manage project proposals, Economic Planning Study requests, and submission of project-related data. The Request Window is a 3.5 month window, *opening on August 15th and ending on November30th* of each year, during which TPP Participants may submit project proposals, Economic Planning Study requests, and other necessary data related to those projects and studies. Submissions during the Request Window will be evaluated against defined criteria in a screening process.

The screening process functions to:

- Ensure sufficient information is provided to the CAISO to allow consideration of the submission in the Transmission Planning Process
- Establish if other threshold criteria have been met, as described in Section 3.4 of this BPM.

Submissions that satisfy the screening process may be considered in the current year approval process or may be included within the scope of the following year's Study Plan. In general, project proposals for which all necessary technical studies have been performed will be considered in the current year approval process while High Priority study requests[10] will be included in the following year Study Plan. The CAISO will conduct up to five (5) High Priority studies in each planning cycle. In addition, valid Economic Planning Study requests with a regional or sub-regional study scope may be referred to, and the study performed by, a sub-regional planning group or the Transmission Expansion Planning Policy Committee (TEPPC) of WECC in accordance with the TEPPC synchronized economic planning study process. Project proposals or Economic Planning Study requests that do not satisfy the Request Window requirements or are not otherwise selected may be submitted to the CAISO's alternative dispute resolution process under Section 13 of the CAISO Tariff.

The major components of the Request Window to be discussed are:

- Scope of the proposals and projects that may be submitted
- Submission process
- Data included in submission process
- Screening process

[10] Up to five studies that include Study Requests under Economic Planning study and the evaluation of major project proposals that additional technical studies are required before the projects can be submitted for CAISO approval.

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3.1 Scope of Proposals and Projects in Request Window

CAISO Tariff Section 24.2.2

Section 2.1.2 describes the categories of proposed transmission additions, upgrades, or economic study requests which, regardless of the Project Sponsors, must go through the Request Window process to be considered for CAISO approval. These project proposals are as show below:

- Reliability transmission upgrades or additions – PTOs with PTO Service Territories and TPP participants may propose reliability transmission upgrades or additions through the Request Window
- Merchant Transmission Facilities – Transmission upgrades or additions in which the Project Sponsor will seek revenue recovery through the receipt of Merchant Congestion Revenue Rights under Section 36.11 of the CAISO Tariff, rather than through the CAISO's Transmission Access Charge
- Economic transmission upgrades or additions – Transmission upgrades or additions proposed by PTOs or entities applying to become PTOs for approval primarily based on the economic efficiency of the projects and for which the PTOs intend to obtain revenue recovery through the CAISO's Transmission Access Charge. (Note that projects that are less than $50 million may also be identified through mitigation proposals submitted by PTOs with PTO Service Territories)
- LCRIF – proposed transmission projects to connect Location Constrained Interconnection Resource Generators in designated ERAs
- Projects to preserve Long-term Congestion Revenue Rights – These projects will be an output of CAISO studies conducted in conformity with the developed Study Plan
- Demand Response programs – For possible inclusion in base case/assumptions or as a resource alternative to resolve planning targets
- Generation projects – Information on proposed Generating Units may be submitted as proposed solutions along with study requests under Economic Planning Study
- Network Upgrades identified through the SGIP/LGIP – Transmission associated with requests to interconnect Generating Units will be identified through the SGIP or LGIP, as applicable
- Economic Planning Study requests – These are TPP Participant requests for the CAISO to develop conceptual transmission solutions to mitigate identified system congestion and perform preliminary assessment of the economic benefits of such mitigation
- Operational solutions to address Local Capacity Requirements

3.2 Request Window Submission Process

This section describes the steps for submitting the required proposals or requests through the Request Window process. Proposals and requests submitted through the Request Window will be considered, provided that the following process steps are satisfactorily completed:

1. Initiation – Submitters shall start the process by submitting the appropriate forms to the CAISO at requestwindow@caiso.com. The appropriate forms, including instructions for

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submission and the data requirements necessary, will be posted on the CAISO website at http://caiso.com/1f42/1f42d6e628ce0.html. These data forms include the details of the Economic Planning Study request or project proposals necessary to allow initial evaluation. The CAISO will assign responsibility for the project or Economic Planning Study request to its staff and acknowledge receipt of the project information or Economic Planning Study request to the submitter within three Business Days.

2. Validation/Selection – Within ten business days after receiving the form, the CAISO will apply the screening test to validate the transmission proposals or Economic Planning Study requests. At that time, the CAISO will inform submitters by e-mail whether the proposed project satisfies the screening criteria. For those submitters whose data or information are deemed incomplete by the CAISO, such submitters will have five business days to supplement their submissions.

3. Secondary Validation – For those submitters whose data or information are deemed incomplete by the CAISO as part of the initial validation in step 2 above, such submitters will have five business days to supplement their submissions (if the fifth day falls on a weekend or holiday, the deadline with be the following Business Day). Within five business days after receiving the supplemental submission, the CAISO will inform the project proponent whether the screening criteria have been satisfied.

3.3 Data Requirements for Request Window Submissions

The data requirements necessary to initiate the Request Window process, as discussed in Section 3.2, will be described further in this section with respect to different categories of projects and/or requests. Data templates and accompanying instructions for submission to the Request Window may be found at http://caiso.com/1f42/1f42d6e628ce0.html under the Request Window Forms and Instructions link.

3.3.1 Economic Transmission Project Proposals

CAISO Tariff Section 24.2.2.1

As noted, any economic project, including those seeking cost recovery through Long-term Congestion Revenue Rights or to reduce Local Capacity Requirements, whether submitted by a PTO or sponsor of a Merchant Transmission Facility, must submit the following project information, which includes, but is not limited to:

General Data

- Basic description of the proposal, such as the scope, the nature of alternative (AC/DC), objectives, and the qualifications for the proposal to meet certain policies such as LCRIF, LT-CRRs, etc.
- Geographical location and proposed preferred project route
- Evidence of securing the route or ability to secure the route

Technical Data

- Network model for power flow study

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- Dynamic models for stability study
- Short-circuit data
- Protection data

Planning Level Cost Data

- Detailed project construction, operation, and other costs necessary for the study
- Explanation of the accuracy of the cost estimate, and the level of risk of actual cost exceeding the estimate.

Miscellaneous Data

- Proposed entity to construct, own, and finance the project
- Planned operator of the project
- Construction schedule and expected online date

3.3.2 Generation Project Proposals

CAISO Tariff Section 24.2.2.1

Proposed Generating Facilities may also be submitted to the CAISO for purposes of evaluating the effect of such generation on resolving previously identified grid concerns, including Congestion, voltage support, etc. Proponents of generation projects for consideration in the Transmission Planning Process need to provide a similar set of project data that is required by the LGIP process:

General Data

- Basic description of the project, such as fuel type, size, location, etc.
- Proof of site control and CEC licensing status
- Description of the issue sought to be resolved by the Generating Facility, including any reference to results of prior technical studies included in published Transmission Plans.

Technical Data

- Network model of the project for power flow study
- Geographical location, evidence of land procurement
- Dynamic models for stability study
- Short-circuit data
- Protection data
- Other technical data that may be required for specific types of resources, such as wind generation

Planning Level Cost Data

- Detailed project construction, heat rate, and operation costs
- Proponent should specify expected contractual information necessary to assign generator profit, for estimate of CAISO transmission ratepayer benefits

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Miscellaneous Data

- Entity responsible for constructing, owning, and financing the project, and the entity responsible for the costs of the project
- Planned operator of the project
- Construction schedule and expected online date
- Any additional miscellaneous data that may be applicable

3.3.3 Demand Responses and Other Proposals

CAISO Tariff Section 24.2.2.1

Information regarding demand management resources (*e.g.*, amount of load impact, location, cost of the program) may be submitted to CAISO for consideration in its Transmission Planning Process. The purpose of requesting such information is to properly account for demand response resources in assessing transmission infrastructure needs. Accordingly, validated demand management programs are to be included in the CAISO's Unified Planning Assumptions. The mechanisms and standards to be applied are currently in development based on ongoing coordination between the CAISO, CPUC, CEC and other Market Participants.

3.3.4 Location Constrained Resource Interconnection Facilities (LCRIFs)

CAISO Tariff Section 24.1.3

Any party proposing an LCRIF shall include the following information in accordance with Section 24.1.3 of the CAISO Tariff:

- A description of the proposed facility, setting forth:
  - Transmission study results demonstrating that the transmission facility meets Applicable Reliability Requirements and CAISO Planning Standards
  - Identification of the most feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objectives of the proposal
  - A planning level cost estimate for the proposed facility and all proposed alternatives
  - An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans
  - The estimated in-service date of the proposed facility, and
  - A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

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- Information showing that the proposal meets the criteria outlined in Section 24.1.3.1(a) of the CAISO Tariff. This information permits the CAISO to conditionally approve the LCRIF if the following criteria are met:
  - The transmission facility is to be constructed for the primary purpose of connecting two or more Location Constrained Resource Interconnection Generators (LCRIG) in an Energy Resource Area, and at least one of the LCRIG is to be owned by an entity or entities not an Affiliate of the owner(s) of another LCRIG in that Energy Resource Area
  - The transmission facility will be a High Voltage Transmission Facility
  - At the time of its in-service date, the transmission facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF
  - That there is a need for the proposed facility. CAISO will consider the factors set forth in Section 24.1.3.4 to evaluate compliance with Section 24.1.3.1(a):

    (1) The extent to which the facility meets or exceeds CAISO Planning Standards;

    (2) The extent to which the facility has the capability and flexibility to interconnect LCRIGs in the ERA and to be converted to a network transmission facility;

    (3) Whether the projected cost of the facility is reasonable in light of its projected benefits, in comparison to the costs and benefits of other alternatives for connecting Generating Units or otherwise meeting a need identified in the CAISO Transmission Planning Process, including alternatives that are not LCRIFs. In making this determination, the CAISO shall take into account (among other factors):

    (a) The potential capacity of LCRIGs and the potential Energy that could be produced by LCRIGs in each ERA;

    (b) The capacity of LCRIGs in the CAISO's Interconnection process for each ERA;

    (c) The projected cost and in-service date of the facility in comparison with other transmission facilities that could connect LCRIGs to the CAISO Controlled Grid;

    (d) Whether, and if so, the extent to which, the facility would create a risk of stranded costs.

- For final qualification as an LCRIF project, the proponent must provide the information required by Section 24.1.3.1(b), which, in addition to all of the above information required for conditional approval, includes a showing that the following requirements have been met:

    (a) The addition of the capital cost of the project will not exceed the 15% aggregate TRR net investment cap,

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calculated at the time of CAISO's evaluation of the facility; and,

(b) The demonstration of commercial interest requirement set forth in §24.1.3.2 has been met.

3.3.5 Economic Planning Studies

CAISO Section 24.2.2.2

Requests to perform an Economic Planning Study must identify the congested transmission element (binding constraint) or limiting facilities to be studied. The request should also include reference to the Congestion Data Summary for Congestion associated with the binding constraint, if applicable, or other information supporting the potential for increased future Congestion on the binding constraint. Furthermore, requester may submit up to 2 conceptual mitigation plans along with study requests. However, for the conceptual mitigation plans to be considered, sufficient data, *i.e.*, network model, planning level cost data in accordance with section 3.3 of this BPM, and anticipated online date of the alternatives must be provided to CAISO by the closing date of Request Window.

3.3.6 Other Planning Data

The Request Window is designed to be a centralized process to accommodate not only alternative transmission proposals, but also the exchange of information for purposes of developing the Unified Planning Assumptions. Thus, the CAISO will actively solicit updated data from PTOs, other Market Participants and neighboring control areas or transmission providers, and sub-regional planning groups in order to supplement existing WECC/TEPPC data.

3.3.6.1 Information from PTOs

CAISO Tariff Section 24.2.3.1

In addition to any information that must be provided to the CAISO under the NERC Reliability Standards PTOs shall provide the CAISO on an annual or periodic basis in accordance with the schedule, procedures and in the form required by this BPM any information and data reasonably required by the CAISO to conduct the TPP, including, but not limited to: (1) modeling data for power flow, including reactive power and stability analyses; (2) a description of the total Demand to be served from each substation, including a description of any Energy efficiency programs reflected in the total Demand; (3) the amount of any interruptible Loads included in the total Demand (including conditions under which an interruption can be implemented and any limitations on the duration and frequency of interruptions); (4), a description of Generating Units to be interconnected to the Distribution System of the PTO, including generation type and anticipated Commercial Operation Date; (5) transmission system changes, including equipment replacement not requiring approval by the CAISO; (6) transmission network information, operating diagrams, including line ratings, line length, conductor sizes and lengths, substation equipment ratings, circuits on common towers and with common rights-of-ways and cross-overs, special protection schemes, and protection setting information; and (7) Contingency lists.

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3.3.6.2 Information Provided by Participating Generators

CAISO Tariff Section 24.2.3.2

In addition to any information that must be provided to the CAISO under the NERC Reliability Standards, Participating Generators shall provide the CAISO on an annual or periodic basis in accordance with the schedule, procedures and in the form required by this BPM any information and data reasonably required by the CAISO to conduct the TPP, including, but not limited to (1) modeling data for short-circuit and stability analysis and (2) data, such as term and status of any environmental or land use permits or agreements the expiration of which may affect that the operation of the Generating Unit.

3.3.6.3 Information Requested from Load Serving Entities

CAISO Tariff Section 24.2.3.3

In addition to any information that must be provided to the CAISO under the NERC Reliability Standards, the CAISO shall solicit from Load Serving Entities through their Scheduling Coordinators information required by, or anticipated to be useful to, the CAISO in its management of the TPP, including, but not limited to (1) long-term resource plans; (2) existing long-term contracts for resources and transmission service outside the CAISO Control Area; (3) resource capacity and Energy bid information received through requests for offers or similar solicitations; and (4) Demand Forecasts, including forecasted effect of Energy efficiency and Demand response programs.

3.3.6.4 Information Requested from Interconnected Control Areas, Sub-Regional Planning Groups and Electric Utility Regulatory Agencies

CAISO Tariff Section 24.2.3.4

The CAISO shall solicit from interconnected Balancing Authority Area operators and transmission providers, regional and sub-regional planning groups within the WECC, the CPUC, the CEC, and Local Regulatory Authorities information required by, or anticipated to be useful to, the CAISO in its performance of the Transmission Planning Process, including, but not limited to (1) long-term transmission system plans; long-term resource plans; (3) generation interconnection queue information; and (4) Demand forecasts.

3.4 Screening Process

3.4.1 Transmission Projects

CAISO Tariff Section 24.2.2.1

In order to ensure that the TPP proceeds in an efficient and timely manner, transmission project proposals are subject to screening criteria as set forth below:

- All data and other requested information must be complete. The CAISO will determine whether the proponent has provided sufficient information to evaluate the transmission proposal, other resource, or Economic Planning Study request. Failure to fully complete the appropriate data templates after the period allowed for supplemental submissions will constitute a failure to satisfy this requirement.

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- A proposed transmission project must connect to the CAISO Control Grid.

- Duplication – The proposals received during the Request Window must not duplicate benefits from transmission projects that have previously been approved by the CAISO. However, competing proposals received during a Request Window may be included in the Study Plan. As appropriate, the CAISO may encourage joint ownership of an optimal project that utilizes the superior features of each proposal.
- If a sub-regional or regional project that affects other Balancing Authority Areas, whether the proposal has previously been identified by the appropriate sub-regional or regional planning entity as a "preferred" solution.
- If the transmission proposal constitutes facilities to access renewable resources, whether one or more of the projects increase transfer capability with respect to a Competitive Renewable Energy Zone, Energy Resource Area, or similar designation identified through a state sanctioned entity.

3.4.2 Economic Planning Studies

CAISO Tariff Section 24.2.2.2

The screening process will generally place requests for Economic Planning Studies into one of three categories.

In each planning cycle, the CAISO will perform a maximum of five High Priority Economic Planning Studies on behalf of TPP Participants. However, the CAISO retains discretion to perform greater than five High Priority Economic Planning Studies should patterns of Congestion so warrant. High Priority Economic Planning Studies will be selected based on consideration of at least one of the following:

- Whether the requested study seeks to address Congestion identified by the CAISO in the Congestion Data Summary.
- Whether the requested study seeks to address delivery of Location Constrained Resource Interconnection Generators in an Energy Resource Area or similar designation from a state sanctioned entity.
- Whether the requested study seeks to reduce or address the need for Local Capacity Area Resources in a Local Capacity Area.
- Whether resource and Demand information indicate that Congestion described in the request is projected to increase over the planning horizon used in the Transmission Planning Process and the projected magnitude of the Congestion.
- Whether the Economic Planning Study is intended to encompass the upgrades necessary to integrate new generation resources or loads on an aggregated or regional basis.

High Priority Economic Planning Studies will be included in the Study Plan and performed by the CAISO at its cost as part of the TPP cycle. The CAISO will notify TEPPC and other sub-regional planning groups of the selected High Priority Economic Planning Studies prior to the close of TEPPC's request window on January 31st of each year. To the extent that CAISO determines particular study requests under High Priority category should impact multi controlled

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areas, these study requests will be submitted to TEPPC or the sub-regional planning group by January 31st as well.

Where the request is not designated as a High Priority Economic Planning Study and the request is regional or sub-regional in scope, the CAISO will submit the requested Economic Planning Study to TEPPC as part of its request window that closes on January 31st of each year.

Requests that are neither High Priority Economic Planning Studies nor regional or sub-regional in scope will be rejected for inclusion in the CAISO's Study Plan, but still will be submitted to TEPPC for inclusion in the consolidated list of potential studies. The submitting entity may still perform the proposed Economic Planning Study at its own cost and submit the results to the CAISO for review and potential inclusion in the final Transmission Plan. The CAISO will coordinate with any third party performing its own study to ensure that the study is consistent with the data, assumptions, and methodology employed by the CAISO.

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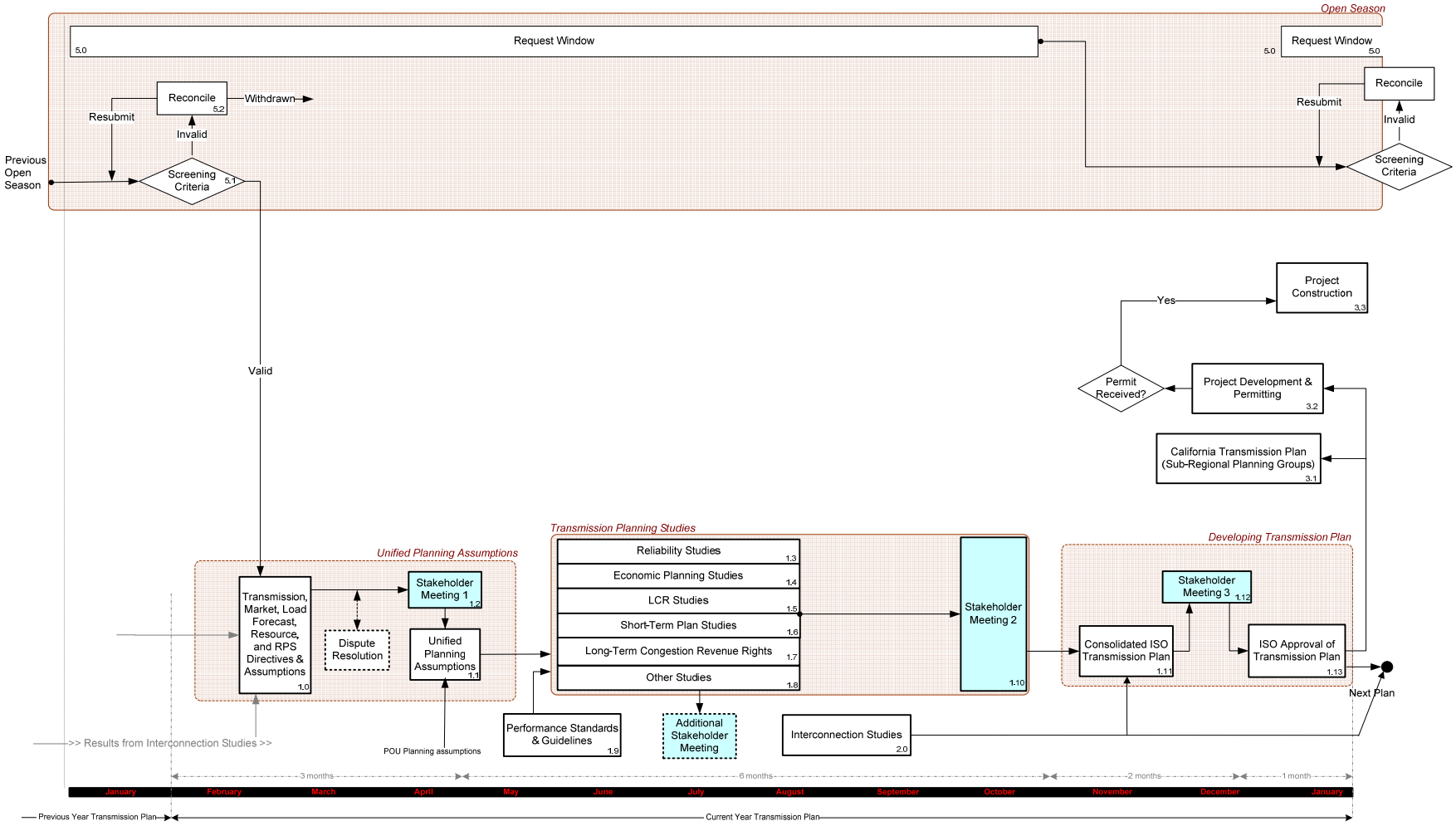

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4. Transmission Plan Development Process

Sections 4.1–4.3 below articulate the three stages of the CAISO's Transmission Planning Process in more detail.

4.1 Development of the Study Plan

Following the close of the Request Window, the CAISO will compile applicable information from the previous Request Window submissions along with the information it receives from PTOs, neighboring Balancing Authorities, regional, sub-regional planning group, state agencies, and TPP participants who respond to the data request issued by the CAISO and engage in the first stage of the TPP. *The timeframe for Stage 1 development is January through April of each year*. The objective of this stage is to determine the goals, agree on data assumptions and inputs for creation of a base case, identify necessary modifications to the base case for individual technical studies, identify the technical studies to be performed as part of the TPP cycle, and allow TPP Participants to review and comment on the scope of the upcoming technical studies. This stage creates the Unified Planning Assumptions and Study Plan.

4.1.1 Input into the Study Plan

CAISO Tariff Section 24.2.4.1

The CAISO develops the Unified Planning Assumptions that will be documented in the Study Plan using information including, but not limited to:

- Information received during the prior TPP cycle's Request Window
- Applicable Reliability Criteria and CAISO Planning Standards
- WECC/TEPPC base cases for the relevant planning horizon
- Transmission upgrades and additions approved by the CAISO and scheduled to be energized within the planning horizon
- LCRIF conditionally approved under Section 24.1.3.1(a) of the CAISO Tariff
- Network Upgrades identified pursuant to Section 25, Appendix U or Appendix W relating to the CAISO's Large Generator Interconnection Procedures and Appendix AA relating to the CAISO's Small Generator Interconnection Procedures
- Operational solutions validated by the CAISO to address Local Capacity Area Resource requirements as part of the Local Capacity Technical Study
- Real-time operational data for CAISO short-term studies
- Regulatory initiatives, as appropriate, including state regulatory agency initiated programs
- Energy Resource Areas or similar resource areas identified by the CPUC or CEC; and
- Results and analyses from Economic Planning Studies or other assessments that may have identified potentially needed transmission upgrades or additions performed in past CAISO Transmission Planning Process cycles.

4.1.1.1 CAISO Planning Standards Committee

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CAISO Tariff Section 24.2.1

The CAISO maintains a Planning Standards Committee, which shall be open to participation by all Market Participants, electric utility regulatory agencies within California, and other interested parties, to review, provide advice on, and propose modifications to CAISO Planning Standards for consideration by CAISO management and the CAISO Governing Board. The CAISO Planning Standards are Reliability Criteria that:

- address specifics not covered in the NERC and WECC planning standards
- provide interpretations of the NERC and WECC planning standards specific to the CAISO Controlled Grid, and
- identify whether specific criteria should be adopted that are more stringent than the NERC and WECC planning standards.

The Planning Standards Committee shall meet, at a minimum, on an annual basis prior to publication of the draft Unified Planning Assumptions and Study Plan. To the extent necessary, the CAISO may notice additional meetings, web conferences, and teleconferences. Meetings of the Planning Standards Committee shall be noticed by Market Notice and such notice shall be posted to the CAISO Website. Teleconference capability will be made available for all meetings of the Planning Standards Committee.

The CAISO Vice President of Market and Infrastructure Development or his or her designee shall serve as chair of the Planning Standards Committee. All materials addressed at or relating to such meetings, including agendas, presentations, background papers, and party comments shall be posted to the CAISO Website. The chair of the Planning Standards Committee shall seek approval by the CAISO Governing Board of any modifications to the CAISO Planning Standards, as those CAISO Planning Standards exist as of December 21, 2007, and must include in the report to the CAISO Governing Board a summary of the positions of parties with respect to the proposed modifications to the CAISO Planning Standards and the ground(s) for rejecting modifications, if any, proposed by Market Participants or other interested parties.

4.1.2 Process for Developing the Study Plan

CAISO Tariff Section 24.2.4.3

During the period from January through February of each year, the CAISO, in coordination with TPP Participants, will review information received and validated during the Request Window or otherwise obtained by the CAISO, to develop a draft Study Plan for the annual TPP cycle. This draft Study Plan is posted to the CAISO Website at least one week prior to the meeting and subsequently, after an opportunity for review by TPP Participants, presented at a TPP Participant public meeting for comment by early April. A Market Notice will announce the availability of the draft, solicit comments and establish a deadline for such comments, and schedule the public meeting. Comments on the draft Study Plan must be submitted to the CAISO electronically to regionaltransmission@caiso.com. All TPP Participant comments will be posted to the CAISO Website for Transmission Planning. If needed, additional public meetings, web conferences, or teleconferences may be scheduled as determined by the CAISO. Following all public meetings and by May of each year, the CAISO will publish to the CAISO Website, the final Study Plan which describes the Unified Planning Assumptions.

It should be noted that the annual Local Capacity Requirements Technical Study that sets targets for the forthcoming Resource Adequacy Compliance Year pursuant to Section 40.3 of the CAISO Tariff, will proceed separately from the development of the Unified Planning Assumptions and Study Plan. The final results of the Local Capacity Technical Study must be presented in May of

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each year. The timing of the Local Capacity Technical Study was developed in order to complete the study in sufficient time to allow Load Serving Entities sufficient time to procure necessary capacity prior to regulatory deadlines. This annual Local Capacity Technical Study will incorporate the outcome of the most recently completed Transmission Plan. Similarly, the Unified Planning Assumptions will incorporate operating procedures that affect the transmission system as identified in the Local Capacity Technical Study.

The Study Plan, however, will account for the Longer-Term Local Capacity Requirements Study that the CAISO performs to estimate Local Capacity Area Resource requirements three and five years out. The Local Capacity Technical Study Manual for the annual Local Capacity Technical Study is posted on the CAISO Website each year in October under Transmission Planning and Local Capacity Technical Study. CAISO also manages and performs technical studies on generation interconnection requests through the Large and Small Generator Interconnection Procedures (LGIP/SGIP). CAISO incorporates results from generation interconnection studies, including "Clustered" interconnection studies, in the annual Transmission Planning Process as input assumptions. As outlined in section 2.1.4, in addition to the information regarding new Generation projects, details of network upgrades and Net Qualifying Capacity resulting from generation Deliverability Assessments are key information to be included in the Transmission Planning Process.

4.1.3 Output

CAISO Tariff Section 24.2.4.2

The Study Plan describes the details of the subsequent TPP cycle. At minimum, the Unified Planning Assumptions and Study Plan (*see* Section 4.1) will include:

- Objectives – Define the goal of each technical study performed and how those studies will be used in decision-making processes.
- Summary and roadmap of CAISO TPP for the current cycle:
  - Preliminary schedule for TPP Participant activities for the remaining TPP
  - Instructions for TPP Participants to receive notifications or communication, and to provide comments to the CAISO
  - Website locations where TPP information will be available and instructions regarding any steps necessary to gain access to such information
  - CAISO contact information for each study and the TPP
- Planning data:
  - Demand forecasts – values, source of the Demand forecasts, and methodology to derive Demand forecasts and any adjustments to original forecast as necessary to perform a particular technical study
  - Generation assumptions – values, source of generation data, modeling of generation, description of generation dispatch methodology, and any adjustments to the foregoing as necessary to perform a particular technical study
  - Generation retirement – values, source of generation retirement data, and list of generation retirement modeled in the studies
  - Transmission Projects – Source of transmission project information and list of transmission projects modeled in the studies. These generally include the CAISO-approved transmission projects from the previous CAISO Transmission Plans.

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- Import – values, source of import data, and methodology, and any adjustments to the foregoing as necessary to perform a particular technical study.

- Planning studies:
  - List of all technical studies, including High Priority Economic Planning Studies, to be done for incorporation into the Transmission Plan or Transmission Planning Process generally, *i.e.*, technical studies that may not be completed by the publication date of the Transmission Plan
  - For each study, explain:
    - Study assumptions (*e.g.*, study year, planning data applied to each technical study, any modifications to be made).
    - To the maximum extent possible, based on TPP Participant input, identified sensitivity analyses and project or solution alternatives to be included in each technical study, as appropriate
    - Methodology – describe how the study will be performed
    - Criteria – reliability or criteria applied to each study
    - Software – list software and tools for the study
    - Entity to perform the study or elements of the study.

- Comments received from TPP Participants, and CAISO responses thereto regarding the draft Unified Planning Assumptions and Study Plan.

An overview of the Unified Planning Assumption and Study Plan development is shown in Figure 4.

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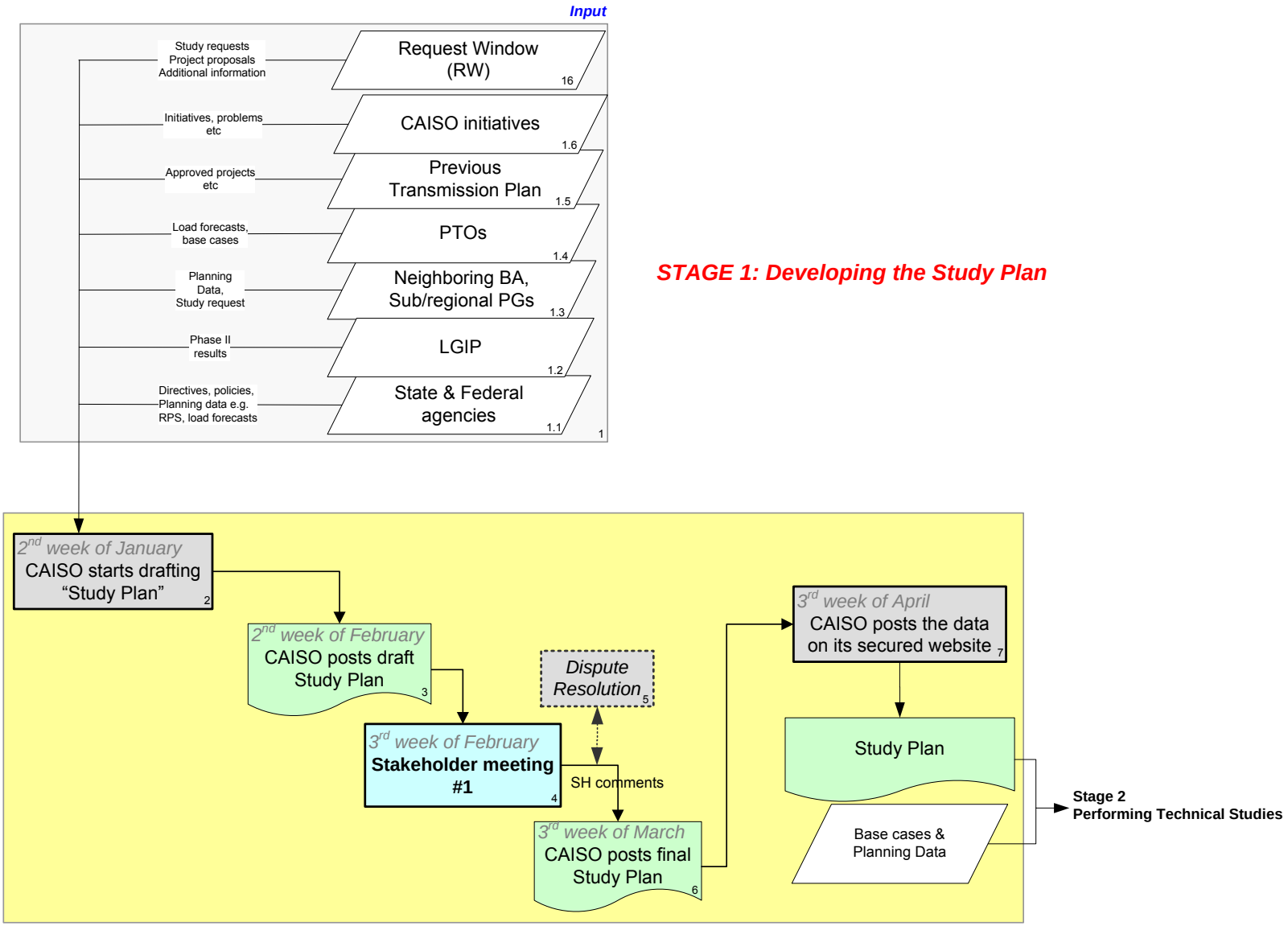

Figure 4: Developing the Study Plan

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4.2 Performance of Technical Studies and Other Necessary Review Procedures

As indicated by the outline of the Study Plan, each TPP cycle will conduct a number of technical studies to meet TPP Participant objectives. The technical studies provide the bases for identifying potential physical and economic limitations of the CAISO Controlled Grid and potential upgrades to maintain or enhance system reliability, promote economic efficiency, maintain the feasibility of Long Term CRRs for the length of their terms, while also seeking to promote other policy objectives. These assessments involve, but are not limited to, the following technical studies:

- Power Flow Simulation – The study focusing on equipment thermal loadings and voltage magnitudes in the system at a specific study scenario
- Stability Analysis – Assessments of system responses during the transient period after disturbances or small signal stability of the system under various scenarios
- Voltage Stability – Analysis of reactive power sufficiency to ensure reliable system conditions under different system conditions and disturbances. Power flow and stability are primary technical studies in reliability assessment
- Short-Circuit – The study to be performed as part of interconnection process which focuses on the system's capability to withstand major short-circuits
- Economic Planning Studies (production cost simulation) – Assessments of future market conditions based on the historical input and future plan. The study concentrates on identifying potential congestions and mitigation plans that could relieve or eliminate the congestions
- Long Term Congestion Revenue Rights Feasibility Study (LTCRRs) – A Simultaneous Feasibility Test (SFT) will be performed to ensure that allocated Long Term CRRs will still be feasible according to their allocation.
- Long-Term Projected Local Capacity Requirement (LCR) Study – The study, which relies primarily on power flow analysis, determines capacity requirements in Local Capacity Areas over a projected 3-5 year planning horizon. The Local Capacity Technical Study, not the Long-Term LCR Study, establishes effective Local Capacity Area Resource requirements for the next Resource Adequacy Compliance Year.
- Short-Term Plan Study – The study analyzes recent system conditions and proposes upgrades or other recommendations based on the experience of CAISO system operators. This is similar to the Operating Guide which is the informational guideline for CAISO grid operations regarding possible impacts of new transmission projects and the need to revise existing—or develop new—operating procedures.
- Generation Interconnection – The results of the Phase II LGIP studies will be coordinated with this TPP as described above in Section 2.1.4.
- Other studies – From time to time, specific technical studies may be included in the Transmission Plan. These studies address special issues in addition to the scope of the other annual studies, such as long-term plans for particular areas or renewable resource integration studies

The technical studies are required, to the maximum extent practicable, to utilize the Unified Planning Assumptions and any deviations must be documented in the preliminary results of the

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technical study. Results from the technical studies will be measured against the following planning standards to quantify system performance. The following reliability criteria violations will be used as fundamental to justify transmission upgrades:

- NERC Planning Standards
- WECC Planning Standards
- CAISO Planning Standards

For the evaluation of projects proposed to promote economic efficiency, the CAISO relies on criteria defined in Transmission Economic Assessment Methodology (TEAM) and other practices adopted by the industry to justify economic benefits of the proposals. Principles underlying TEAM may be found on the CAISO Website at http://www.caiso.com.docs/2004/06103/2004060313241622985.pdf and http://www.caiso.com/184b/184bd6cc2d70.html.

This second stage of the planning process is summarized in Figure 5.

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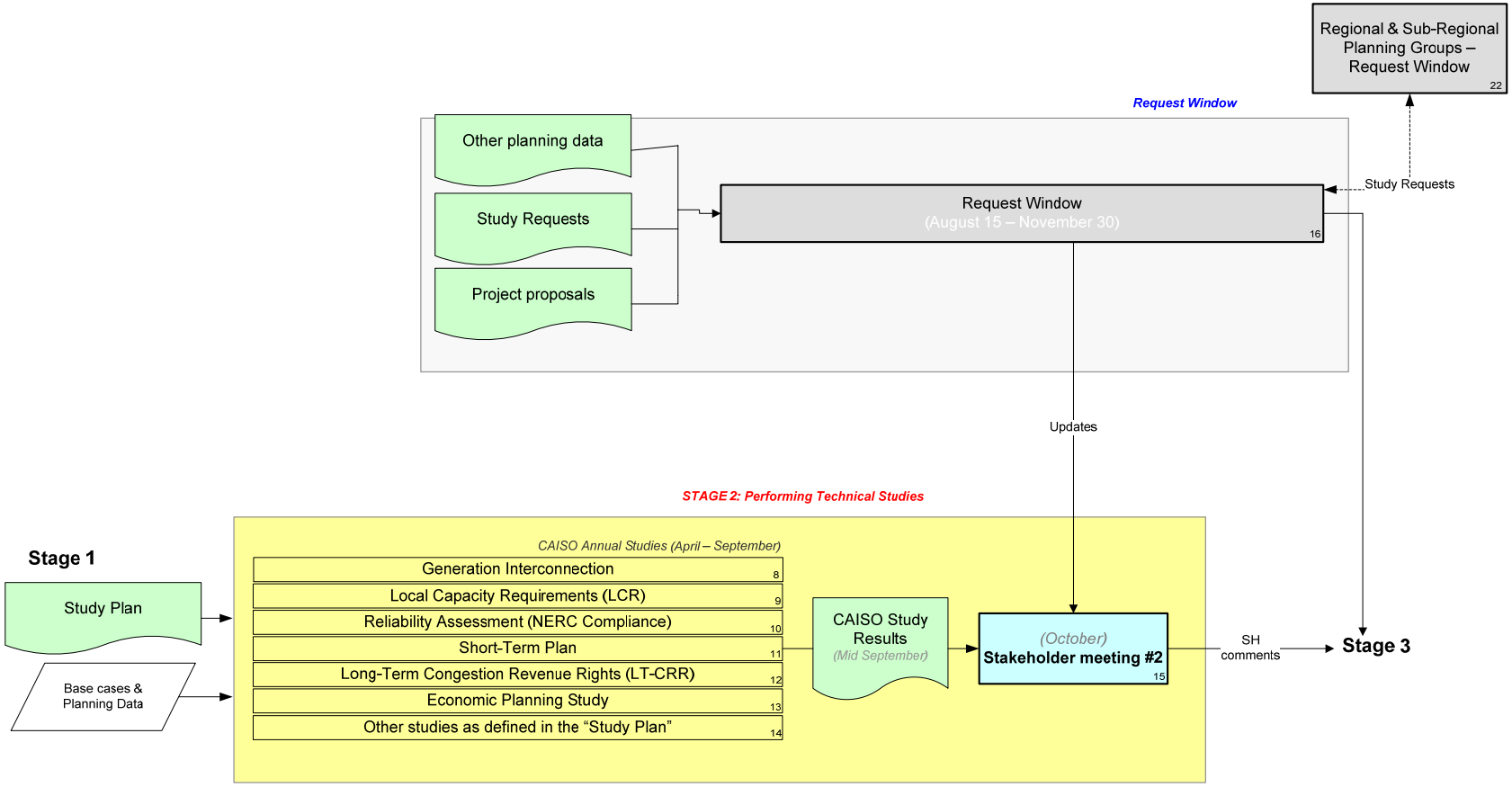

Figure 5: Performing Planning Studies

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Based on resource considerations, technical expertise, and the roles of PTOs with PTO Service Territories as NERC Transmission Planners, the CAISO may assign technical studies or portions of technical studies to Project Sponsors or the PTOs to perform. Similarly, the CAISO may seek the voluntary commitment of other market participants to perform technical studies or portions thereof.

Once the responsible entities have completed the technical studies, the preliminary results will be presented to TPP Participants during one or more additional TPP Participant meetings to be held in the fall of each year.

4.2.1 Determining Reliability Projects

CAISO Tariff Section 24.1.2

Reliability projects will be identified and justified using the following study tools identified in Section 4.2:

- Power Flow
- Transient Stability
- Voltage Stability

As required by applicable planning standards, technical studies must be performed on both the short-term (up to five years) and long-term (≈ ten years or more) under various stress conditions (*e.g.*, summer peak), while considering the impact from losing critical system elements. Thresholds for demonstrating compliance with these standards are included in the NERC reliability standards e.g. the summary in Table 1 of the Standard TPL-001-0 — System Performance Under Normal Conditions document, located at http://www.nerc.com/page.php?cid=2|20.

As indicated in the Study Plan, reliability assessments may be performed by PTOs with a PTO Service Territory as a component of their role as a NERC designated Transmission Planner. While these assessments may be performed by the PTOs, the assessments must utilize the Unified Planning Assumptions, except as otherwise justified and documented. Accordingly, as part of the plan to maintain reliability and serve Load within the CAISO Balancing Area Authority, the CAISO anticipates receiving each year power flow and stability study results from PTOs with PTO Service Territories, along with the comparison between these results and the reliability standards. If criteria violations have been identified, mitigation plans to address the violations will be proposed by the PTOs as part of the October 15 submission by the PTOs, described in previous sections of this BPM. PTOs must propose alternatives to address each criteria violation to assess the efficiency and effectiveness of the competing alternatives. Each alternative should set forth a sufficient description of the upgrades, costs, schedules, impacts on the grid, and other information related to the alternative.

The CAISO relies on the following guidelines for approving proposals as the appropriate solution:

- Need – The analysis shows violations of reliability criteria that require mitigation to be in place to ensure compliance of reliability standards.
- Sufficient Data – Sufficient information on each of the mitigation proposals to be evaluated compared with other alternatives. For example, project scope, descriptions, cost estimate

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of the proposals and alternatives, benefits (*e.g.* reliability criteria violations will be mitigated by the proposals), and scheduled in-service date are necessary information that must be provided to CAISO.

- Technically Sound – The suggested alternatives demonstrate an ability to eliminate the violation(s) based on a technically sound approach. This requires the PTO to demonstrate that the proposed alternative utilizes technology that has been accepted by the industry. In cases where a new technology has been proposed as a preferred alternative, sufficient proof demonstrating that the alternative will work reliably, efficiently, and comply with all applicable standards will be required as part of the approval process.
- Cost-Effective – The preferred alternative must be an economically efficient approach to resolve criteria violations. Generally, this requires a least-cost solution. However, in some circumstances, least-cost solutions may not be selected or recommended if the CAISO finds that another approach appears to be more prudent. For example, if the analysis identifies that several criteria violations in the same vicinity can be anticipated in the future, the CAISO may recommend a construction of capital projects to eliminate all violations at the same time rather than incrementally addressing each violation in a potentially piece-meal fashion. This approach tries to avoid expenditures on redundant upgrades which may result in higher costs to the ratepayers.

CAISO management may approve proposals with an estimated capital cost of $50 million or less, while the CAISO Governing Board must approve proposals with an estimated capital cost of greater than $50 million, including Large Projects studied through a separate TPP Participant process. Moreover, for those proposals that must receive CAISO Governing Board approval, factors in addition to the reliability benefits may be considered as part of the recommendation and approval process, including, but not limited to:

- Economic advantages from mitigating congestion
- Reducing Local Capacity Area Resource requirements
- Operational flexibility
- Environmental benefits

4.2.2 Determining Economically Efficient Projects

4.2.2.1 Economic Planning Studies

CAISO Tariff Section 24.9

The CAISO Economic Planning Studies focus on identifying expected Congestion and other transmission element constraints and exploring potential mitigation plans for such bottlenecks on the grid. This will be accomplished by simulating future system conditions along with the observation of the Congestion that occurred in the past operating years, Local Capacity Area resource requirements, and other expected grid conditions consistent with the Unified Planning Assumptions, including use of the WECC base case for economic studies. The CAISO may also consider other data submitted through the Request Window, such as the long-term power supply plans for Long-Term CRR purposes. The studies utilize production simulation cost software using Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED) to determine market conditions. The framework to quantify potential benefits will be consistent with CAISO's TEAM approach.

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The mitigation plans recommended from the studies which include the High Priority Economic Planning Studies will consider: 1) expansion or acceleration of previously approved transmission projects; and 2) new proposed upgrades or conceptual projects that can relieve the constraint. In order to efficiently manage the requests, CAISO will try to maximize the use of a batch or cluster approach to perform the High Priority Economic Planning Studies. In this case, one High Priority study may represent one batch or cluster of study.

The CAISO intends to coordinate High Priority Economic Planning Study efforts with sub-regional planning groups and TEPPC at the regional planning level. This collaboration emphasizes assigning Congestion-related studies to the proper forum. For example, Congestion observed in the CAISO Balancing Authority Area may impact multiple entities and should be addressed on a sub-regional or regional basis.

In each annual TPP cycle, the CAISO will conduct a maximum of five High Priority Studies as requested by TPP Participants during the Request Window period. However, the CAISO may elect to perform additional High Priority Studies should Congestion or other system conditions warrant such studies. TPP Participants will have the opportunity to comment on selected High Priority Studies during the development of the Study Plan which will be presented to the TPP Participant during the first public meeting. The CAISO's performance of Economic Planning Studies also coordinates with sub-regional and regional planning processes as described below.

In general, the Economic Planning Study process involves three major steps:

- Step 1: Publication of the Congestion Data Summary that provides information on Congestion on the CAISO Controlled Grid[11] and specifically identifies Significant and Recurring Congestion. This step occurs by mid-September of each year and is intended to provide information to TPP Participants to assist with Economic Planning Study requests during the Request Window. Due to the possibility that results from grid operations during the past 12 months period may reflect a large number of congestion locations, CAISO intends to use the criteria in this step to filter out and provide a shorter list of major congestions that may beneficial to TPP Participants. Significant and Recurring congestion is identified for the following scenarios:
    - Congestion during the past 12 months ending September 1.
    - Congestion during a 10-year planning horizon simulation. CAISO-approved reliability transmission projects and future system conditions will be modeled in these studies to ensure the impact from reliability projects is reflected in any resulting Economic Planning Study.

  Significant and Recurring Congestion is determined by the cost and duration of the Congestion as follows:

    - Congestion that costs more than 5 million dollars,
    - Congestion that occurs more than 8 percent of the time[12]

[11] The compilation and publication of congestion data will begin upon implementation of the new market design (Market Redesign and Technology Upgrade – MRTU) to enable the performance of Economic Planning studies using production cost simulation software based on the CAISO TEAM methodology.

[12] However, due to the transition to a new market environment based on Locational Marginal Prices under the Market Redesign and Technology Upgrade (MRTU), if future congestion under MRTU appears to be significantly different from the past and other means to quantify Significant and Recurring congestion appear to be more appropriate, the CAISO may propose different criteria to address this issue.

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- Step 2: Select High Priority Studies. The criteria used to make this determination are similar to the criteria set forth in Sections 2.1.2.1 and 3.4.2 of this BPM. In this context, the cost of the congestion is the primary selective criterion while the duration of the congestion shall be used as a tiebreaker. The CAISO's selection of the five High Priority Studies will be discussed during the first CAISO TPP Participant meeting to address the Unified Planning Assumptions and Study Plan.

  In addition to studies addressing congestion, Economic Planning Study requests seeking to integrate new generation resources or loads on an aggregated regional basis also can be selected as High Priority Studies. Under such circumstances, the study requesters must provide sufficient information about the new generation resources or load as part of the Request Window submission.

- Step 2a:- The CAISO will use the following guidelines to cluster or batch multiple study requests it receives from the Request Window:
  - Several study requests can be assigned to the same cluster if they address the same congestion
  - If several study requests address different congestion but the congestion is related to each other, the study can be assigned to the same cluster
  - Several study requests for integrating new generation resources or loads that impact the same facility(ies) can be assigned to the same cluster

  During the process of selecting the High Priority Studies, a cluster of study requests shall be treated as equivalent to one study request. Therefore, more than five study requests may be selected as High Priority Studies if a cluster is chosen during this process.

- Step 2b – All Economic Planning Study requests are communicated to TEPPC by January 31st as part of that organization's request window. The CAISO will earmark those that it has identified as High Priority Studies that will be conducted by the CAISO. Other Economic Planning Study requests with a regional or sub-regional scope will be considered by TEPPC as part of its congestion study process.

- Step 2c – The CAISO will fully participate in the TEPPC congestion study process and may alter the scope of any selected High Priority Study to effectuate any identified efficiencies resulting from "clustering" or combining study requests received by TEPPC. However, consistent with TEPPC principles, the CAISO anticipates taking responsibility for performing, completing and communicating the results of all High Priority Studies whether or not modified.

- Step 2d – To the extent non-High Priority Studies are not determined by TEPPC to be high priority for regional or sub-regional study, the CAISO will so notify the submitting entity and such submitting entity may elect to perform the proposed Economic Planning Study at its own cost. The CAISO will coordinate with any third party performing its own study to ensure that the study is consistent with the data, assumptions, and methodology employed by the CAISO.

- Step 3: Evaluate Congestion Mitigation Alternatives: In this step, the CAISO identifies or evaluates potential plans to mitigate the Congestion studied in each High Priority Economic Planning Study. Each study analyzes up to 2 mitigation plans for future year scenarios. Study results will be presented to TPP Participants during the second public

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meeting to address technical study preliminary results and during the third meeting to address the draft Transmission Plan. The results from studies conducted by third parties may be submitted to the CAISO for review and potential inclusion in the final Transmission Plan.

The overview of the Economic Planning Study process is shown in Figure 6.

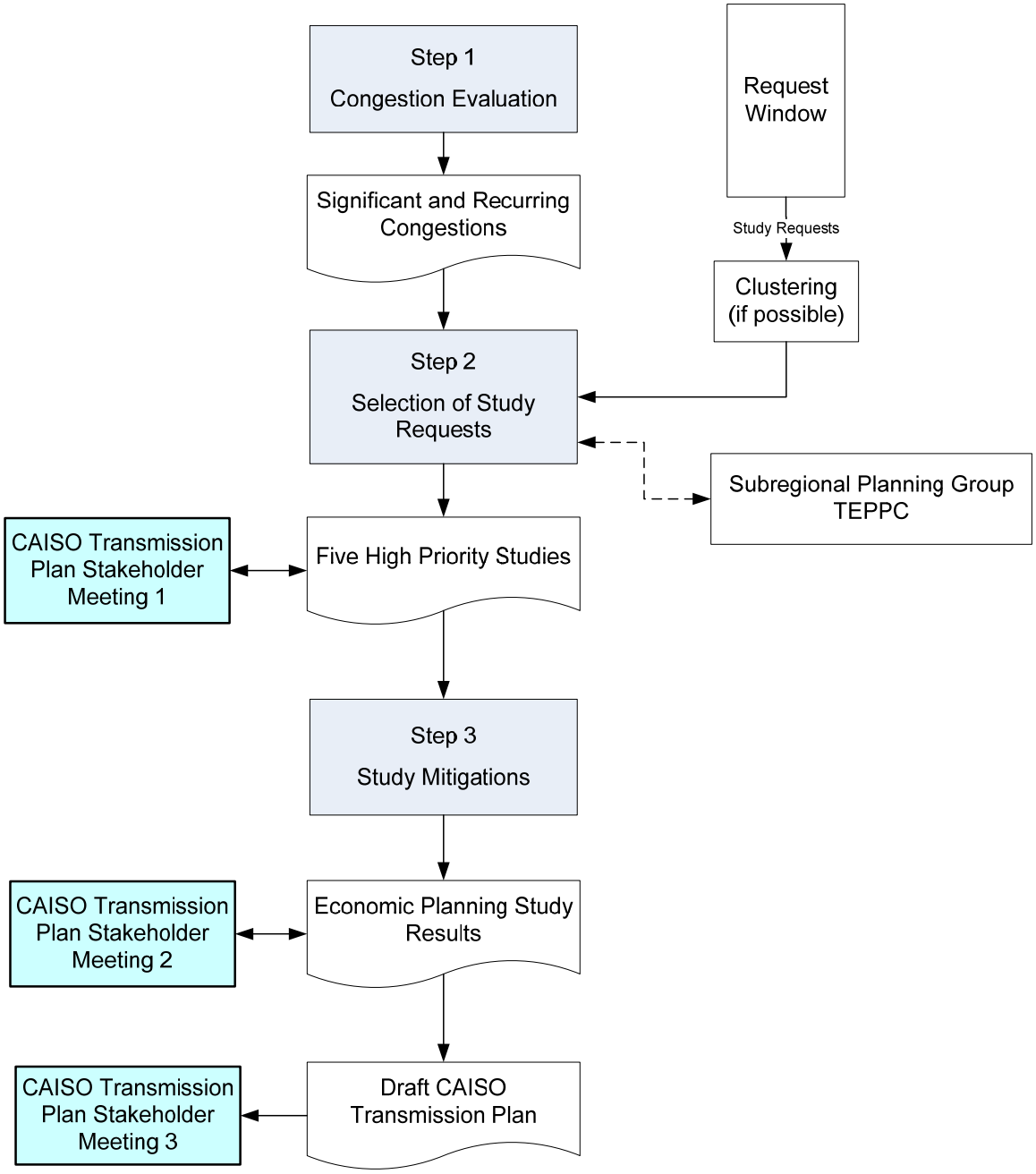

Figure 6: Overview of Economic Planning Study

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4.2.2.2 Technical Assessment for Specifically Proposed Economic Projects

CAISO Tariff Section 24.1.1

At the end of Request Window, when all valid project proposals have been collected, the following technical assessments will be conducted for each proposed economic project in the Study Plan as part of project evaluation:

- Power Flow – Determine thermal loadings on facilities and bus voltages due to the implementation of the project. Study results will be compared with applicable reliability standards to ensure system performance will meet reliability criteria
- Stability Analysis– Capability of the system to meet applicable reliability standards during various conditions, such as after disturbances
- Short-Circuit Study – Capability of the system to withstand faults
- Economic Study – Determine potential impact on system operating conditions and cost-benefits of the project (for TAC projects)
- Simultaneous Feasibility Test (SFT) – Determine amounts and source-sink combinations of incremental CRRs due to the project (for Non-TAC projects)

4.2.3 Determining LCRIF

CAISO Tariff Section 24.1.3

The requirements for approval or conditional approval of a LCRIF are set forth in detail in 24.1.3 of the CAISO Tariff and in Section 3.3.4 above.

4.2.4 Determining Projects to Maintain Long-Term Congestion Revenue Rights

CAISO Tariff Section 24.1.4

The CAISO expects that released Long Term CRRs (LT-CRRs) will remain feasible during their full term. This expectation is based on the fact that the transfer capacity of existing grid facilities will be reduced to 60 percent of the normal ratings for the release of LT-CRRs, as well as the expectation that most proposed transmission upgrades will reduce Congestion; that is, the flows on binding constraints will be reduced or the flow capability through constrained facilities will be increased. However, for those infrequent changes to the transmission system that could result in substantial adverse impacts on binding constraints and cause infeasibility in certain LT-CRRs, the CAISO plans to perform an annual Simultaneous Feasibility Test (SFT) analysis to identify this outcome. In such instances, the Transmission Planning Process identifies potential ways to mitigate the adverse impacts, to be considered in conjunction with the overall Transmission Plan.

This new technical study, consisting of Simultaneous Feasibility Tests, will be integrated in the CAISO TPP and will be performed in the context of (a) planned or proposed transmission projects; (b) Generating Unit or transmission retirements; (c) Generating Unit interconnections; and (d) the interconnection of new Load. In assessing the need for transmission additions or upgrades to maintain the feasibility of allocated Long Term CRRs, the CAISO, in coordination with the PTOs and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, Demand-side management, Remedial Action Schemes, constrained-on Generation, interruptible

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Loads, reactive support, or in cases where the infeasible Long Term CRRs involve a small magnitude of megawatts, ensuring against the risk of any potential revenue shortfall using the CRR Balancing Account and uplift mechanism in Section 11.2.4 of the CAISO Tariff.

4.2.5 Merchant Transmission Process

CAISO Tariff Sections 24.1.1 and 36.11

Currently, any Market Participant, group of Market Participants or PTO may act as a Project Sponsor to identify a possible transmission upgrade and seek its incorporation into the CAISO Transmission Planning Process for ultimate approval and construction. A Project Sponsor may elect to pursue the transmission upgrade or addition as a Merchant Transmission Facility. A Merchant Transmission Facility is a transmission upgrade or addition that is part of the CAISO Controlled Grid where the Project Sponsor does not seek a regulated rate of recovery, but rather funds the project itself and recovers its costs through an allocation of incremental Merchant Transmission CRRs. A Merchant Transmission Facility will be deemed "needed" by the CAISO upon satisfaction of three elements:

- Mitigation of operational concerns identified under CAISO Tariff Section 24.5
- Mitigation of any impact from the proposed project that impairs the continuing feasibility of allocated Long Term CRRs over the length of their terms
- Proof that the Project Sponsor is financially able to pay the construction and operating costs of the Merchant Transmission Facility by requiring (1) a demonstration of creditworthiness (*e.g.* an appropriate credit rating), or (2) sufficient security in the form of an unconditional and irrevocable letter of credit or other similar security sufficient to meet its responsibilities and obligations for the full costs of the transmission addition or upgrade.

Accordingly, the CAISO and affected Participating TOs will perform technical studies to determine whether and how the project can be safely and reliably integrated with the CAISO Controlled Grid. Further, detailed Facilities Studies are performed by the Participating TOs with PTO Service Territories who own the existing transmission facilities to which the new project would interconnect, and these studies are performed at the expense of the Project Sponsor pursuant to provisions of the Transmission Owner Tariff of the applicable Participating TO.

4.2.6 Long-Term Local Capacity Requirements Study

CAISO Tariff Sections 24.2, 24.2.4, and 24.1.1

In each planning cycle, the CAISO conducts technical studies to evaluate Local Capacity Area Resource needs under the following scenarios:

- Local Capacity Technical Study – Determines the Local Capacity Area Resource needs for the next Resource Adequacy Compliance Year.
- Long-Term Local Capacity Requirements (LCR) Study – Evaluates Local Capacity Area Resource needs on a 3 and 5 year planning horizon.

The Local Capacity Technical Study is used to implement that assignment of Local Capacity Area Resource responsibility under Section 40.3 of the CAISO Tariff. The Long-Term LCR Study provides Market Participants with information to utilize in the Transmission Planning Process or in

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their individual procurement activities. Both studies assess the minimum level of capacity needed to ensure reliable CAISO Controlled Grid operation under peak Demand conditions consistent with NERC and WECC standards and CAISO Planning Standards. The studies also evaluate the existing local areas and potentially identify the changes in local areas or sub-areas definitions due to the impacts from system topology changes. Both studies utilize a similar methodology, but evaluate different time horizons. Detailed study assumptions, methodology, tools, and other information necessary for the studies are found in the Local Capacity Technical Study Manual posted to the CAISO Website at Transmission Planning.

4.2.7 Preservation of Generation Deliverability

CAISO Tariff, Appendix U, Section 3.3

The CAISO uses the deliverability analysis embodied in its Interconnection procedures to ensure that new Generation does not degrade the deliverability of existing resources. This mechanism generally maintains the stability of Net Qualifying Capacity (NQC) ratings for a given existing resource. Generally, economically and reliability driven transmission upgrades will enhance generation deliverability. However, a transmission project could potentially degrade the deliverability of one or more generation projects. During the development and review of transmission project proposals, the potential for adverse impacts on generation deliverability will be assessed by the CAISO and the estimated cost impacts associated with the reduction in NQC will be considered in the analysis of project alternatives.

4.3 Project Approval Process and Development of CAISO Transmission Plan

CAISO Sections 24.2.5.2 and 24.2.5.3

Stage 3 of the TPP involves approval of the projects being proposed for CAISO through the Request Window, the development of the CAISO Transmission Plan and presentation of the Transmission Plan to the CAISO Governing Board. The timeframe for this activity is December through February.

4.3.1 Timeframes for Project Approvals

Depending on the costs and voltage levels of the proposed projects, project approval will be granted through one of the following mechanisms:

- A project with capital costs that are less than $50 Million may be approved by CAISO management during TPP Stage 3. Such projects will be presented for approval to the CAISO Executive Leadership Team (ELT) at the first meeting scheduled after the stakeholders have had an opportunity to review and comment on the draft Transmission Plan and prior to the presentation of the Transmission Plan to the CAISO Governing Board According to the TPP timeframe set forth at Section *** above, this will be the February ELT meeting.
- A project with capital costs greater than $50 Million that has been identified during TPP Stage 2 but has not been designated as a Large Project may be presented to the CAISO Board of Governors for approval. Once the CAISO management has received sufficient information to certify that the project is justifiable and ready to be submitted to the board,

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the tentative schedule of the CAISO Board of Governor's meetings that each project will be presented to the board will be documented in the Transmission Plan.

- A project that qualifies as a Large Project (transmission upgrade or addition, or substation and related facilities, of 200 kV and above with capital costs greater than $200 Million) will require comprehensive studies and may be evaluated through a separate public process that would qualify the CAISO economic evaluations for a rebuttable presumption of reasonableness if submitted to the CPUC as evidence of electrical need for the project during the CPCN approval process. The evaluation process for Large Projects may span more than one planning cycle. Large Projects will be submitted to the CAISO Board of Governors for approval in accordance with the public process established for that project.

4.3.2 Development and Content of the Transmission Plan

The CAISO will develop a draft CAISO Transmission Plan report based on the final study results from Stage 2 and CAISO management approval of projects with capital costs of less than $50 million. The draft Transmission Plan report will be presented to TPP Participants for review and comment during the 3rd CAISO public meeting. The CAISO will independently provide the draft Transmission Plan to representatives from neighboring transmission providers or interconnected Balancing Authority Areas and sub-regional and regional planning groups for input and to facilitate transmission expansion coordination. After collecting TPP Participant comments on the draft Transmission Plan, which will be posted to the CAISO Website, the Transmission Plan will be finalized and scheduled for presentation to the CAISO Governing Board. Upon presentation of the Transmission Plan to the CAISO Governing Board, the CAISO will post the Final CAISO Transmission Plan on the CAISO Regional Transmission Webpage under Transmission Planning and deliver the CAISO Transmission Plan to sub-regional and regional planning groups.

The draft and final Transmission Plan may include, but is not limited to:

- The results of technical studies performed under the Study Plan;
- Determinations, recommendations, and justifications for the need for identified transmission upgrades and additions;
- Assessments of conceptual transmission upgrades and additions for which need has not been formally determined by the CAISO Governing Board or management, but which have been identified by the CAISO as potential solutions to transmission needs studied during the Transmission Planning Process cycle;
- Results of Economic Planning Studies and other studies conducted by CAISO during the Transmission Planning Process cycle;
- Updates on the status of transmission upgrades or additions previously approved by the CAISO, including identification of mitigation plans, if necessary, to address any potential delay in the anticipated completion of an approved transmission upgrade or addition;
- Updates on other key issues related to transmission planning activities i.e., new and ongoing initiatives; and
- The Board approval schedule for transmission upgrades and additions with capital costs of over $50 million that have been recommended for approval by the CAISO.

Figure 7 shows an overview of Stage 3 for the CAISO Transmission Plan.

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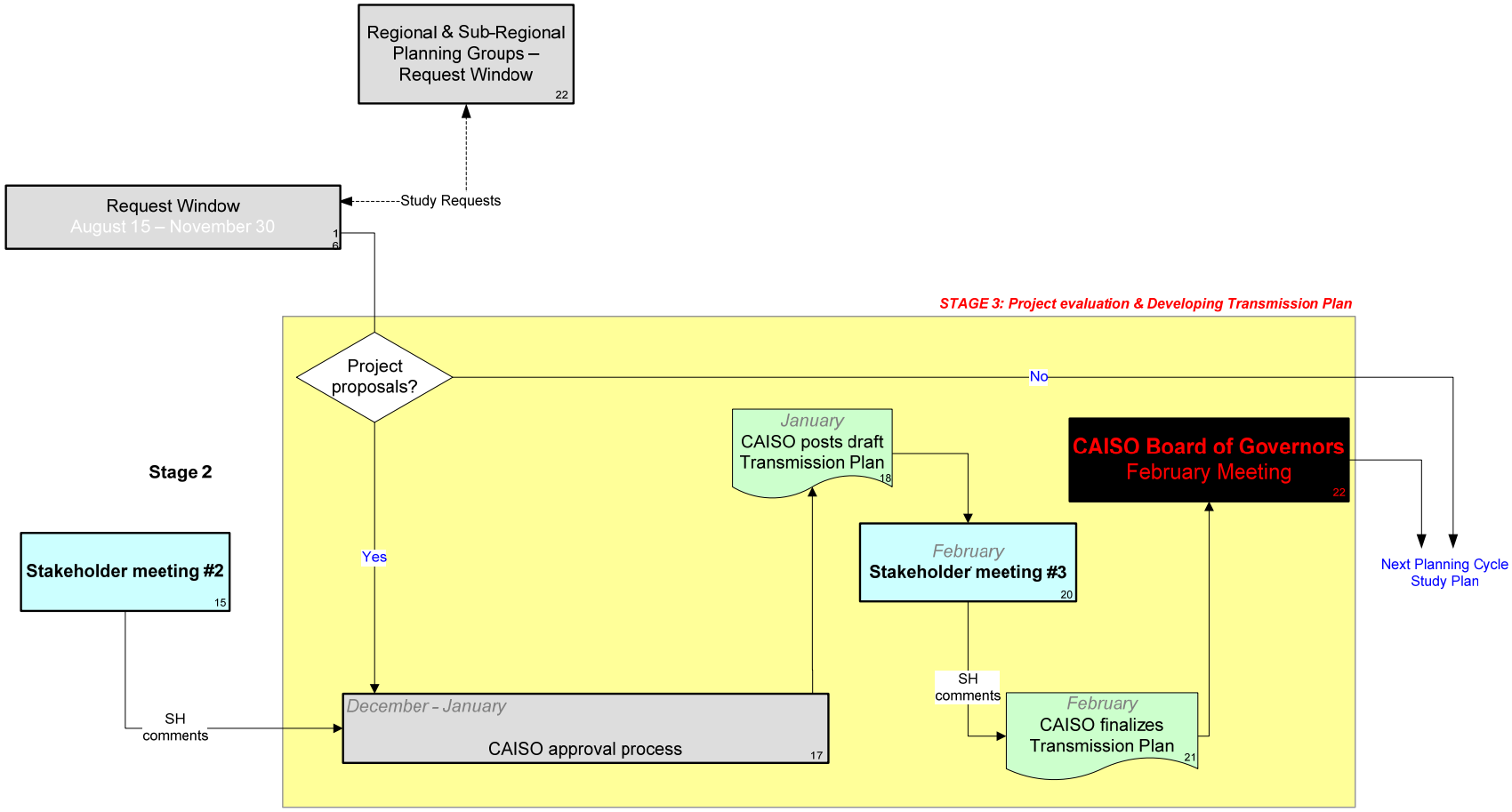

Figure 7: Development of CAISO Transmission Plan

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5. Regional Coordination

To enhance the ongoing coordination efforts with neighboring transmission providers and regional and sub-regional organizations, as a component of the CAISO's Transmission Planning Process, the CAISO acts as an initiator, organizer, and participant in relevant forums for sub-regional and regional transmission planning. This section explains the CAISO's coordination with interconnected systems at both the sub-regional and regional levels.

5.1 Sub-Regional Coordination

CAISO Tariff Section 24.8

Ensuring regional coordination through a robust sub-regional planning process is an important objective of the CAISO's Transmission Planning Process. The CAISO will enhance its existing provisions regarding coordination within the WECC by including specific requirements to exchange information with sub-regional planning groups and, in their absence, directly with interconnected transmission providers. The CAISO is currently pursuing a bifurcated approach. First, the CAISO's Transmission Planning Process itself offers an open, transparent, and structured opportunity for interconnected neighbors to exchange planning information and objectives. Second, the CAISO is participating in the development of a Pacific Southwest Planning Association (PSPA), which hopes to encompass most of the transmission systems in California. Through either of these means, the CAISO will satisfy its requirement that transmission providers coordinate with neighboring systems to ensure simultaneous feasibility of their respective plans and assess the possibility of efficiencies through mutual cooperation.

Until a California sub-regional planning group is created and participant responsibilities defined, the CAISO will perform the transmission planning functions for its Balancing Authority Area in accordance with Section 24 of the CAISO Tariff and this BPM. However, the CAISO will continue to collaborate with representatives from adjacent transmission providers and existing sub-regional planning organizations through existing processes. At a minimum, the CAISO shall:

- solicit the participation, whether through sub-regional planning groups or individually, of all interconnected Control Areas in the development of the Unified Planning Assumptions and Study Plan and in reviewing the results of technical studies performed as part of the TPP in order to:
    - (1) coordinate, to the maximum extent practicable, planning assumptions, data and methodologies utilized by the CAISO, regional and sub-regional planning groups or interconnected Control Areas;
    - (2) ensure transmission expansion plans of the CAISO, regional and sub-regional planning groups or interconnected Control Areas are simultaneously feasible and seek to avoid duplication of facilities.
- coordinate with regional and sub-regional planning groups regarding the entity to perform requests for Economic Planning Studies or other Congestion related studies;
- transmit to applicable regional and sub-regional planning groups or interconnected Control Areas information on technical studies performed as part of the CAISO Transmission Planning Process;

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- post on the CAISO Website links to the planning activities of applicable regional and sub-regional planning groups or interconnected Control Areas.

In order to effectively work together with neighboring transmission providers and other regional planning entities, the CAISO shall expressly request the participation of the proposed interconnected transmission providers and other entities in providing information during the Request Window, participating in the creation of the Unified Planning Assumptions and Study Plan, and reviewing study results and draft Transmission Plans. Requests for participation will be sent directly through electronic means to identified transmission planning representatives of entities, including, but not limited to:

- WestConnect Sub-Regional Groups
- Los Angeles Department of Water and Power
- ColumbiaGrid
- The Northern Tier Transmission Group
- The Northwest Transmission Assessment Committee of the Northwest Power Pool
- SWAT (Southwest Area Transmission)
- WATS (Western Arizona Transmission Studies)
- RETI (Renewable Energy Transmission Initiative)
- Arizona BTA (Biennial Transmission Assessment)

The CAISO will also participate, as appropriate, in the planning activities of the foregoing entities and provide any information requested to facilitate those activities (subject to confidentiality limitations).

Through this interim collaboration, the CAISO intends to:

- Exchange information such as Transmission Plan and other information
- Ensure transmission expansion plans from neighboring transmission providers and the CAISO are simultaneously feasible and maximize the efficiency of infrastructure investment
- Communicate major activities that may impact respective control areas
- Coordinate requests for planning or economic studies that appear to impact more than one control area.

5.2 Regional Coordination

CAISO actively participates at the WECC through various WECC committees such as the Board of Directors, Planning Coordination Committee, Operations Committee, and the TEPPC (Transmission Expansions Planning Policy Committee), among other subcommittees or workgroups. Through this participation, the CAISO seeks to:

- Exchange information, such as supplying data for the TEPPC data base and notifying WECC of potential projects that may impact multiple entities
- Participate in regional technical studies, such as the WECC path rating process

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- Participate in the review of proposed reliability and economic projects that may have regional impact
- Potentially refer to TEPPC requests for economic studies that impact multiple sub-regions
- Cooperate in development and maintenance of the use in Transmission Planning analysis, including power flow, stability, dynamic voltage, and economic studies (*i.e.*, production cost simulation)
- Obtain policy guidelines and standards and software recommendations to maximize uniformity in the west-wide Transmission Planning Process
- Obtain path ratings for approved projects, when appropriate.

6. Obligation to Build

CAISO Tariff Sections 24.1.1, 24.1.2, 24.1.4, and 24.6

Sections 24.1.1, 24.1.2, 24.1.4 of the CAISO Tariff govern the assignment of responsibility to construct needed transmission facilities proposed by CAISO through the TPP. That section requires a PTO to construct transmission additions or upgrades determined by the CAISO to be "needed," where:

- The additions or upgrades to the transmission facilities are located within its PTO Service Territory, unless it does not own the facility being upgraded or added *and* neither terminus of such facility is located within its PTO Service Territory
- The additions or upgrades are to existing transmission facilities that the PTO owns, which are part of the CAISO Controlled Grid and are located outside of its PTO Service Territory, unless any joint ownership arrangement does not permit construction by the PTO
- The PTO is also a Local Furnishing PTO, if the CAISO or Project Sponsor tenders an application under Federal Power Act, Section 211, which requests the FERC to issue an order directing the Local Furnishing PTO to construct such facilities. After receiving the Section 211 application, the Local Furnishing Participating TO is required to waive its right to request service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The obligation to construct arises after the FERC order, if granted, is no longer subject to rehearing or appeal.

"Need" arises under Section 24 of the CAISO Tariff when the transmission upgrade or addition maintains System Reliability (*see* Section 4.2.1 of this BPM); promotes economic efficiency, including maintaining the feasibility of allocated LT-CRRs (*see* Sections 4.2.2 and 4.2.4 of this BPM); or satisfies the requirements of LCRIF (*see* Section 4.2.3 of this BPM).

It should be noted that the obligation to construct does not attach to all PTOs, but rather to those PTOs with PTO Service Territories. A PTO Service Territory is "the area in which an IOU, a Local Public Owned Electric Utility, or federal power marketing administration that has turned over its transmission facilities and/or Entitlements to ISO Operational Control is obligated to provide electric service to Load. A PTO Service Territory may be comprised of the Service Areas of more than one Local Public Owned Electric Utility, if they are operating under an agreement with the ISO for aggregation of their MSS and their MSS Operator is designated as the Participating TO." (CAISO Tariff, Appendix A.)

However, the obligation to construct is further subject to the following conditions:

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- The ability of the PTO, after making a good faith effort, to obtain all necessary approvals and property rights under applicable federal, state, and local laws
- The presence of a cost recovery mechanism with cost responsibility assigned in accordance with Section 24 of the CAISO Tariff
- The right of the PTO to dispute any need determination under the CAISO's ADR Procedures

The obligation of a PTO to construct a needed transmission upgrade or addition further extends to a Merchant Transmission Facility, which is a transmission addition or upgrade that is part of the CAISO Controlled Grid and whose costs are paid by a Project Sponsor that does not recover the cost of the transmission investment through the CAISO's Transmission Access Charge (TAC) or Wheeling Access Charge (WAC) or other regulatory cost recovery mechanism. Rather than obtain a recovery of costs through a regulated rate, the Project Sponsor of the Merchant Transmission Facility obtains Merchant Congestion Revenue Rights in accordance with CAISO Tariff Section 36.11. (*See* Section 4.2.5 of this BPM and Section 4.2.4 of the BPM for Congestion Revenue Rights.) The PTO's obligation to construct a Merchant Transmission Facility is contingent on the Project Sponsor demonstrating that it is financially able to pay "the costs of the project to be constructed by the Participating TO," such that the PTO may require:

- A demonstration of creditworthiness, such as an appropriate credit rating
- Sufficient security in the form of an unconditional and irrevocable letter of credit or other similar security sufficient to meet its responsibilities and obligations for the full costs of the transmission addition or upgrade

If the PTO cannot secure the necessary approvals and, therefore, is unable to construct the transmission upgrade or addition, the PTO shall notify the CAISO and the CAISO shall convene a technical meeting to evaluate alternative proposals. The CAISO may take any action reasonably appropriate, after coordination with the PTO, or Project Sponsor if not the PTO, and other affected Market Participants, to develop and evaluate alternatives, including the discretion to confer the right to construct the transmission addition or upgrade on a non-PTO. The obligation to construct can be distinct from the right to own. As noted, a non-PTO Project Sponsor (*e.g.*, a Transmission Owner), may retain ownership of a Merchant Transmission Facility notwithstanding the PTO's role in operating and maintaining the transmission upgrade or addition. Similarly, a PTO without a PTO Service Territory may hold ownership as well as responsibility for maintenance of a transmission upgrade or addition approved to promote economic efficiency, in accordance with Section 14 of the Transmission Control Agreement. In the latter case, the PTO sponsoring the project may, but is not required to, construct the project itself.

Transmission upgrades or additions to maintain System Reliability in accordance with Applicable Reliability Criteria and CAISO Planning Standards will primarily be sponsored, and therefore owned, by PTO's with PTO Service Territories. This arises from:

- The practice of those PTOs to perform annually, at the direction of the CAISO, reliability assessments of their PTO Service Territories that may cover all Loads within their geographic PTO Service Territories to ensure compliance with Applicable Reliability Criteria and CAISO Planning Standards
- The obligation of those PTOs to act as a Project Sponsor for transmission additions or upgrades in its PTO Service Territory identified or approved by the CAISO as needed to ensure System Reliability.

Similarly, to the extent that a transmission upgrade or addition constitutes the most efficient means to maintain the feasibility of allocated Long Term CRRs under Section 24.1.3 of the

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CAISO Tariff—apart from the expansion of, or acceleration of, an existing transmission project not sponsored by the PTO—the CAISO will direct the appropriate PTO to sponsor the needed transmission project. This is consistent with the CAISO's designation of PTO's with PTO Service Territories as the entity with the obligation to construct needed transmission upgrades or additions.

However, should the PTO prove to be unable or unwilling to fund and construct transmission upgrades or additions deemed as required to resolve reliability criteria violations or maintain the feasibility of LT- CRRs, the CAISO may exercise its right, as noted above, to seek a third-party Project Sponsor.

The Project Sponsor for Economic transmission projects will generally be the entity that submits the successful proposal through the Request Window process. To the extent the Project Sponsor cannot own, finance and construct the Economic transmission project, including where the project is proposed by the CAISO, the CAISO will designate one or more of the PTOs with PTO Service Territories in which the terminus of the transmission addition or upgrade will be located to act as Project Sponsor. Where two or more PTOs are designated as Project Sponsors, such CAISO designation will include the proportionate responsibility between or among PTOs to own, construct, and finance the transmission addition or upgrade. If a PTO refuses to act as a Project Sponsor, the CAISO will first request other designated PTO(s) to assume the remainder or greater proportionate responsibility, and if no other PTO had been designated or is willing to increase its proportionate responsibility, the CAISO may solicit bids to finance, own, and construct the transmission addition or upgrade.

A Transmission Owner that is neither a PTO, nor seeking Merchant Transmission Facility treatment under the CAISO Tariff, retains any rights to construct and expand transmission facilities as those rights would exist absent any other obligations the Transmission Owner may have under the CAISO Tariff.

7. Cost Allocation – Transmission Access Charge

There are four general mechanisms by which a Transmission Owner can recover, or attempt to recover, its revenue requirement associated with transmission facilities turned over to the CAISO's Operational Control. The selected mechanism will depend on whether the Project Sponsor is a PTO or not and, if a PTO, whether the transmission facility constitutes a network facility or a Location Constrained Resource Interconnection Facility. Figure 8 illustrates the three mechanisms.

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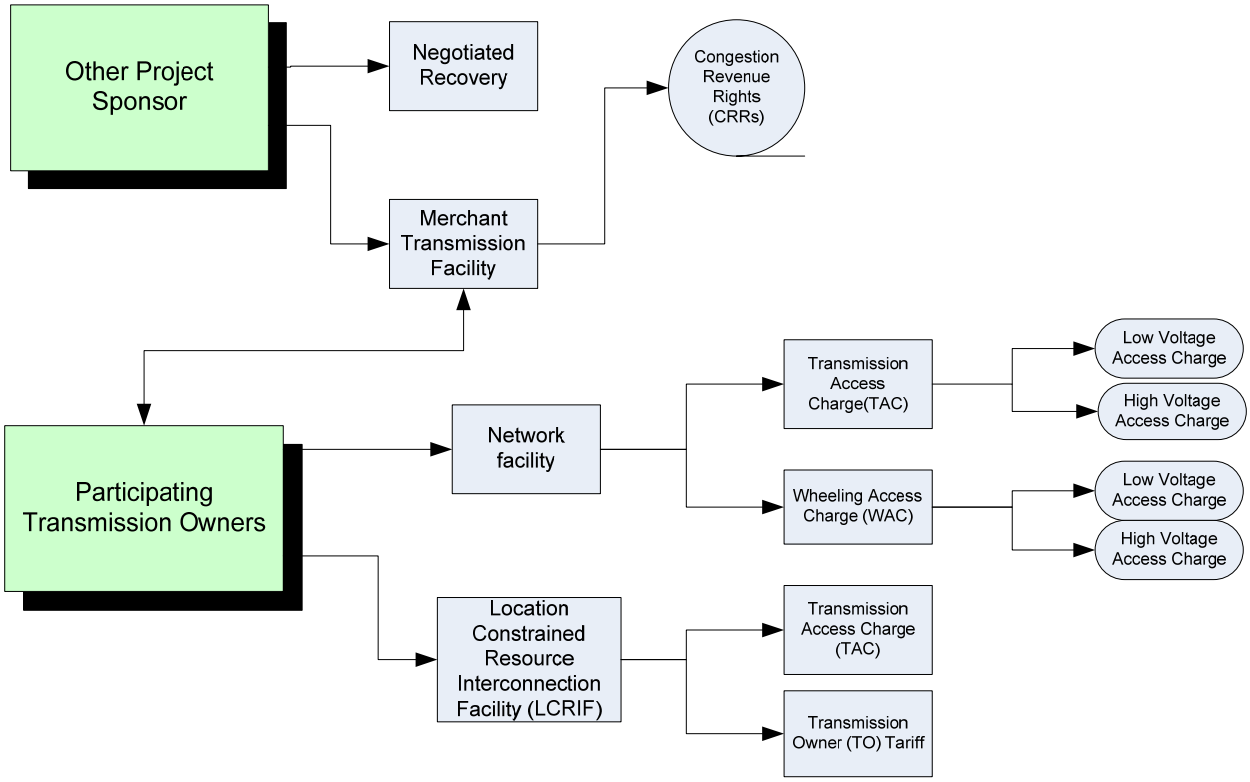

Figure 8: Mechanisms for Cost Allocation

7.1 Merchant Transmission Facility

CAISO Tariff Section 24.1.1 and 36.11

A Project Sponsor may elect to fund and construct a Merchant Transmission Facility. In this case, the Project Sponsor does not seek to recover the cost of the Merchant Transmission Facility transferred to the CAISO's Operational Control through the CAISO's Access Charge and Wheeling Access Charge or other regulatory cost recovery mechanisms. Instead, the Project Sponsor of a Merchant Transmission Facility seeks an allocation, at the Project Sponsor's election, of either CRR Options or Obligations that reflect the contribution of the facility to grid transfer capacity. The conditions for receiving CRRs, for determining of the quantity of CRRs to be allocated, and for determining potential revenue from allocated CRRs, are set forth in Section 36.11 of the CAISO Tariff and the BPM for Congestion Revenue Rights, located at http://www.caiso.com/1840/1840b23c226f0.html.

7.2 Negotiated Recovery

CAISO Tariff Section 24.7.3

Under the current version of the MRTU Tariff, a Project Sponsor that elects not to receive Merchant Transmission CRRs may still receive cost recovery other than through the Access Charge. The CAISO anticipates modifying this authority to apply solely to projects previously

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electing recovery under Section 24.7.3 of the "Simplified and Renumbered" ISO Tariff such that new transmission projects approved after the commencement of MRTU would not be eligible for negotiated rate recovery. Until such modification is made, a Project Sponsor that does not recover the investment cost under a FERC-approved rate through the Access Charge or a reimbursement or direct payment from a Participating TO, provided the upgrade or addition is under CAISO Operational Control, shall be entitled to receive a compensation package based on a negotiation between the Project Sponsor, CAISO and the relevant PTO. The compensation for the Project Sponsor shall be commensurate with the amount of additional transmission capacity that results from the upgrade, determined by subtracting the rating of the transmission facility before the upgrade or addition from the new rating for the upgraded or additional transmission facility. The full amount of capacity added to the system will be as determined through the regional reliability council process of the WECC. If the parties agree to a compensation package, the CAISO will provide notice of agreement on the CAISO Website. The CAISO will file a proposed compensation package with FERC.

7.3 PTO Transmission Facility

CAISO Tariff Section 24.7.2 and 24.7.4

A facility constructed by a PTO for transfer to the CAISO's Operational Control will be either a network transmission upgrade or addition, or a Location Constrained Resource Interconnection Facility.

7.3.1 Network Transmission Facility

A PTO's recovery of costs for facilities turned over to the CAISO Operational Control begins with its FERC-approved Transmission Revenue Requirement. The Transmission Revenue Requirement is comprised of the total annual authorized revenue requirements associated with such network transmission facilities and Entitlements. The Transmission Revenue Requirement includes the costs of transmission facilities and Entitlements and deducts Transmission Revenue Credits, credits for Standby Transmission Revenue, and the transmission revenue expected to be actually received by the PTO for Existing Rights and Converted Rights. The remainder of the PTO's Transmission Revenue Requirement is intended to be recovered through a combination of the CAISO's Transmission Access Charge (TAC) or Wheeling Access Charge (WAC).

The TAC is a charge paid by entities serving Load on the transmission and distribution systems of the PTOs under the CAISO's Operational Control. The TAC includes the High Voltage Access Charge for facilities at 200kV and above, the Transition Charge and the Low Voltage Access Charge. The Low Voltage Access Charge is collected by each PTO under its Transmission Owner Tariff, based on the transmission revenue requirement associated only with its own low voltage transmission facilities and Entitlements. The details of the High Voltage Access Charge and Transition Charge are set forth in Section 26 of the CAISO Tariff and Appendix F, Schedule 3.

The WAC is a charge assessed by the CAISO that is paid by a Scheduling Coordinator for Wheeling in accordance with Section 26.1. Wheeling can be in the form of a Wheel Out or Wheel Through. The former is defined as the use of the CAISO Controlled Grid for the transmission of energy from a Generating Unit located within the CAISO Controlled Grid to serve a Load located outside the transmission and distribution system of a PTO, except for Energy utilizing an Existing Contract. On the other hand, a Wheel Through is the use of the CAISO Controlled Grid for the

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transmission of Energy from a resource located outside the CAISO Controlled Grid to serve a Load located outside the transmission and distribution system of a PTO, except for Energy utilizing an Existing Contract. The WAC may also consist of a High Voltage Wheeling Access Charge and a Low Voltage Wheeling Access Charge. The details of the WAC are set forth in Section 26 of the CAISO Tariff and Appendix N, Part F.

7.3.2 LCRIF

CAISO Tariff Section 26.6

PTOs finance the up-front costs of constructing LCRIF. The recovery of costs for such facilities comes from two sources. First, the costs of any unsubscribed capacity of qualifying LCRIFs will be rolled into the CAISO's TAC, similar to a network transmission facility. As generation resources are developed in the area and connect to the LCRIFs, cost recovery will be transferred on a going forward, *pro rata* basis to those new generation owners, and the costs included in TAC will be reduced accordingly. Once the anticipated generation is fully developed and the capacity of the LCRIF fully subscribed, the going forward costs of the project will be borne entirely by generation developers and will not be included in the TAC. Thus, the costs associated with the unsubscribed portion of the LCRIF will be included in TAC, until additional generators are interconnected, at which time costs will be assigned to such generators.

8. Study Charges

The CAISO's costs of conducting its TPP and producing the annual Transmission Plan are generally recovered through the CAISO's Grid Management Charge (GMC). The GMC consists of charge codes assessed monthly to participating Scheduling Coordinators for the purpose of recovering all of the CAISO's administrative and operating costs. GMC rates are calculated as set forth in Section 11 of the CAISO Tariff. The formula rate methodology provides Market Participants with the financial security of predictable GMC pricing, while ensuring that the CAISO is able to recover its actual costs in a timely manner. The charges are shown as a monthly charge on the Settlements Statements for the last day of each month, with billable quantities being published on daily statements where applicable. A detailed discussion of GMC is beyond the scope of this BPM. For more information on GMC please see:

- Section 11 of MRTU Tariff - http://www.caiso.com/1c40/1c407ff21c570.html
- BPM for Settlements and Billing - http://www.caiso.com/17ba/17baa8bc1ce20.html
- Structure of GMC under MRTU - GMC http://www.caiso.com/1872/18728fb96b370.html

To the extent that a proposed transmission project, or High Priority Economic Planning Study, is accepted by the CAISO for evaluation as part of the Study Plan, the costs of those activities will typically be borne, based on the division of responsibilities, either by the CAISO and recovered through existing GMC procedures and practices or by the third party assigned or accepting responsibility for the study task under the Study Plan in accordance with that entity's tariff authority. Participants in the TPP will be financially responsible for costs incurred in participating in the TPP, including activities in support of the CAISO or PTO evaluations. Further, the cost responsibilities of performing Interconnection Studies are governed by the CAISO's LGIP or SGIP Tariff language.

However, there is an exception to the foregoing. Where a requested Economic Planning Study is not selected for High Priority status, and therefore is not included by the CAISO in the Study Plan,

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the study requestor may nevertheless conduct the study in coordination with the CAISO. The CAISO's costs of assisting the third-party requestor to conduct its own Economic Planning Study will be the responsibility of the study requestor, and such party will be asked to enter into a study agreement with the CAISO. The *pro forma* study agreement shall be posted to the CAISO Website under Transmission Planning. Further, the CAISO intends to evaluate the need to develop terms and conditions under which participants of projects included in the Study Plan would be required to contribute or otherwise pay for the cost of specific tasks or elements of the Transmission Planning Process. If necessary, this cost recovery process is expected to be restricted to a "time and materials" basis.

9. The TPP Public Processes and Communications

9.1 TPP Public Processes

The CAISO initiates and coordinates a minimum of three annual meetings that are open to the public as part of the TPP. The CAISO may in its sole discretion arrange additional public meetings (*e.g.*, a meeting to discuss preliminary study results). The three required public meetings correspond to the three stages of development of the Transmission Plan. Thus, meetings that are open to the public will be held to 1) facilitate development of the Unified Planning Assumptions and Study Plan; 2) review preliminary results of technical analyses; and 3) present the draft CAISO Transmission Plan and announce approved projects.

All public meetings are open to TPP Participants and other interested parties. In each case, notice of the meeting will be given a reasonable time prior to the scheduled meeting through Market Notices and will be included in the CAISO event calendar found on the CAISO Website. Entities can subscribe to Market Notices through the CAISO Website at http://www.caiso.com/docs/2005/10/12/2005101209381421288.html. Teleconference and/or web conference services also will be provided for all meetings. Further, all interested parties will be allowed to subscribe to any CAISO TPP e-mail service that also will provide notice of TPP activities, including the publication of draft and final Unified Planning Assumptions and Study Plans, technical study results, Transmission Plans, and other transmission planning reports. Interested parties can subscribe to the CAISO Transmission Planning Process e-mail service by contacting regionaltransmission@caiso.com.

To the extent the CAISO delegates to the PTOs or other third parties, through the Study Plan, the responsibility to perform technical analyses, the CAISO also will require those entities to conduct a minimum of one public meeting, which also facilitated by the CAISO and noticed through the CAISO's standard stakeholder notification mechanisms. In addition, the CAISO will include on the calendar of events maintained on the CAISO Website a schedule of the public meetings conducted jointly between the CAISO and any PTO or third party, as well as other relevant meetings of the CEC, CPUC, sub-regional, and regional planning groups.

To maximize public participation, the open meetings scheduled in accordance with the evaluation process for Large Projects, described in Section *** of this BPM, may be noticed through standard CAISO stakeholder notice procedures, through the media in the area in which the project will be located (particularly if public meetings are held near the project location) and through electronic (E-mail) notices to specific parties who might have an interest in the process.

For all events relating to the Transmission Planning Process, interested parties will have the opportunity to submit comments on documents relevant to the meeting, and upon the meeting itself. Generally, comments from TPP participants shall be submitted to regionaltransmission@caiso.com. The CAISO shall incorporate comments in subsequent

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planning activities and decisional items relating to those activities. In the case of decisional items (*i.e.* adoption of final a Study Plan or final Transmission Plan), the CAISO will indicate the manner in which it responded to such comments.

Established CAISO stakeholder process protocols and standard guidelines for market notices, document postings, and the format of stakeholder meetings will be applied to all TPP public meetings.

- Market notices to announce the public meetings will be sent out at least 3 weeks prior to the meeting.
- The draft documents to be discussed during the public meetings will typically be posted no later than 1 week before the meeting. Consequently, interested parties can anticipate the posting of the draft Study Plan, CAISO study results, and the draft CAISO Transmission Plan on CAISO website at least 7 days before each public meeting.

9.2 Access to Transmission Planning Process Information

CAISO Tariff Sections 20.2 and 20.4

The CAISO provides access to non-confidential information related to the TPP, including data, assumptions, decision criteria, study methodologies, and results to all TPP Participants through the Study Plan, interim study reports, study manuals, the Transmission Plan, and relevant BPMs. Public documents related to the TPP will be posted to the CAISO Website mainly under the regional Transmission webpage. The CAISO webpage also will provide links to the websites of relevant transmission planning entities including, but not limited to, the CPUC, CEC, and those entities listed in Section 5.1 of this BPM.

The CAISO will attempt to minimize the instances in which the TPP requires the use of confidential information that has been specifically designated as such by the provider of the information. Nevertheless, the CAISO shall maintain the confidentiality of information when:

- The information relates to procurement of resources submitted by LSEs under Sections 24.2.3.2 and 24.2.3.3 of the CAISO Tariff (CAISO Tariff Section 20.2(h)(1))
- The release of such information may harm the competitiveness of wholesale markets, as determined by the CAISO's Department of Market Monitoring (CAISO Tariff Section 20.2(h)(2))
- Release of such information may breach existing agreements and contracts, including previously executed Non-Disclosure Agreements (NDA) (CAISO Tariff Section 20.2(h)(3))
- The information involves third-party developed or other proprietary analysis tools, computer codes, or any other material that is protected by intellectual property rights (CAISO Tariff Section 20.2(h)(4))
- The information constitutes Critical Electric Infrastructure Information (CEII) in accordance with FERC regulations (CAISO Tariff Section 20.2(h)(5))

Apart from public information posted to the CAISO Website at Transmission Planning, the CAISO will post base cases relating to current initiatives the CAISO is working on to the Regional Transmission secure webpage. More information on the instructions and qualifications to receive access to the secure webpage can be found at http://caiso.com/1f42/1f42d6e628ce0.html.

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As part of the application process, entities will be required to comply with the following requirements to gain access to confidential planning information:

- Critical Energy Infrastructure Information may be provided to a requestor where such person is employed or designated to receive CEII by (1) a Market Participant; (2) electric utility regulatory agency within California to receive CEII; (3) an Interconnection Customer that has submitted an Interconnection Request to the CAISO under the CAISO's Large Generator Interconnection Procedure/Small Generator Interconnection Procedures (LGIP); (4) a developer having a pending or potential proposal for development of a Generation Unit or transmission additions, upgrades or facilities and who is performing studies in contemplation of filing an Interconnection Request or submitting a transmission infrastructure project through the TPP; or (5) a not-for-profit organization representing consumer regulatory or environmental interests before Local Regulatory Agencies or federal regulatory agencies. To obtain Critical Energy Infrastructure Information, the requestor submits a statement as to the need for the CEII, and the requestor executes and returns to the CAISO the form of the non-disclosure agreement and non-disclosure statement available on the CAISO website under Transmission Planning. The CAISO may, at its sole discretion, reject a request for CEII and upon such rejection, the requestor will be directed to utilize the FERC procedures for access to the requested CEII.
- Information that is confidential under Section 20.2(h)(1) or 20.2.(h)(2) may be disclosed to any individual designated by a Market Participant, electric utility regulatory agency within California, or other TPP Participant that signs and returns to the CAISO the form of the non-disclosure agreement, nondisclosure statement and certification that the individual is or represents a non-Market Participant, which is any person or entity not involved in a marketing, sales, or brokering function as market, sales, or brokering are defined in FERC's Standards of Conduct for Transmission Providers (18 C.F.R. § 358 et seq.) except that information provided to CAISO pursuant to 20.2(h)(2) will be provided only in composite form so that information specific to individual LSEs will not be disclosed and
- Data base and other transmission planning information obtained from WECC may be disclosed to individuals designated by a Market Participant, electric utility regulatory agency within California, or other stakeholder in accordance with the procedures set forth as follows:
    - A TPP Participant that is a member of WECC and that requests the WECC planning data base: (i) shall execute the Non-Disclosure Agreement which is available on the CAISO website under Transmission Planning and (ii) shall provide to the CAISO a non-disclosure statement, the form of which is attached as an exhibit to the Non-Disclosure Agreement executed by the TPP Participant and by each employee and consultant of the TPP Participant who will have access to WECC planning data base.

A TPP Participant who is not a member of WECC and requests the WECC planning data base: (i) shall execute the Non-Disclosure Agreement attached to this BPM, (ii) shall provide to the CAISO a fully executed WECC Non-Member Confidentiality Agreement for WECC Data, and (iii) shall provide to the CAISO a non-disclosure statement, the form of which is attached as an exhibit to the Non-Disclosure Agreement executed by the TPP Participant and by each employee and consultant of the TPP Participant who will have access to the WECC planning data base.

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10. Dispute Resolution Process

CAISO Tariff Section 13

The Alternative Dispute Resolution (ADR) Procedures set forth in Section 13 of the CAISO Tariff apply to all disputes arising under CAISO Documents, including those related to the Transmission Planning Process. The ADR Procedures can be found at http://www.caiso.com/1bcc/1bcc775734780ex.html The ADR Procedures provide for a three-tier process, progressing from negotiation to mediation to arbitration. Both substantive and procedural disputes arising from the TPP will be addressed through the existing ADR Procedures.

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Attachment 1

Template - Study Plan in CAISO Transmission Plan

Section 1: Objectives

- What this transmission planning effort attempts to achieve
- Roles and responsibilities of each entity contributing to each Transmission Plan component.

Section 2: Summary of CAISO Planning Process

- Overview of coordination process
- Schedules of all meetings open to the public and other related activities
- Scope of each meeting
- Options available for participation by interested parties in the meetings, such as in-person, conference call, Webcast, etc.
- Location where information such as planning assumptions or other related documents will be available for interested parties
- Instructions for interested parties to receive notifications or communicate or provide comments to CAISO
- Contact persons and contact information of
    - Overall planning process
    - Subject matter experts (SME) for each technical study

Section 3: Planning Data

- Load forecast – Source of the load forecast, amount, and detailed methodology if original load is adjusted to the scope of each study
- Generation assumptions – Source of new generation data and list of new generation projects modeled in the study
- Generation retirement – Source of generation retirement data, list of generation retirement modeled in the studies
- Transmission projects – Source of transmission project information and list of transmission project modeled in the studies
- Import – Source of Import data, amount of import modeled, and methodology to determine the import (*e.g.*, Import Allocation Methodology)
- Project proposals and study requests received during the Request Window

Section 4: Planning Studies

- List of all planning studies to be done in each Transmission Plan
- Each study defines:
    - The objective the study tries to achieve
    - The study assumptions (*e.g.*, study year, planning data applied to each study, or any modifications made to original planning data described in Section 4.1.3.)
    - Methodology – Describe how the study will be performed (this may refer to appropriate Business Practice Manuals or documents that have been produced and posted on the CAISO website at *[URL to be determined]*)
    - Criteria – Reliability or criteria applied to each study, such as NERC/WECC or other standards being used
    - Software and Tools – List software and tools for each study

- Entity to perform the study
- Expected study results and location where interested parties may access pages dedicated to the study
- Public meetings or any major activities to be completed in addition to the regular schedules in CAISO Transmission Plan (if applicable)

Section 5: Comments, Responses, and Disputes

- Comments received from interested parties that need to be addressed in the study plan
- CAISO responses to the comments
- Records of disputes CAISO has received, particularly for the unified planning assumptions and the resolutions through the ADR process

The above template is based on the study plan for the 2008 Transmission Plan that CAISO discussed during the meeting, June 11, 2007, available at http://caiso.com/1bf4/1bf4740146650.pdf.

Attachment 2

Detailed NERC Reliability Assessment Studies

The current NERC Reliability Standards related to transmission planning (TPL-001 through TPL-004) define the scope of and deliverables from the technical studies for which each entity is responsible under its compliance obligations related to those standards applicable to the entity's registration. The requirements apply to the annual assessments to be conducted by the CAISO and PTOs. These general requirements, such as types of technical studies, study scenarios, modeling in the base cases and the study results, are described in Sections A.1 through A. 7, below.

A.1. Types of Technical Studies

In each assessment, power flow, voltage stability, and transient stability studies must be conducted to demonstrate that system performance meet or exceed the criteria as identified in Table I of the effective TPL standards. The technical studies must evaluate impacts to the system under system normal and under Category B, C and D contingency conditions.

A.2. Study Areas

Due to the differences in load patterns and local area peaking, the technical studies will be performed on the following 11 study areas throughout CAISO balancing authority area~~.~~:

1. PG&E Humboldt peak (non-coincident peak)
2. PG&E North Coast and North Bay peak (non-coincident peak)
3. PG&E North Valley peak (non-coincident peak)
4. PG&E Central valley (non-coincident peak)
5. PG&E Greater Bay Area (non-coincident peak)
6. PG&E Central Coast and Los Padres (non-coincident peak)

7. PG&E San Joaquin Valley (non-coincident peak)
8. Entire PG&E area coincident peak (represents all of Northern California)
9. Entire SCE area coincident peak
10. Entire SDG&E area coincident peak
11. Entire Southern California (CAISO Control Area) coincident peak

A. 3. Frequency of the Assessment

The assessment must be made annually.

A. 4. Study Years

For the extreme contingency (Category D) studies, the study must be conducted for the near-term (each year: Years One through Five). For the study under system normal, Category B, and Category C contingencies, both the near term (each year: Years One through Five) and long-term (each year: Years Six through Ten) must be studied unless changes to system conditions do not warrant such analyses.

A.5. Study Scenarios

The technical studies must cover critical system conditions and be performed for selected demand levels over the range of forecasted system demand. In general, the summer peak scenarios with appropriate stressed -path flows must be studied for each study area. Additional scenarios can be studied if they are needed to ensure a complete planning analysis. The list of study scenarios, MW demand forecasts, and the stressed -path flows will be documented in the Study Plan of each year's Transmission Plan.

A.6. Base Cases and Contingencies Being Studied

The standards also require certain components must be included in the studies and need to be documented for auditing purposes. Table 1 lists these modeling requirements and descriptions of contingencies according to the current TPL 001 through TPL 004 standards.

Summary of Modeling Requirements

Requirements	Apply To
Have established normal (pre-contingency) operating procedures in place Category A study.	Category A Study
All Category B contingencies must be studied and mitigations proposed for those that would produce severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	Category B Study
Consider all possible C contingencies. Perform studies and evaluate those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	Category C Study
Consider all possible D contingencies but studies must be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	Category D Study
Have all projected firm transfers modeled.	Category A, B, C and D Studies
Include existing and planned facilities; transmission facilities that have been approved by the CAISO and applicable generation projects that have been approved by regulatory agencies.	Category A, B, C and D Studies
Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	Category A, B, C and D Studies
Include the effects of existing and planned protection systems, including any backup or redundant systems.	Category B, C and D Studies
Include the effects of existing and planned control devices Category B, C, and D studies.	

	Category B, C and D Studies
Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.	Category B, C and D Studies

A.7. Study Results and Mitigation Plans

The CAISO and PTO must demonstrate that the portion of system under their respective responsibilities meets the requirements identified in the Table 1 of TPL reliability standards. Therefore, both the CAISO and PTOs shall consistently document the following information in their respective study reports:

1. For the study under system normal and Category B and Category C contingencies, the study results list all study scenarios, identified reliability criteria violations, and the associated mitigation plans.
2. For the studies under Category D contingencies, the study results must show the evaluation for the risks and consequences of each extreme contingency.
3. For each identified reliability criteria violation, the study results must elaborate the conditions that violation occurs (e.g., study year, season, contingency that trigger the problem, special protection system that has been modeled, limiting facility or limiting conditions).
4. For the proposed mitigation plans, must provide:
    a. A written summary of its plans to achieve the required system performance as described above throughout the planning horizon;
    b. Schedule of implementation;
    c. Discussion of expected required in-service dates of facilities;
    d. Consider lead times necessary to implement plans. Review, in subsequent annual assessments where sufficient lead-time exists, the continuing need for identified system facilities. Detailed implementation plans are not needed.

Attachment 3

Major Activities and Milestone Dates

Table 3 describes the major milestone and major activities that occur throughout the year. These include projected due dates of major activities such as submitting planning data, schedules for stakeholder meetings, the opening date and deadline for submitting projects through Request Window, development of the transmission plan, and presenting the plan to CAISO Board of Governors.

Major Milestones, Activities, Due Dates, and Responsible Entities

No.	Due Date	Entity	Activity
1	2nd week of December	CAISO	Sends a letter to neighboring Balancing Authorities, sub-regional and regional planning groups requesting planning data and other related information to be included in the CAISO Transmission Plan
2	2nd week of January	PTOs	Provide CAISO: 1) Local area load forecasts; 2) The methodology to calculate local area load forecasts and comparison to the CEC load forecast
3	2nd week of February	CAISO	CAISO develops the Draft Study Plan and posts it on CAISO website
4	End of February	CAISO	**Hosts Stakeholder Meeting #1**
5	End of March	PTOS	Provide CAISO: 1) All base cases for NERC compliance studies 2) Contingency files for NERC compliance studies 3) Change files or EPC files that describe the changes made to this year's base cases (compared to last year cases) 4) Verified dynamic files for transient stability study
		CAISO	1) Creates base cases for its studies 2) Posts planning data on the secured website
6	End of July	CAISO and PTOs	Host 2 stakeholder meetings (1 for Northern CA and 1 for Southern CA) to provide the update of study results and project proposals
7	August 15	CAISO	Request Window Opens
		CAISO	Complete all technical studies Posts preliminary study results on website Provides its portion of NERC compliance studies to PTOs

8	September 15	PTOs	Provide CAISO: 1) Reliability assessment report that contains study results and mitigation plans in the format that comply with the requirements of the NERC Reliability Standards 2) Updated status of the projects that have been approved (but are not yet in-service) from the previous transmission plan 3) Submit reliability project proposals through the Request Window
9	End of October	CAISO	**Hosts Stakeholder Meeting #2**
10	November 30	CAISO	Request Window Closes
11	End of December	CAISO	Submit the projects that are subject to Right to Construct, Own and Operate held by the applicable PTOs
12	End of January	PTOs	For projects submitted under No. 11, PTO response to CAISO exercising or waiving PTO's Right to Construct, Own and Operate
13	2nd week of February	CAISO	**Hosts Stakeholder Meeting #3**
14	End of February	CAISO	Present Transmission Plan to CAISO Board of Governors

2008 SDG&E GRID ASSESSMENT STAKEHOLDER MEETING

Nov 20, 2008

MEETING AGENDA

Introduction

2008 Grid Assessment Study

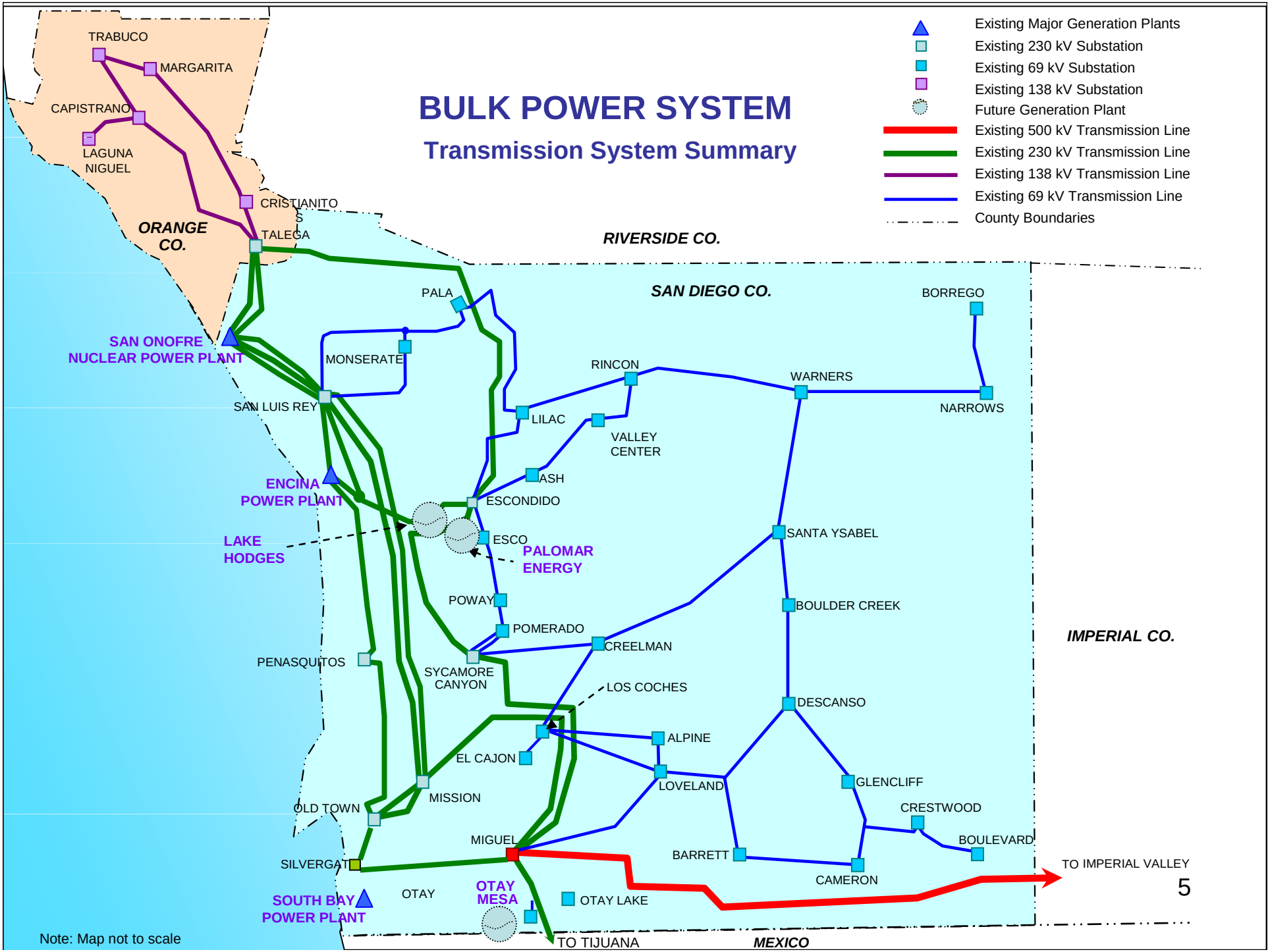
- Study Scope
- Study Results & Expansion Plan

Questions

2008
Grid Assessment Study

2008 STUDY SCOPE

- **Near-Term Five-Year Studies 2009-2013**
- **Ten-Year Study (2018)**


BULK POWER SYSTEM
Transmission System Summary
Existing Major Generation Plants
Existing 230 kV Substation
Existing 69 kV Substation
Existing 138 kV Substation
Future Generation Plant
Existing 500 kV Transmission Line
Existing 230 kV Transmission Line
Existing 138 kV Transmission Line
Existing 69 kV Transmission Line
County Boundaries
ORANGE CO.
RIVERSIDE CO.
SAN DIEGO CO.
IMPERIAL CO.
MEXICO
TRABUCO
MARGARITA
CAPISTRANO
LAGUNA NIGUEL
CRISTIANITOS
TALEGA
SAN ONOFRE NUCLEAR POWER PLANT
PALA
MONSERATE
SAN LUIS REY
RINCON
LILAC
VALLEY CENTER
ASH
ENCINA POWER PLANT
ESCONDIDO
LAKE HODGES
ESCO
PALOMAR ENERGY
POWAY
POMERADO
CREELMAN
PENASQUITOS
SYCAMORE CANYON
LOS COCHES
ALPINE
EL CAJON
LOVELAND
MISSION
OLD TOWN
MIGUEL
SILVERGATE
SOUTH BAY POWER PLANT
OTAY
OTAY MESA
OTAY LAKE
TO TIJUANA
BORREGO
WARNERS
NARROWS
SANTA YSABEL
BOULDER CREEK
DESCANSO
GLENCLIFF
CRESTWOOD
BOULEVARD
BARRETT
CAMERON
TO IMPERIAL VALLEY
Note: Map not to scale

EXPANSION PLAN

Projects Completed in 2008

Project Title	ISD
Lake Hodges Pump Storage Project (Transmission Only)	Complete
Rearrange 230 kV Switchyard: San Luis Rey	Complete

TRANSMISSION EXPANSION PLAN (1 OF 2)

Project #	Project Title	ISO Approval Status	ISD
Proposed Projects Requiring CAISO Approval			
P08159	New Tap Configuration for TL661, TL664: Eastgate	Pending	Jun-09
P08158	New Tap Configuration for TL13835: Talega	Pending	Oct-09
P07XXY	New 230,138 kV Reactive Support: Mission, Sycamore, Telegraph Canyon	Pending	Jun-10
Proposed Projects Requiring CAISO Board Approval			
P08XXY	New 500/230/69 kV Substation: ECO	Pending	Sep-11
P06132	Relocate South Bay Substation	Pending	Nov-11
P08XXX	Orange County Transmission Expansion Project (OCTEP)	Pending	Oct-13
Previously Approved Projects Requiring CAISO Approval for Change in Status, Scope, or In-Service Date			
P00154	Reconductor TL13802B, Shadowridge- Calavera Tap	Approved	Jun-10
P06133	New 230/138 kV transformer: Miguel Substation	Approved	Jun-11
Cancelled Projects Requiring CAISO Approval			
P061XY	Reconductor TL13812, Talega-San Mateo	Approved	Jun-09
P00153	Reconductor TL13837, Capistrano-Laguna Niguel	Approved	Jun-10

TRANSMISSION EXPANSION PLAN (2 OF 2)

Previously Approved Projects with No Proposed Changes			
P99126	Transmission for Otay Mesa Power Generation Project	Approved	Oct-08
P03170	New 230/69 kV Substation: Silvergate	Approved	Dec-08
P06130	Construct 2nd 230 kV line: Encina-Penasquitos	Approved	Jun-09
P07146	Reconductor TL6915, TL6924: Pomerado-Sycamore	Approved	Jun-09
P01141	Reconductor TL13836, Talega – Pico	Approved	Jun-09
P04137	Construct 2nd 69 kV line: Division-Naval Station Metering	Approved	Jun-09
P05153	Reconductor TL689, Escondido-Felicita Tap	Approved	Jun-09
P06134	Loop-in TL651: Silvergate 69 kV Switchyard	Approved	Jun-09
P06131	Loop-in TL13825: Shadowridge 138 kV Switchyard	Approved	Jun-09
P03183	Reconductor TL678, Los Coches-Alpine	Approved	Jun-10
P061XX	Reconfigure TL13821 & 13822, Carlton Hills Area	Approved	Jun-10
P04138	New 500 kV line: Sunrise Powerlink	Approved	Jun-12
P01142	Reconductor TL683, Lilac-Rincon	Approved	Deferred

Project Summaries

Projects Requiring CAISO Approval

New Eastgate Taps: TL661 & TL664

Budget Project 08159

Beach Cities

DRIVING FACTORS:
Load growth in Mira Mesa & Miramar

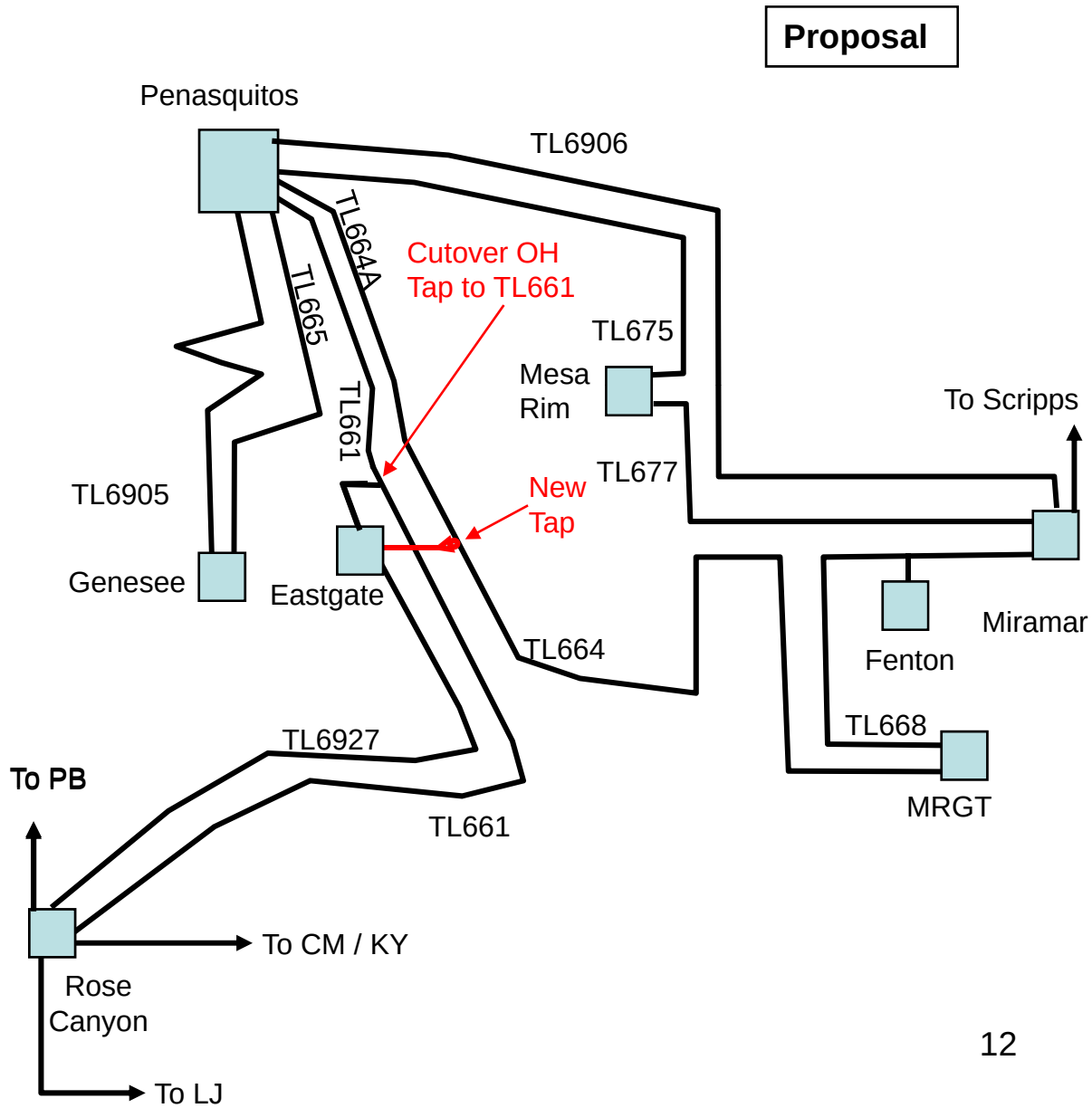
ISSUES:
N-1 (TL675), 1% overload on TL664A

SCOPE:
Construct a new TL664 UG tap line to Eastgate. Cutover the existing TL664 OH tap line to TL661.

ALTERNATIVE:
Reconductor TL664A
(More expensive)

STATUS: Newly Proposed

IN-SERVICE DATE: June 2009



New 138kV Tap: TL13835

Budget Project 08158

Orange County

DRIVING FACTORS:
Load growth in Laguna Niguel & San Mateo areas

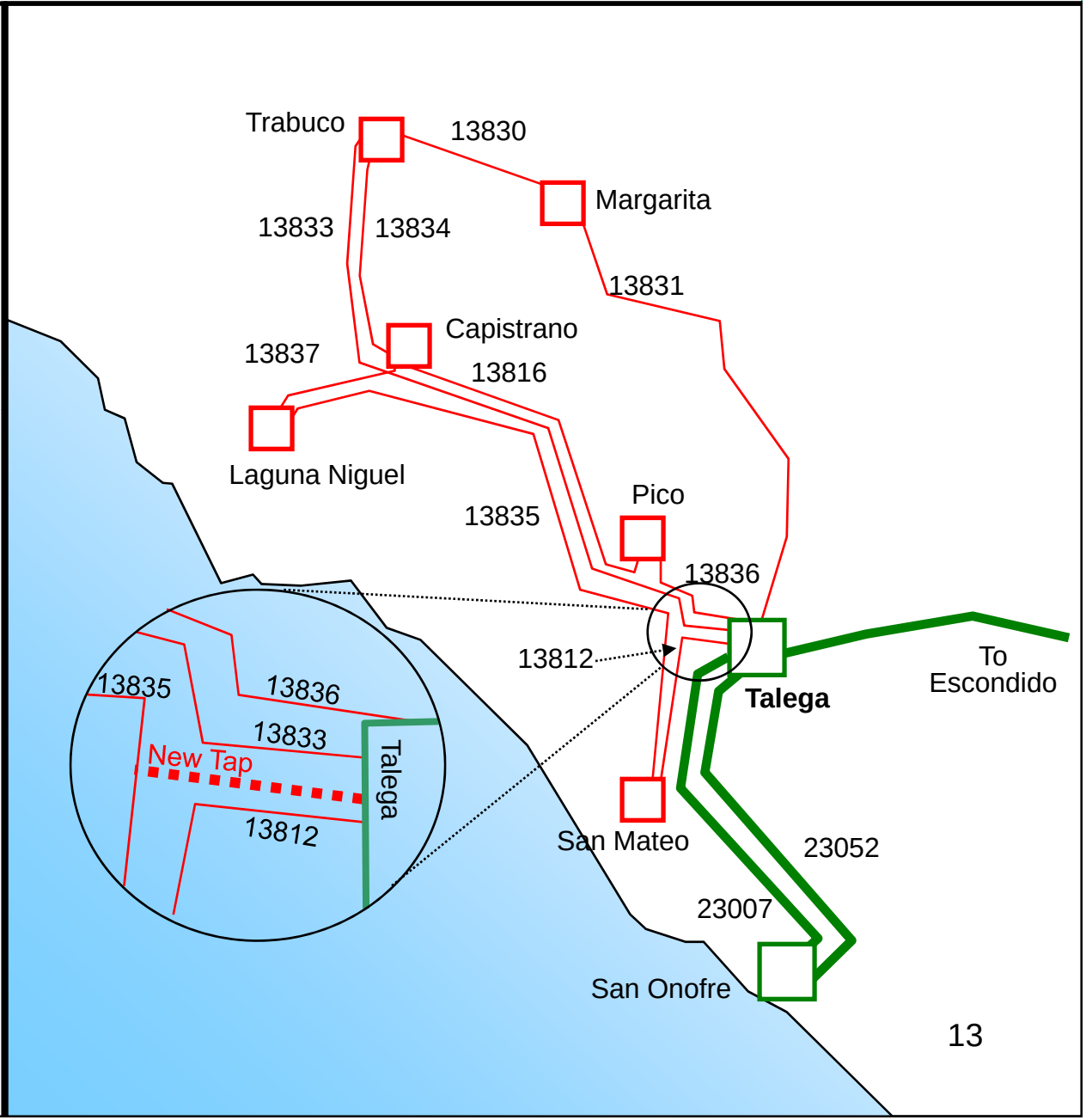
ISSUES:
1. N-1 (TL13812), 3% overload on TL13837
2. N-1 (TL13837), 4% overload on TL13812

SCOPE:
Build new 138kV tap line (OH & UG) from Talega to TL13835. Install a new 138kV circuit breaker at Talega.

ALTERNATIVE:
Reconductor TL13812 & TL13837 (More Expensive)

STATUS: Newly Proposed

IN-SERVICE DATE: Oct 2009



New 230 & 138KV Capacitors

Budget Project P07XXY

Transmission Planning

DRIVING FACTORS:

- Load growth, Insufficient reactive power support

ISSUES:

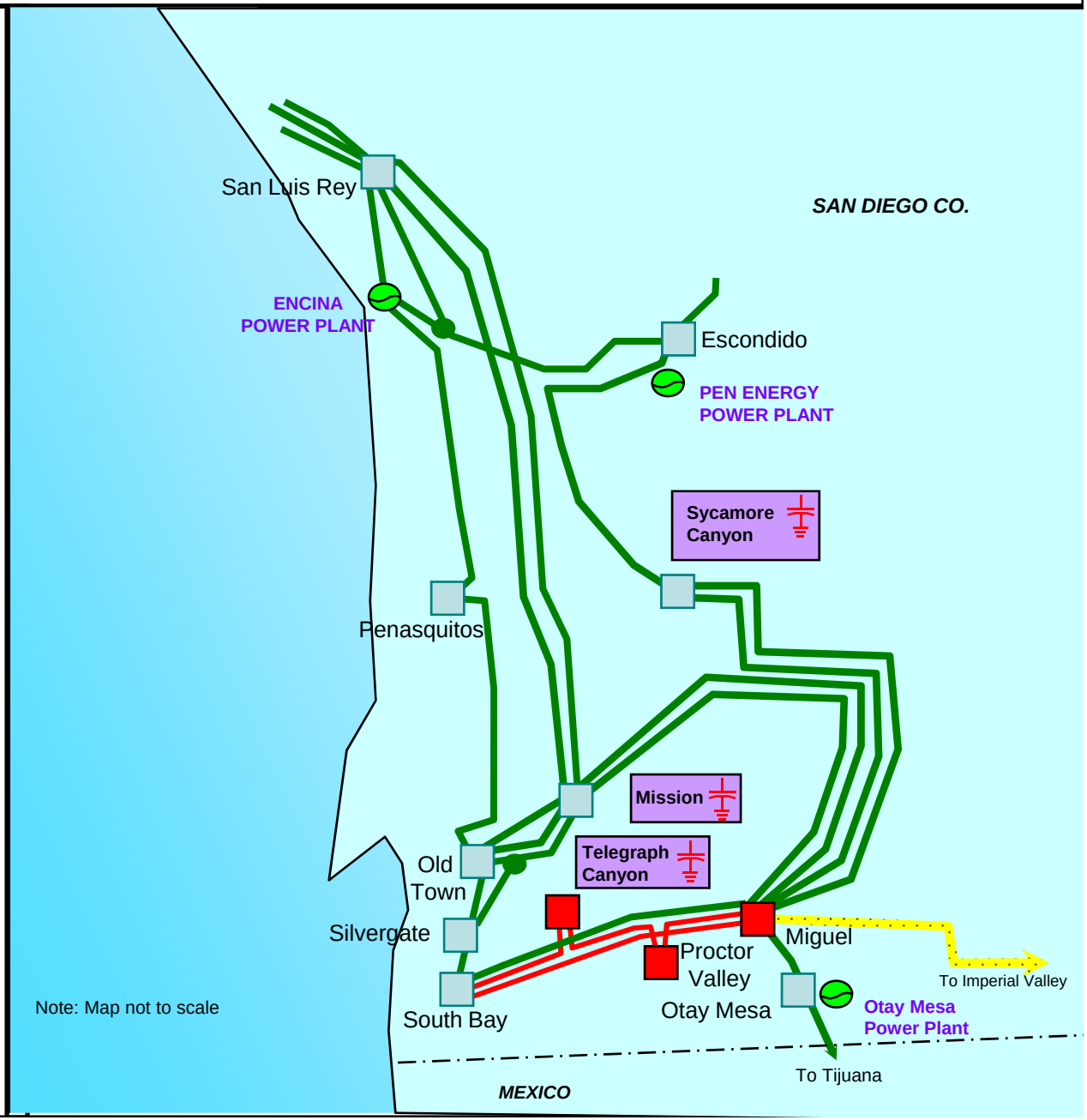
- In 2010, a contingency of SWPL, IV Gens w/ CFE Cross trip creates a need for reactive support to maintain post-transient voltage stability

SCOPE:

- Installation of 192 MVAR:
- Mission 230kV 63MVAR
- Telegraph C 138kV 43MVAR
- Sycamore C 138kV 43MVAR(2)

STATUS: Proposed in 2007

IN-SERVICE DATE: June 2010



Projects Requiring CAISO Board Approval

South Bay Substation Relocation

Budget Project 06132

Transmission Planning

DRIVING FACTORS:

Aging Infrastructure

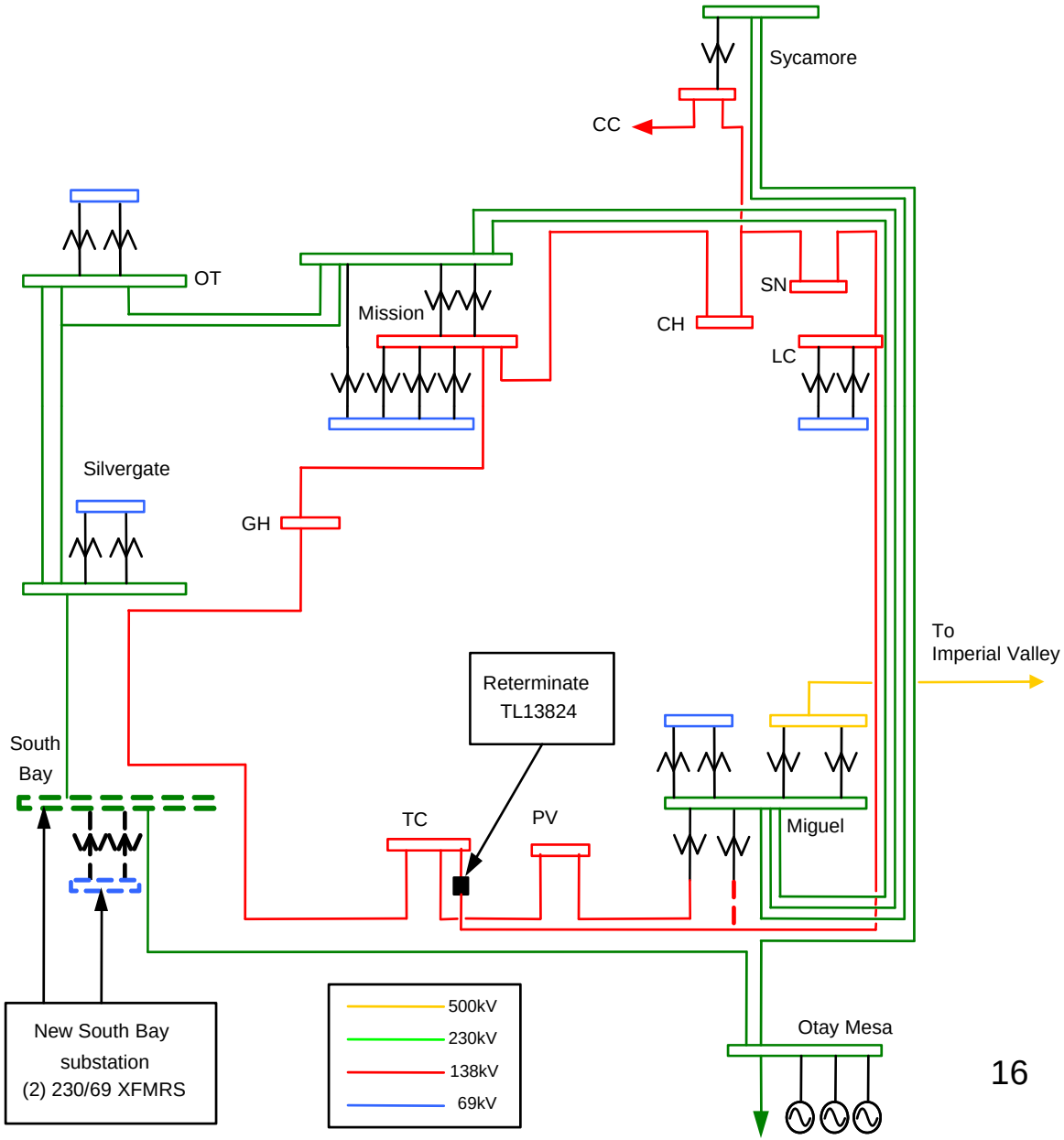
- Structures not to seismic standards
- Breakers scheduled for replacement
- Bus undersized and poor configuration

Generation Retirement

- Port lease expires in November 2009
- New source for South Bay 69kV bus needed
- Sunrise Powerlink and Otay Mesa will allow retirement

ISSUES:

- South Bay bank 50 sole source for South Bay 69kV bus with retirement of SBPP



South Bay Substation Relocation & Miguel 230/138kV Transformers

Budget Project 06132/6133

Transmission Planning

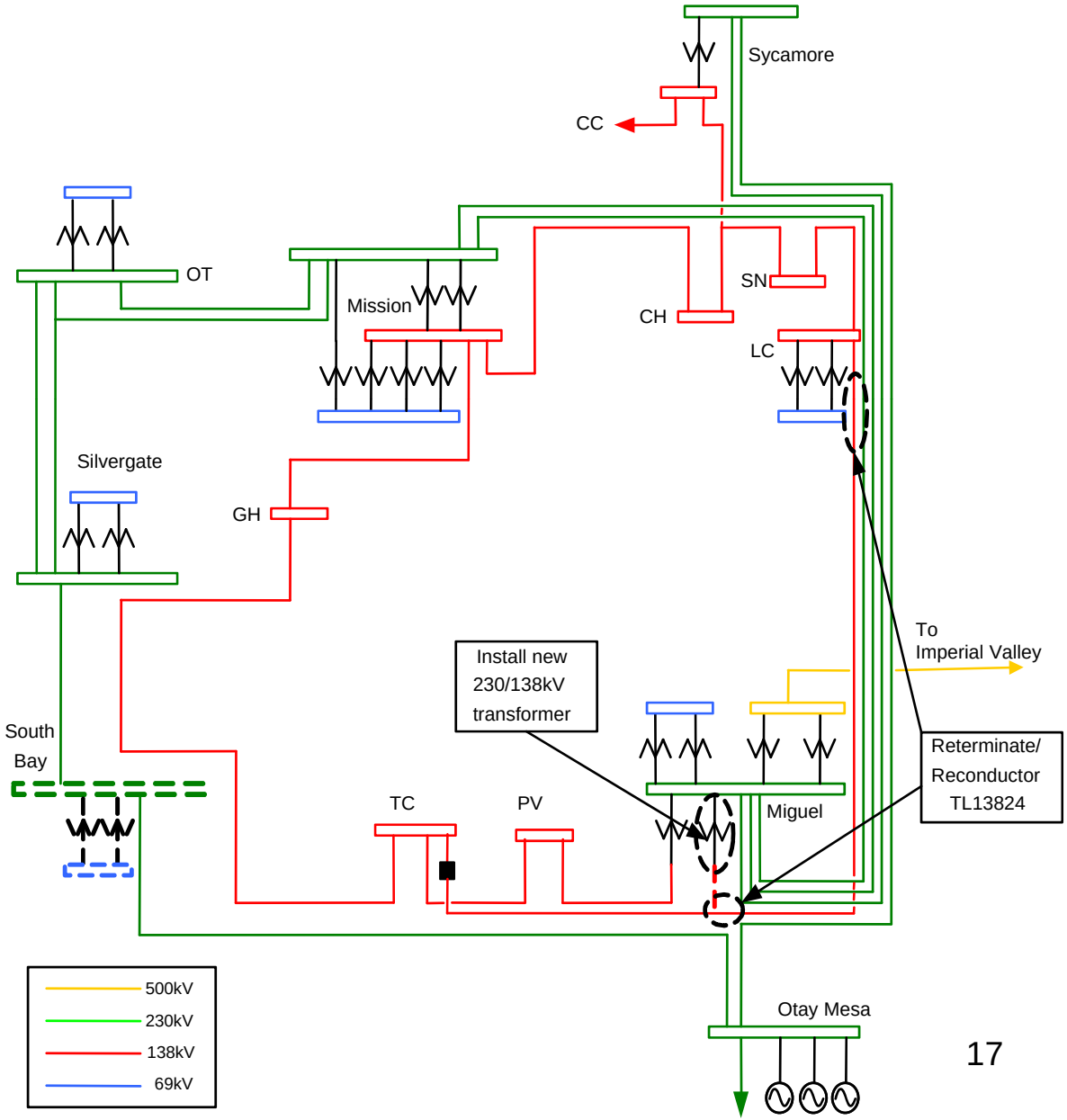
SCOPE:

- **06132 - Construct new 230/69kV substation at South Bay and loop in TL23042**
- **Tie together TL13815 & TL13823 at South Bay site**
- **Reconductor two small portions of TL13824**

- **06133 - Install new 230/138kV transformer at Miguel, tap into TL13824**

STATUS: Proposed in 2007

IN-SERVICE DATE:
Dec. 2011 (BP06132)
Jun. 2011 (BP06133)



New 500/230/69 kV Substation: ECO

Budget Project 07139

Transmission Planning

DRIVING FACTOR:

- Facilitate interconnection of Renewable Generation
- Improve reliability to the Boulevard and Crestwood Substations (maintenance, operations, outage restoration)

SCOPE:

- Construct new 500/230/69 kV ECO Substation
- Loop SWPL into ECO Substation
- Rebuild Boulevard Substation
- Construct new ECO-BU 69 kV line

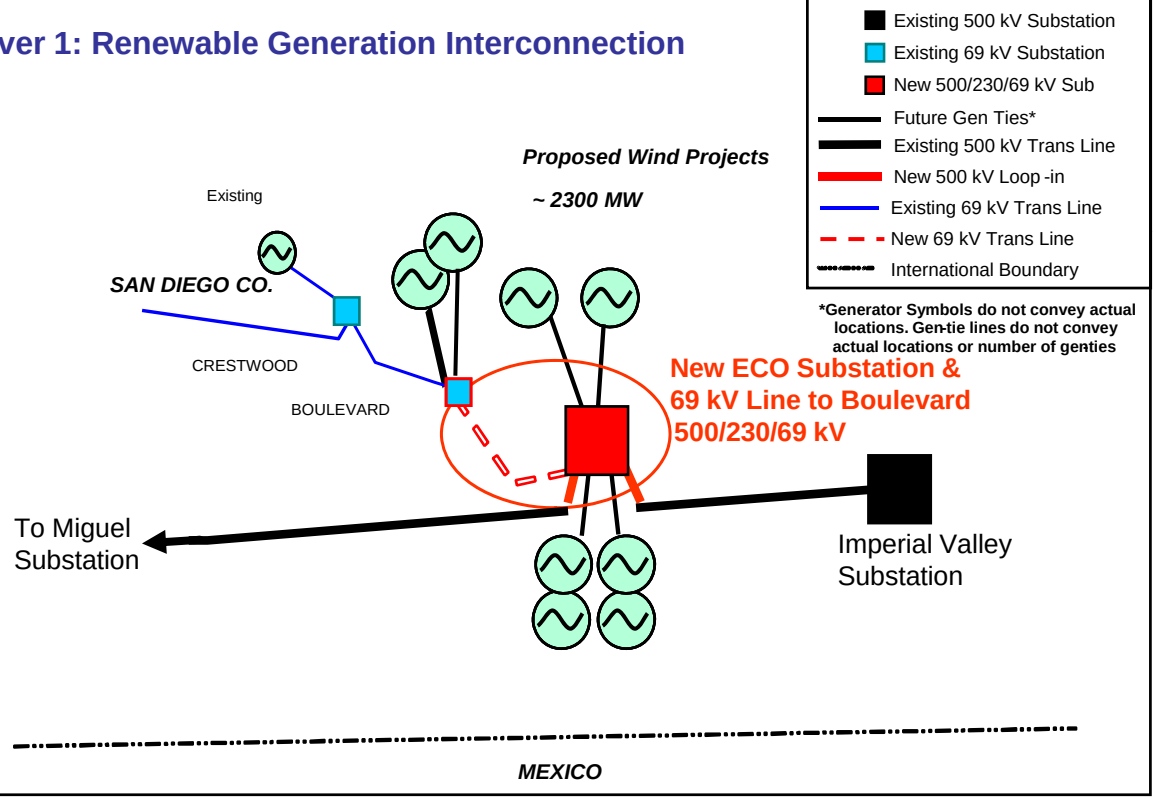
STATUS: Newly Proposed

IN-SERVICE DATE: Sep 2011

New 500/230/69kV Substation & New 69kV Tie Line to BU

Proposed System (not to scale)

Driver 1: Renewable Generation Interconnection



Orange County Transmission Expansion

Budget Project 06129

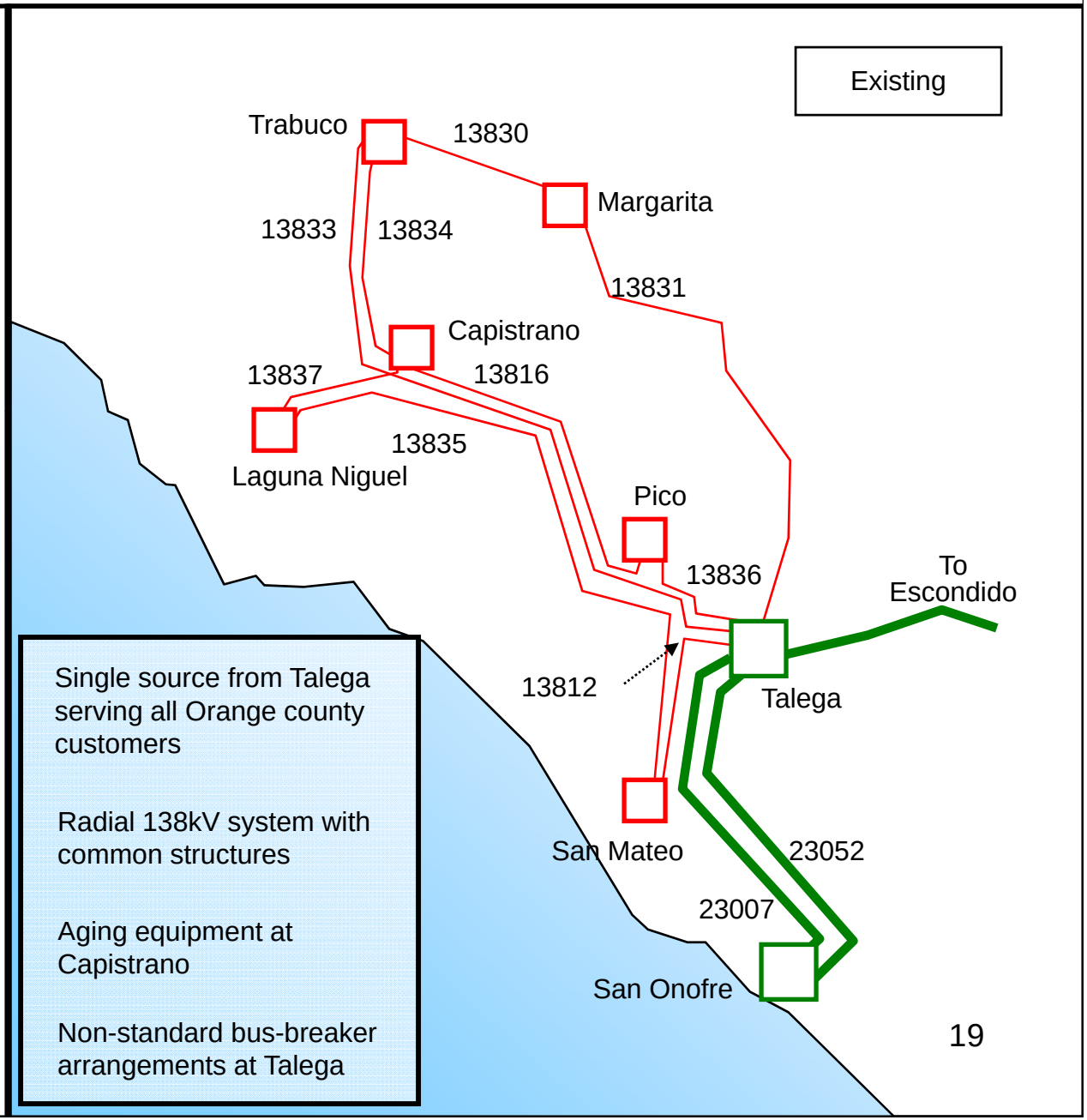
Transmission Planning

DRIVING FACTORS:

- Develop long range plan to meet the area load growth and service reliability

ISSUES:

- Bus breaker arrangements at Talega
- Single event could drop the entire Orange County load
- Radial configuration of 138kV system in Orange County
- Common structures on 138kV system
- Load growth, 457MW (in 2006) to 515MW (in 2016)



Single source from Talega serving all Orange county customers

Radial 138kV system with common structures

Aging equipment at Capistrano

Non-standard bus-breaker arrangements at Talega

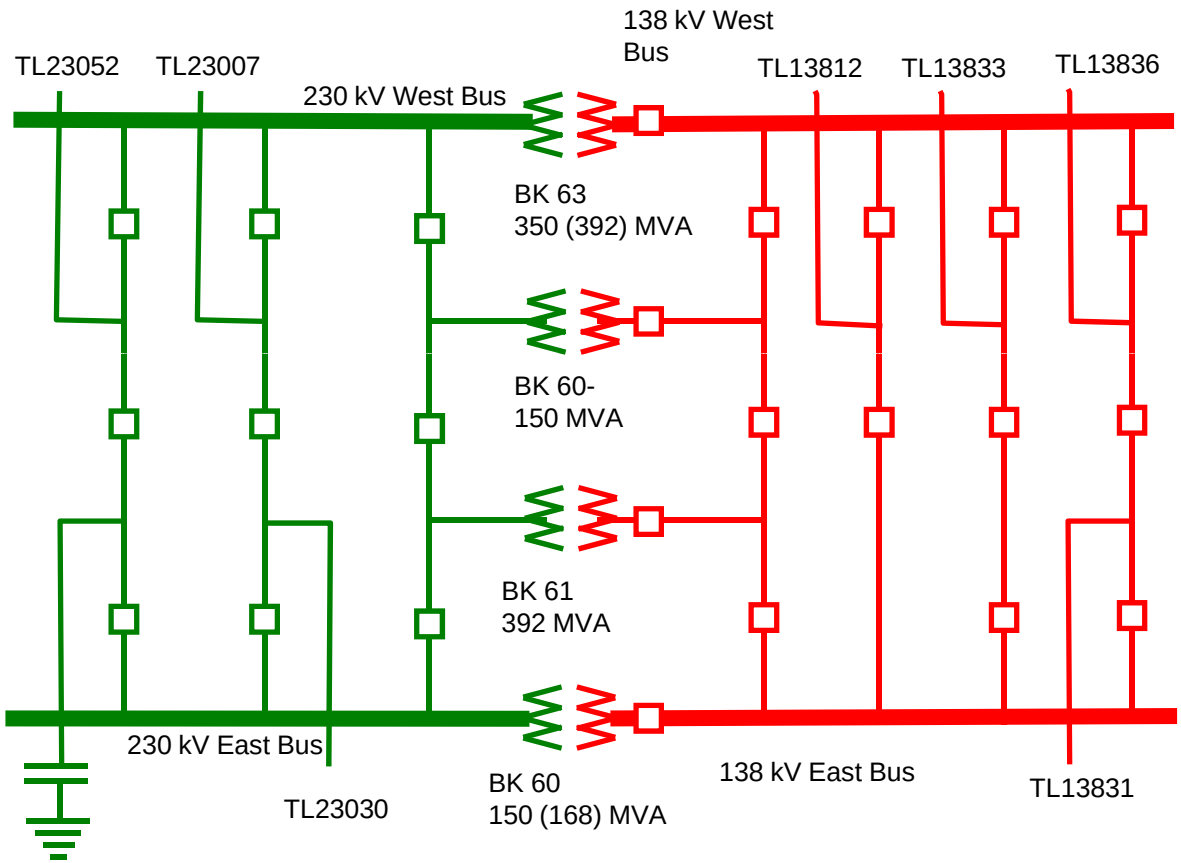
Orange County Transmission Expansion

Budget Project 06129

Transmission Planning

ISSUES:

- **Bus/breaker arrangements inadequate at Talega Substation**



Orange County Transmission Expansion

Budget Project 06129

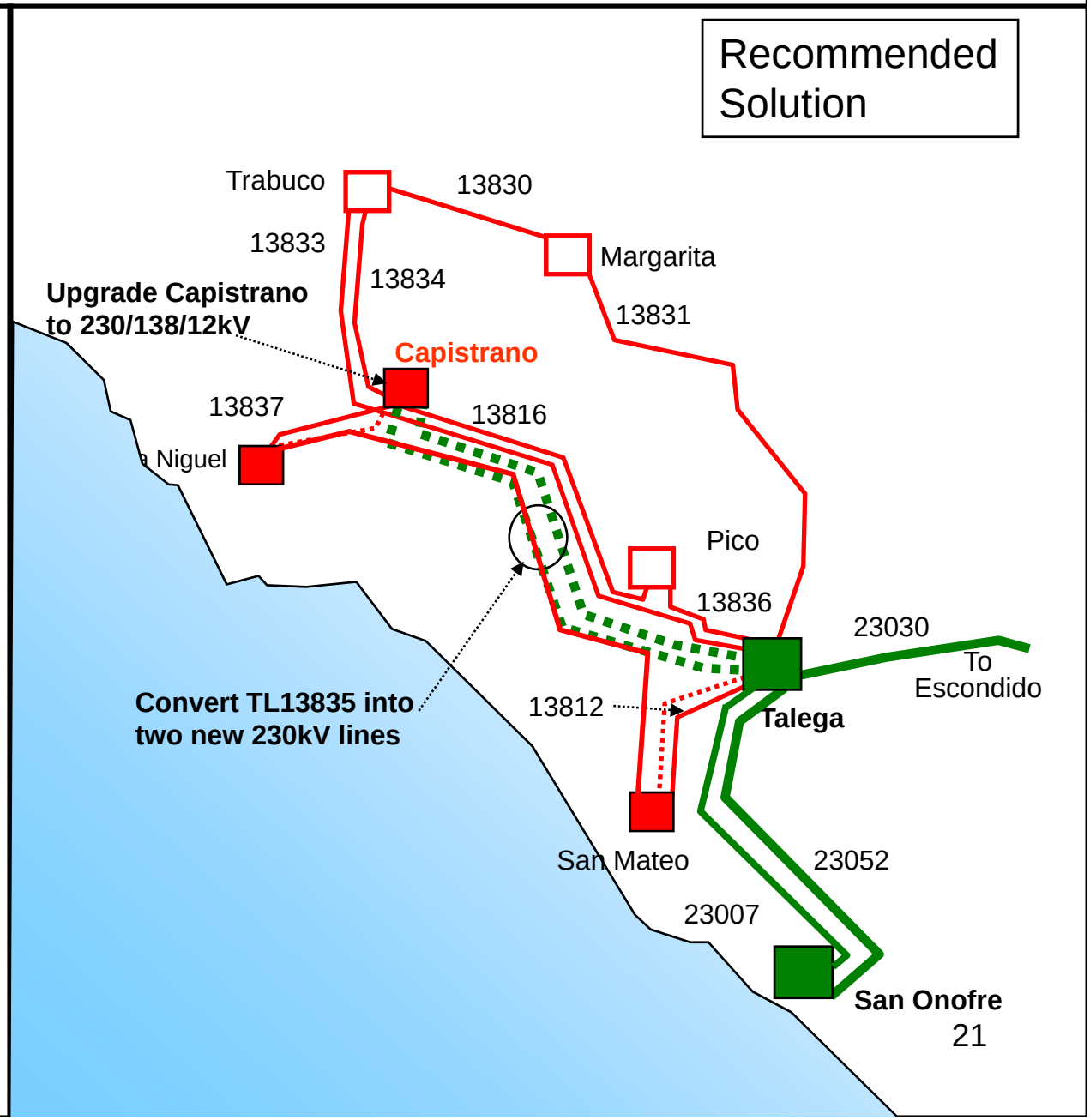
Transmission Planning

SCOPE:

- Construct a 230/138/12kV substation at Capistrano
- Construct two new 230kV lines by rebuilding the existing TL13835 with double 230kV structures between Talega and Capistrano (8 miles).

STATUS: Newly Proposed

IN-SERVICE DATE: Oct 2013



Projects with a Change in Scope or ISD

UpgradeTL13802B & D

Budget Project 00154

Transmission Planning

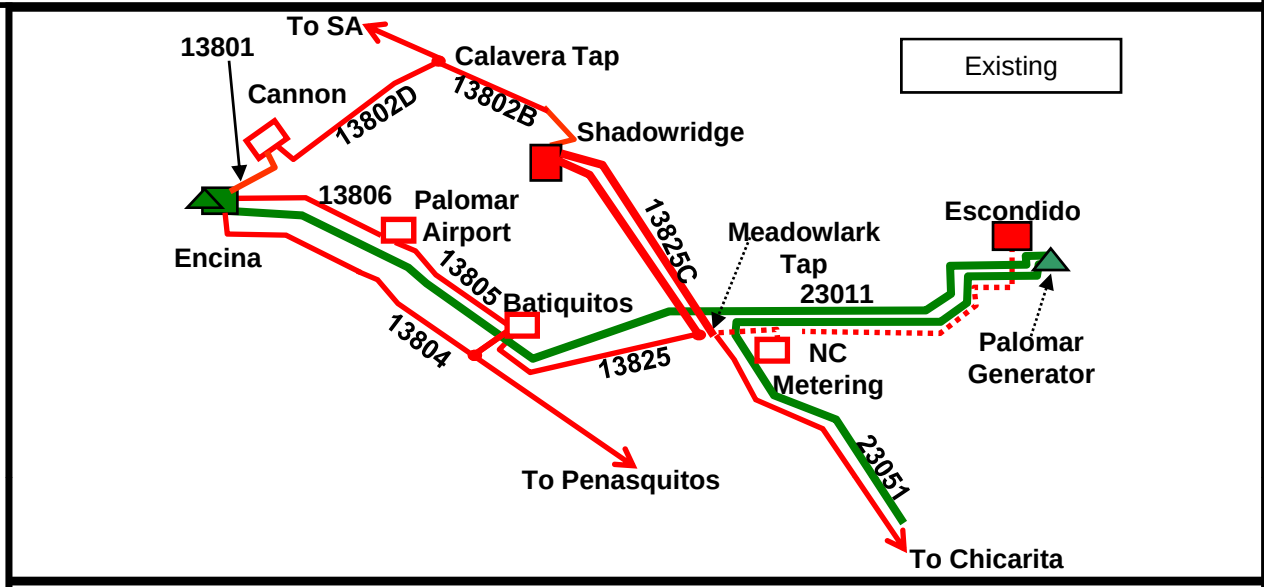
DRIVING FACTORS:
Meet load growth and improve Encina generation dispatch capability

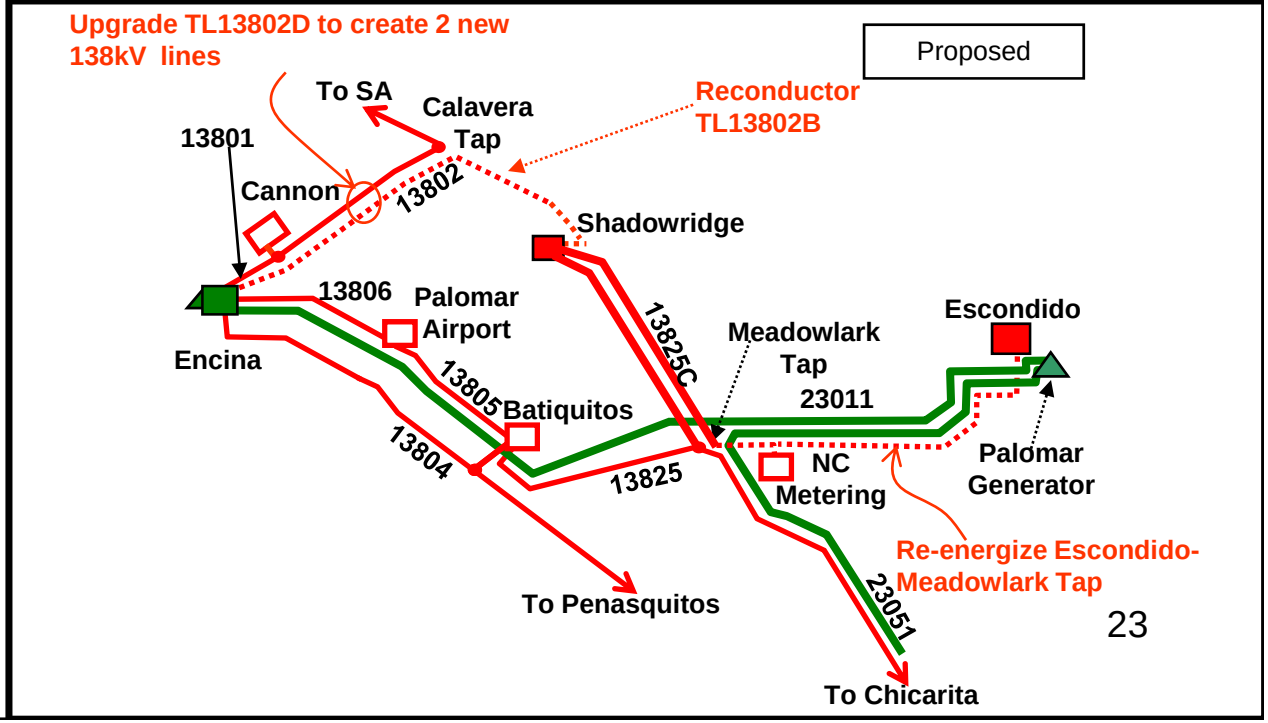
ISSUES: N-1 (TL13804)
3% overload on TL13802D
6% overload on TL13802B
11% overload on SA 138/69kV Bank

SCOPE:
- Rearrange TL13801 & TL13802 by using the existing open wire on the tower and adjacent 12kV line (insulated for 138kV) to form two new 138kV circuits (CAN-SA and EA-SH).
- Upgrade the existing 400 CU with 274MVA rated conductor for the proposed new lines.
- Reconductor TL13802B (Calavera Tap-Shadowridge) to 274MVA.
- Re-energize Escondido-Meadowlark Tap

STATUS: Approved

IN-SERVICE DATE: June 2010





Canceled Projects

Reconductor Talega-San Mateo (TL13812)

Budget Project P061XY

Orange County

DRIVING FACTOR:
- Load Growth

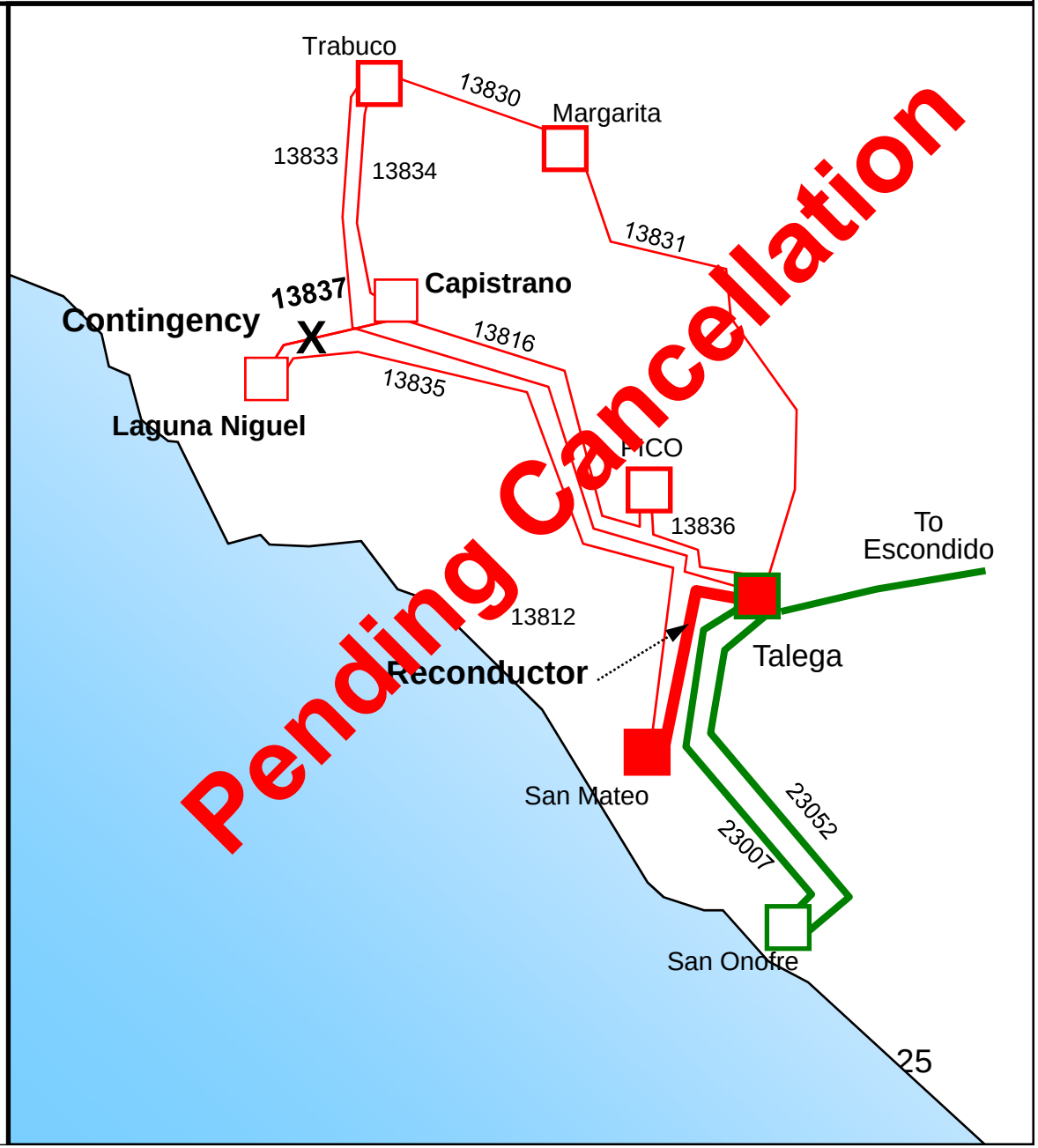
ISSUES:
- N-1 (TL13837) causes an overload on TL13812

SCOPE:
- Reconductor 3.5 miles of TL13812 from 336.4 ASCR/AW to 1033.5 ACSR/AW

- This will increase the rating from 137 MVA to 274 MVA

STATUS: Approved

IN-SERVICE DATE: June 2009
Cancelled pending approval of P08158



Reconductor Capistrano-Laguna Niguel (TL13837)

Budget Project 00153

Transmission Planning

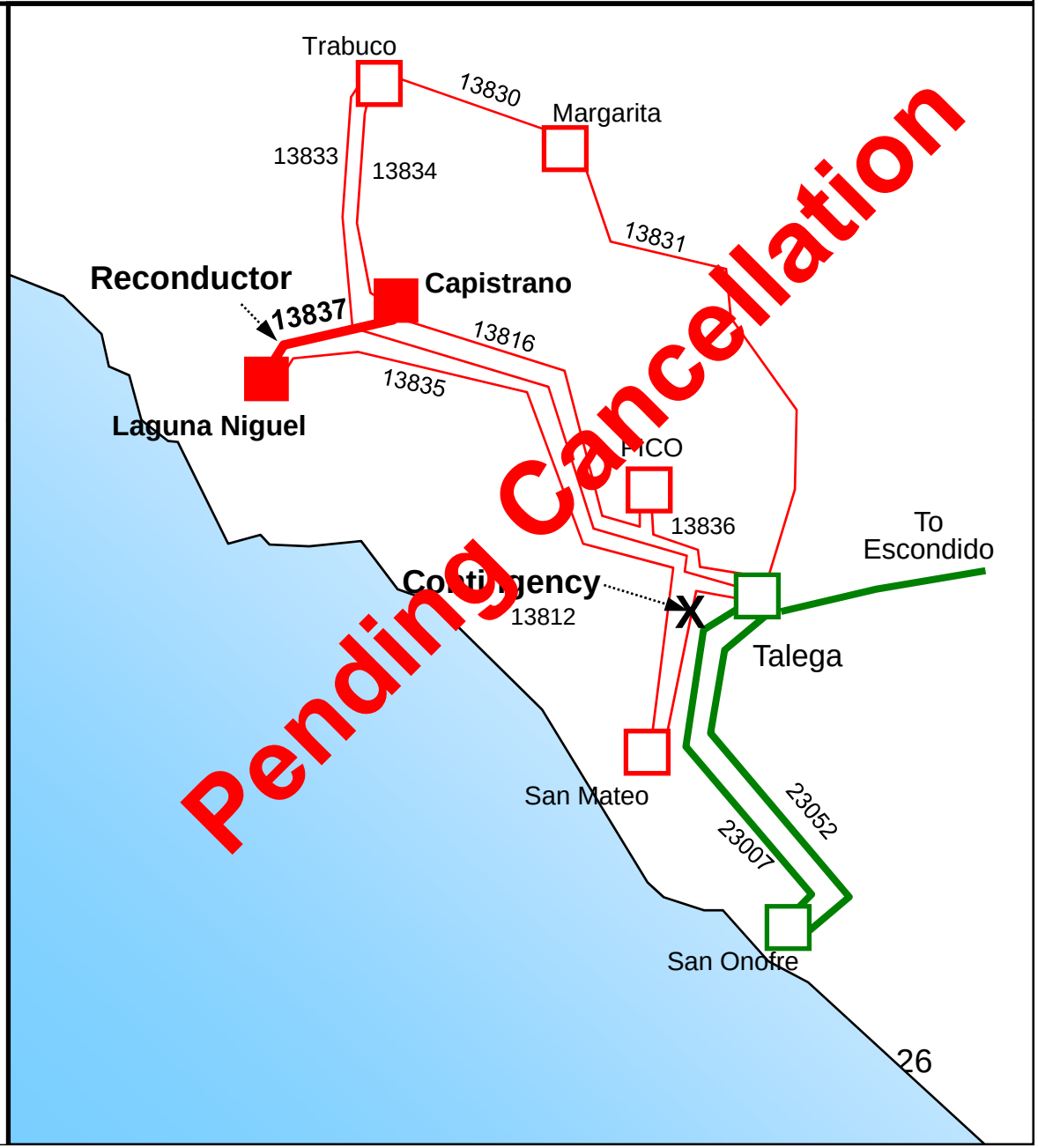
DRIVING FACTOR:
- Load growth

ISSUES:
- N-1 (TL13812) causing over on TL13837

SCOPE:
- Reconductor 3 miles of TL13837 from 136MVA (336ACSR) to 274MVA (OH and UG)

STATUS: Approved

IN-SERVICE DATE: June 2009
Cancelled pending approval of P08158



Projects with No Changes

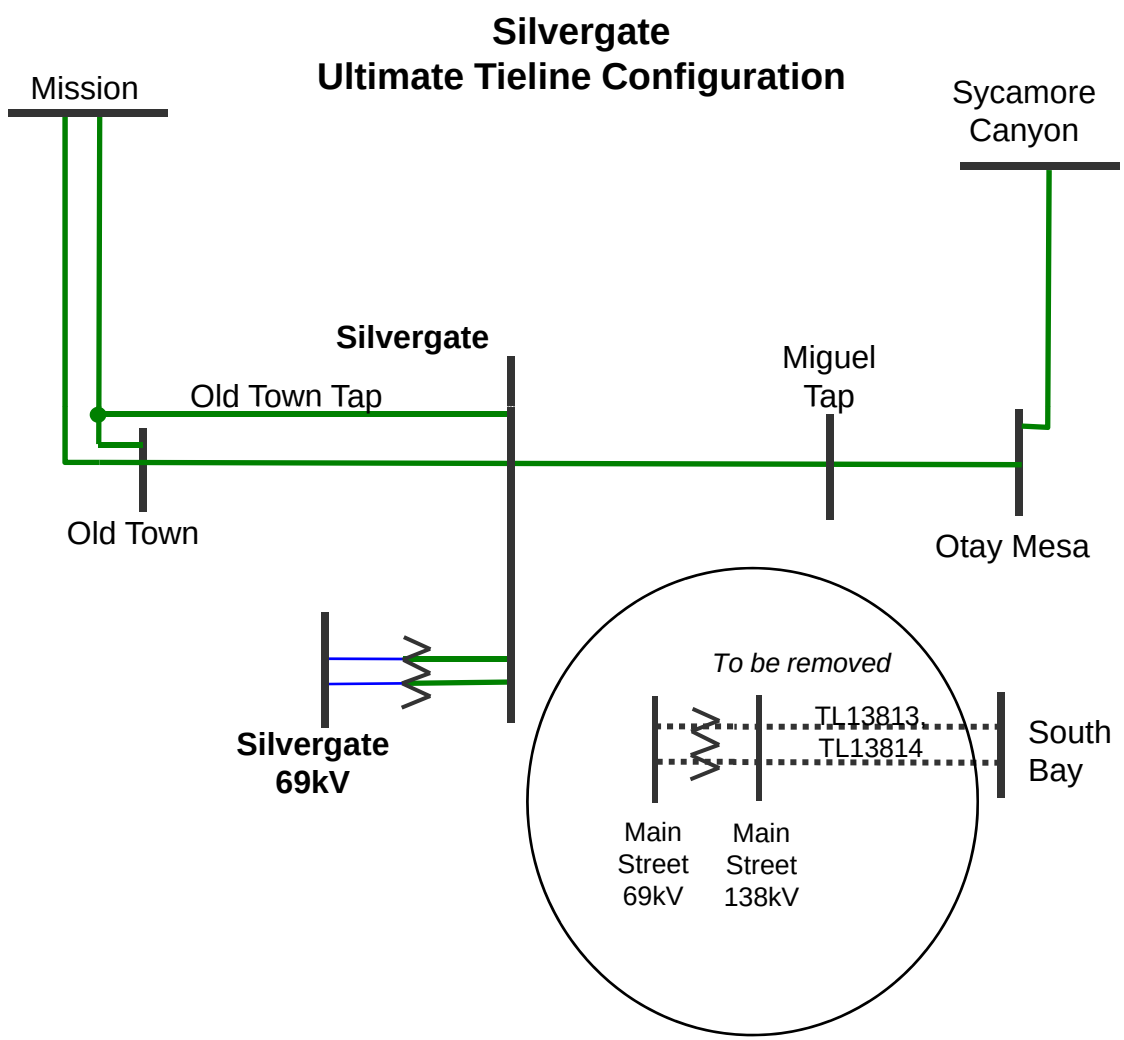
Silvergate 230/69kV Substation — Budget Project 03170 — Transmission Planning

DRIVING FACTORS:
- Aging infrastructure
- Increase transmission reliability
- Increase substation reliability

SCOPE:
- Construct 230/69kV switchyard on former Silvergate power plant site to replace Main St. 138/69kV Substation
- Loop in Otay Mesa - Old Town 230kV line
- Remove existing TL13813, TL13814
- Move seven Main St. 69kV lines to Silvergate

STATUS: Approved

IN-SERVICE DATE: Dec. 2008



Loop-in TL13825: Shadowridge

Budget Project 06131

Transmission Planning

DRIVING FACTORS:

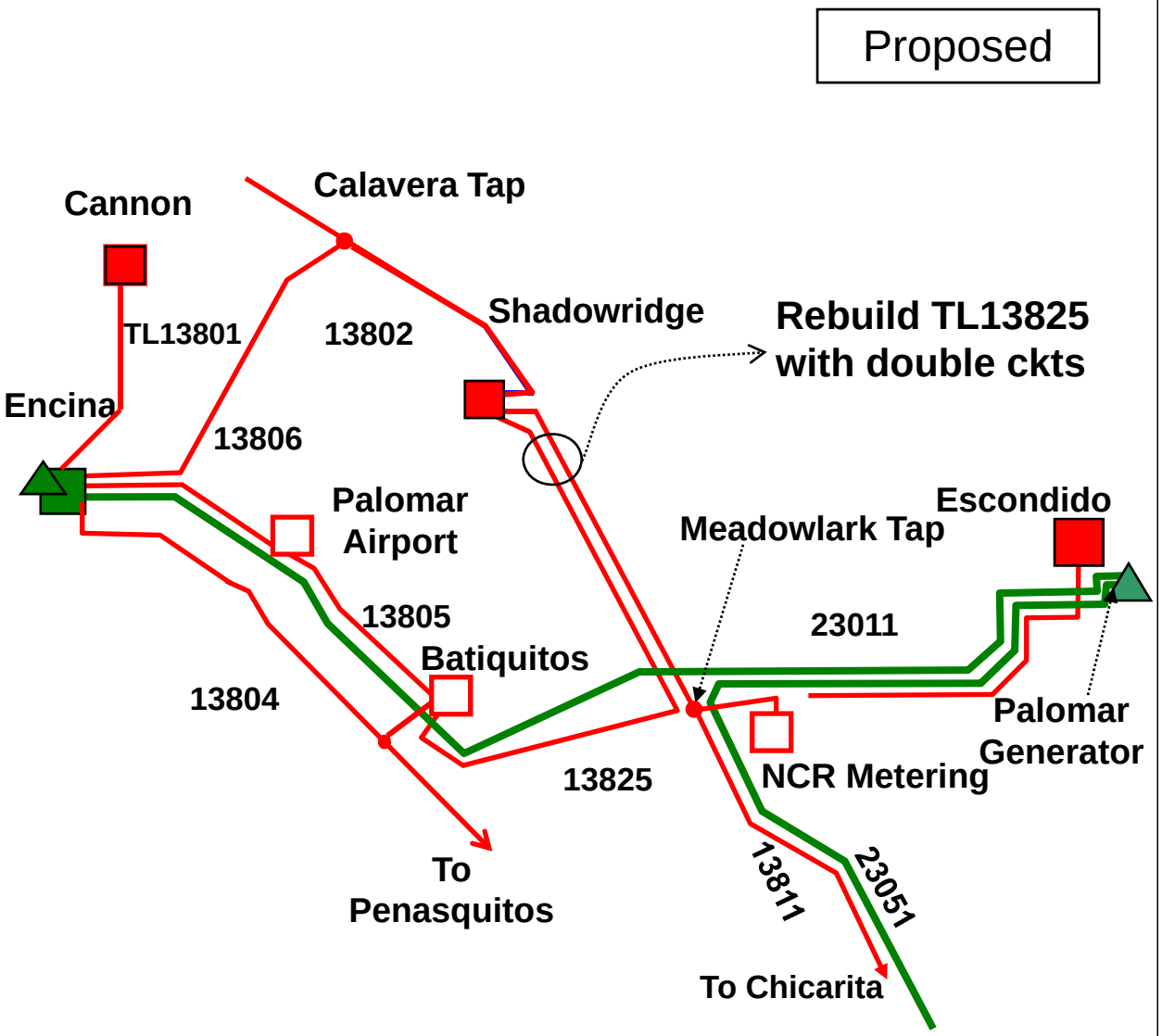
- N-1: Loss of Encina-Cannon (TL13801) causing 28% overload on TL13825 (Shadowridge-Meadowlark Tap).
- Support the proposed dist. load transfer and new substation (Ocean Ranch).

SCOPE:

Rebuild 3.5 miles of TL13825 with a double circuit for new Batiquitos - Shadowridge and Chicarita - Shadowridge
A new breaker at Shadowridge

STATUS: Approved

IN-SERVICE DATE: June 2009



Reconductor TL6915, TL6924: Pomerado-Sycamore

Budget Project 07146

Transmission Planning

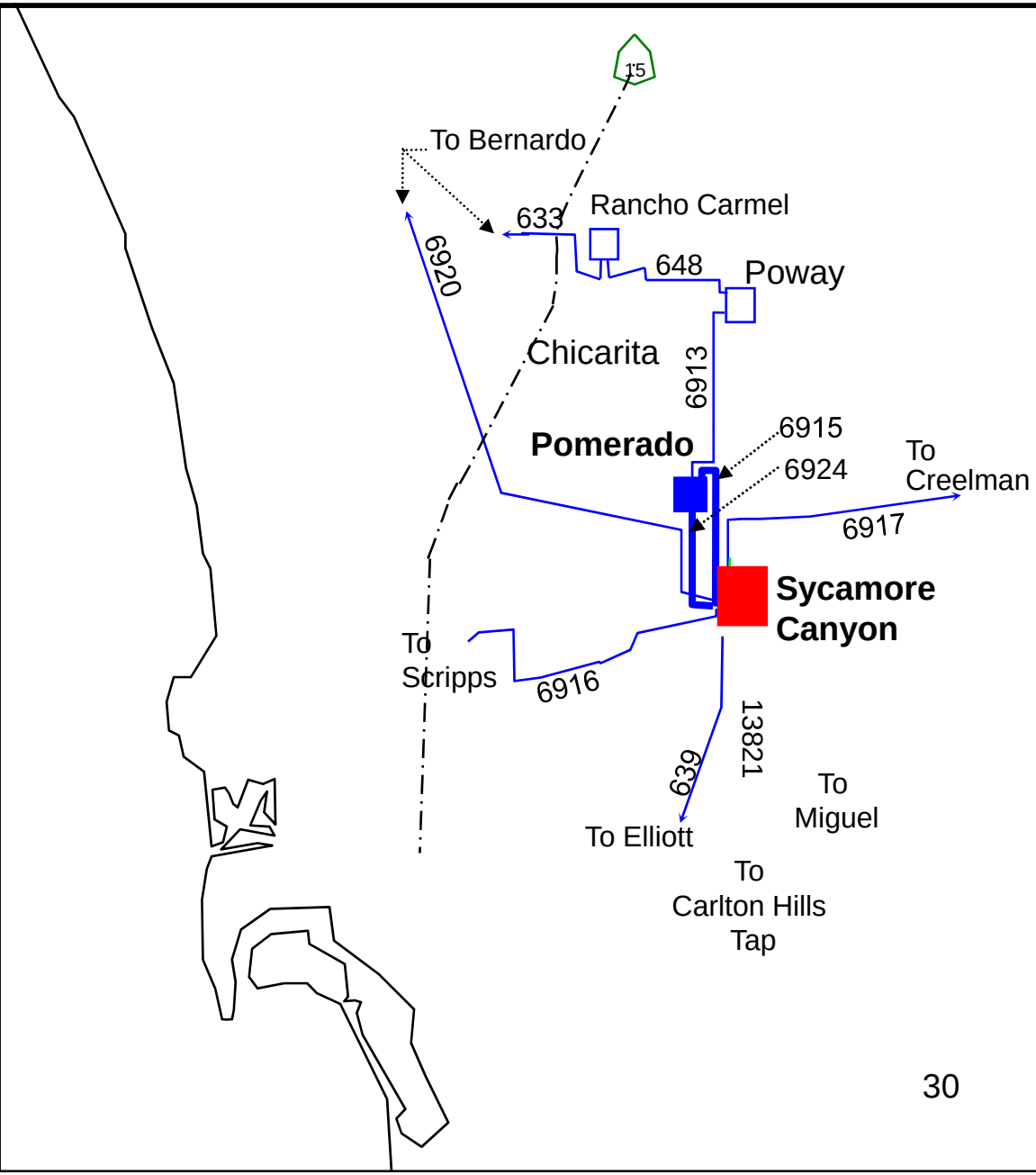
DRIVING FACTORS:
- Load Growth

ISSUES:
- N-1 of either TL6915 or TL6924 overloads the remaining line above emergency rating

SCOPE:
- Replace approximately 2000' of 1750 AL UG cable with 3000 kcmil Cu

STATUS: Approved

IN-SERVICE DATE: June 2009



Reconductor Escondido-Felicita Tap (TL689)

Budget Project 05153

Transmission Planning

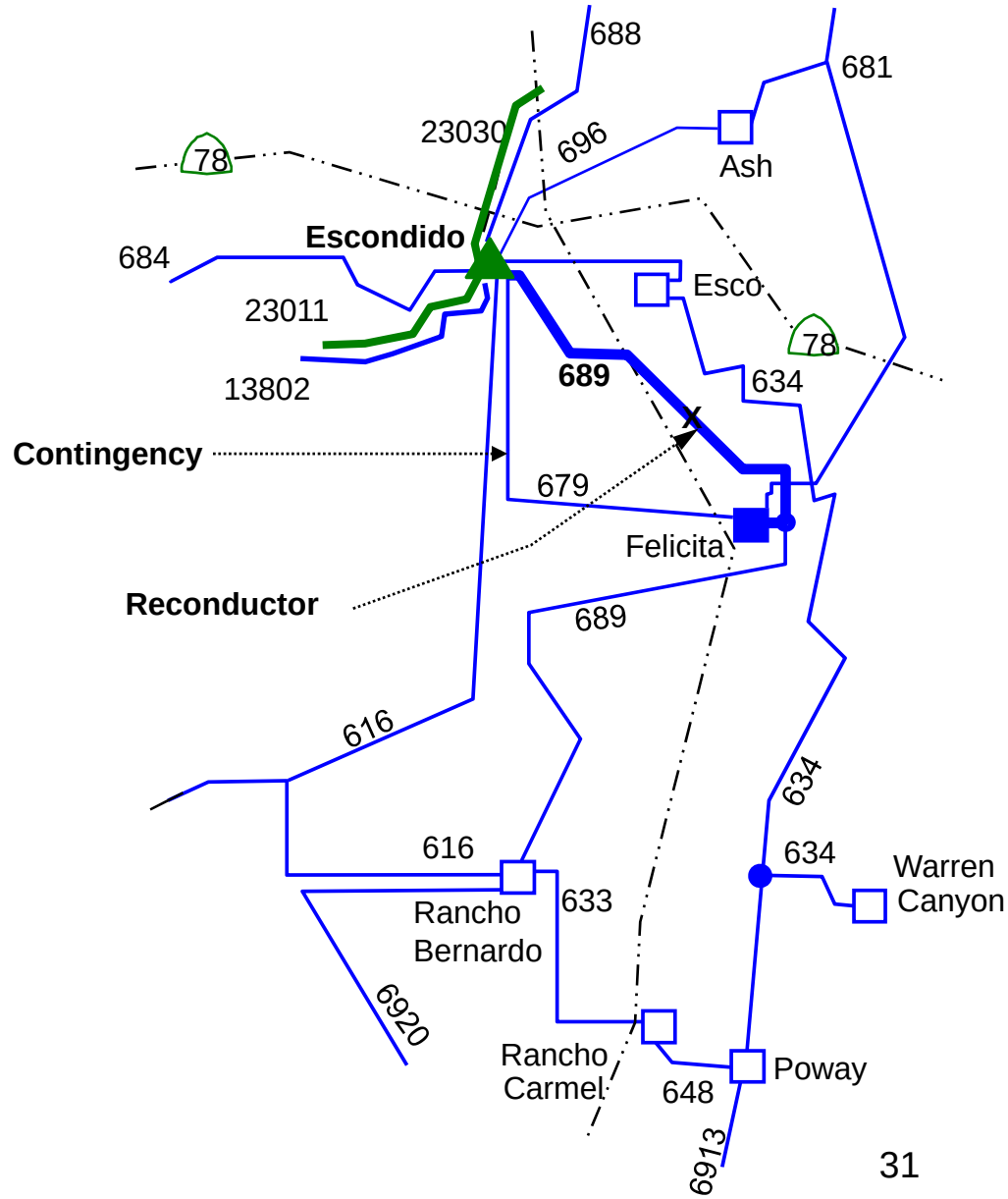
DRIVING FACTOR:
- Load growth

ISSUES:
- N-1(TL679), 2% overload
- N-1(TL679), Low Encina Gen 5% overload
- N-1/ G-1(TL696 & Goal Line), 7% overload

SCOPE:
- Reconductor 4.6 miles of 636 ACSR\AW with 900ACSS\AW to improved normal rating from 102 MVA to 212 MVA.

STATUS: Approved

IN-SERVICE DATE: June 2009



Reconductor Talega-Pico (TL13836)

Budget Project 01141

Transmission Planning

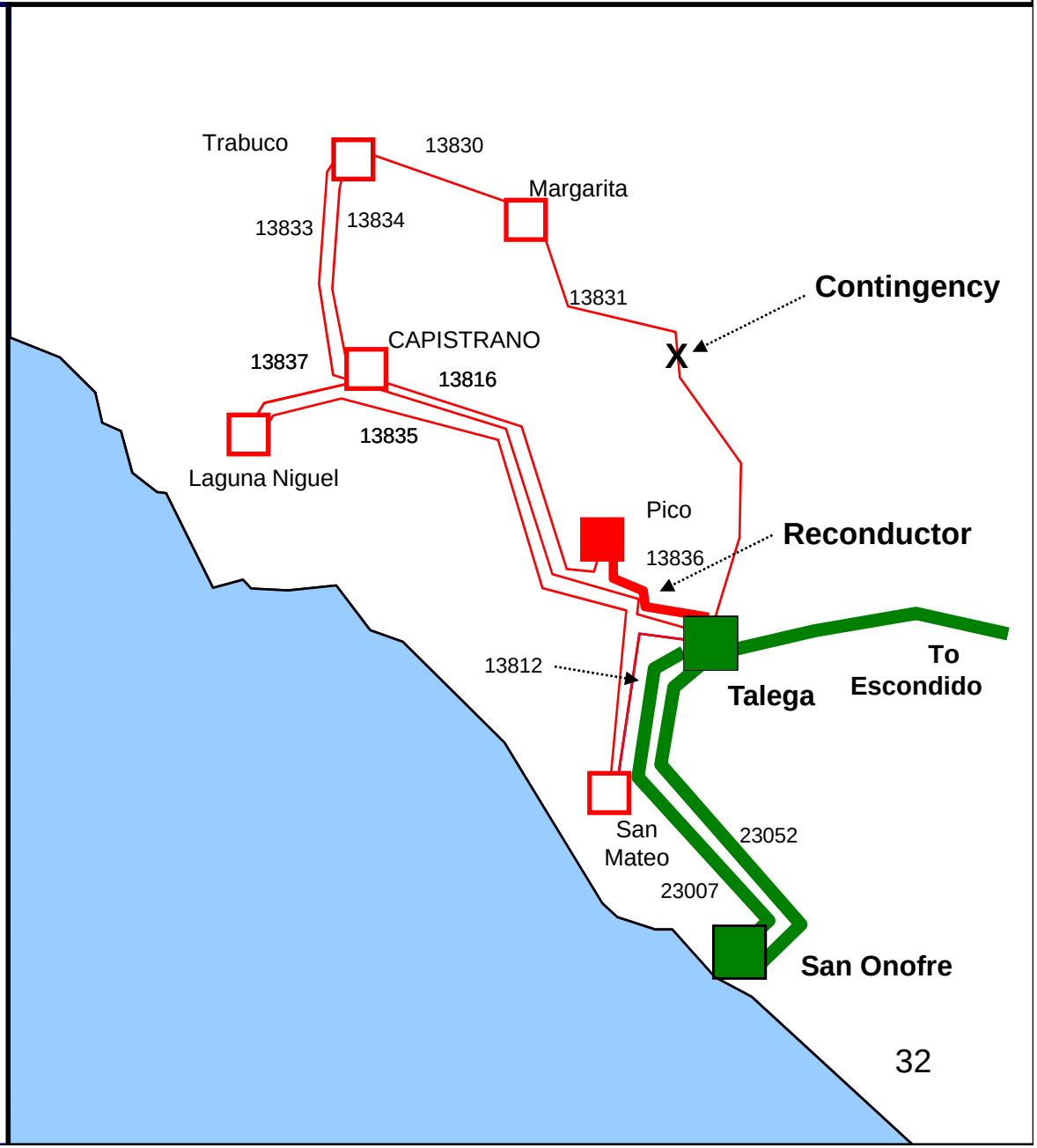
DRIVING FACTOR:
- Load growth

ISSUES:
- N-1 (TL13812) or (TL13831), TL13836 loaded at 100% normal capacity

SCOPE:
- Reconductor 0.7 mile of 636ACSR with 1033ACSR

STATUS: Approved

IN-SERVICE DATE: June 2009



New Division – Naval Station Metering Line #2

Budget Project 04137

Transmission Planning

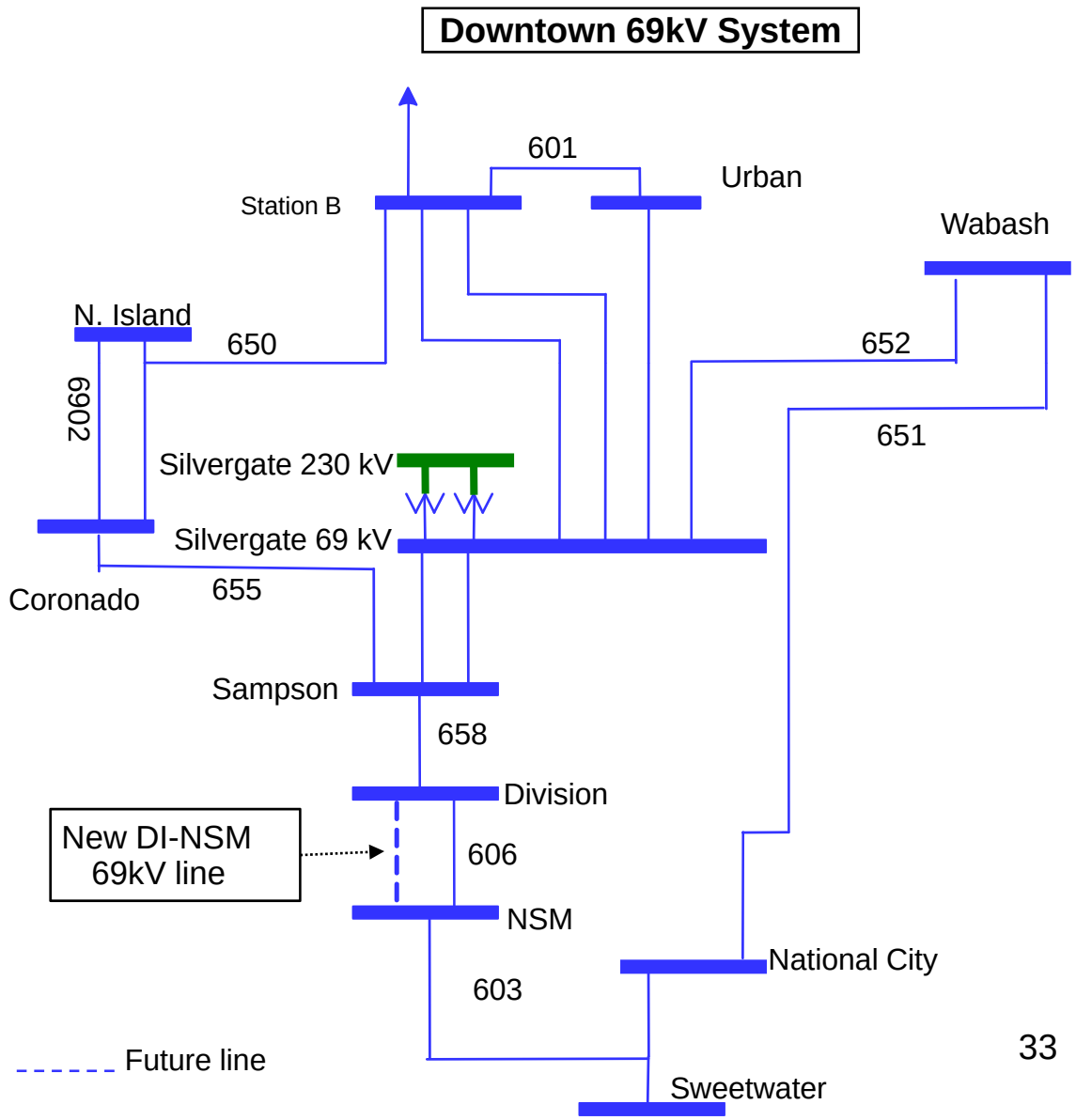
DRIVING FACTOR:
- Downtown load growth

ISSUES:
- Needed to eliminate overload on existing 69kV line between Division – Naval Station Metering line

SCOPE:
- Construct a second Division – Naval Station Metering line and rebuild existing TL606

STATUS: Approved

IN-SERVICE DATE: June 2009



Wabash – National City Loop-in (TL651)

Budget Project 06134

Transmission Planning

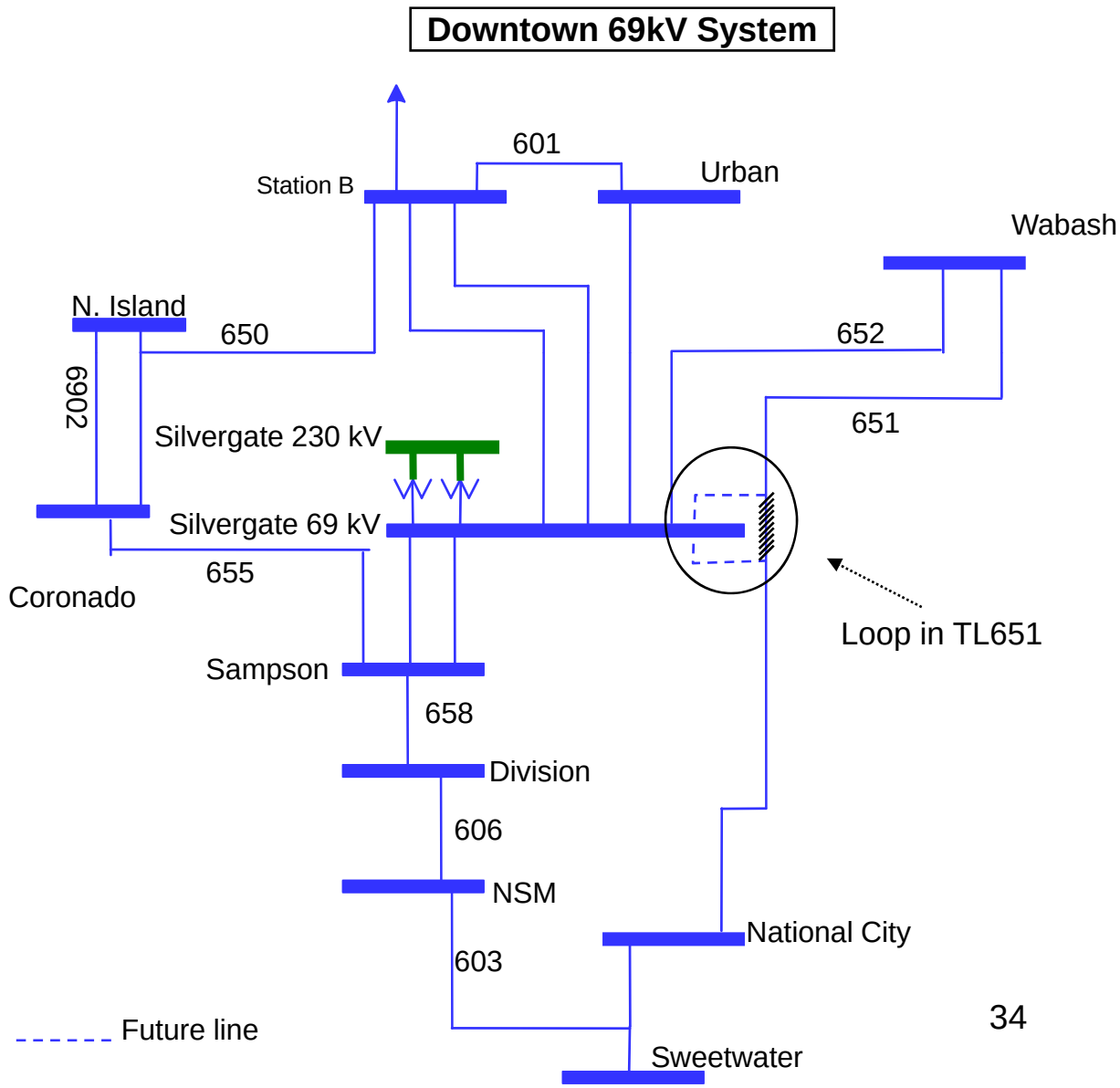
DRIVING FACTOR:
- Downtown load growth

ISSUES:
- Needed to eliminate an overload on the existing 69kV Wabash - Main St. line

SCOPE:
- Loop TL651 into Silvergate to form a new Wabash – Silvergate and Silvergate – National City
- Replaces Wabash – Silvergate reconductor project

STATUS: Approved

IN-SERVICE DATE: June 2009



Encina – Penasquitos 230kV #2

Budget Project 06130

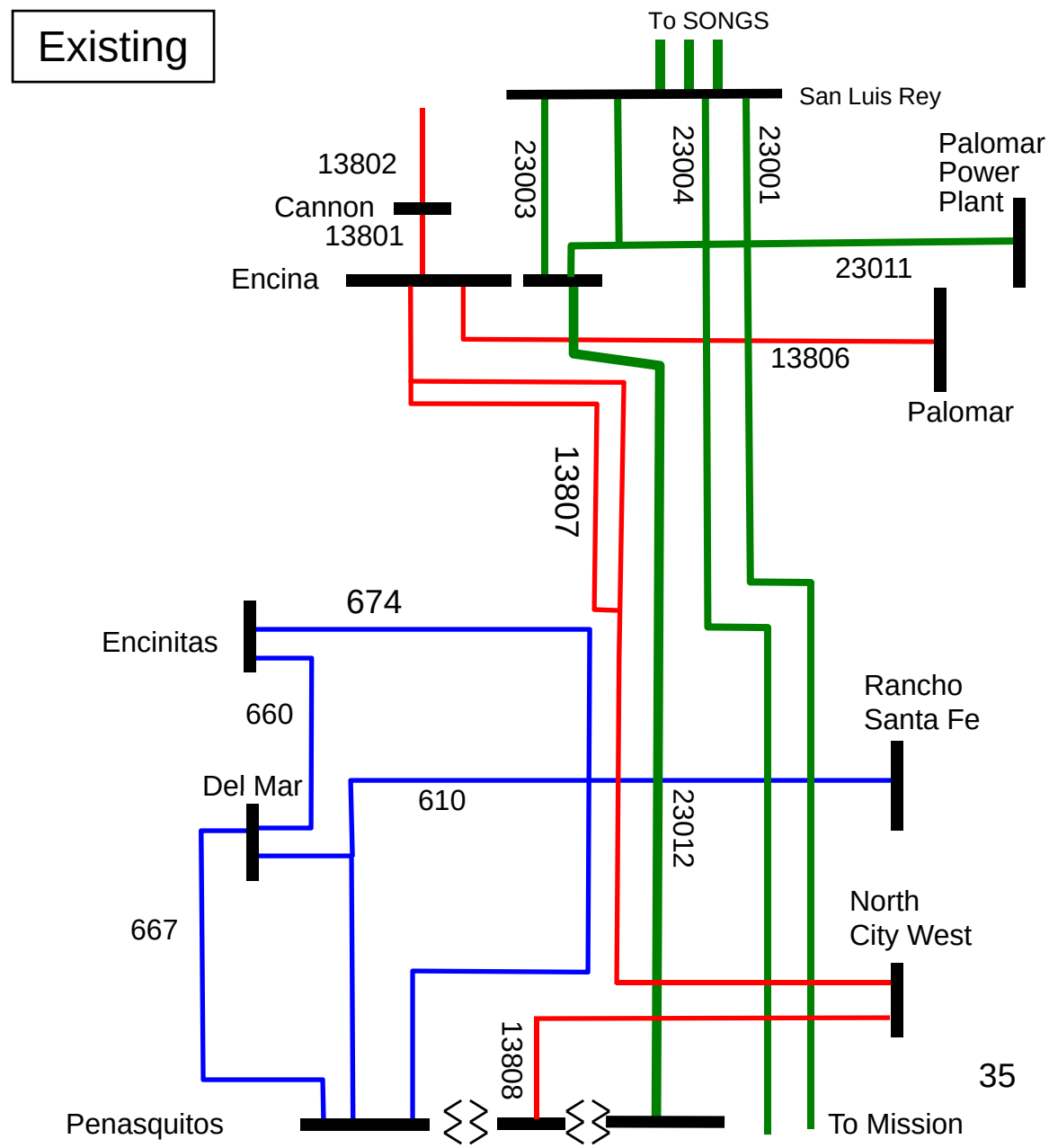
Transmission Planning

DRIVING FACTOR:

Support South of SONGS import and Encina & Palomar Power Plants dispatch

ISSUES:

- **When South of SONGS import at 2500 MW:**
- **N-1 (TL23012) overloads TL23001 & TL23004 by 6%**
- **N-1 (TL23001 or TL23004) overloads TL23012 by 1%**
- **N-1 (23051) overloads TL23012 by 3.5%**



Encina – Penasquitos 230 kV #2

Budget Project 06130

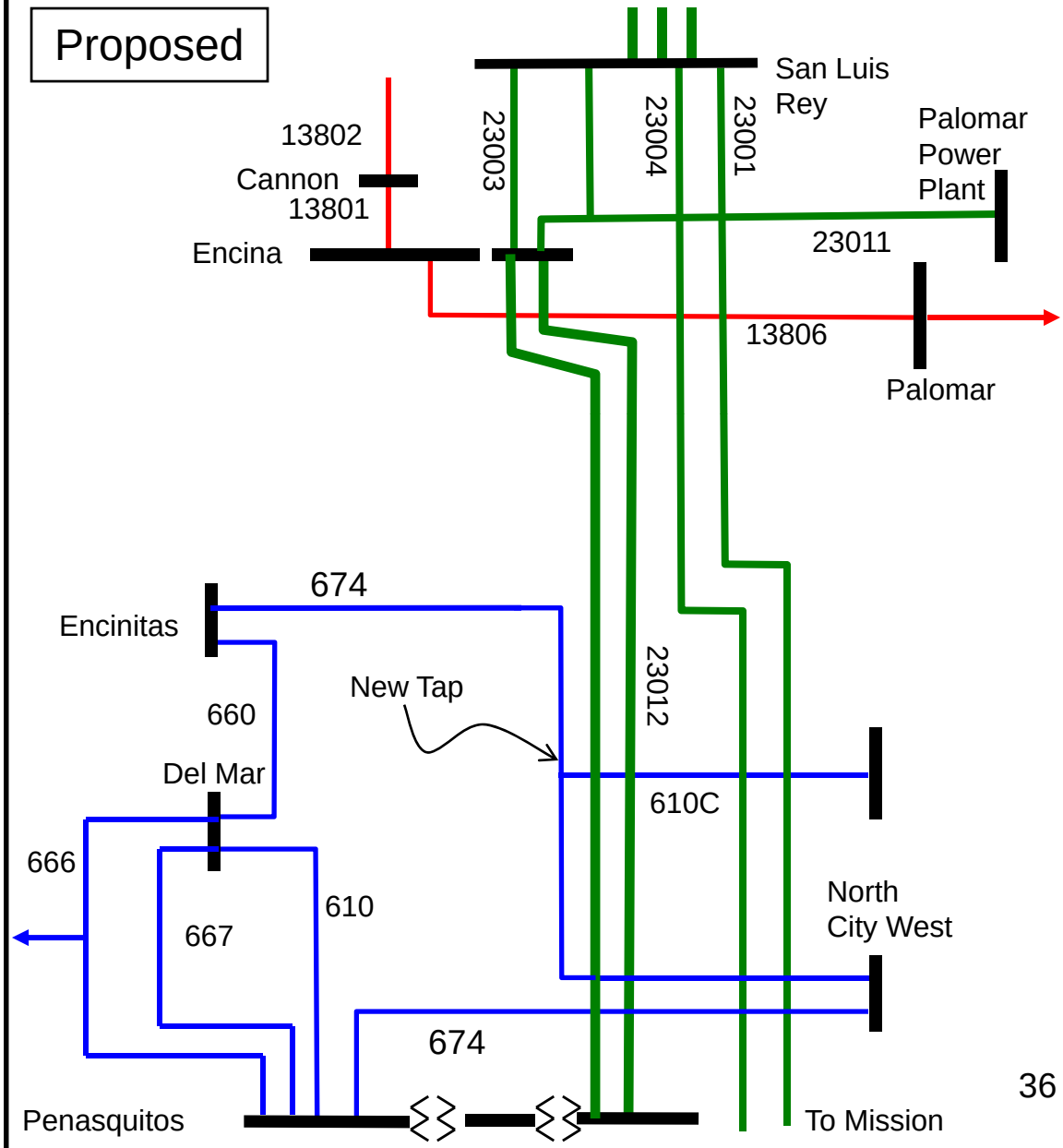
Transmission Planning

SCOPE:

- Convert TL13807 & TL13808 to 230 kV between EA-Penasquitos
- Upgrade 8 miles conductor with 2-1033 ACSR
- Convert North City West Sub from 138/12kV to 69/12kV and loop TL674 into North City West
- Connect Rancho Santa Fe tap to TL674 to form a new 69 kV line North City West-RSF-Encinitas
- Install two new 230 kV circuit breakers at PQ and one circuit breaker at Encina

STATUS: Approved

IN-SERVICE DATE: June 2009



Reconductor Los Coches – Alpine (TL678)

Budget Project 03183

Transmission Planning

DRIVING FACTOR:

- **Load growth**

ISSUES:

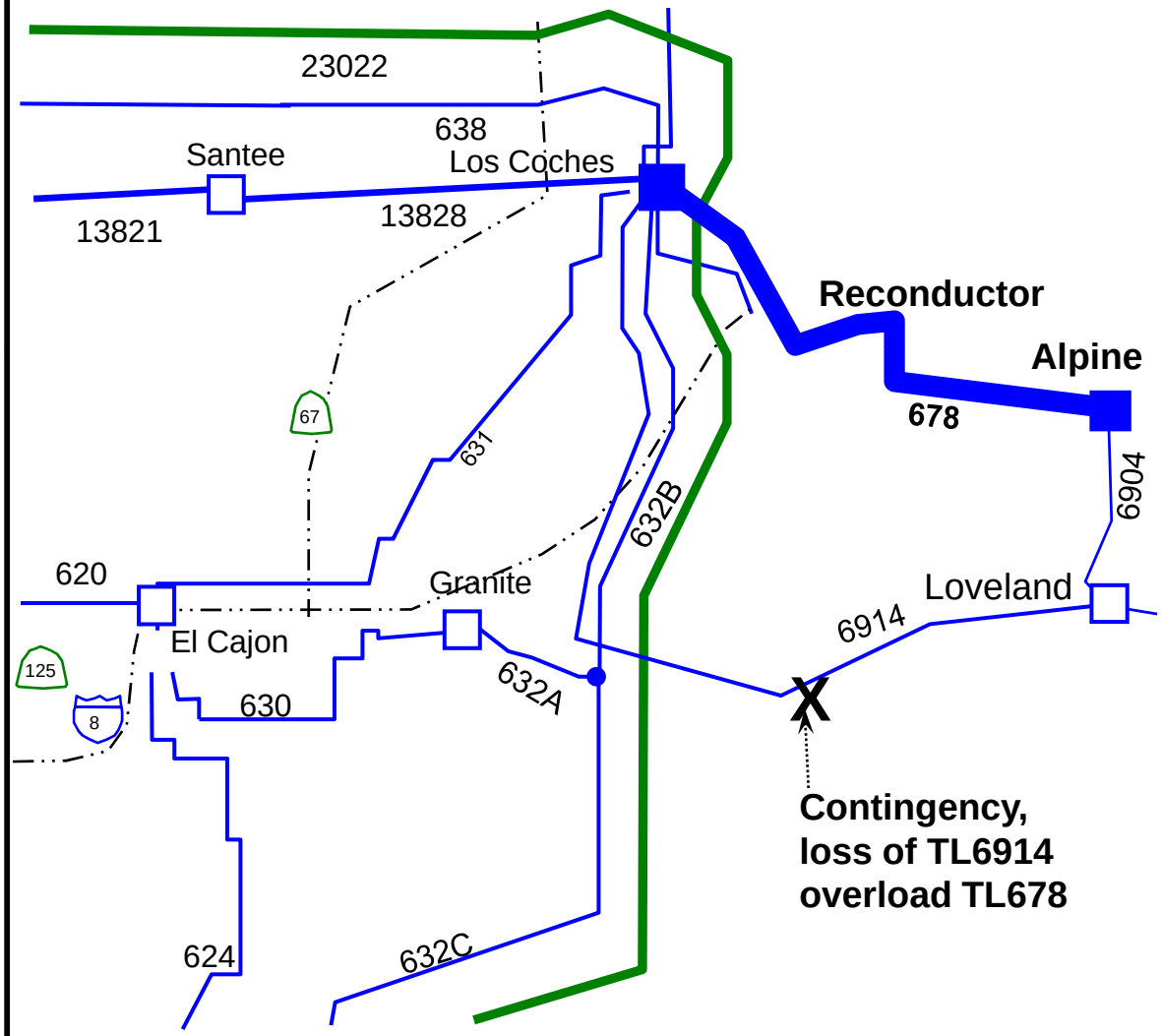
- **TL678 (Los Coches-Alpine) 2% overload for N-1 TL6914 (Los Coches-Loveland)**

SCOPE:

- **Reconductor 8.2 miles of TL678 (Los Coches-Alpine). To achieve a circuit rating of 95MVA**

STATUS: **Approved**

IN-SERVICE DATE: **Jun. 2010**



Reconfiguring TL13821 and TL13822

DRIVING FACTOR:

- High import causes overload on Sycamore-Carlton Hills Tap 138kV line (247MVA maximum rating)

ISSUES:

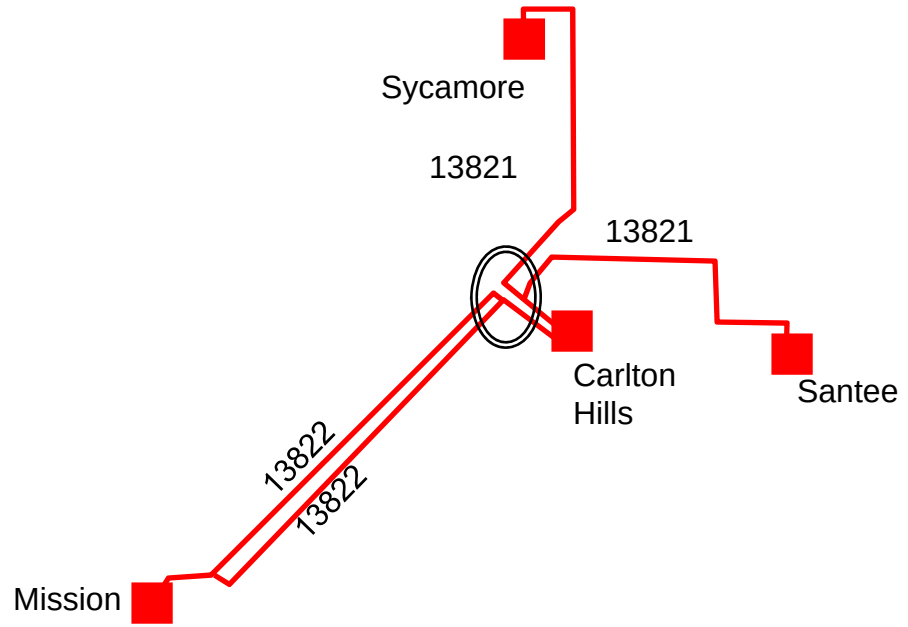
- 4% overload on Sycamore-Carlton Hills Tap 138kV line caused by N-1 outages: TL50001 (SWPL) or Silvergate-South Bay 230kV Line

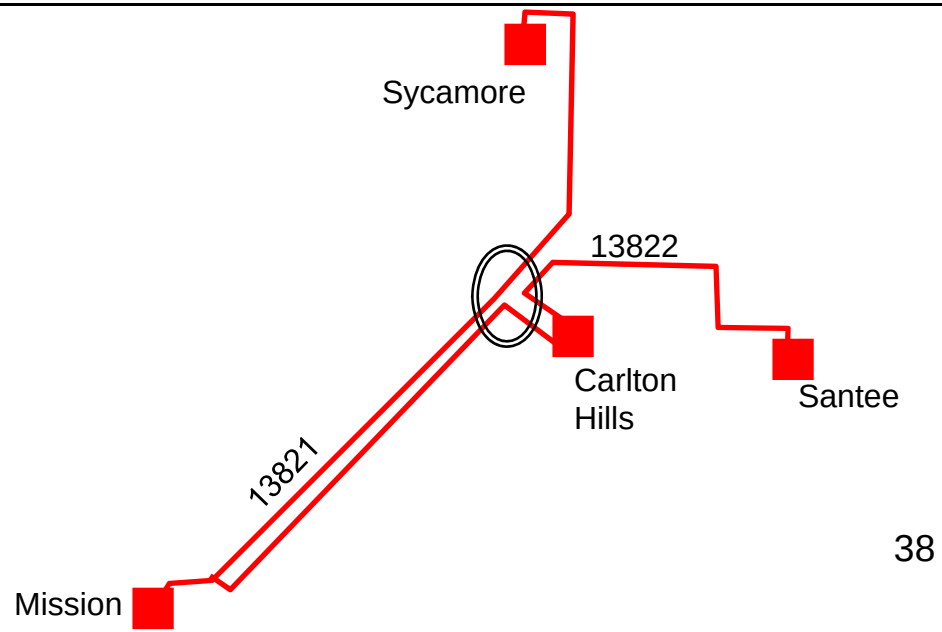
SCOPE:

- Rearrange TL13821 at Carlton Hills Tap and bypass Carlton Hills.
- TL13821 will become SX-MS-CH and TL13822 to CH-SN

STATUS: Approved

IN-SERVICE DATE: June 2010





Reconductor Lilac-Rincon (TL683)

Budget Project 01142

Transmission Planning

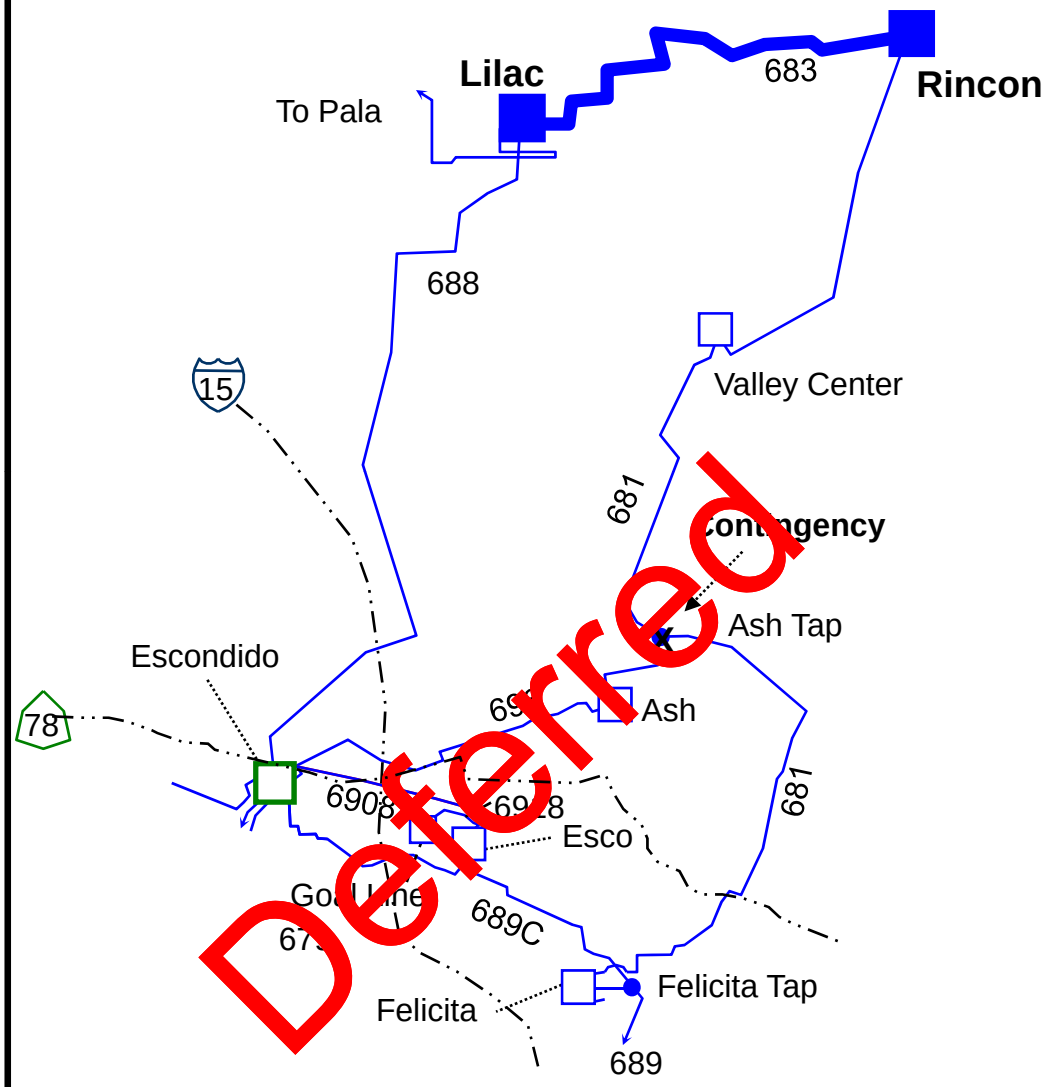
DRIVING FACTOR:
- Load growth

ISSUES:
- N-1 (TL681), highly loaded

SCOPE:
- Reconductor 12.2 miles of TL683 from 394.5/500AL (55MVA) to 1033 ACSR (137MVA)

STATUS: Approved

IN-SERVICE DATE: Deferred beyond 2013- potential future generation may trigger a need for this project



Questions?

- ***Send comments to:***

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San Diego, CA 92123
Phone: (858) 654-1892
e-mail: BRMurphy@Semprautilities.com

2009 CAISO Transmission Plan for San Diego Gas & Electric (SDG&E) Service Area

Luba Kravchuk

Regional Transmission Engineer

2009 CAISO Transmission Plan Stakeholder Meeting

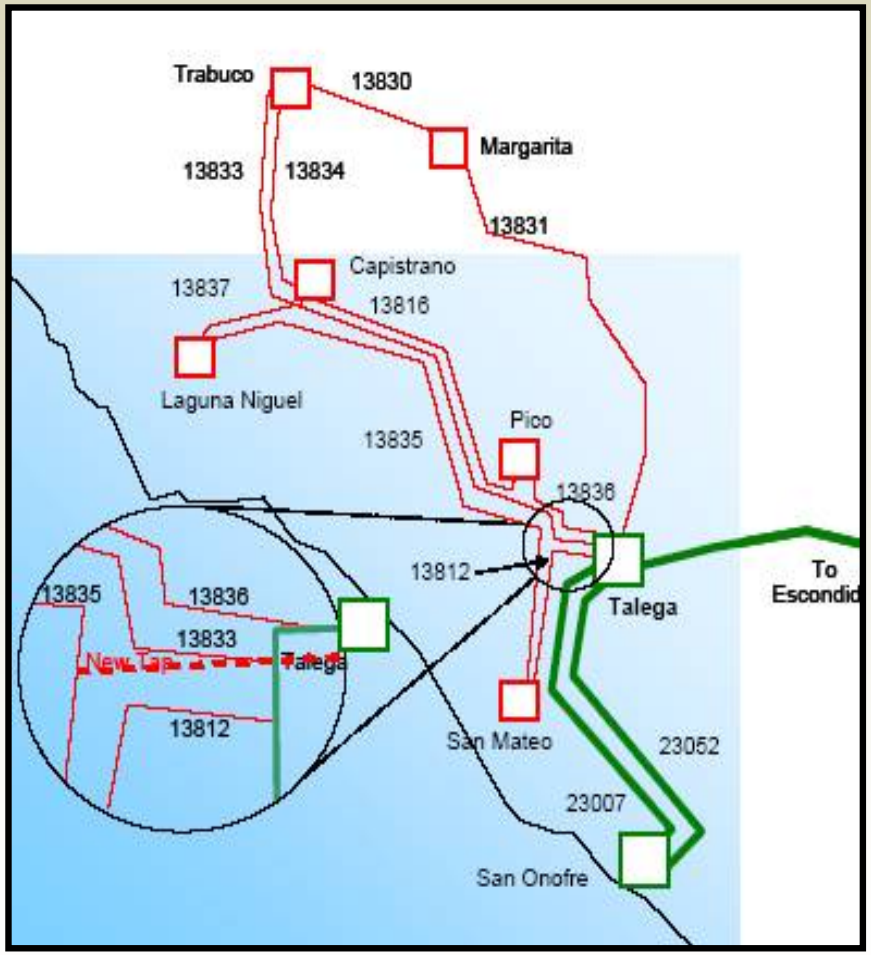
February 27, 2009

Overview of 2008 Request Window

- A total of 8 projects were submitted through the Request Window
- 7 projects were submitted by SDG&E, 1 by Third Party
- CAISO Staff recommends ISO Management approval of 1 project
- CAISO Staff recommends ISO Management denial of 1 project
- CAISO Staff recommends further review on the remaining 6 projects

Projects Recommended for CAISO Management Approval

(1) New 138 Tap: TL13835 San Mateo-Laguna Niguel



Project Proponent

- SDG&E

Needs

- NERC Category B overloads
- Talega-San Mateo overloads for Capistrano-Laguna Niguel outage and visa versa

Project Scope

- Create a new 138kV tap on TL13835 serving Laguna Niguel and San Mateo areas

Other Considered Alternatives

- Reconductor Talega-San Mateo and Capistrano-Laguna Niguel (proposed tap will save approximately $18M)

Costs

- $7.8M

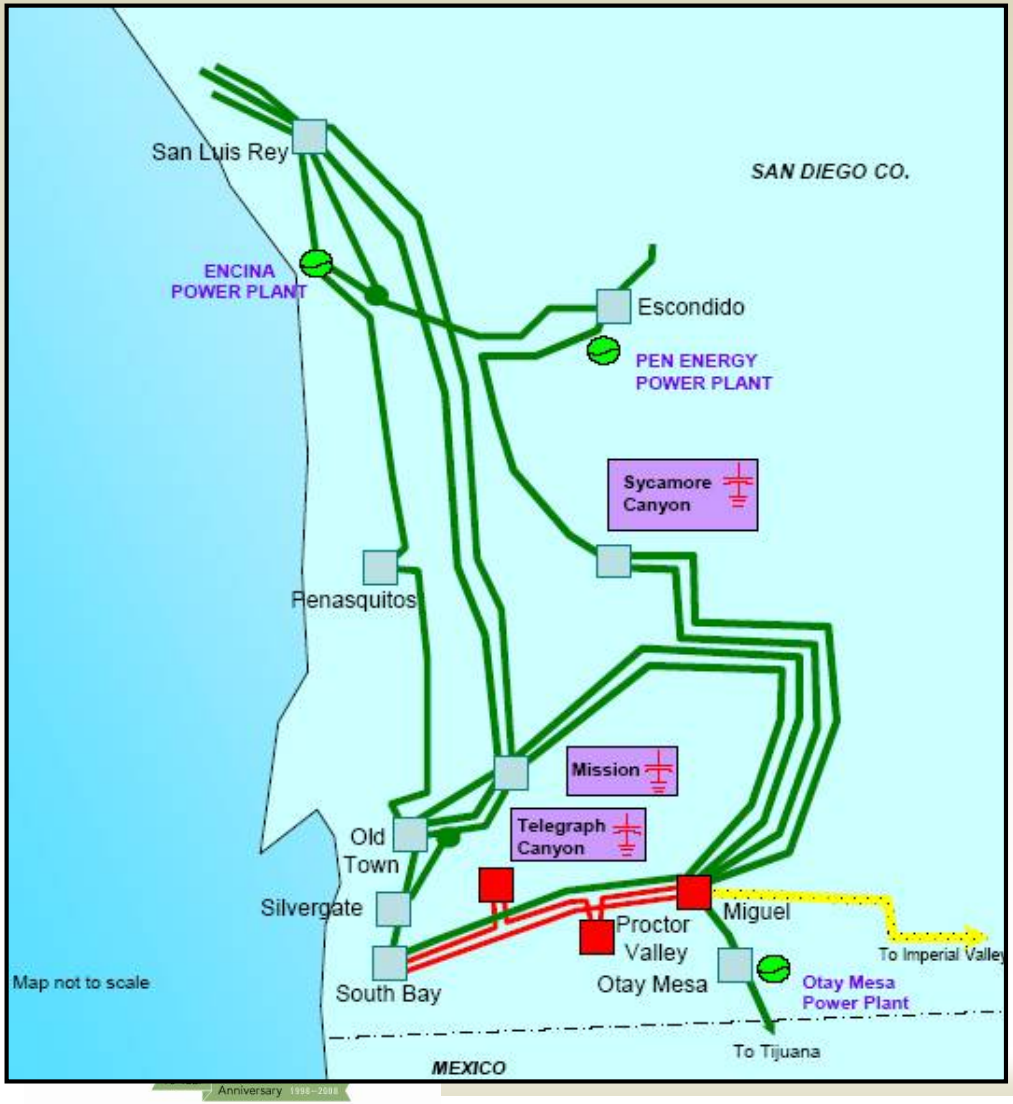
Expected In-Service

- October 2009

Recommended Action: Approval by CAISO Management

Project denied

(1) New 230 & 138 kV Capacitors: Mission, Telegraph Canyon, Sycamore Substations



Project Proponent

- SDG&E

Needs

- Insufficient reactive margin for SWPL outage

Project Scope

- Install a total of 192 MVAR of capacitors at three substations: 1x63 MVAR at Mission 230 kV, 1x43 MVAR Telegraph Canyon 138 kV, 2x43 MVAR Sycamore Canyon 138 kV

Cost

- $10.1M

Expected In-Service

- June 2010

Recommended Action

- The CAISO studies did not show insufficient reactive margin for this outage. At this time, the project cannot be recommended to be approved.

Projects Requiring Further Evaluation

- Orange County Transmission Expansion
- Bayfront Transmission Substation
- New ECO 500/230/69kV Substation & New 69kV Transmission Line to Boulevard Substation
- East Gate Tap 69 kV Project
- Barrett Interim Solution
- Addition of 3rd 500/230 kV Transformer bank at Imperial Valley

California ISO
Your Link to Power

DRAFT

2009

California ISO Transmission Plan

A Long – Term Assessment of the California ISO's Controlled Grid

(2009 – 2018)

Department of Market and Infrastructure Development

March 2009

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Executive Summary

Chapter 1

Under development

CHAPTER 2

Under development

Chapter 3 – ISO reliability assessment, Reliability Standards, Compliance Criteria, Methodology and Assumptions

3.1 Objectives and Scope

The primary objective of the ISO annual assessment is to identify the needs for system upgrades and to recommend enhancements to the system within the ISO balancing authority area (BAA) consistent with applicable reliability standards.

The scope of the ISO assessment consists of several technical studies such as reliability assessment which evaluates both the bulk transmission system and specific local areas within the ISO BAA under various reliability criteria and system conditions, local capacity requirements that identify capacity need in local areas, short-term plan that focus on the issues found while operating the system, and other studies such as once-through cooling, and renewable integration. The assumptions and methodology of these studies have been discussed with stakeholders during the first 2009 ISO Transmission Plan stakeholder meeting and can be accessed through the Study Plan at (http://www.caiso.com/1f80/1f809d7723f70.pdf). This document summarizes the assumptions and methodology of the reliability assessment for NERC compliance purposes.

3.2 Overview of the ISO Reliability Assessment

Generally, the ISO reliability assessment is a comprehensive annual study that consists of the following:

- Power flow studies,
- Transient stability analysis,
- Voltage stability studies.

The main focus of the reliability assessment is to identify reliability criteria violations which can be measured by thermal loadings of transmission facilities, voltage magnitude, voltage deviations, and system dynamic responses within the ISO BAA.

The study uses the WECC full-loop power flow base cases, and is performed on an annual basis to evaluate the performance of the transmission system under the ISO control. The study spans a broader geographical area and incorporates several factors, including but not limited to, weather patterns, network configuration, system operating conditions, etc. In order to arrive at practical conclusions, several studies are performed by focusing on impacts on both the bulk and local areas in northern and southern California. Furthermore, appropriate study methodologies and assumptions are considered for certain portions of the system to achieve a more accurate study results. The ISO reliability assessment focuses on three (3) bulk system areas, and eight (8) local areas as given in Sections 3.2.1 and 3.2.2.

3.2.1 Bulk system area assessment

For the assessment of the bulk system, governor power flow studies were performed to evaluate the system performance under normal conditions and following the contingencies of power system equipment of voltage levels 230 kV and above. The bulk transmission system studies include:

- Northern California – PG&E system,
- Southern California – SCE system,
- Southern California – SDG&E system,

3.2.2 Local area assessment

The reliability assessment studies for the eight (8) local areas focused primarily on the response of the local areas to impacts from the grid under normal system conditions following category B, C, and D outages of power system equipment of voltage levels 60 kV through 230 kV. The eight local areas were all under the PG&E service territory, namely:

- Humboldt area,
- North coast and north bay area,
- North valley area
- Central Valley area which generally includes Sierra, Sacramento, and Stockton divisions,
- Greater Bay area,
- Fresno area,
- Kern area,
- Central Coast and Los Padres area.

3.3 Reliability Standards Compliance Criteria

The main focus of the 2009 ISO Transmission Plan is the long-term and short-term reliability assessment. The studies are performed to ensure compliance with the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and the ISO reliability standards. Sections 3.3.1 through 3.3.3 provide more details or references to these standards.

3.3.1 NERC

The NERC reliability standards that were considered in the reliability assessment are as follows:

- TPL-001: System Performance Under Normal Conditions,
- TPL-002: System Performance Following Loss of a Single BES Element,
- TPL-003: System Performance Following Loss of Two or More BES Elements
- TPL-004: System Performance Following Extreme BES Events

3.3.2 WECC

The WECC planning standards were used in the studies, especially for transient stability assessment. The WECC criteria and standards is available on ISO website at http://www.caiso.com/docs/09003a6080/14/37/09003a6080143749.pdf

3.3.3 California ISO

The ISO Grid Planning standards are available at

http://www.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf. This standard may require more stringent criteria to be used in some local areas where specific reliability issues have been known to exist.

3.4 Study Methodology and Assumptions

Sections 3.4.1 and 3.4.2 summarize the study methodology and assumptions in the reliability assessment.

3.4.1 Study methodology

The reliability assessment of the northern area transmission system was performed using the following methodology.

3.4.1.1 Generation dispatch

The ISO market units in the area were dispatched at or close to their maximum active power (MW) generating levels. Qualifying Facilities (QFs) and self-generating units were modeled based on their historical power generating output levels. The status of the reactive power source in the area was modeled as in-service in all the base cases.

3.4.1.2 Power flow contingency analysis

Power flow contingency analyses was performed for all local area studies under system normal and emergency conditions consistent with the ISO planning standards, NERC (TPL 001 through TPL 004), and WECC standards

Under the ISO planning standards, a combined L-1 and G-1 is a Category B event. The following system conditions were considered for all the local area studies:

- All single contingencies (including all combinations of L-1 and G-1 contingencies),
- All double-circuit tower line outages plus all combinations of any two elements, (generator, line, or transformer) outages,
- Combinations of any one element outage followed by double-circuit tower line outages.

Depending on the type, characteristics, construction and technology of a particular power plant, certain G-1 contingencies may be classified as an outage of the whole power plant which may include multiple units. Examples of such generation facilities are the Delta Energy Center and Otay Mesa power plant G-1 contingencies. Line and transformer bank ratings in the power flow cases were updated to reflect the rating of the most limiting component. This includes substation circuit breakers, disconnect switches, bus position related conductors, and wave traps.

Additional studies were performed for the SDG&E area to account for the following operating conditions:

- Simultaneous import limits (SIL),
- Non-simultaneous import limits (NSIL).

With the proposed Sunrise Power Link Project in service, the simultaneous import capability for the SDG&E service area could increase from 2,850 MW to 4,200 MW. For a more conservative assumption, the SDG&E area SIL was modeled at 4,000 MW. For the NSIL studies, the operating status of the Southwest Power Link (SWPL) was modeled as out-of-service and the

import limit for the SDG&E area under these conditions was reduced to 3,500 MW. The import capability limit (ICL) is defined as the import limit following the most limiting Category B event with the system readjusted to within continuous ratings and path ratings such that the system meets Category B performance criteria. Operating the system within the ICL allowed for meeting the applicable reliability criteria for a subsequent contingency.

Power flow studies were performed to account for several scenarios of generation dispatch of the large power plants, namely: Otay Mesa, Encina and Palomar.

3.4.1.3 Post transient analyses

For the PG&E, SCE, and SDG&E area bulk system assessment, post transient analyses were performed to ascertain compliance with the WECC post transient voltage deviation standards. For the SCE system, voltage deviations of 7% and 10% were observed (per SCE Guidelines for 7% deviation requirements for “N-1” contingencies) for the “N-1” and “N-2” contingency analyses respectively.

3.4.1.4 Post transient voltage stability analyses

Post transient voltage stability analyses were performed as part of the bulk system assessment for outages for which the power flow analyses indicated significant voltage drops. The two methodologies used were the post transient voltage deviation, and reactive power margin analyses.

3.4.1.5 Post transient voltage deviation analyses

Contingencies that showed significant voltage deviations in the power flow studies were selected for further analysis based on the WECC standards of 5% and 10% criteria for “N-1” and “N-2” contingencies respectively.

3.4.1.6 Transient stability analyses

Transient stability simulations were also performed as part of the bulk system assessment for critical contingencies to determine whether the system was stable and exhibited sufficient (positive) damping of system oscillations. This was done to ensure that the transient stability criteria for performance levels B and C as shown in table 3-1 were met.

Table 3-1: WECC transient stability criteria

Performance Level	Disturbance	Transient Voltage Dip Criteria	Minimum Transient Frequency
B	Generator One Circuit One Transformer PDCI	Max V Dip – 25% Max Duration of V Dip Exceeding 20% - 20 cycles Not to exceed 30% at non-load buses.	59.6 Hz for 6 cycles or more at a load bus.
C	Two Generators Two Circuits IPP DC	Max V Dip – 30% at any bus. Max Duration of V Dip Exceeding 20% - 40 cycles at load buses	59.0 Hz for 6 cycles or more at a load bus.

3.4.2 Study assumptions

3.4.3.1 Frequency of the study

Consistent with the ISO business practice manual (BPM) for transmission planning, the ISO reliability assessment is performed once annually as part of its annual transmission planning process (TPP).

3.4.2.2 Study horizon

The NERC TPL 001, 002, and 003 standards and compliance related studies were performed for both the near term (i.e., year 2013) and long term (i.e., year 2018) scenarios. Additionally, the NERC TPL 004 standards relating to extreme system events were performed for the short-term (2013) scenarios only.

3.4.2.3 Study scenarios

The study scenarios cover critical system conditions driven by several factors. These factors are described below.

Peak Demands

Most of the ISO BAA experience summer peaking conditions. Hence, summer peak conditions were considered in all the various studies. In addition, for areas that experienced highest demand in the winter season, or where historical data indicated other conditions may require separate studies, winter peaks and summer off-peak studies were also performed. Examples of such areas are the Humboldt and Greater Fresno in the PG&E service area. Table 3-2 summarizes these study areas and the corresponding scenarios for the 2009 ISO reliability assessment.

Table 3-2: Summary of study scenarios in the ISO reliability assessment

Study Area	2013	2018
Humboldt	Summer Peak Winter Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak	Summer Peak
North Valley	Summer Peak	Summer Peak
Central Valley	Summer Peak	Summer Peak
Greater Bay Area	Summer Peak	Summer Peak
Fresno	Summer Peak Summer Off-Peak	Summer Peak
Kern	Summer Peak Summer Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak	Summer Peak
PG&E Bulk System	Summer Peak Summer Off-Peak	Summer Peak
Southern California Edison (SCE) area	Summer Peak	Summer Peak
San Diego Gas and Electric (SDG&E) area	Summer Peak	Summer Peak

Stressed import path flows

High import path flows to each study area were assumed to have been modeled in the base cases, hence representing operating conditions of the stressed system.

Contingencies

In addition to the system under normal operating conditions, the following contingencies were evaluated as part of the study:

- Loss of a single bulk electric system (BES) element which includes loss of one generator (G-1), one transformer (T-1), one transmission line (L-1), DC lines, and a selected loss of one generator and one transmission line (G-1/L-1) were simulated in the study (i.e., NERC TPL 002 standard). These include all outages of transmission facilities in the ISO BAA of voltage levels 115 kV and above, in addition to most of the 60 kV, 69 kV and 70 kV facilities. The outages of transmission facilities that inter-connect the ISO with neighboring Balancing Authority areas (i.e., inter-ties) were also included in the study (please refer to the ISO secured website for the contingencies). Consequently, the scope of this study included contingencies that produced more severe impacts to the grid.
- All loss of two or more BES elements was considered in the study. Contingencies that were candidates for producing more severe impacts to the grid such as loss of two transmission facilities on the same corridor, double circuit tower line outages, loss of two nuclear units, and a large number of two element outages (i.e., B-3 contingencies) were also included in the assessment. Most transmission facilities were designed to transfer large amounts of electricity, and as a result these contingencies covered the most critical contingencies that produced more severe impacts than other Category C contingencies. The impact of outages of two or more elements that resulted from a combination of two Category B outages at voltage levels of 60 kV and above were also evaluated for a number of the local area studies.

Although all contingencies applicable to Category D were candidates for studies, only a selected number of category D contingencies (TPL 004) that were expected to produce more severe impacts to the grid were included in the study. A document in the ISO secured website explains the methodology and list of category D contingencies that were performed in this assessment.

Unless otherwise noted, the assumptions and methodology for each study scenario that were common to all the various studies are described in the next sections.

3.4.2.4 Generation projects

Both existing and planned generation facilities that fell within the respective study horizons (i.e., years 2013 and 2018) were modeled in the studies in accordance with the ISO final study plan (http://www.caiso.com/1f80/1f809d7723f70.pdf), and the ISO guidelines for modeling new generation interconnection projects. (http://caiso.com/docs/2001/06/25/20010625134406100.pdf). Table 3-3 shows the new generation projects that were modeled in the base case.

Table 3-3: New generation units modeled in the reliability assessment

Generation project	Capacity (MW)	Expected In-Service
Inland Empire	800	2009
Gateway	530	2009
Starwood Midway Firebaugh	120	2009
ELF Panoche	400	2009
Otay Mesa	590	2009
Humboldt Bay Generating Station	163	2010
CPV Colusa	560	2010

3.4.2.5 Transmission projects

The study included all existing in-service transmission projects, and the expected future transmission projects that had received ISO approval for interconnection in accordance with the project approval status list in the 2008 ISO TPP (http://caiso.com/1f52/1f52d6d93a3e0.pdf). Please refer to appendix A for the list of transmission projects modeled in the base cases.

3.4.2.6 Load forecast

The study relied on load forecast from the California Energy Commission (CEC) as the primary source for estimating the overall future California electricity demand. However, this load forecast did not provide bus-level demand projections hence, the local area load forecasts used in the study were developed by the respective PTOs. The local area load forecast was developed using the CEC load forecast as the starting point. The 1-in-10 load forecasts were modeled in each local area in the PG&E service area, SCE, and SDG&E studies. The 1-in-5 coincident peak load forecasts were used for the northern area bulk system assessment as it covers a vast geographical area with varying temperature diversity. More details of the demand forecast will be provided in the discussion sections of each of the study areas.

3.4.2.7 Reactive power resources

Existing and new reactive power resources were modeled in the base cases for the study to ensure realistic reactive power support capability. These resources include generators, capacitors, Static Var Compensator (SVC) and other devices. A list of generation plants and corresponding assumptions related to each of the eight local areas are provided in Chapter 4. Appendix A also provides a list of several key reactive power resources that were modeled in the studies. For a complete list of these resources, refer to the base cases available at the ISO secured website.

3.4.2.8 Operating procedures

ISO operating procedures for both the system under normal (pre-contingency) and emergency (post-contingency) conditions were modeled in the study. Table 3-4 summarizes key operating procedures that were included in the study.

Table 3-4: Normal (pre-contingency) operating procedures:

Operating Procedure	Scope
G 206	San Diego Area Generation Requirements
G 217	South of Lugo Generation Requirements
G 219	SCE Area Generation Requirements
G 233	Bay Area Generation Requirements
T 144	South of Lugo 500 kV Lines
T 116	AC/DC Nomogram for N/S Flow
T 103	SCIT

3.4.2.9 Firm transfer

Power flow on the major power transmission paths was considered and modeled as "firm transfer". In general, the northern California system has 2 major power transfer paths (i.e., Path 66 and Path 26). Consequently, Table 3-5 lists the transfer capability and power flows that were modeled in each scenario on these paths in the northern area assessment that were modeled in both the 2013 and 2018 base cases.

Table 3-5: Major path flows in northern California

Path	Limit (MW)	Path Flow (MW)		
		Summer Peak	Summer Off-Peak	Winter Peak
Path 26 (N-S)	+/-4000	4000	4000	-1619
Path 66 (N-S)	+/-4800	4800	4800	-3679

Table 3-6 lists the major paths in the SCE system in southern California and the corresponding MW transfer capabilities under various conditions.

Table 3-6: Major paths and power transfer capabilities under given conditions in the SCE system assessment

Path	Path Flow (MW)			
	2013 Summer Peak		2018 Summer Peak	
	All Gen in Srvc	G-1 SONGS	All Gen in Srvc	G-1 SONGS
West of River (WOR)	7960	7891	8329	8330
East of River (EOR)	5684	5687	5603	5300
Pacific DC Intertie (PDCI)	3000	3000	2998	2998
Path 26	2274	3495	2348	3524
S of Lugo	4068	4415	4776	5149
Vincent - Mira Loma	419	648	458	680
SCIT	15983	17131	16859	18030

Table 3-7 lists the major paths in the SDG&E system in southern California and the corresponding MW transfer capabilities under various conditions that were modeled in the base cases for the SDG&E area studies.

Table 3-7: Major path flows in the SDG&E area assessment

Path	Path Flow (MW)	
	2013 Summer Peak	2018 Summer Peak
West of River (WOR)	6,533	6,855
East of River (EOR)	4,025	4,086
Pacific DC Intertie (PDCI)	3,000	3,000
Path 26	1,875	1,932
South of SONGS	498	1,490
North of SONFS	1,652	660
SDG&E Import	2,355	3,997
SDG&E Miguel Import	1,101	1,521
SWPL(Imperial Valley-Miguel)	1,109	1,537
Sunrise Power Link	507	753
Tijuana-Otay Mesa	249	233

3.4.2.10 Protection systems

To help ensure reliable operation of the system, many remedial action schemes (RAS) or special protection systems (SPS) have been installed in some areas of the system. Typically, these protection systems trip load and/or generation, upon detection of system overloads, by strategically tripping circuit breakers under selected contingencies. Some SPS are designed to operate upon detecting unacceptable low voltage conditions caused by certain contingencies. Appendix A lists major new and existing RAS/SPS that were included in the study.

3.4.2.11 Control devices

Several control devices were also modeled in the study. These control devices were:

- All shunt capacitors in the SCE service area,
- Static Var Compensators (SVC) at several locations such as Potrero, Newark, Rector, and Devers substations,
- DC transmission lines such as the Pacific direct current interface (PDCI), inter-mountain power plant direct current (IPPDC), and the Transbay projects.

For the complete details of the control devices that were modeled in the study, please refer to the base cases that are available through the secured section of the ISO website.

Chapter 4 – PG&E Service Area Assessment

PG&E service area covers most of the area in northern California stretching from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada in the east. There are 123,054 circuit miles of electric distribution lines and 18,610 circuit miles of interconnected transmission lines serving 5.1 million electric customer accounts. In 2008, PG&E's peak demand of 21,926 MW occurred on July 8, 2009.

4.1 General Assessment Summary

The 2013 and 2018 summer peak and 2013 off-peak cases were all found to satisfy the transient and post-transient performance criteria. However, some thermal limits were exceeded during post-transient contingency conditions in all three cases.

4.1.1 PG&E bulk transmission system assessment summary

- The 2013 summer peak studies identified the need to mitigate a marginal overload on the Colusa-Cortina 230 kV line section for a 500 kV double line contingency south of Round Mountain by either reconductoring or congestion management.
- The 2013 summer off peak studies revealed a few facilities exceeding their ratings for path 15 contingencies. However, these violations would be addressed by the Central California clean energy and transmission project (C3ETP) studies.
- The 2018 summer peak studies identified the need to establish an emergency rating for the Table Mountain 500/230 kV transformer bank for a 500 kV double line outage south of Table Mountain.

4.1.2 2013 PG&E local area assessment summary

In 2013, xx overloads were observed under normal operating conditions, xx overloads were observed following several Category B and C contingencies and xx transient stability violations were found. In 2018, xx normal overloads and xx overloads following category B and C contingencies were observed.

In order to address these violations, the ISO proposed 196 transmission solutions.

During the 2008 Open Request Window the ISO received 134 project proposals:

- 46 were approved,
- Seven were withdrawn,
- Eight were denied,
- 60 are on-going projects (i.e., to be approved at a later date).

This gives a total of xxx active projects in the 2009 transmission plan for the PG&E service area.

4.2 Bulk Transmission System Description

The 500 kV bulk transmission systems in northern California consist of three parallel 500 kV lines that traverse the state from the California-Oregon border in the north and continue past Bakersfield

in the south. This system transfers power between California and other States in the Northwestern portion of the United States and Western Canada. The transmission system is also a gateway for excess resources located in the sparsely populated portions of northern California and typically delivers these resources to population centers in the Greater San Francisco Bay Area and Central Valley. There is also a large amount of generation resources in the central California area that is delivered over the 500 kV systems into southern California. The typical direction of power flow through Path 26 is from north to south (N-S) during on-peak load periods and in the reverse direction during off-peak load periods. As a result of this bi-directional power flow pattern on the 500 kV Path 26 lines, both the summer peak (N-S) and off-peak (S-N) flow scenarios were analyzed. Transient stability and post transient contingency analyses were also performed for both flow patterns and scenarios.

4.3 Study Assumptions and System

The northern area bulk transmission system study was performed consistent with the general study methodology and assumptions described in Chapter 3. The ISO secured website lists the contingencies that were performed as part of this assessment. In addition, specific methodology and assumptions that are applicable to the northern area bulk transmission system study are provided below in the next sections.

4.3.1 Generation and path flows

The bulk transmission system studies considered the same set of generation plants that were modeled and used in the local area study. An initial study was performed using the summer peak base cases that were consistent with the 2009 unified planning assumptions as discussed in Chapter 3.

The Palo Verde two-unit outage was simulated on these cases since it is known to be the worst contingency and the standard practice is to test this outage to ensure that the flow conditions are within the upper bound of the currently expected operating range.

Therefore, the flows through the 500 kV transmission path interface known as the California-Oregon Inter-tie (Path 66) were incrementally reduced to allow for acceptable system performance during the simulation of this two-unit outage. Table 4-1 lists all major path flows affecting the 500 kV systems in northern California along with the hydroelectric generation dispatch percentage in Northern California.

Table 4-1: Major import flow for the northern area bulk study

Parameter	2013 Summer Peak	2018 Summer Peak	2013 Off-Peak
California-Oregon Intertie Flow (N-S) (MW)	4800/4644*	4800/4577*	-3529
Pacific DC Intertie Flow (N-S) (MW)	3000	2900	-1846
Path 15 Flow (S-N) MW	-376	-342	5372
Path 26 Flow (N-S) MW	3845	3976	-1578
Northern California Hydro % dispatch of nameplate	86%	86%	n/a

4.3.2 Load forecast

Per the ISO Grid planning criteria for regional transmission planning studies, the demand within the ISO area reflects a coincident peak load for 1-in-5-year heat wave conditions for the summer peak cases. Loads in the off-peak case were modeled at approximately 50 % of the 1 in 5 summer peak

load level. Table 4-2 shows the assumed ISO load levels for selected areas under summer peak and off-peak conditions.

Table 4-2: Load modeled in Northern area bulk system assessment

Scenario	Area	Load (MW)	Loss (MW)	Total (MW)
2013 Summer Peak	PG AND E	28310	1105	29415
	SANDIEGO	4889	104	4993
	SOCALIF	25774	436	26210
	CAISO	58973	1644	60617
2018 Summer Peak	PG AND E	30369	1222	31591
	SANDIEGO	5360	120	5480
	SOCALIF	27553	460	28013
	CAISO	63282	1802	65084
2013 Summer Off-Peak	PG AND E	14219	676	14895
	SANDIEGO	2515	36	2551
	SOCALIF	10705	303	11008
	CAISO	27439	1015	28454

4.3.3 Existing protection systems

There are extensive SPS or RAS that are installed in the northern California area 500 kV systems to ensure reliable system performance. These systems were modeled and included in the contingency studies. A comprehensive detail of these protection systems are provided in various ISO operating procedures, engineering and design documents. Refer to Table A-2 in Appdendix A.

4.4 Study results and Discussions

The studies were performed under normal and emergency system conditions and various scenarios with the primary focus on transmission systems in the northern and central California.

The 2013 and 2018 summer peak and 2013 off-peak cases were all found to satisfy the transient and post-transient performance criteria. However, some thermal limits were exceeded during post-transient contingency conditions in all three cases.

4.4.1 2013 Summer peak base case

A one percent overload on the Colusa-Cortina 230 kV line section was identified for a South of Round Mt 500 kV line double circuit contingency. This overload occurred at the COI inter-tie flow level that resulted in adequate system performance for all other 500 kV contingencies analyzed. Therefore it was reasonable to expect that this overload could be the limiting factor in determining future operating transfer capability limits. Other recent ISO studies also showed an exacerbation of this overload condition by increasing the San Francisco Bay area import levels.

Potential recommendations to mitigate against this overload condition is to reconductor the overloaded line section, or looping in one of the existing Colusa-Vaca Dixon 230 kV circuits into Cortina substation. Alternatively, it could also be mitigated by reducing Colusa generation output or the operational transfer capability of the COI transmission corridor.

The presence of this constraint could potentially impact congestion cost.

4.4.2 2018 Summer peak base case

A one percent overload on the Table Mt 500/230 kV transformer was identified for a south of Table Mountain 500 kV line double circuit contingency. Since this transformer does not have an emergency rating, the recommended potential mitigation plan was to establish an emergency rating on the transformer.

A three percent overload on the Bogue-Rio Oso 115 kV circuit was identified for a Vaca Dixon breaker failure contingency. However, this circuit was also found to be overloaded for the local area analysis. The recommended mitigation plan is to reconductor the circuit.

4.4.3 2013 Off-peak base case

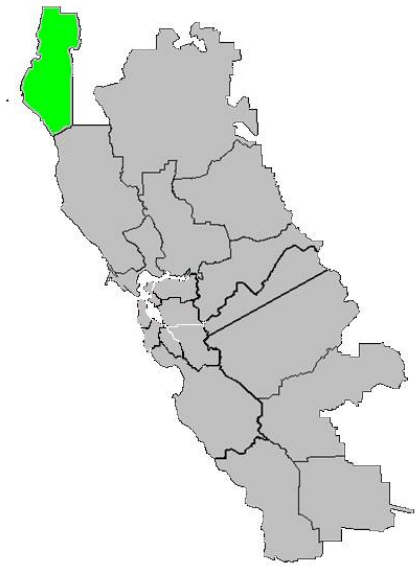
A few underlying facilities exceeded their summer line ratings during contingency conditions on Path 15. These overloads could be mitigated if the pumping capability of the Helms pump-storage facility were to be restricted as load increases in the Fresno area. However, this is not a practical solution.

Additionally, the C3ETP project alternatives could also potentially provide mitigation for these overloads. The presently on-going C3ETP study is expected to provide long term mitigation plans for maintaining and expanding Path 15 transfer capability and pumping capability of the Helms facility.

4.5 Local Area Reliability Assessment

4.5.1 Humboldt area

The Humboldt area covers approximately 3,000 square miles, and is located in the northwestern corner of PG&E's service territory. Some of the large cities in the area that are served by PG&E area are Eureka, Arcata, Garberville and Fortuna. The figure below depicts the approximate geographical location of the Humboldt area.



Humboldt's electric transmission system is comprised of 60 kV and 115 kV transmission facilities. Electric supply to the Humboldt area is provided primarily by generation at Humboldt Bay power plant and local QF generation units. It is supplemented by transmission imports from the North Valley and North Coast areas. The Humboldt division is connected to the bulk PG&E transmission system by four transmission circuits, each about 80 to 100 miles in length. Power imports are from two 115 kV lines and one 60 kV line from the Cottonwood substation in the east and one 60 kV line from Mendocino substation in the south.

Historically, the Humboldt area experiences its highest demand during the winter season. Load forecasts indicate Humboldt should reach its winter and summer peak demand of 220 MW and 170 MW respectively by 2018 assuming an annual load growth of approximately 2 to 3 MW per year (MW/year).

4.5.1.1 Area-specific assumptions and system discussions

The Humboldt area study was performed consistent with the general study assumptions and methodology described in Chapter 3. The lists of contingencies analyzed are located in the ISO secured website. Additionally, specific methodology and assumptions that were specifically applicable to the Humboldt area study are provided in the next sections.

Generation

Generation resources in the Humboldt area consist of market, Qualifying Facilities (QFs) and self-generating units. The Humboldt Bay re-powering project was included in all scenarios. Table 4-3 lists generating plants in the Humboldt area.

Table 4-3: Generation plants in the Humboldt area

Generation Plants	Max. Capacity (MW)
Humboldt Bay	166
Kekawaka	4.9
Pacific Lumber	32.5
LP Samoa	25
Fairhaven	17.3
Ultra Power	0
Generation Total	**246**

Load forecast

The load assumptions in the summer and winter peak conditions modeled in the Humboldt study were between 152 MW and 173 MW and 191 MW to 220 MW respectively. Losses in the Humboldt area are roughly 10 MW and 11 MW in 2013 and 2018 (winter peak) respectively. Please refer to Appendix A for the detailed load forecast.

4.5.1.2 Study results and discussions

This section covers study results and proposed mitigation plans for the Humboldt area under each category of the planning standards.

TPL 001- System Performance Under Normal Conditions

Under both the summer and winter peak conditions, there is no overload or voltage violation under Category A performance requirement.

TPL 002-System Performance Following Loss of a Single BES Element

Under the summer peak conditions, there were three overloads caused by six contingencies that did not meet the Category B performance criteria. Also, there were eleven 11 substations which that did not meet the Category B performance criteria due to low voltages caused by four contingencies. The details of these violations are provided in Tables 4-4 and 4-6.

Under the winter peak conditions, there were two overloads caused by two contingencies that did not meet Category B performance criteria and 11 substations that did not meet Category B performance criteria due to low voltages caused by four contingencies. The details of these violations are provided in Tables 4-5 and 4-7.

TPL 003 – System Performance Following Loss of Two or More Elements

Under the summer peak conditions, 16 overloads caused by 12 contingencies did not meet Category C performance criteria and 20 substations did not meet Category C performance criteria due to low voltages caused by three contingencies. Details of these violations are provided in Tables 4-4 and 4-6.

Under winter peak conditions, there are seven overloads caused by four contingencies and low voltages at 20 substations caused by five contingencies. Details of these violations are provided in Tables 4-5 and 4-7.

Table 4-4: Worst line/equipment overload summaries for summer peak load conditions

Overloaded Transmission Equipment	Rating (A)	Loading 2013	Loading 2018	Critical Contingenc(ies)	Category	Proposed Solutions
Humboldt Bay - Humboldt 60kV Line#1 (Humboldt - Humboldt Jct)	346	104	102	L-1 Humboldt Bay - Humboldt #2 60kV and G-1 Fairhaven Generator	B	Reconductor approx 10 miles of this section
		197	194	L-1 Humboldt Bay - Humboldt #2 60kV and L-1 Humboldt Bay - Eureka 60kV	C	
Humboldt Bay - Humboldt 60kV Line#1 (Humboldt Jct - Humboldt Bay)	500	137	135	L-1 Humboldt Bay - Humboldt #2 60kV and L-1 Humboldt Bay - Eureka 60kV	C	Drop Humboldt 60 kV generation or drop the load
Humboldt - Eureka 60kV Line#1	346	141	134	L-1 Humboldt Bay - Humboldt #2 60kV and L-1 Humboldt Bay - Humboldt #1 60kV	C	
Humboldt Bay - Eureka 60kV Line#1	414	160	157	L-1 Humboldt Bay - Humboldt #2 60kV and L-1 Humboldt Bay - Humboldt #1 60kV	C	
Humboldt Bay - Bridgeville 60kV Line#1 (Riodell Tap - Carlotta - Bridgeville)	375	133	122	L-1 Humboldt - Bridgeville 115kV and L-1 Humboldt - Trinity 115kV	C	
Bridgeville - Garberville 60kV Line#1 (Bridgeville - Fruitland Jct)	371	116	113	L-1 Bridgeville - Cottonwood 115kV and L-1 Humboldt - Trinity 115kV	C	
Bridgeville - Garberville 60kV Line#1 (Fruitland Jct - Fort Seward)	340	118	112	L-1 Bridgeville - Cottonwood 115kV and L-1 Humboldt - Trinity 115kV	C	
Arcata Jct - Essex Jct 60kV Line #1 (Jancreek Tap - Arcata Jct)	352	97	104	L-1 Arcata- Humboldt 60 kV#1 and L-1 Humboldt - LP Flakeboard 60 kV #1	C	Load dropping in the area north of Humboldt
Arcata Jct - Essex Jct 60kV Line #1 (Arcata Jct - Fairhaven)	553	94	102	L-1 Arcata- Humboldt 60 kV#1 and L-1 Humboldt - LP Flakeboard 60 kV #1	C	

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Table 4-5: Summaries of voltage violation and divergence for summer peak study

Substation	Critical Contingency(ies)	Category	Min Post-Contingency Voltage (PU)		Proposed Solutions
			2013	2018	
Orick, Big Lagoon, Trinidad, Essex Junction, Jans Creek, Bluechip Mill, Blue Lake, Simpson 60 kV	L-1 Arcata - Humboldt 60 kV and L-1 Humboldt - LP_Flkboard #1 60 kV	C	0.89	0.88	Need approximately 6 MVAR of reactive support. The preferred locations are at the end of 60 kV line such as Simpson, Blue Lake, Orick or use the mittgation plan for thermal overload
Ridge Cabin, Maple Creek, Russ Ranch, Willow Creek, and Hoopa 60 kV	L-1 Humboldt - Maple Creek 60 kV and	B	0.85	0.82	Need approximately 10 MVAR of reactive support at Ridge Cabin, Russ Ranch, or Willow Creek
	L-1 Humboldt - Bridgeville 115 kV and L-1 Humboldt - Maple Creek 60 kV	C	0.83	0.80	
	L-1 Humboldt - Trinity 115 kV and L-1 Humboldt - Maple Creek 60 kV	C			
	L-1 Bridgeville - Cottonwood 115 kV and L-1 Humboldt - Maple Creek 60 kV	C			
Bridgeville, Fruitland, Fort Seward 60 kV	T-1 Bridgeville 115/60 Transformer No.1 and	B	0.88	0.86	Need additional reactive resources at Garberville or surrounding area. This should also benefit Bridgeville 115 kV
	L-1 Rio Dell Jct. - Bridgeville 60 kV and T-1 Bridgeville 115/60 Transformer No.1	C	0.68	Diverge	
Garberville, Kekawaka, Laytonville, Covelo 60 kV	L-1 Bridgeville - Garberville 60 kV and	B	0.79	0.78	
	T-1 Bridgeville 115/60 Transformer No.1 and	B	0.87	0.86	
	L-1 Rio Dell Jct. - Bridgeville 60 kV and T-1 Bridgeville 115/60 Transformer No.1	C	0.70	0.69	

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Table 4-6: Worst line/equipment overload summaries for winter peak conditions

Overloaded Facility	Rating (A)	Loading 2013	Loading 2018	Critical Contingenc(ies)	Category	Loading 2013	Loading 2018	Proposed Solutions
Humboldt 115/60kV Bank #2	45 MVA	100	106	G-1 HBPP 1 Unit on the 60kV side and L-1 Tie line & Tie with 60kV HBPP units	B	100	106	Replace both Banks with the higher rating banks
		100	106	G-1 Fairhaven Generator and L-1 Tie line & Tie with 60kV HBPP units	B	100	106	
		159	177	L-1 Tie line & Tie with 60kV HBPP units and T-1 Humboldt 115/60 Bank No.1	C	159	177	
Humboldt 115/60kV Bank #1	45 MVA	100	110	G-1 HBPP 1 Unit on the 60kV side and L-1 Tie line & Tie with 60kV HBPP units	B	100	110	
		100	110	G-1 Fairhaven Generator and L-1 Tie line & Tie with 60kV HBPP units	B	100	110	
		159	177	L-1 Tie line & Tie with 60kV HBPP units and T-1 Humboldt 115/60 Bank No.2	C	159	177	
Arcata Jct - Essex Jct 60kV Line #1 (Janck Tap - Arcata Jt 2)	443	102	117	L-1 Arcata- Humboldt 60 kV#1 and L-1 Humboldt - LP Flakeboard 60 kV #1	C	102	117	Load dropping in the area north of Humboldt
Arcata Jct - Essex Jct 60kV Line #1 (Arcata Jct - Fairhaven)	702	100	115	L-1 Arcata- Humboldt 60 kV#1 and L-1 Humboldt - LP Flakeboard 60 kV #1	C	100	115	
Humboldt bay - Humboldt 60kV #1 (Humboldt - Humbolt Jct)	443	153	149	L-1 Humboldt Bay - Humboldt #2 60kV and L-1 Humboldt Bay - Eureka 60kV	C	153	149	Drop Humboldt 60 kV generation or drop the load
Humboldt - Eureka 60kV #1	443	104	96	L-1 Humboldt Bay - Humboldt #2 60kV and L-1 Humboldt Bay - Humboldt #1 60kV	C	104	96	
Humboldt Bay - Eureka 60kV #1	443	148	145	L-1 Humboldt Bay - Humboldt #2 60kV and L-1 Humboldt Bay - Humboldt #1 60kV	C	148	145	

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Table 4-7: Summary of voltage violations for winter peak conditions

Substation	Critical Contingency(ies)	Category	Post-Contingency 2013	Post-Contingency 2018	Proposed Solutions
Orick, Big Lagoon, Trinidad, Essex Junction, Jans Creek, Bluechip Mill, Blue Lake, Simpson, Arcata 60 kV	L-1 Arcata - Humboldt 60 kV and L-1 Humboldt - LP_Flkboard #1 60 kV	C	0.83	0.82	Need approximately 6 MVAR of reactive support. The preferred locations are at the end of 60 kV line such as Simpson, Blue Lake, Orick or use the mitigation plan for thermal overload
Ridge Cabin, Maple Creek, Russ Ranch, Willow Creek, Hoopa 60 kV	L-1 Humboldt - Maple Creek 60 kV and	B	0.77	0.76	Need approximately 10 MVAR of reactive support at Ridge Cabin, Russ Ranch, or Willow Creek
	L-1 Humboldt - Trinity 115 kV and L-1 Humboldt - Maple Creek 60 kV	C	0.74	0.7	
	L-1 Humboldt - Bridgeville 115 kV and L-1 Humboldt - Maple Creek 60 kV	C			
Bridgeville 60 kV	L-1 Rio Dell Jct. - Bridgeville 60 kV and T-1 Bridgeville 115/60 Transformer No.1	C	0.70	0.69	Need additional reactive resources at Garberville or surrounding area.
Fruitland, Fort Seward 60 kV	T-1 Bridgeville 115/60 Transformer No.1 and	B	0.91	0.90	
	L-1 Rio Dell Jct. - Bridgeville 60 kV and T-1 Bridgeville 115/60 Transformer No.1	C	0.69	0.68	
Garberville, Kekawaka, Laytonville, Covelo 60 kV	L-1 Bridgeville - Garberville 60 kV and	B	0.87	0.86	
	L-1 Bridgeville - Garberville 60 kV and T-1 Kekawaka GSU	C	0.70	0.69	

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4.5.1.3 Recommended solutions for reliability criteria violations

Thermal overload mitigations

- **Humboldt Bay-Humboldt 60 kV line#1 (Humboldt-Humboldt Jct)**

  This overload was identified in both the 2013 and 2018 summer and winter peak conditions caused by various Category B and C contingencies. This overload is caused by the limitation of transmission capability to accommodate the full output of the new Humboldt Bay Power Plant under emergency conditions which is more severe in the summer peak conditions due to lighter load. Although the study results show the severity of the overloads will decrease over time due to load growth, a mitigation plan for this overload is still needed. The proposed solutions are to re-rate this section of the line, reconductor the section of the line between Humboldt-Humboldt Junction (Humboldt Bay-Humboldt 60 kV line #1) or upgrade the limiting facility of this section.

- **Humboldt Bay-Humboldt 60 kV line#1 (Humboldt Jct-Humboldt Bay)**

  Similar to the overload #1, this overload was identified in the 2013 and 2018 summer peak conditions caused by the outage of Humboldt Bay-Humboldt 60 kV line #2 and Humboldt Bay-Eureka 60 kV line #1 (Category C). The proposed solution is to implement a load dropping scheme post contingency.

- **Humboldt-Eureka 60 kV line#1**

  This overload was identified in the 2013 and 2018 summer and winter peak scenarios caused by the outage of Humboldt Bay-Humboldt 60 kV line #2 and Humboldt Bay-Eureka 60 kV line #1 (Category C). The proposed solution is to use the operating procedure identified for the overload of Humboldt Bay-Humboldt 60 kV line#1.

- **Humboldt Bay-Eureka 60 kV line#1**

  This overload was identified in the 2013 and 2018 summer and winter peak scenarios caused by the outage of Humboldt Bay-Humboldt 60 kV line #2 and Humboldt Bay-Eureka 60 kV line #1 (Category C). Since this is an overload triggered by the same contingency, the proposed solution is to use the scheme identified in the overload of Humboldt Bay-Humboldt 60 kV line #1.

- **Humboldt Bay-Bridgeville 60 kV line#1 (Riodell Tap-Carlotta-Bridgeville)**

  This overload was identified in the 2013 and 2018 summer peak scenarios caused by the outage of Humboldt – Bridgeville 115 kV line #1 and Humboldt-Trinity 115 kV line #1 (Category C). The proposed solution is to implement the operating procedures to drop the output from Humboldt Bay Power Plan post contingency.

- **Bridgeville-Garberville 60 kV line#1 (Bridgeville-Fruitland Jct)**

  This overload was identified in the 2013 and 2018 summer peak scenarios caused by the outage of Bridgeville-Cottonwood 115 kV line #1 and Humboldt-Trinity 115 kV line #1 (Category C). The proposed solution is to implement the operating procedures to drop the

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output from Humboldt Bay Power Plan post contingency.

- **Bridgeville-Garberville 60 kV line#1 (Fruitland Jct-Fort Seward)**

  This overload was identified in the 2013 and 2018 summer peak scenarios caused by the outage of Bridgeville-Cottonwood 115 kV line #1 and Humboldt-Trinity 115 kV line #1 (Category C). The proposed solution is to use the operating procedure identified in the overload of Bridgeville-Garberville 60 kV line#1.

- **Arcata Jct.-Essex Jct 60 kV line #1 (Jancreek Tap-Arcata Jct)**

  This overload was identified in the 2013 and 2018 winter peak scenarios caused by the outage of Arcata-Humboldt 60 kV #1 and Humboldt-Lp Flakeboard 60 kV #1 (Category C). The proposed solutions are to implement an operating procedure to close switch 67 or drop load post contingency.

- **Arcata Jct.-Essex Jct. 60 kV line #1 (Arcata Jct.-Fairhaven)**

  This overload was identified in the 2013 and 2018 winter peak scenarios (and 2016 summer peak conditions and beyond) caused by the outage of Arcata-Humboldt 60 kV #1 and Humboldt-Lp Flakeboard 60 kV #1 (Category C). The proposed solution is to use the operating procedure identified to mitigate the overload of Jancreek Tap-Arcata Jct.

- **Humboldt 115/60 kV Transformer #1**

  This overload was identified in the 2013 and 2018 winter peak scenarios caused by the outage of Humboldt 115/60 kV Transformer #2 (Category B). This overload was identified in the local capacity requirement (LCR) studies. The proposed solution is the Humboldt 115/60 kV Transformer Replacement project that the ISO received through the Request Window.

- **Humboldt 115/60 kV Transformer #2**

  This overload was identified in the 2013 and 2018 winter peak scenarios caused by the outage of Humboldt 115/60 kV Transformer #1 (Category B). This overload was identified in the local capacity requirement (LCR) studies. The proposed solution is the Humboldt 115/60 kV Transformer Replacement project that the ISO received through the Request Window.

Under Voltage Problems Mitigations

- **Orick, Big Lagoon, Trinidad, Essex Junction, Jans Creek, Bluechip Mill, Blue Lake, Simpson, Arcata 60 kV substations**

  These low voltages were identified in the 2013 and 2018 summer and winter and summer peak scenarios. These under voltages were caused by the outage of Arcata-Humboldt 60 kV #1 and Humboldt-Lp Flakeboard 60 kV #1 (Category C). The proposed solution is to use close switch 67, drop load post contingency, or install approximately 6 MVAr of reactive resource in this area.

- **Ridge Cabin, Maple Creek, Russ Ranch, Willow Creek, Hoopa 60 kV**

  These low voltages were identified in the 2013 and 2018 summer and winter and summer peak scenarios. These under voltages were caused by various Category B and C

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contingencies. The proposed solution is to utilize Maple Creek reactive support project or Garberville Interim Solution projects that the ISO received through the Request Window.

- **Bridgeville 60 kV**

  These low voltages were identified in the 2013 and 2018 summer and winter and summer peak scenarios. These under voltages were caused by various Category B and C contingencies. The proposed solution is to utilize the Garberville reactive support project or Garberville Interim Solution that the ISO received through the Request Window.

- **Fruitland, Fort Seward 60 kV**

  These low voltages were identified in the 2013 and 2018 summer and winter scenarios. These under voltages were caused by the various Category B and C contingencies. The proposed solution is to utilize the Garberville reactive support project or Garberville Interim Solution that the ISO received through the Request Window.

- **Garberville, Kekawaka, Laytonville, Covelo 60 kV**

  These low voltages were identified starting in the 2009 summer and winter and summer peak conditions. These under voltages were caused by the various Category B and C contingencies. The proposed solution is to utilize Garberville reactive support project or Garberville Interim Solution that the ISO received through the Request Window.

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4.5.1.4 Key conclusions

Based on the ISO study assessment, the Humboldt area had:

- No overloads under normal conditions,
- Nine overloads caused by nine critical single contingencies under summer peak conditions and two overloads caused by four single contingencies under winter peak conditions,
- No overloads caused by any critical multiple contingencies under summer peak conditions, and no overloads driven by any multiple contingencies under winter peak conditions,

Among those studied, there are no extreme contingency conditions with potential voltage collapse,

In order to address all of these concerns the ISO proposed seven transmission solutions.

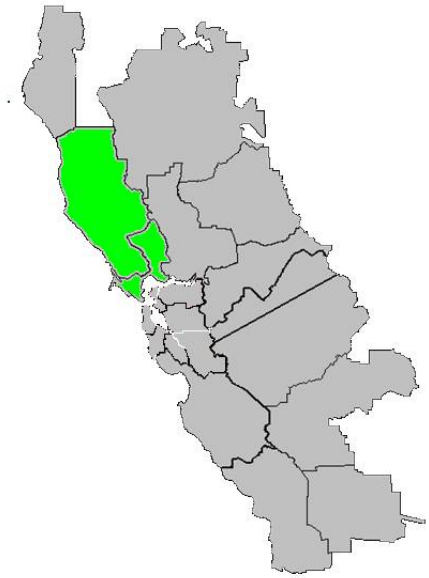
During the 2008 Open Request Window the ISO received five project proposals:

- Three were approved,
- None were withdrawn,
- Two were denied,
- Zero on-going projects (i.e., to be considered for approval at a later date).

This gives a total of three projects in the 2009 transmission plan for the Humboldt area.

4.5.2 North Coast and North Bay area

The North Coast area is located north of the Bay Area and south of the Humboldt area along the northwest coast of California. It extends from Laytonville in the north to Petaluma in the south.



The North Coast area has both coastal and interior climate regions covering an area of approximately 10,000 square miles with a population of approximately 800,000 people in Sonoma, Mendocino, Lake and a portion of Marin counties. Projection of demand in North Coast is expected to reach 833 MW in 2011 with the growth rate of approximately 1.6% per year. A significant amount of North Coast generation is from geothermal (The Geysers) resources. The figure on the left depicts the approximate geographical location of the North Coast and North Bay area.

North Bay encompasses the area just north of San Francisco. This transmission system serves the counties of Marin, Napa and portions of Solano and Sonoma Counties. Novato, San Rafael, Vallejo and Benicia are among the cities PG&E provides electric service to within this area. North Bay's electric transmission system is comprised of 60, 115, and 230 kV facilities supported by transmission facilities from the North Coast, Sacramento, and Bay Area. The forecast for load growth in the North Bay area is approximately 1.5% and is expected to reach 750 MW by 2011.

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4.5.2.1 Area-specific assumptions and system conditions

The North Coast and North Bay area study was performed consistent with the general study assumptions and methodology described in Chapter 3 and Appendix A. The ISO secured website lists the contingencies that were performed as part of this assessment. In addition, specific assumptions and methodology applied to the North Coast and North Bay area studies are provided in this section.

Generation

Generation resources in North Coast and North Bay areas consist of market, QFs and self-generating units. Table 4-8 lists generating plants in the North Coast and North Bay areas.

Table 4-8: Generator in North Coast and North Bay areas

Generation Plants	Max. Capacity (MW)
Bottle Rock	55
Potter Valley	7.2
Bear Canyon	20
Geo Energy	20
Geysers 11	64
Gersers 12	52
Geysers 13	61
Geysers 14	49
Geysers 16	56
Geysers 17	52
Geysers 18	47
Geysers 20	42
Geysers 7	34
Geysers 8	34
Geysers 5	40
Geysers 6	40
Indian Valley	1.6
Monticello	5.7
NCPA Unit 1	67
NCPA Unit 2	62
Santa Fe	160
Smud Geo	41
Sonoma Landfill	4.7
Westford Flat	30
Generation Total	**1045**

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Load forecast

Loads within the North Coast and North Bay areas reflect a coincident peak load for 1-in-10-year heat wave conditions of each study scenario. Tables 4-9 show load level in the base case under summer peak conditions.

Table 4-9: Summer peak load forecasts modeled in North Coast and North Bay area assessments

	MW Load Forecast										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Humboldt	131	132	134	136	138	140	142	144	145	147	149
North Coast	843	857	870	884	899	913	927	941	954	968	981
North Valley	761	772	784	799	816	829	842	855	868	881	894
Sacramento	1,025	1,037	1,049	1,064	1,076	1,089	1,101	1,114	1,127	1,139	1,152
Sierra	1,025	1,054	1,082	1,114	1,147	1,176	1,206	1,235	1,264	1,293	1,322
North Bay	748	755	764	774	783	793	803	812	822	832	841
East Bay	914	920	927	934	941	948	955	962	969	975	982
Diablo	1,627	1,644	1,662	1,684	1,704	1,723	1,742	1,761	1,780	1,798	1,817
San Francisco	912	920	928	938	947	956	965	974	983	992	1,002
Peninsula	994	1,011	1,023	1,033	1,041	1,055	1,069	1,083	1,096	1,110	1,123
Stockton	1,309	1,327	1,347	1,371	1,394	1,416	1,438	1,461	1,483	1,505	1,527
Stanislaus	221	228	233	238	244	249	254	258	263	268	273
Yosemite	795	805	817	828	839	851	862	874	886	898	909
Fresno	1,986	2,013	2,040	2,072	2,104	2,132	2,159	2,187	2,215	2,242	2,269
Kern	1,401	1,422	1,444	1,467	1,491	1,513	1,535	1,557	1,580	1,601	1,623
Mission	1,258	1,270	1,281	1,295	1,307	1,320	1,333	1,346	1,359	1,371	1,384
De Anza	919	927	936	946	956	966	977	987	998	1,008	1,018
San Jose	1,713	1,734	1,754	1,771	1,789	1,810	1,831	1,853	1,875	1,895	1,916
Central Coast	730	743	754	764	775	783	791	799	807	816	824
Los Padres	521	530	538	547	557	566	575	585	594	603	612
Total	19,835	20,100	20,366	20,658	20,945	21,229	21,507	21,788	22,069	22,343	22,617

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4.5.2.2 Study results and discussions

Study results in the North Coast and North Bay area are shown in Tables 4-10 and 4-11.

Table 4-10: Worst line/equipment overload summaries for North Coast and North Bay areas

Overloaded Facility	Rating (Amps)	Critical Contingenc(ies)	Category	Loading (%) 2013	Loading (%) 2018	CAISO Proposed Solutions
Bridgeville - Garberville 60kV #1 (Bridgeville - Fruitland Jct)	371	T-1 CORTINA 230/115 Bank #4	B	105	112	Second Cortina 230/115 kV Bank or increase import capability to North Geysers
		L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	120	Diverge	
Bridgeville - Garberville 60kV #1 (Fruitland Jct - Ft. Seward)	340	T-1 CORTINA 230/115 Bank #4	B	107	114	
		L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	124	Diverge	
Bridgeville - Garberville 60kV #1 (Ft. Seward - Garberville)	340	T-1 CORTINA 230/115 Bank #4	B	106	113	
		L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	122	Diverge	
Willits - Garberville 60kV #1 (Kekawaka - Laytonville)	337	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	101		
Geysers 3 - Cloverdale 115kV #1	743	L-1 Cortina-Mendocino 115kV and L-1 Redbud-Eagle Rock 115kV	C	113	124	Load dropping
Fulton - Santa Rosa 115kV #1 (Fulton - Monroe 1)	1125	L-1 Fulton-Santa Rosa #2 115kV and L-1 Lakeville-Corona 115kV	C	126	129	Load dropping scheme
Fulton - Santa Rosa 115kV #2 (Fulton - Monroe 2)	1125	L-1 Fulton-Santa Rosa #1 115kV and L-1 Lakeville-Corona 115kV	C	126	129	
Eagle Rock - Cortina 115kV #1 (Cache Jct - Cortina)	668	L-1 Cortina-Mendocino 115kV and G-1 GEYSER #11	B	100	109	Reconductor this section or connect the 115 kV system with 60 kV system
		L-1 Eagle Rock-Geysers#7&8 and L-1 Cortina-Mendocino 115kV	C	102	110	
Eagle Rock - Cortina 115kV #1 (Eagle Rock - Homestake - Highland Jct)	602	L-1 Eagle Rock-Geysers#7&8 and L-1 Cortina-Mendocino 115kV	C	95	103	Load dropping scheme
Sonoma - Pueblo 115kV #1 (Fulton - Pueblo)	743	L-1 Lakeville-Sonoma #1 115kV and L-1 Lakeville-Sonoma #2 115kV	C	109	116	
	602	L-1 Lakeville-Sonoma #1 115kV and L-1 Lakeville-Sonoma #2 115kV	C	135	143	
Fulton - Calistoga 60kV #1 (Fulton - St. Helena)	422	L-1 Lakeville - Dunbar 60kV #1	B	123	135	Reconductor the overloaded section
Fulton 230/115 kV Bank #4	463 MVA	L-1 Lakeville-Corona 115 kV and T-1 Fulton 230/115 kV Bank #9	C	100	110	Load dropping scheme

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Table 4-10: Worst line/equipment overload summaries for North Coast and North Bay areas (cont.)

Overloaded Facility	Rating (Amps)	Critical Contingenc(ies)	Category	Loading (%) 2013	Loading (%) 2018	CAISO Proposed Solutions
Eagle Rock - Redbud 115kV #1	512	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	158	Diverge	Second Cortina 230/115 kV Bank or increase import capability to North Geysers
Eagle Rock - Redbud 115kV #1 (Lower Lake Jct - Eagle Rock)	743	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	109		
Eagle Rock 115/60kV Bank #1	80 MVA	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	106		
Fulton - Hopland 60kV #1	327	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	113		
Hopland 115/60kV Bank #2	48 MVA	T-1 EAGLE ROCK 115/60 Bank #1	B	101		1) Second Eagle Rock Bank or 2) A new line between Geyser 17 and Middletown or 3) Connecting 115 kV system from Cortina with 60 kV system
		L-1 Vaca-Tulucay 230kV and T-1 EAGLE ROCK 115/60 Bank #1	C	118		
Mendocino - Clear Lake 60kV #1 (Mendocino - Upper Lake - Hartley)	338	T-1 EAGLE ROCK 115/60 Bank #1	B	110		
		L-1 Elk-Gualala 60kV and T-1 EAGLE ROCK 115/60 Bank #1	C	144		
Clear lake - Eagle Rock 60kV #1 (Clear lake - Konocti)	380	T-1 EAGLE ROCK 115/60 Bank #1	B	128		
		L-1 Elk-Gualala 60kV and T-1 EAGLE ROCK 115/60 Bank #1	C	197		
Clear lake - Eagle Rock 60kV #1 (Lower Lake - Konocti)	344	L-1 Elk-Gualala 60kV and T-1 EAGLE ROCK 115/60 Bank #1	C	142		
Clear lake - Eagle Rock 60kV #1 (Konocti - Eagle Rock)	610	L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	C	124		Second Cortina 230/115 kV Bank
		T-1 EAGLE ROCK 115/60 Bank #1	B	143		Option 1), 2) or 3) above
Clear lake - Hopland 60kV #1 (Clear Lake - Granite)	346	T-1 EAGLE ROCK 115/60 Bank #1	B	143		
Clear lake - Hopland 60kV #1 (Granite - Hopland Jct)	346	T-1 EAGLE ROCK 115/60 Bank #1	B	155		
Ignacio - Mare Island 115kV #2 (Highway Jct - Ignacio)	407	L-1 Ignacio - Carquinez 115kV #1	B	118	128	Reconductor the overloaded sections or long-term plan for this area is needed
	407	L-1 Ignacio - Carquinez 115kV #1 and T-1 Ignacio 230/115 Bank #6	C	121	131	
Ignacio - Mare Island 115kV #1 (Ignacio - Skagg Jct)	407	L-1 Ignacio - Highway 115kV #1	B	103	114	
	407	L-1 Ignacio - Highway 115kV #1 and T-1 Ignacio 230/115 Bank #6	C	104	116	

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Table 4-10: Worst line/equipment overload summaries for North Coast and North Bay areas (cont.)

Overloaded Facility	Rating (A)	Critical Contingenc(ies)	Category	Loading (%) 2013	Loading (%) 2018	CAISO Proposed Solutions
Ignacio - Alto - Sausalito 60kV #1 (Ignacio - Hamilton Field Tap)	600	L-1 Greenbrae - Ignacio Jct 60kV #1 and L-1 Ignacio A - Sausalito 60kV #1	C	144	152	Eliminate the switching scheme and use Load dropping
Ignacio - Alto - Sausalito 60kV #2 (Ignacio - Hamilton Field Tap)	600	L-1 Greenbrae - Ignacio Jct 60kV #1 and L-1 Ignacio A - Alto 60kV #1	C	144	152	
Ignacio - Alto 60kV #1(Ignacio Jct - San Rafael Jct - Greenbrae)	558	L-1 Ignacio A - Alto 60kV #1 and L-1 Ignacio A - Sausalito 60kV #1	C	125	131	Load dropping scheme
	558	L-1 Ignacio A - Alto 60kV #1 and L-1 Ignacio A - Sausalito 60kV #1	C	125	131	
Vaca Dixon - Lakeville 230kV #1	1051	L-1 Lakeville-Geysers #9 230kV and L-1 Vaca-Tulucay 230kV	C	107	104	
Tulucay - Vaca Dixon 230kV #1	1129	L-1 Lakeville-Geysers #9 230kV and L-1 Vaca-Lakeville 230kV	C	105	102	
Lakeville 230/60kV Bank #3	96	L-1 Fulton-Molino-Cotati 60kV and T-1 LAKEVILLE 230/60 Bank #4	C	100	109	
Fulton - Lakeville 230 kV #1	976	L-1 Fulton-Geysers 12 230 kV and T-2 Cotina 230/115 kV Bank #4	C	92	100	
Lakeville 60kV #2	400	L-1 Lakeville-Petaluma C 60kV	B	114	124	Reconductor the overloaded section
	400	L-1 Fulton-Molino-Cotati 60kV and L-1 Lakeville-Petaluma C 60kV	C	154	167	
	481	L-1 Fulton-Molino-Cotati 60kV and L-1 Lakeville-Petaluma C 60kV	C	122	132	
	512	L-1 Fulton-Molino-Cotati 60kV and L-1 Lakeville-Petaluma C 60kV	C	121	130	

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Table 4-11: Low voltages summary for North Coast and North Bay areas

Substation	Critical Contingency(ies)	Category	Min Post- 2013	Min Post- 2018	CAISO Proposed Solutions
Fruitland, Fort Seward 60 kV	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.80	0.79	Already addressed in Humboldt mitigation
	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.75	0.74	
Garberville, Kekawaka 60 kV	T-1 Cortina 230/115 Transformer #4	B	0.90	0.89	
	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.65	0.64	
Laytonville, Covelo, Fort Bragg, Big River, Elk, Point Arena, Garcia, Philo 60 kV, Mendocino 115 kV	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.80	0.79	Already addressed in Humboldt mitigation
Sonoma 115 kV	L-1 Lakeville-Sonoma #1 115 kV and L-1 Lakeville-Sonoma #2 115 kV	C	0.86	0.85	The mitigation plan for thermal problem can be used
Upper Lake 60 kV, Cortina 115 kV, City of Ukiah 115 kV	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.90	0.89	
Hartley, Granite 60 kV	T-1 Eagle Rock 115/60 Transformer #1	B	0.92	0.91	
	L-1 Ukiah-Hopland-Cloverdale 115 kV and T-1 Cortina 230/115 Transformer #4	C	0.90	0.89	
Clear Lake 60 kV	T-1 Eagle Rock 115/60 Transformer #1	B	0.87	0.86	
	L-1 Vaca-Tulucay 230 kV and T-1 Eagle Rock 115/60 Transformer #1	C	0.75	0.74	
Konocti, Lower Lake, Middle Town, Eagle Rock 60 kV	T-1 Eagle Rock 115/60 Transformer #1	B	0.67	0.66	
	L-1 Elk-Gualala 60 kV and T-1 Eagle Rock 115/60 Transformer #1	C	0.40	0.39	
Pueblo 115 kV	L-1 Lakeville-Sonoma #1 115 kV and L-1 Lakeville-Sonoma #2 115 kV	C	0.89	0.88	The mitigation plan for thermal problem can be used
Dunbar, St Helena, Calistoga 60 kV	L-1 Lakeville -Dunbar #1 60 kV	B	0.86	0.90	The mitigation plan for thermal problem can be used or eliminate switiching scheme
Greenbrae, Alto, Sausalito 60 kV	L-1 Greenbrae - Ignacio Jct 60 kV #1 and L-1 Ignacio A - Alto 60 kV #1	C	0.83	0.82	The mitigation plan for thermal problem can be used
	L-1 Greenbrae - Ignacio Jct 60 kV #1 and L-1 Ignacio A - Sausalito 60 kV #1	C	0.83	0.82	

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4.5.2.3 Recommended solutions for reliability criteria violations

TPL 001-System Performance Under Normal Conditions

There is no overload or voltage violation under Category A system performance requirements.

TPL 002-System Performance Following Loss of a single BES Element

- **Bridgeville-Garberville 60 kV line#1 (Bridgevillee-Fruitland Jct.-Ft. Seward-Garberville) Overload**

  This overload was identified starting in the 2013 summer peak conditions due to power flow to the north Geysers area from the Humboldt area following the outages of Cortina 230/115 kV Bank #4 and its combination. The proposed solutions are:

  - Install a second Cortina 230/115 kV transformer
  - Improve import capability to the North Geysers area by reinforcing interconnection between the north and south Geysers.

- **Hopland 115/60 kV Transformer #2 Overload**

  This transformer can be overloaded following the outage of Eagle Rock 115/60 kV Transformer due to transferred power to serve the North Geysers area. The proposed mitigation plan for this overload is to increase the import capability to the north Geysers area. These may include:

  - Installing a second Eagle Rock 115/60 kV Transformer,
  - Connecting Geysers 17 with the Middletown substation,
  - Connecting the Cortina 115 kV system from the Cortina substation with the local 60 kV system in the North Geysers. In addition, an expansion plan to improve the voltage and thermal loading at Middletown substation area is also recommended.

- **Mendocino – Clear Lake –Eagle Rock 60 kV line Overload**

  This overload was triggered, mainly by, the outage of the Eagle Rock 115/60 kV transformer. The proposed solutions for the Hopland 115/60 kV transformer #2 will also mitigate this overload.

- **Clear Lake –Hopland 60 kV line Overload**

  This overload was triggered, mainly by, the outage of the Eagle Rock 115/60 kV transformer. The proposed solutions for the Hopland 115/60 kV transformer #2 will also mitigate this overload.

- **Eagle Rock – Cortina 115 kV line #1 Overload**

  An overlapping G-1/L-1 contingency can cause an overload of this line. The proposed mitigation plan is to reconductor the overloaded section. In addition, other proposed upgrades for the North Geysers area might mitigate the overload of this facility.

- **Fulton-Calistoga 60 kV #1 Overload**

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This facility can also be overloaded following the outages of Lakeville-Dunbar 60 kV #1 that triggers the operation of the switching scheme in the area. The permanent solutions to this problem are to reconductor the overloaded section. The short-term solution is to disable the automatic switching scheme during high loads such as summer peak. In addition, the upgrade proposed for the Hopland 115/60 kV transformer #2 may also mitigate this problem as well.

- **Ignacio-Mare Island 115 kV #1 and #2 Overload**

  This facility can also be overloaded following an outage of the parallel line. The proposed upgrades for these problems are to reconductor both of these lines. In addition, transferring load from Highway substation to a stronger source will mitigate these overloads as well.

- **Lakeville 60 kV line #2 Overload**

  This facility can be overloaded following the outage of the Lakeville – Petaluma 60 kV line #1. The proposed mitigation plan for this overload is to reconductor the overloaded facility.

- **Low voltages on Laytonville, Covelo, Fort Bragg, Big River, Elk, Point Arena, Garcia, Philo 60 kV substations**

  This facility can be overloaded following an outage of the Lakeville-Petaluma 60 kV line #1. The proposed mitigation plan for this overload is to reconductor the overloaded facility.

- **Low voltages on Sonoma, Cortina, Pueblo, City of Ukiah 115 kV and Upper lake, Hartley, Granite, Clearlake, Konocti, Lower Lake, Middletown, Dunbar, St Helena, Calistoga, Greenbrae, Alto, Sausalito, and Eagle Rock60 kV substations**

  Low voltages on these substations can be observed following several category B contingencies. However, the proposed solution for the thermal overloads will also improve voltage profile in this area.

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TPL 003-System Performance Following Loss of Two or More BES Elements

- **Bridgeville-Garberville 60 kV line#1 (Bridgeville-Fruitland Jct.-Ft. Seward-Garberville) Overload**

  This is the same overload shown under Category B contingency. However, the percentage overload on these facilities is higher due to the outages of multiple transmission facilities. In general, the proposed solutions for the Category B overloads can also be used.

- **Willits-Garberville 60 kV line# (Kekawaka-Laytonville) Overload**

  This section of the line can be overloaded under the same Category B contingency that overload the Bridgeville-Garberville 60 kV line. Consequently, the same mitigation plans proposed earlier or load dropping schemes can be used to mitigate this overload.

- **Geysers 3-Cloverdale 115 kV line #1 Overload**

  This section of the line can be overloaded following the outages of Cortina-Mendocino 115 kV and L-1 Redbud-Eagle Rock 115 kV lines. The proposed solution for this overload is to drop the load post contingency or to improve import capability to the North Geysers area.

- **Eagle Rock-Redbud 115 kV line #1 Overload**

This section of the line can be overloaded under the same category B contingency that overload the Bridgeville – Garberville 60 kV line. Consequently, the same mitigation plans proposed earlier or load dropping schemes can be used to mitigate this overload.

- **Eagle Rock115/60 kV Transformer #1 Overload**

  This section of the line can be overloaded under the same Category B contingency that overload the Bridgeville – Garberville 60 kV line. Consequently, the same mitigation plans proposed earlier or load dropping schemes can be used to mitigate this overload. Increasing import capability to the North Geysers will also mitigate this overload.

- **Fulton-Hopland 60 kV line #1 Overload**

  This section of the line can be overloaded under the same category B contingency that overload the Bridgeville – Garberville 60 kV line. Consequently, the same mitigation plans proposed earlier or load dropping schemes can be used to mitigate this overload. Increasing import capability to the North Geysers will also mitigate this overload.

- **Hopland 115/60 kV Transformer #2 Overload**

  This overload has been identified under category B contingency and the mitigation plans for category B overload also mitigate this overload problem.

- **Mendocino-Clear Lake-Eagle Rock 60 kV line Overload**

  This overload has been identified under category B contingency and the mitigation plans for category B overload also mitigate this overload problem.

- **Fulton-Santa Rosa 115 kV line #1 or #2 Overload**

  The overlapping outages of the parallel line and the Lakeville – Corona 115 kV line can overload the remaining line that is still in-service. The proposed solution is to install a load dropping scheme.

- **Fulton 230/115 kV transformer #4 Overload**

  This overload was identified following the overlapping outages of the parallel transformer and the Lakeville – Corona 115 kV line. The proposed solution is to install load dropping scheme.

- **Ignacio-Sausalito 60 kV lines #1 and #2 Overload**

  This facility can also be overloaded following the outages of Greenbrae – Ignacio Jct. and Ignacio-Sausalito 60 kV lines, mainly due to automatic switching scheme. The permanent solution to this problem is to install a oad dropping scheme. The short-term solution is to disable the automatic switching scheme during high load such as summer peak.

- **Ignacio-Alto 60 kV line #1 Overload**

  This facility can also be overloaded following the outages of Ignacio-Alto and Ignacio-Sausalito 60 kV lines. The proposed solution to this problem is to install a load dropping scheme.

- **Vaca Dixon-Lakeville and Tulucay-Vaca Dixon 230 kV lines overload**

These are parallel facilities which can be overloaded after the outages of the parallel line and

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the Lakeville-Geysers 9 230 kV lines. The proposed solutions to these problems are to install load dropping scheme or to implement an operating procedure.

- **Lakeville 230/60 kV Transformer #3 Overload**

This facility can be overloaded after the outage of the parallel transformer and the Fulton-Molino-Cotati 60 kV line. The proposed solutions to these problems are to install load dropping scheme or to implement an operating procedure.

- **Fulton – Lakeville 230 kV line #1 Overload**

This facility can be overloaded after the outage of Fulton-Geysers 12 230 kV line and Cortina 230/115 kV transformer #4. The proposed solutions to these problems are to install load dropping scheme or to implement an operating procedure.

- **Lakeville 60 kV line #2 Overload**

This is the same overload identified under Category B contingency overload. Consequently, the same mitigation plan proposed for category B overload can be used for this condition.

- **Low voltages on Laytonville, Covelo, Fort Bragg, Big River, Elk, Point Arena, Garcia, Philo 60 kV substations**

These low voltages can be triggered by the outages of Cortina 230/115 kV transformer and Ukiah-Cloverdale 115 kV line. The proposed solution to install reactive support in the Humboldt area will also improve voltage level at these substations. However, addition reactive support might be needed.

- **Low voltages on Sonoma, Cortina, Pueblo, City of Ukiah 115 kV and Upper lake, Hartley, Granite, Clearlake, Konocti, Lower Lake, Middletown, Dunbar, St Helena, Calistoga, Greenbrae, Alto, Sausalito, and Eagle Rock60 kV substations**

Low voltages at these substations can be observed following several category C contingencies. However, the proposed solution for the thermal overloads will also improve voltage profile in this area.

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4.5.2.4 Key conclusions

Based on the ISO study assessment, the North Coast/Bay area had:

- No overloads under normal conditions,
- Nine overloads caused by nine critical single contingencies under summer peak conditions,
- 25 overloads caused by 12 critical multiple contingencies under summer peak conditions,
- Among those studied, there were no extreme contingency conditions with potential voltage collapse.

In order to address all these concerns the ISO has proposed 11 transmission solutions.

During the 2008 Open Request Window the ISO received five project proposals:

- Three were approved,
- Two were withdrawn,

- None were denied,
- One is on-going (i.e. to be considered for approval at a later date).

This gives a total of four projects in the 2009 transmission plan for the North Coast and North Bay area.

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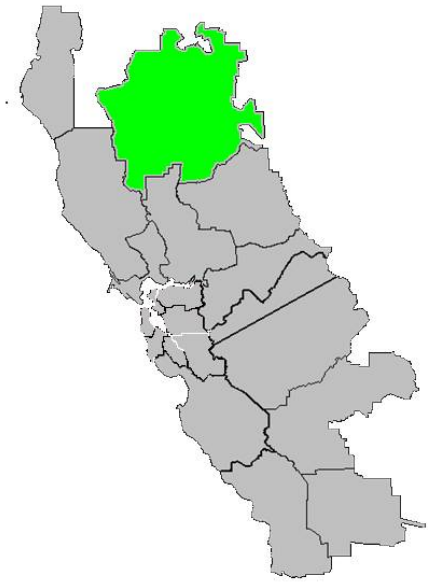
4.5.3 North Valley area

The North Valley area is located in the northeastern corner of the PG&E's service area and covers approximately 15,000 square miles. This area includes the northern end of the Sacramento Valley, and parts of the Siskiyou and Sierra mountain ranges and the foothills. Chico, Redding, Red Bluff and Paradise are some of the cities in this area. The figure below depicts the approximate geographical location of the North Valley area.



North Valley's electric transmission system is comprised of 60, 115, 230, and 500 kV transmission facilities. The 500 kV facilities are part of the Pacific Inter-tie between California and the Pacific Northwest. The 230 kV facilities, which complement the Pacific Inter-tie, also run north to south with connections to hydroelectric generation facilities. The 115 and 60 kV facilities serve the local electricity demand. In addition to the Pacific inter-tie, there is one other external interconnection to the PacifiCorp system. The internal transmission system connections to the Humboldt and Sierra areas are via Cottonwood, Table Mountain, Palermo, and Rio Oso substations.

Historically, North Valley experiences its highest demand during the summer season, however there are very few and small areas in the mountains that experience highest demand during the winter season. Load forecasts indicate North Valley should reach its summer peak demand of 1074 MW by 2018 assuming load is increasing at approximately 16-16 MW per year (MW/year).

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4.5.3.1 Area-specific assumptions and system conditions

The North Valley area study was performed consistent with the general study methodology and assumptions described in Chapter 3 and appendix A. The ISO secured website lists contingencies that were performed as part of this assessment. Additionally, specific methodology and assumptions that are applicable to the North Valley area study are provided below.

Generation

Generation resources in the North Valley area consist of market, QFs and self-generating units. There are over 2,000 MW of hydroelectric generation facilities in this area. These hydroelectric facilities are fed from the following river systems: Pit River, Battle Creek River, Cow Creek, North Feather River, South Feather River, West Feather River and Black Butt. Pit, James Black, Caribou, Rock Creek, Cresta, Butt Valley, Belden, Poe, and Bucks Creek are some of the large powerhouses on the Pit River and the Feather River watersheds. The largest generation facility in the area will be the Colusa County Generation Plant, which is planned to start commercial operational date by 2010. This plant will consist of a combined total rating of 715 MW when completed, and will interconnect to the four Cottonwood-Vaca Dixon 230 kV lines at a site near Colusa, CA. The following table summarizes the in-area generation capacity

Table 4-12: Generation Plants in North Valley Area

Plant Name	Max Capacity (MW)
Pitt River	757
Battle Creek	38
Cow Creek	5
North Feather River	730
South Feather River	127
West Feather River	26
Black Bute	11
Colusa County	717
QFs and Other	353
Generation Total	**2764**

Load forecast

Loads within the North Valley area reflect a coincident peak load for 1-in-10-year heat wave conditions of the study scenario. Table 4-13 shows loads assumed in these studies under summer peak conditions. System losses amount to roughly 53 and 57 MW for the North Valley area in 2013 and 2018 respectively.

Table 4-13: Summer peak load forecasts modeled in North Valley area assessment

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	MW Load Forecast										
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Humboldt	131	132	134	136	138	140	142	144	145	147	149
North Coast	635	645	655	666	677	688	698	709	719	729	739
North Valley	915	927	943	960	980	996	1,012	1,028	1,043	1,059	1,074
Sacramento	963	974	985	999	1,010	1,022	1,034	1,046	1,058	1,070	1,082
Sierra	1,157	1,189	1,222	1,257	1,294	1,328	1,361	1,394	1,427	1,459	1,492
North Bay	588	594	600	608	616	623	631	639	646	654	661
East Bay	807	812	817	824	831	837	843	849	855	860	866
Diablo	1,341	1,355	1,370	1,388	1,404	1,420	1,436	1,451	1,467	1,482	1,497
San Francisco	822	829	836	845	853	861	869	878	886	894	903
Paninsula	791	804	814	822	829	840	851	861	872	883	894
Stockton	1,262	1,279	1,299	1,322	1,344	1,365	1,387	1,408	1,430	1,451	1,472
Sanislaus	215	221	226	231	237	241	246	251	256	261	265
Yosemite	854	865	877	889	901	913	926	939	951	964	976
Fresno	2,132	2,161	2,191	2,225	2,259	2,289	2,319	2,349	2,379	2,407	2,436
Kern	1,410	1,432	1,453	1,476	1,501	1,523	1,545	1,568	1,590	1,612	1,634
Mission	1,188	1,200	1,210	1,222	1,234	1,246	1,258	1,271	1,283	1,295	1,307
De Anza	800	807	815	824	832	842	851	860	869	878	887
San Jose	1,410	1,427	1,443	1,457	1,472	1,490	1,507	1,525	1,543	1,560	1,577
Central Coast	693	705	715	725	735	743	751	759	766	774	782
Los Padres	507	515	523	532	542	551	559	568	577	586	595
Total	**18,621**	**18,874**	**19,129**	**19,410**	**19,688**	**19,960**	**20,226**	**20,495**	**20,763**	**21,025**	**21,288**

4.5.3.2 Study results and discussions

TPL 001-System Performance Under Normal Conditions

There are two overloads and three worst low voltages under Category A, summer peak normal conditions as summarized respectively in Tables 4-14 and 4-15 below.

Table 4-14: Summary of overloads for summer normal peak load conditions

Facility	Loading (%)		Solution
	2013	2018	
Burney QF-Burney 60 kV	103%	103%	Modeling Error
Wyandotte-Wyandotte Jct. 115 kV	<100%	101%	Reconductor

Table 4-15: Summary of worst voltage criteria violations for summer normal peak load conditions

Worst Bus Name	Voltage (PU)		Solution
	2013	2018	
Leavit #1 69 kV	0.82	0.84	Voltage support and/or new interconnection
Leavit #2 69 kV	0.82	0.84	
NCPA gen 69 kV	0.82	0.84	

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TPL 002 – System Performance Following Loss of a Single BES Element

For the loss of a single element, which included loss of one generator and transmission facilities according to the ISO planning standards, there were one divergent case, and eight overloads that were caused by nine critical contingencies as well as four worst buses with low voltages that were as a result of six critical contingencies.

TPL 003-System Performance Following Loss of Two or More BES Elements

For Category C multiple contingency conditions (TPL 003) there were 18 overloads caused by 15 critical contingency conditions as well as seven worst buses with low voltages that were as a result of five critical contingencies.

TPL 004-System Performance Following Extreme BES Events

Among those studied, there were no Category D extreme contingency conditions (TPL 004) with potential voltage collapse.

Table 4-16 through 4-18 document the worst overloads and worst low voltage violations for the summer peak emergency conditions and ISO proposed solutions to mitigate these problems

Table 4-16: Divergent cases summary for summer emergency peak load conditions

2018 Divergent Cases	Category	Solution
Caribou-Plumas Junction 60 kV	B	Voltage support and/or new interconnection

Table 4-17: Worst equipment overload summary for summer emergency peak load conditions

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Nord-Sycamore 115 kV	Table Mountain-Notre Dame-Sycamore 115 kV and Table Mountain-Butte #1 115 kV	C3	<100	102	Chico area reinforcement consisting of SPS + line reconductoring and/or rearrangement or new DCTL from Table Mountain to Sycamore
	Table Mountain-Notre Dame-Sycamore 115 kV and Table Mountain-Butte #2 115 kV	C5	<100	102	
Butte-Nord 115 kV	Table Mountain-Notre Dame-Sycamore 115 kV and Table Mountain-Butte #1 115 kV	C3	<100	110	
	Table Mountain-Notre Dame-Sycamore 115 kV and Table Mountain-Butte #2 115 kV	C5	<100	111	
	Table Mountain-Notre Dame-Sycamore 115 kV	B	<100	105	
	Table Mountain-Notre Dame-Sycamore 115 kV and Table Mountain-Butte #1 115 kV	C3	112	126	
	Table Mountain-Notre Dame-Sycamore 115 kV and Table Mountain-Butte #2 115 kV	C5	112	126	
	Table Mountain-Notre Dame-Sycamore 115 kV	B	108	120	
Table Mountain-Butte #1 115 kV	Table Mountain-Notre Dame-Sycamore 115 kV and Table Mountain-Butte #2 115 kV	C3	133	146	
		C5	133	146	
	Table Mountain-Notre Dame-Sycamore 115 kV and Table Mountain-Butte #2 115 kV	C5	155	171	
		C3	155	171	
	Table Mountain-Notre Dame-Sycamore 115 kV	B	<100	104	

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Table 4-17: Worst equipment overload summary for summer emergency peak load conditions (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Table Mountain-Butte #2 115 kV	Table Mountain-Notre Dame-Sycamore 115 kV and Table Mountain-Butte #1 115 kV	C3	132	147	Chico area reinforcement consisting of SPS + line reconductoring and/or rearrangement or new DCTL from Table Mountain to Sycamore
Table Mountain-Notre Dame-Sycamore 115 kV	Table Mountain-Butte #1 and #2 115 kV	C3	129	141	
Table Mountain-Paradise 115 kV	Table Mountain-Butte #1 and #2 115 kV	C3	<100	105	
Trinity-Maple Creek 60 kV	Humboldt-Trinity 115 kV and Bridgeville-Cottonwood 115 kV	C3	106	<100	Trinity area reconfiguration and/or emergency operating procedures
		C3	105	<100	
		C3	104	<100	
Trinity-Keswick 60 kV	Cottonwood-Benton #2 60 kV and Cascade #1 115/60 kV	C3	110	115	
	Cottonwood-Trinity 115 kV and Bridgeville-Cottonwood 115 kV	C3	121	106	
	Benton-Cascade-Deschutes 60 kV and Cottonwood-Cascade 115 kV	C3	119	112	
		C3	127	120	
		C3	135	128	
Keswick-Cascade 60 kV	Benton-Cascade-Deschutes 60 kV and Cottonwood-Cascade 115 kV	C3	175	174	
	Trinity 115/60 kV and Cascade 115/60 kV	C3	158	Divergent	
	Benton-Cascade-Deschutes 60 kV and Cottonwood-Cascade 115 kV	C3	167	161	

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Table 4-17: Worst equipment overload summary for summer emergency peak load conditions (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Cottonwood #2 230/60 kV	Cottonwood #1 230/60 kV and Cascade #1 115/60 kV	C3	111	125	Cascade area reinforcement
Cottonwood-Cascade 115 kV	Cascade-Delta 115 kV and Trinity 115/60 kV	C3	105	114	
Cottonwood -Benton #1 60 kV	Cottonwood-Benton #2 60 kV and Cascade #1 115/60 kV	C3	<100	105	
	Trinity 115/60 kV and Cascade 115/60 kV	C3	143	Divergent	
	Cottonwood-Benton #2 60 kV and Cascade #1 115/60 kV	C3	136	153	
	Trinity 115/60 kV and Cascade 115/60 kV	C3	191	Divergent	
	Cottonwood-Benton #2 60 kV and Cascade #1 115/60 kV	C3	184	208	
	Cascade #1 115/60 kV	B	119	135	
Cottonwood -Benton #2 60 kV	Trinity 115/60 kV and Cascade 115/60 kV	C3	114	Divergent	
Benton-Cascade-Deschutes 60 kV	Cascade-Keswick 60 kV and Cottonwood-Cascade 115 kV	C3	161	158	
	Trinity 115/60 kV and Cascade 115/60 kV	C3	252	Divergent	
	Cottonwood-Cascade 115 kV and Volta #1 gen	B	123	116	
	Cottonwood-Cascade 115 kV	B	122	115	
	Trinity 115/60 kV and Cascade 115/60 kV	C3	232	Divergent	
	Cottonwood-Cascade 115 kV and Volta #1 gen	B	138	133	
	Cottonwood-Cascade 115 kV	B	136	131	
	Deschutes-Volta 60 kV and Cascade 115/60 kV	C3	158	174	
	Cascade 115/60 kV	B	108	119	

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Table 4-17: Worst equipment overload summary for summer emergency peak load conditions (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Deschutes-Volta 60 kV	Benton-Cascade-Deschutes 60 kV and Kilarc-Deschutes 60 kV	C3	107	116	Deschutes area reconfiguration and voltage support
	Benton-Cascade-Deschutes 60 kV and Volta #1 gen	B	105	118	
	Benton-Cascade-Deschutes 60 kV	B	<100	109	
Volta-South 60 kV	Benton-Cascade-Deschutes 60 kV and Volta #1 gen	B	171	190	
	Benton-Cascade-Deschutes 60 kV and Kilarc-Deschutes 60 kV	C3	139	152	
	Benton-Cascade-Deschutes 60 kV	B	129	143	
Cottonwood-Red Bluff 60 kV	South-Coleman 60 kV and Cottonwood-Coleman 60 kV	C3	106	119	Red Bluff long-term reinforcement
	Coleman-Red Bluff 60 kV	B	101	107	
	South-Coleman 60 kV and Cottonwood-Coleman 60 kV	C3	106	119	
	Coleman-Red Bluff 60 kV	B	101	107	
Glenn #1 60 kV	Glenn #5 60 kV and Cottonwood-Glenn 230 kV	C3	104	107	Glenn #1 reconductoring
	Glenn #5 60 kV and Colusa #1 gen	B	103	108	
	Glenn #5 60 kV	B	102	107	

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Table 4-18: Worst voltage summary for summer emergency peak load conditions

Worst bus	Worst Contingency	Category	Voltage Change (%) 2013	Voltage Change (%) 2018	Proposed Solution
Sycamore 115 kV	Table Mountain-Butte #1 115 kV and Table Mountain-Notre Dame-Sycamore 115 kV	C3	<10	10.91	Chico area reinforcement
Garberville 60 kV	Humboldt-Trinity 115 kV and Cottonwood-Bridgeville 115 kV	C3	15.23	13.27	Trinity area reconfiguration and/or emergency operating procedures
Mill Station 60 kV	Trinity 115/60 kV and Cascade 115/60 kV	C3	59.69	Divergent	
	Trinity 115/60 kV	B	17.98	18.01	
Hayfork 60 kV	Humboldt-Trinity 115 kV and Cottonwood-Trinity 115 kV	C3	18.21	18.03	
Antler 60 kV	Benton-Cottonwood #2 60 kV and Cascade 115/60 kV	C3	15.02	17.07	Cascade area reinforcement
	Cascade 115/60 kV	B	8.95	10.17	
Deschutes 60 kV	Trinity 115/60 kV and Cascade 115/60 kV	C3	21.56	Divergent	
	Cascade-Benton-Deschutes 60 kV and Volta #1 gen	B	18.4	22.29	Deschutes area reconfiguration and voltage support
	Cascade-Benton-Deschutes 60 kV	B	13.2	15.53	
Red Bluff 60 kV	Cottonwood-Red Bluff 60 kV and Cascade-Benton-Deschutes 60 kV	C3	11.62	14.56	Red Bluff long-term reinforcement
	Cottonwood-Red Bluff 60 kV and Coleman gen	B	10.45	12.17	
	Cottonwood-Red Bluff 60 kV	B	9.59	10.94	

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4.5.3.3 Recommended solutions for reliability criteria violations

- **Burney 60 kV line voltage – Category A**

  The Burney QF to Burney section of the Pit #1-Hat Creek #4-Burney 60 kV line appear to have an overload in error; PG&E to verify model.

- **Wyandotte 115 kV Tap-Line – Category A**

  The Wyandotte-Wyandotte Junction section of the Palermo-Caribou 115 kV line will overload starting in 2018 at present load growth. Solution could include re-rate, reconductoring or load transfer. Another solution would be to loop this substation since its load is above 60 MW and PG&E's own guideline states that substations above 50 MW should be looped in.

- **Plumas-Sierra low voltage – Category A and B**

  Voltages in Plumas-Sierra service territory are constantly low for both 2013 and 2018 cases. Also the loss of the Caribou-Plumas Junction 60 kV line is divergent due to the same voltage support issue. Solution could include voltage support and/or new interconnection with stronger voltage source.

- **Chico area reinforcement – Category B and C**

  Numerous potential overloads for category B and C conditions as well as voltage deviation at Sycamore. Solution could include Special Protection Scheme (SPS) plus line reconductoring and/or rearrangement or a new Double Circuit Tower line (DCTL) from Table Mountain or new connection with from another strong source to Sycamore.

- **Trinity area reconfiguration – Category B and C**

  Numerous potential overloads for category C and voltage deviation for category B and C. The mitigation plan is to reconfigure the Trinity 60 kV system and/or implement new emergency operating procedures in this area.

- **Cascade area reinforcement – Category B and C**

  The local power plants include hydroelectric facilities on Battle Creek (50 MW) and Olsen Cogeneration (9.5 MW). In addition to the internal generation above, the Cascade substation has a connection to PacifiCorp that operates in northern California and other western states. These imports, the local generation and the Cascade 115/60 kV Transformer No. 1 are the key power supply facilities.

  Multiple potential overloads for category B and C conditions as well low voltage and voltage deviations can be mitigated by installing another transformer at Cascade as well as miscellaneous reconductoring and system rearrangement for the 60 kV system in this area. Also a different alternative would be to move some of the loads in this area to the 115 or 230 kV system.

- **Deschutes area reconfiguration and voltage support – Category B and C**

  The local power plants include hydroelectric facilities on Battle Creek (50 MW) and Olsen Cogeneration (9.5 MW).

  Multiple potential overloads for category B and C conditions as well low voltage and voltage

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deviations can be mitigated by reconfiguring the system and installing voltage support or by moving some of these loads to the 115 kV or 230 kV system.

- **Red Bluff long-term reinforcement – Category B and C**

  There is only one local power plant Neo Red Bluff Peaking Plant (50 MW). Sensitivity analysis concluded that an outage of the Neo Red Bluff Peaking Plant would cause a voltage deviation of more than 10% at the Tyler and Rawson local 60 kV substations.

  Multiple potential overloads for category B and C conditions as well low voltage and voltage deviations can be mitigated by moving some of the loads in this area to 230 kV system by building a new 230 kV substation near Red Bluff.

- **Glenn #1 60 kV reconductoring – Category B and C**

  The loss of Glenn #5 60 kV line transfers the Orland load to the Glenn #1 60 kV line and this could potentially overload it. Solution includes reconductoring 6 miles of the Glenn #1 60 kV line from Glenn to Orland Junction. Also another solution would be to disable the automatic transfers at Orland.

In addition, please refer to Chapter 3 more information regarding valid transmission projects in this area that ISO received from the Request Window and ISO decisions on these projects.

4.5.3.4 Key conclusions

Based on the ISO's study assessment, the North Valley area has:

- Two overloads and three worst low voltages under normal conditions,
- One divergent case, eight overloads caused by nine critical contingencies as well as four worst buses with low voltages caused by six critical contingencies under single contingency conditions,
- Eighteen overloads caused by 15 critical contingency conditions as well as seven worst buses with low voltages caused by five critical contingencies under multiple contingency conditions,

Among those studied, there were no extreme contingency conditions with potential voltage collapse. In order to address all the above concerns the ISO has proposed 9 transmission solutions.

During the 2008 Request Window, the ISO received five (5) project proposals:

- One has been approved
- One has been withdrawn
- One has been denied
- Two with on an on-going status (i.e., to be approved at a later date).

Only two of these projects have matched the ISO proposed solutions therefore there are 7 projects proposed by the ISO that are on-going – to be approved at a later date.

In brief, there were a total of twelve projects in the ISO 2009 transmission plan for the North Valley area.

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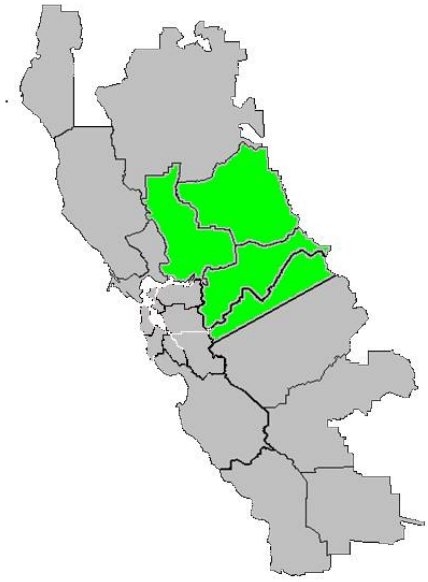
4.5.4 Central Valley area

Central Valley area is located in the eastern part of PG&E's service territory. This area includes the central part of the Sacramento Valley, and it is comprised of the Sacramento, Sierra, Stockton and Stanislaus divisions as shown in the figure below.



Sacramento covers approximately 4,000 square miles of the Sacramento Valley, but excludes the service territory of Sacramento Municipal Utility District (SMUD) and Roseville. Cordelia, Suisun, Vacaville, West Sacramento, Woodland and Davis are some of the cities in this area. The electric transmission system comprises of 60, 115, 230 and 500 kV transmission facilities. Two sets of 230 and 500 kV transmission paths make up the backbone of the system.

Sierra is located in the Sierra-Nevada area of California. Yuba City, Marysville, Lincoln, Rocklin, El Dorado Hills and Placerville are some of the major cities located within this area. Sierra's electric transmission system comprises of 60, 115, and 230 kV transmission facilities. The 60 kV facilities are spread throughout the Sierra system and serve many distribution substations. The 115 and 230 kV facilities transmit generation resources from the north to the south. Generation units located within the Sierra area are primarily hydroelectric facilities located on the Yuba and American River water systems. Transmission interconnections to the Sierra transmission system are from Sacramento, Stockton, North Valley, and the Sierra Pacific Power Company (SPP) in the State of Nevada (Path 24).

Stockton is located east of the Bay Area. Electricity demand in this area is concentrated around the cities of Stockton and Lodi. The transmission system comprises of 60, 115, and 230 kV facilities. The 60 kV transmission network serves downtown Stockton and the City of Lodi. The City of Lodi is a member of the Northern California Power Agency (NCPA) and it's the largest city that is served from the 60 kV transmission network. The 115 kV and 230 kV facilities support the 60 kV transmission network.

Stanislaus is located between the Greater Fresno and Stockton systems. Newman, Gustine, Crows Landing, Riverbank and Curtis are some of the cities in the area. The transmission system comprises of 230, 115, and 60 kV facilities. The 230 kV facilities connect Bellota to Wilson and Borden substations. The 115 kV transmission network is located in the northern portion of the area and has connections to QF generation located in the San Joaquin Valley. The 60 kV network located in the southern part of the area is a radial network. It supplies the Newman and Gustine areas and has a single connection to the transmission grid via a 115/60 kV transformer bank at Salado.

Historically, Central Valley experiences its highest demand during the summer season. Load forecasts indicate Central Valley should reach its summer peak demand of 4311 MW by 2018 assuming load is increasing at approximately 70 MW per year (MW/year).

4.5.4.1 Area-specific assumptions and system conditions

The Central Valley area study was performed consistent with the general study assumptions and methodology described in chapter 43 and the appendix A. ISO secured website describes

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contingencies that were performed as part of this assessment. In additional, specific assumptions and methodology applied to Central Valley area study are provided below in this section

Generation

Generation resources in the Central Valley area consist of market, QFs and self-generating units. These are shown in 4-19. The Total installed capacity is about 3459 MW with another 530 MW of North Valley generation being connected directly to the Sierra division. The following table summarizes the generation capacity in the Sacramento area. Over 800 MW of capacity listed here (from Lambie down) is connected to the new Birds Landing Switching Station and it mostly serves the Bay Area loads.

Table 4-19: Generation plants in the Sacramento area

Plant Name	Max Capacity (MW)
Wadham	27
Woodland Biomass	25
UC Davis Co-Gen	4
Cal-Peak Vaca Dixon	49
Wolfskill Energy Center	50
Lambie, Creed, and Goosehaven	143
EnXco	60
Solano	100
High Winds	200
Shiloh	300
Generation Total	**958**

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The following table summarizes the generation capacity in the Sierra area. There is about 1,247 MW of internal generating capacity within the Sierra Division, and over 530 MW of hydro generation listed under North Valley that flows directly into the Sierra electric system. Over 75% of this generating capacity is from hydro resources. The remaining 25% of the capacity is from QFs, and co-generation plants. The Colgate Powerhouse (294 MW) is the largest generating facility in the Sierra Division. For the purposes of the study,it was assumed that the hydro resources were dispatched around 85% of their rated capacities.

Table 4-20: Generation plants in the Sierra area

Plant Name	Max Capacity (MW)
Bowman Power House	4
Camp Far West (SMUD)	7
Chicago Park Power House	40
Chili Bar Power House	7
Colgate Power House	294
Deer Creek Power House	6
Drum Power House	104
Dutch Flat Power House	49

Table 4-20: Generation plans in the Sierra area (cont)

Plant Name	Max Capacity (MW)
El Dorado Power House	20
Feather River Energy Center	50
French Meadows Power House	17
Green Leaf No. 1	73
Green Leaf No. 2	50
Halsey Power House	11
Haypress Power House	15
Hellhole Power House	1
Middle Fork Power House	130
Narrows Power House	66
Newcastle Power House	14
Oxbow Power House	6
Ralston Power House	83
Rollins Power House	12
Spaulding Power House	17
SPI-Lincoln	18
Ultra Rock (Rio Bravo-Rocklin)	25
Wise Power House	20
Yuba City	49
Yuba City Energy Center	61
Generation Total	**1247**

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The Stockton area has about 950 MW of internal generating capacity. The following table summarizes the generation resources within the area.

Table 4-21: Generation plants in the Stockton area

Plant Name	Max Capacity (MW)
Altamont Co-Generation	7
Camanche Power House	11
Co-generation National POSDEF	44
Electra Power House	101
Flowind Wind Farms	76
GWF Tracy Peaking Plant	172
Ione Energy	18
Lodi Stigg (NCPA)	21
Pardee Power House	29
Salt Springs Power House	46

Table 4-21: Generation plants in the Stockton area (cont)

Plant Name	Max Capacity (MW)
San Joaquin Co-Generation	55
Simpson Paper Co-Generation	50
Stockton Co-Generation (Air Products)	50
Stockton Waste Water Facility	2
Thermal Energy	21
Tiger Creek Power House	55
US Wind Power Farms	158
West Point Power House	16
Generation Total	**932**

The Stanislaus area has about 590 MW of internal generating capacity. Over 90% of this generating capacity is from hydro resources. The remaining capacity consists of QFs and co-generation plants. The Melones power plant is the largest generating facility in the area. The following table summarizes the generation facilities.

Table 4-22: Generation plants in the Stanislaus area

Plant Name	Max Capacity (MW)
Beardsley Power House	11
Donnells Power House	64
Fiberboard (Sierra Pacific)	3
Melones Power Plant	119
Pacific Ultra Power Chinese Station	10
Sand Bar Power House	15
Spring Gap Power House	4
Stanislaus Power House	64
Stanislaus Waste Co-gen	16
Tulloch Power House	17
Generation Total	**323**

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Load forecast

Loads within the Central Valley area reflect a coincident peak load for 1-in-10-year heat wave conditions of the study scenario. Table 4-23 shows the substation loads assumed in these studies under summer peak conditions. System losses amount to roughly 172 MW, 197 MW and 228 MW for the Central Valley area in 2009, 2013 and 2018 respectively. These tables also show loads, for neighboring local areas in PG&E system, modeled in the Central Valley area assessment.

Table 4-23: Summer peak load forecasts modeled in Central Valley area assessment

	MW Load Forecast										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Humboldt	131	132	134	136	138	140	142	144	145	147	149
North Coast	723	735	746	759	771	783	795	807	819	830	842
North Valley	844	856	870	886	905	920	934	948	963	977	991
Sacramento	1,167	1,180	1,195	1,211	1,225	1,239	1,254	1,268	1,283	1,297	1,311
Sierra	1,356	1,394	1,431	1,473	1,517	1,556	1,594	1,633	1,672	1,710	1,748
North Bay	665	672	680	688	697	705	714	723	731	740	748
East Bay	852	858	864	871	878	884	890	897	903	909	915
Diablo	1,625	1,642	1,660	1,681	1,702	1,721	1,740	1,759	1,778	1,796	1,814
San Francisco	859	866	874	883	892	900	909	917	926	935	944
Paninsula	875	890	900	909	917	929	941	953	965	977	989
Stockton	1,415	1,435	1,457	1,482	1,507	1,531	1,555	1,579	1,604	1,627	1,651
Sanislaus	236	244	249	254	260	266	271	276	281	287	292
Yosemite	875	886	899	911	924	936	949	962	975	988	1,001
Fresno	2,186	2,215	2,246	2,280	2,316	2,347	2,377	2,408	2,438	2,468	2,497
Kern	1,501	1,523	1,546	1,571	1,596	1,621	1,644	1,668	1,692	1,715	1,738
Mission	1,303	1,315	1,327	1,341	1,353	1,367	1,380	1,394	1,407	1,420	1,433
De Anza	874	882	890	900	909	920	929	939	949	959	969
San Jose	1,599	1,618	1,637	1,653	1,670	1,690	1,710	1,730	1,750	1,769	1,789
Central Coast	702	715	725	735	745	753	761	769	777	784	792
Los Padres	511	519	528	537	546	555	564	573	582	591	600
Total	**20,302**	**20,578**	**20,856**	**21,163**	**21,466**	**21,763**	**22,053**	**22,347**	**22,640**	**22,927**	**23,214**

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4.5.4.2 Study results and discussions

TPL 001-System Performance Under Normal Conditions

Under both the summer peak conditions, there are six overloads and two worst low voltages under Category A (TPL 001) performance requirement. Tables 4-34 through 4-36 provide more details of these overloads and voltage criteria violations.

TPL 002-System Performance Following Loss of a Single BES Element

With loss of single element, which includes loss of one generator and transmission facilities according to the ISO planning standards, there is one contingency with divergent case, 32 overloads caused by 40 critical contingencies as well as five worst buses with low voltages caused by six critical contingencies. More details of these violations are provided in tables 4-37 and 4-45.

TPL 003-System Performance Following Loss of Two or More BES Elements

For Category C multiple contingency conditions there are 51 overloads caused by 41 critical contingency conditions as well as 12 worst buses with low voltages caused by 15 critical contingencies do not meet Category C performance (TPL 003) requirement. There are also 11 contingencies which power flow fails to solve after the contingencies (divergent cases)

TPL 004-System Performance Following Extreme BES Events

Among the Category D studied, there are 24 contingencies with divergent cases (potential voltage collapse). Tables 4-24 through 4-26 document the worst overloads and worst low voltage violations for the summer peak conditions and ISO proposed solutions to mitigate these problems.

Table 4-24: Worst Equipment Overload Summary for Sierra

Overloaded Transmission Equipment	Loading		Proposed Solutions
	2013	2018	
Rio Oso-Atlantic 230 kV	<100%	103%	Reconductor
Atlantic 230/60 kV	<100%	104%	Atlantic-Placer Voltage Conversion
Placer 115/60 kV	<100%	109%	
Horseshoe Tap #1 and #2 115 kV	<100%	109%	Gold Hill-Horseshoe 115 kV Reinforcement

Table 4-25: Worst Equipment Overload Summary for Stockton

Overloaded Transmission Equipment	Loading		Proposed Solutions
	2013	2018	
Weber-Mormon 60 kV	<100%	101%	Reconductor and/or Linden area reinforcement
Stagg-Hammer 60 kV	<100%	104%	Mosher area reinforcement

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Table 4-26: Worst Voltage Summary for Sierra

Worst Bus	kV	Voltage Change		Proposed Solution
		2013	2018	
Del Mar	60	0.97	0.92	Atlantic-Placer Voltage Conversion
Sierra Pine	60	0.97	0.92	

Summer Emergency Peak Load Conditions:

Table 4-27: Divergent cases summary for Sacramento

Contingency(ies)	Scenario	Category	Solution
Rio Oso-Brighton 230 kV and Brighton-Bellota 230 kV	2018 Summer Peak	C3	Woodland-Davis-West Sacramento long-term and/or Vaca Dixon-Davis 115 kV conversion
Rio Oso-Brighton 230 kV and Brighton-Bellota/Rio Oso-Lockeford DCTL 230 kV	2018 Summer Peak	D	
Rio Oso-Brighton 230 kV and Rio Oso-Woodland #1 and #2 DCTL 115 kV	2018 Summer Peak	D	
Brighton-Bellota 230 kV and Rio Oso-Brighton/Rio Oso-Lockeford DCTL 230 kV	2018 Summer Peak	D	
Rio Oso-Woodland #1 115 kV and Rio Oso-West Sacramento/West Sacramento-Brighton DCTL 115 kV	2018 Summer Peak	D	
Rio Oso-Woodland #2 115 kV and Rio Oso-West Sacramento/West Sacramento-Brighton DCTL 115 kV	2018 Summer Peak	D	
Davis-Woodland 115 kV and Rio Oso-West Sacramento/West Sacramento-Brighton DCTL 115 kV	2018 Summer Peak	D	
Davis-Brighton 115 kV and Rio Oso-West Sacramento/West Sacramento-Brighton DCTL 115 kV	2018 Summer Peak	D	
West Sacramento-Davis 115 kV and Rio Oso-Woodland #1 and #2 DCTL 115 kV	2018 Summer Peak	D	
West Sacramento-Brighton 115 kV and Rio Oso-Woodland #1 and #2 DCTL 115 kV	2018 Summer Peak	D	

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Table 4-28: Divergent cases summary for Sierra

Contingency(ies)	Scenario	Category	Solution
Pease-Harter 60 kV and Pease 115/60 kV	2013 Summer Peak	C3	Yuba City area reinforcement
Yuba City co-gen and Pease 115/60 kV	2013 Summer Peak	C3	
Greenleaf #2 gen and Pease 115/60 kV	2013 Summer Peak	C3	
Greenleaf #2 gen and Palermo-Pease 115 kV and Pease-Rio Oso 115 kV DCTL	2013 Summer Peak	D	
Yuba City co-gen and Palermo-Pease 115 kV and Pease-Rio Oso 115 kV DCTL	2013 Summer Peak	D	
Yuba City EC gen and Palermo-Pease 115 kV and Pease-Rio Oso 115 kV DCTL	2013 Summer Peak	D	
Pease-Harter 60 kV and Palermo-Pease 115 kV and Pease-Rio Oso 115 kV DCTL	2013 Summer Peak	D	
Pease-Marysville-Harter 60 kV and Palermo-Pease 115 kV and Pease-Rio Oso 115 kV DCTL	2013 Summer Peak	D	
Wise #1 gen and Placer-Gold Hill #1 and #2 115 kV DCTL	2013 Summer Peak	D	Atlantic-Placer Voltage Conversion
Halsey gen and Placer-Gold Hill #1 and #2 115 kV DCTL	2013 Summer Peak	D	
Chicago Park gen and Placer-Gold Hill #1 and #2 115 kV DCTL	2013 Summer Peak	D	
Drum 115/60/13.8 kV and Palermo-Pease 115 kV and Pease-Rio Oso 115 kV DCTL	2013 Summer Peak	D	
Pease-Harter 60 kV and Yuba City co-gen	2018 Summer Peak	B	Atlantic-Placer Voltage Conversion
Greenleaf #2 gen and Yuba City co-gen	2018 Summer Peak	C3	
Pease-Harter 60 kV and Pease 115/60 kV	2018 Summer Peak	C3	
Yuba City co-gen and Pease 115/60 kV	2018 Summer Peak	C3	
Greenleaf #2 gen and Pease 115/60 kV	2018 Summer Peak	C3	
Palermo-Pease 115 kV and Pease-Rio Oso 115 kV	2018 Summer Peak	C3	
Palermo-Pease 115 kV and Pease-Rio Oso /Rio Oso-west Sacramento 115 kV DCTL	2018 Summer Peak	D	
Pease-Rio Oso 115 kV and Caribou-Palermo/Palermo-Pease 115 kV DCTL	2018 Summer Peak	D	
Pease-Rio Oso 115 kV and Palermo-Wyandotte/Palermo-Pease 115 kV DCTL	2018 Summer Peak	D	

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Table 4-28: Divergent cases summary for Sierra (cont)

Contingency(ies)	Scenario	Category	Solution
Placer-Gold Hill #1 and #2 115 kV DCTL	2018 Summer Peak	C5	Atlantic-Placer Voltage Conversion
Placer-Gold Hill #1 and #2 115 kV	2018 Summer Peak	C3	
Placer-Gold Hill #2 and Middle Fork-Gold Hill 230 kV/ Placer-Gold Hill #1 115 kV DCTL	2018 Summer Peak	D	
Rio Oso-Atlantic 230kV and Atlantic-Gold Hill 230 kV	2018 Summer Peak	C3	Loop Rio Oso-Gold Hill 230 kV into Atlantic
Rio Oso-Atlantic 230kV and Rio Oso-Gold Hill/Atlantic-Gold Hill 230 kV DCTL	2018 Summer Peak	D	
Atlantic-Gold Hill 230kV and Rio Oso-Gold Hill/Rio Oso-Atlantic 230 kV DCTL	2018 Summer Peak	D	

Table 4-29: Divergent cases summary for Stockton

Contingency(ies)	Scenario	Category	Solution
Tesla-Stagg and Tesla Eight Mile 230 kV	2018 Summer Peak	C5	Stagg 230 kV area reinforcement and/or Eight Mile-Tesla 230 kV Lines Reconductor
Tesla-Stagg and Tesla Eight Mile 230 kV	2018 Summer Peak	C3	
Tesla-Eight Mile 230 kV and Stagg #4 230/60 kV	2018 Summer Peak	C3	

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Table 4-30: Worst equipment overload summary for Sacramento

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Cortina 230/115/60 kV	CVP Colusa-Cortina 230 kV and Wadham gen	B	103	110	New Cortina 230/115/60 kV #2 transformer
	Wadham gen	B	103	110	
Vaca-Suisun-Jameson 115 kV	Vaca-Vacaville-Jameson-North Tower 115 kV and Vaca-Suisun 115 kV	C3	125	129	Suisun-Jameson back-up
Rio Oso-Woodland #1 115 kV	Rio Oso-Brighton 230 kV and Rio Oso-Woodland #2 115 kV	C3	110	112	Woodland-Davis-West Sacramento long-term and/or Vaca Dixon – Davis 115 kV Conversion
Rio Oso-Woodland #2 115 kV	Rio Oso-Brighton 230 kV and Rio Oso-Woodland #1 115 kV	C3	111	112	
West Sacramento-Brighton 115 kV	Woodland-Davis 115 kV and Brighton-Davis 115 kV	C3	108	115	
	Rio Oso-Woodland #1 and #2 115 kV	C5	<100	102	
West Sacramento-Davis 115 kV	Woodland-Davis 115 kV and Brighton-Davis 115 kV	C3	105	106	Woodland-Davis-West Sacramento long-term and/or Vaca Dixon – Davis 115 kV Conversion
	Rio Oso-West Sacramento 115 kV and West Sacramento-Brighton 115 kV	C5	100	115	
	Woodland-Davis 115 kV and Brighton-Davis 115 kV	C3	104	104	
Woodland-Davis 115 kV	Rio Oso-Brighton 230 kV and Brighton-Bellota 230 kV	C3	149	Divergent	
	Rio Oso-West Sacramento 115 kV and West Sacramento-Brighton 115 kV	C5	107	112	
	Rio Oso-Brighton 230 kV and Brighton-Bellota 230 kV	C3	149	Divergent	
	Rio Oso-West Sacramento 115 kV and West Sacramento-Brighton 115 kV	C5	107	112	
	Rio Oso-Brighton 230 kV and Brighton-Bellota 230 kV	C3	131	Divergent	

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Table 4-30: Worst equipment overload summary for Sacramento (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Brighton-Davis 115 kV	Woodland-Davis 115 kV and West Sacramento-Brighton 115 kV	C3	149	156	Woodland-Davis-West Sacramento long-term and/or Vaca Dixon – Davis 115 kV Conversion
	Rio Oso-West Sacramento 115 kV and West Sacramento-Brighton 115 kV	C5	124	136	
	Brighton-West Sacramento 115 kV and Woodland Biomass gen	B	<100	105	
	Woodland-Davis 115 kV and West Sacramento-Brighton 115 kV	C3	148	155	
	Rio Oso-West Sacramento 115 kV and West Sacramento-Brighton 115 kV	C5	122	136	
	Brighton-West Sacramento 115 kV and Woodland Biomass gen	B	<100	104	
	Woodland-Davis 115 kV and West Sacramento-Brighton 115 kV	C3	148	155	
	Rio Oso-West Sacramento 115 kV and West Sacramento-Brighton 115 kV	C5	122	136	
	Brighton-West Sacramento 115 kV and Woodland Biomass gen	B	<100	104	
Rio Oso-West Sacramento 115 kV	Rio Oso-Brighton 230 kV and Brighton-Bellota 230 kV	C3	151	Divergent	
	Rio Oso-Woodland #1 and #2 115 kV	C5	105	108	
	Brighton-West Sacramento 115 kV and Woodland Biomass gen	B	<100	103	

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Table 4-31: Worst equipment overload summary for Sierra

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Rio Oso-Atlantic 230 kV	Rio Oso-Gold Hill 230 kV and Rio Oso-Lincoln 115 kV	C3	115	131	Loop Rio Oso-Gold Hill 230 kV into Atlantic and reconductor from Rio Oso to Atlantic
	Rio Oso-Gold Hill 230 kV and Ralston generator	B	101	113	
	Rio Oso-Gold Hill 230 kV	B	<100	107	
Rio Oso-Gold Hill 230 kV	Rio Oso-Atlantic 230 kV and Rio Oso-Lincoln 115 kV	C3	103	117	
Atlantic-Gold Hill 230 kV	Rio Oso-Atlantic 230 kV and Rio Oso-Lincoln 115 kV	C3	<100	108	
Palermo-Pease 115 kV	Colgate-Rio Oso 230 kV and Palermo-East Nicolaus 115 kV	C3	109	120	Reconductor Palermo-Pease-Rio Oso 115 kV and/or Yuba City area reinforcement and/or South of Palermo 115 kV Reinforcement
	Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C5	109	119	
	Palermo-East Nicolaus 115 kV and Yuba City EC gen	B	<100	109	
	Colgate-Rio Oso 230 kV and Palermo-East Nicolaus 115 kV	C3	110	121	
	Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C5	110	119	
	Palermo-East Nicolaus 115 kV and Yuba City EC gen	B	101	110	
Pease-Rio Oso 115 kV	Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C5	120	124	
	Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C3	120	124	
	Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C5	120	124	
	Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C3	120	124	
	Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C5	120	124	
	Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C3	120	124	

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Table 4-31: Worst equipment overload summary for Sierra (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Bogue-Rio Oso 115 kV	Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C5	120	123	Reconductor
	Table Mountain-Rio Oso 230 kV and Colgate-Rio Oso 230 kV	C3	120	123	
Gold Hill #2 230/115 kV	Drum-Higgins 115 kV and Gold Hill #1 230/115 kV	C3	125	144	New Gold Hill #3 230/115 kV and Upgrade Atlantic-Placer corridor to 115 kV operation
	Gold Hill #1 230/115 kV	B	103	121	
Gold Hill #1 230/115 kV	Drum-Higgins 115 kV and Gold Hill #2 230/115 kV	C3	125	144	
	Gold Hill #2 230/115 kV	B	103	121	
Gold Hill-Placer #1 115 kV	Gold Hill-Placer #2 115 kV and Drum-Higgins 115 kV	C3	148	174	Gold Hill-Horseshoe 115 kV Reinforcement and Upgrade Atlantic-Placer corridor to 115 kV operation
	Gold Hill-Placer #2 115 kV and Chicago Park gen	B	<100	114	
	Gold Hill-Placer #2 115 kV	B	<100	104	
Gold Hill-Placer #2 115 kV	Gold Hill-Placer #1 115 kV and Drum-Higgins 115 kV	C3	162	192	Gold Hill-Horseshoe 115 kV Reinforcement and Upgrade Atlantic-Placer corridor to 115 kV operation
	Gold Hill-Placer #1 115 kV and Chicago Park gen	B	101	125	
	Gold Hill-Placer #1 115 kV	B	<100	111	
Drum-Higgins 115 kV	Gold Hill-Placer #1 and #2 115 kV	C5	122	Divergent	Atlantic-Placer Voltage Conversion
	Gold Hill-Placer #1 and #2 115 kV	C3	122	Divergent	
	Gold Hill-Placer #1 and #2 115 kV	C5	114	Divergent	

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Table 4-31: Worst equipment overload summary for Sierra (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Clarksville 115 kV Tap	Gold Hill-Clarksville 115 kV	B	113	136	Clarksville area reinforcement
Missouri Flat-Gold Hill #1 115 kV	Gold Hill-Clarksville 115 kV and Missouri Flat #2 115 kV	C3	146	176	
	Gold Hill-Clarksville 115 kV and El Dorado #1 generator	B	<100	113	
	Gold Hill-Clarksville 115 kV	B	<100	110	
	Gold Hill-Clarksville 115 kV and Missouri Flat #2 115 kV	C3	145	176	
	Gold Hill-Clarksville 115 kV and El Dorado #1 generator	B	<100	113	
	Gold Hill-Clarksville 115 kV	B	<100	110	
Placer 115/60 kV	Halsey generator	B	<100	107	Atlantic-Placer Voltage Conversion
Drum-Grass Valley-Weimar 60 kV	Colgate-Grass Valley 60 kV and Spaulding generator	B	130	149	Reconductor and/or disable automatics at Grass Valley and change configuration at Weimar
	Rollins generator and Oxbow Generator	C3	<100	104	
	Colgate-Grass Valley 60 kV	B	<100	103	
	Colgate-Grass Valley 60 kV and Spaulding generator	B	138	156	
	Rollins generator and Oxbow Generator	C3	<100	111	
	Colgate-Grass Valley 60 kV	B	<100	109	
	Colgate-Grass Valley 60 kV and Spaulding generator	B	143	162	
	Rollins generator and Oxbow Generator	C3	104	117	
	Colgate-Grass Valley 60 kV	B	100	115	

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Table 4-31: Worst Equipment overload summary for Sierra (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Rio Oso-Lincoln 115 kV	Rio Oso-Atlantic 230 kV and Atlantic-Gold Hill 230 kV	C3	149	Divergent	Loop Rio Oso-Gold Hill 230 kV into Atlantic
	Rio Oso-Atlantic 230 kV and Rio Oso-Gold Hill 230 kV	C5	111	129	New Rio Oso-Pleasant Grove 115 kV or SPS
Lincoln-Pleasant Grove 115 kV	Rio Oso-Atlantic 230 kV and Atlantic-Gold Hill 230 kV	C3	139	Divergent	Loop Rio Oso-Gold Hill 230 kV into Atlantic
	Rio Oso-Atlantic 230 kV and Rio Oso-Gold Hill 230 kV	C5	<100	111	New Rio Oso-Pleasant Grove 115 kV or SPS
	Rio Oso-Atlantic 230 kV and Atlantic-Gold Hill 230 kV	C3	144	Divergent	Loop Rio Oso-Gold Hill 230 kV into Atlantic
	Rio Oso-Atlantic 230 kV and Rio Oso-Gold Hill 230 kV	C5	101	116	New Rio Oso-Pleasant Grove 115 kV or SPS
	Rio Oso-Atlantic 230 kV and Atlantic-Gold Hill 230 kV	C3	157	Divergent	Loop Rio Oso-Gold Hill 230 kV into Atlantic
	Rio Oso-Atlantic 230 kV and Rio Oso-Gold Hill 230 kV	C5	110	125	New Rio Oso-Pleasant Grove 115 kV or SPS
	Rio Oso-Atlantic 230 kV and Atlantic-Gold Hill 230 kV	C3	157	Divergent	Loop Rio Oso-Gold Hill 230 kV into Atlantic
	Rio Oso-Atlantic 230 kV and Rio Oso-Gold Hill 230 kV	C5	110	125	New Rio Oso-Pleasant Grove 115 kV or SPS
Atlantic-Pleasant Grove #2 115 kV	Rio Oso-Lincoln 115 kV and Atlantic-Pleasant Grove #1 115 kV	C3	100	116	New Rio Oso-Pleasant Grove 115 kV or SPS
Atlantic-Pleasant Grove #1 115 kV	Rio Oso-Lincoln 115 kV and Atlantic-Pleasant Grove #2 115 kV	C3	<100	101	New Rio Oso-Pleasant Grove 115 kV or SPS

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Table 4-32: Worst equipment overload summary for Stockton

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Tesla-Stagg 230 kV	Tesla-Eight Mile 230 kV & Tesla-Weber 230 kV	C3	121	123	Stagg 230 kV area reinforcement and/or Eight Mile-Tesla 230 kV Lines Reconductor
	Tesla-Eight Mile 230 kV & Collierville #1 gen	B	114	117	
	Tesla-Eight Mile 230 kV	B	112	115	
	Rio Oso-Atlantic 230 kV & Rio Oso-Gold Hill 230 kV	C5	<100	104	
Stagg-Eight Mile 230 kV	Stagg-Hammer 60 kV & Stagg #4 230/60 kV	C3	<100	103	
	Tesla-Stagg 230 kV & Collierville #1 gen	B	<100	101	
	Tesla-Stagg 230 kV	B	<100	101	
Tesla-Eight Mile 230 kV	Tesla-Weber 230 kV & Stagg #4 230/60 kV	C3	103	125	
	Tesla-Stagg 230 kV & Collierville #1 gen	B	<100	118	
	Stagg #4 230/60 kV	B	<100	116	
Tracy-Kasson-Vierra 115 kV	Tesla-Kasson-Manteca 115 kV & Tesla-Salado-Manteca 115 kV	C3	<100	110	Tesla-Bellota 115 kV area reinforcement
	Tesla-Kasson-Manteca 115 kV & Schulte-Lammers 115 kV	C3	145	166	
Tesla-Kasson-Manteca 115 kV	Schulte-Lammers 115 kV & Tesla-Tracy 115 kV	C3	156	178	Tesla-Bellota 115 kV area reinforcement
	Schulte-Lammers 115 kV & Stanislaus gen	B	<100	109	
Tesla-Tracy 115 kV	Tesla-Kasson-Manteca 115 kV & Schulte-Lammers 115 kV	C5	143	163	Tesla-Bellota 115 kV area reinforcement
		C3	143	163	
	Schulte-Lammers 115 kV & Stanislaus gen	B	103	116	
	Schulte-Lammers 115 kV	B	<100	106	
Manteca-Riverbank Junction 115 kV	Bellota-Riverbank-Melones 115 kV & Donnells-Curtis 115 kV	C3	<100	107	Curtis UVLS
Stockton "A"-Lockeford-Bellota #1 115 kV	Stockton "A"-Lockeford-Bellota #2 115 kV & Stockton Co-gen	B	<100	102	Stockton “A” reinforcement
Stockton "A"-Lockeford-Bellota #2 115 kV	Stockton "A"-Lockeford-Bellota #1 115 kV	B	<100	100	

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Table 4-32: Worst equipment overload summary for Stockton (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Valley Springs 230/60 kV	Weber-Mormon Junction 60 kV & West Point gen	B	<100	109	Linden area reinforcement
	Weber-Mormon Junction 60 kV & Valley Springs #2 60 kV	C3	<100	102	
Valley Springs #1 60 kV	Weber-Mormon Junction 60 kV & Valley Springs-Bellota 230 kV	C3	115	128	
	Weber-Mormon Junction 60 kV & North Hogan #1 gen	B	111	121	
	Weber-Mormon Junction 60 kV	B	113	124	
	Weber-Mormon Junction 60 kV & West Point gen	B	114	127	
Stockton "A"-Weber #1 60 kV	Stockton "A"-Weber #2 60 kV & Cogeneration National gen	B	104	110	Reconductor
Kasson 115/60 kV	Tesla-Kasson-Manteca 115 kV & Tracy-Kasson-Vierra 115 kV	C3	107	116	Kasson-Manteca 60 kV system rearrangement
Manteca-Louise 60 kV	Tesla-Kasson-Manteca 115 kV & Tracy-Kasson-Vierra 115 kV	C3	130	148	
Kasson-Louise 60 kV	Tesla-Kasson-Manteca 115 kV & Tracy-Kasson-Vierra 115 kV	C3	128	142	
	Tesla-Kasson-Manteca 115 kV & Manteca-Vierra 115 kV	C5	<100	100	
Stagg-Country Club #2 60 kV	Stagg-Hammer 60 kV & Stagg-Country Club #1 60 kV	C3	200	217	Mosher area reinforcement plus Hammer area reliability
	Stagg-Country Club #1 60 kV & GWF Tracy #1 gen	B	<100	104	
	Stagg-Country Club #1 60 kV	B	<100	104	
Stagg-Country Club #1 60 kV	Stagg-Hammer 60 kV & Stagg-Country Club #2 60 kV	C3	200	217	
	Stagg-Country Club #2 60 kV & GWF Tracy #1 gen	B	<100	104	
	Stagg-Country Club #2 60 kV	B	<100	104	
Stagg-Hammer 60 kV	Stagg-Country Club #1 & #2 60 kV	C3	201	219	
	Stagg-Country Club #1 60 kV & GWF Tracy #1 gen	B	<100	102	
	Stagg-Country Club #1 60 kV	B	<100	102	

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Table 4-32: Worst equipment overload summary for Stockton (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Weber #2 & #2A 230/60 kV	Weber #1 230/60 kV & Cogeneration National gen	C3	116	123	Weber #2 transformer replacement
	Weber #1 230/60 kV	B	<100	102	
Lockeford #2 230/60 kV	Lockeford #3 230/60 kV & Hammer-Country Club 60 kV	C3	100	114	Industrial area reinforcement
Lockeford #3 230/60 kV	Lockeford #2 230/60 kV & Hammer-Country Club 60 kV	C3	100	114	
Lockeford Bus#1 to Bus #2 60 kV	Lockeford-Industrial 60 kV & Lockeford-Lodi #2 60 kV	C3	<100	104	
Lockeford-Lodi #2 60 kV	Lockeford-Industrial 60 kV & Industrial-Lodi 60 kV	C3	142	155	
	Lockeford-Industrial 60 kV & Lodi CT gen	B	<100	104	
Lockeford-Lodi #1 60 kV	Lockeford-Industrial 60 kV & Lockeford-Lodi #2 60 kV	C3	166	180	
	Lockeford-Industrial 60 kV & Lodi CT gen	B	<100	102	
	Lockeford-Industrial 60 kV & Lockeford-Lodi #2 60 kV	C3	161	176	
Lockeford-Lodi #3 60 kV	Lockeford-Industrial 60 kV & Lockeford-Lodi #2 60 kV	C3	172	187	
	Lockeford-Industrial 60 kV & Lodi CT gen	B	<100	103	
Lockeford-Industrial 60 kV	Lockeford-Lodi #2 60 kV & Industrial-Lodi 60 kV	C3	134	148	
	Lockeford-Lodi #2 60 kV & Lodi CT gen	B	100	107	
Lodi-Industrial 60 kV	Lockeford-Industrial 60 kV & Lockeford-Lodi #2 60 kV	C3	172	192	

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Table 4-32: Worst equipment overload summary for Stockton (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Hammer-Country Club 60 kV	Stagg-Hammer 60 kV & Stagg #4 230/60 kV	C3	116	126	Mosher area reinforcement
	Stagg-Hammer 60 kV & Collierville #1 gen	B	115	125	
	Stagg-Hammer 60 kV	B	115	124	
	Stagg-Country Club #1 & #2 60 kV	C3	136	149	
Lockeford #1 60 kV	Lockeford-Bellota 230 kV & Country Club-Hammer 60 kV	C3	209	Divergent	
	Country Club-Hummer 60 kV & Lodi CT gen	B	171	195	
	Country Club-Hummer 60 kV	B	171	195	
	Lockeford-Bellota 230 kV & Country Club-Hammer 60 kV	C3	134	Divergent	
	Country Club-Hummer 60 kV & Lodi CT gen	B	110	125	
	Country Club-Hummer 60 kV	B	110	125	

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Table 4-33: Worst voltage summary for Sacramento

Worst bus	Worst Contingency	Category	Voltage Change (%) 2013	Voltage Change (%) 2018	Proposed Solution
Cortina D 115 kV	CPV Colusa-Cortina 230 kV and Cortina-Vaca 230 kV	C3	17.02	19.19	Cortina voltage support
Grand Island 115 kV	Rio Oso-Brighton 230 kV and Brighton-Bellota 230 kV	C3	17.44	Divergent	Woodland-Davis-West Sacramento long-term
Deepwater 115 kV	Brighton-West Sacramento 115 kV and Brighton-Davis 115 kV	C3	11.61	10.67	
	Brighton-West Sacramento 115 kV and Rio Oso-West Sacramento 115 kV	C5	<10	12.9	

Table 4-34: Worst voltage summary for Sierra

Worst bus	Worst Contingency	Category	Voltage Change (%) 2013	Voltage Change (%) 2018	Proposed Solution
Harter 60 kV	Pease-Harter 60 kV and Yuba City Co-gen	B	17	Divergent	Yuba City area reinforcement
	Yuba City Co-gen and Greenleaf #2 gen	C3	17	Divergent	
Forest Hill 60 kV	Colgate-Grass Valley 60 kV and Rollins generator	B	<10	12	Reconductor and/or disable automatics at Grass Valley and change configuration at Weimar
	Rollins generator and Oxbow generator	C3	<10	11	
Placer 115 kV	Gold Hill-Placer #1 and #2 115 kV DCTL	C5	15	Divergent	Atlantic-Placer Voltage Conversion
	Gold Hill-Placer #1 and #2 115 kV	C3	15	Divergent	
Del Mar 60 kV	Rio Oso-Atlantic 230 kV and Atlantic-Gold Hill 230 kV	C3	25	Divergent	Loop Rio Oso-Gold Hill 230 kV into Atlantic
SPI Lincoln 115 kV	Rio Oso-Atlantic 230 kV and SPI Lincoln generator	B	12	15	Modeling error or new voltage support
	SPI Lincoln generator	B	15	14	

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Table 4-35: Worst voltage summary for Stockton

Worst bus	Worst Contingency	Category	Voltage Change (%) 2013	Voltage Change (%) 2018	Proposed Solution
Oil Glass 115 kV	Schulte-Lammers 115 kV and Tesla-Tracy 115 kV	C3	<10	12.96	Tesla-Bellota 115 kV area reinforcement
Linden 60 kV	Weber-Mormon Junction 60 kV and Valley Springs-Bellota 230 kV	C3	<10	10.29	Linden area reinforcement
	Weber-Mormon Junction 60 kV	B	7.95	6.61	
Curtis 115 kV	Donnells-Curtis 115 kV and Bellota-Riverbank-Melones 115 kV	C3	<10	12.71	Curtis UVLS
Industrial 60 kV	Lockeford-Bellota 230 kV	B	<5	9	Industrial area reinforcement
	Brighton-Bellota 230 kV and Lockeford-Bellota 230 kV	C3	<10	22	
	Lockeford-Industrial 60 kV and Lockeford-Lodi #2 60 kV	C3	11	12	
Mosher 60 kV	Country Club-Hammer 60 kV and Lockeford-Bellota 230 kV	C3	20	Divergent	Mosher area reinforcement
	Tesla-Eight Mile 230 kV and Stagg #4 230/60 kV	C3	13	Divergent	

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4.5.4.3 Recommended solutions for reliability criteria violations

- **New Cortina 230/115/60 kV Transformer #2 – Category B**

  Under single contingency conditions of Wadham generator, the Cortina 230/115/60 kV transformer could overload. Solution includes the installation of a second Cortina 230/115/60 transformer (or a new 230/60 or 115/60 kV transformer) and a small SPS to cover new category C conditions.

- **Cortina Voltage Support – Category C**

  Under category C contingency conditions, for the loss of one 230 kV source in the Cortina substation followed by the loss of the second 230 kV source, the Cortina 115 and 60 kV system voltages are very depressed with high voltage deviations. One solution includes looping another one of the three remaining 230 kV lines that run north to south from Cottonwood to Vaca into the Cortina substation. A second solution would be to add voltage support at the Cortina substation. A third solution would be to install an SPS to trip load and/or de-loop the 230 kV bus such that the entire Cortina 115 kV and 60 kV load is dropped for this contingency.

- **Suisun-Jameson Back-up – Category C**

  The Vaca Dixon-Suisun-Jameson 115 kV line is the back-up for two different single 115 kV contingencies. If these two contingencies happen one after the other the Vaca Dixon-Suisun-Jameson 115 kV will overload. Solution includes the installation of an over-thermal relay or other protection to trip this line under this category C condition. Another solution could be reconductoring about 18 miles of this line.

- **Woodland-Davis-West Sacramento Long-Term – Category B and C**

  There are a few single and numerous overlapping contingencies with high potential overloads in this area. Designing an SPS that follows the ISO guidelines for this magnitude of different components is more that challenging if at all possible and it does not constitute a long-term solution for the area. Woodland Biomass, the only generator in this area has been dispatched at maximum during these studies as such the ISO would have to use pre-contingency load shedding immediately after the first contingency in order to protect the equipment for the loss of the next contingency per WECC and NERC standards; in consequence loss of load after a single contingency is very likely in this area. Further aggravating the situation is that many contingencies in 2018 timeframe diverge due to high overloads and no voltage support suggesting a potential voltage collapse in this area. The biggest substations in this area are Woodland, Davis and West Sacramento. Solution includes upgrading some of these substations to 230 kV service. For instance a new Vaca Dixon-Davis-Woodland 230 kV 23 miles DCTL can be build. Another solution would be to upgrade Vaca-Dixon #1 and #2 from 60 to 115 kV and additional 115 kV miscellaneous reconductoring. A third option would be to reconductor most every line in this 115 kV system. Final design could include a combination of the above alternatives that meet ISO and WECC/NERC standards.

- **Rio Oso-Atlantic 230 kV Reconductoring – Category A, B, C and D**

  Under normal conditions as well as numerous single and multiple contingency conditions the Rio Oso-Atlantic 230 kV line could overload. Also the voltages in the Atlantic 115 and 60 kV area are low and have high deviations for certain multiple contingencies. Solution includes

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looping the Rio Oso-Gold Hill 230 kV line into the Atlantic substation as well as reconductoring both Rio Oso-Atlantic 230 kV lines.

- **Yuba City Area Reinforcement – Category B, C and D**

  There are numerous single and multiple contingencies in the Yuba City area that do not converge being suspect of voltage collapse. Also the voltages in this area are low and have high deviations for certain single and multiple contingencies. Solutions include upgrading the Yuba City system at 115 kV operation. This could be couplet with additional reconductoring of the Palermo-Pease-Rio Oso line and/or reconfiguration of the existing 115 kV system around this area.

- **Palermo-Pease-Rio Oso 115 kV lines Reconductoring – Category B, C and D**

  There are single and numerous multiple contingencies in this area that could overload these lines. Solutions include reconductoring 50 miles of 115 kV lines and/or depending of the solution chosen for the Yuba City area reinforcement a different arrangement of the 115 kV system in this area.

- **Bogue-Rio Oso 115 kV line Reconductoring – Category C**

  For the simultaneous DCTL loss of the Table Mountain-Rio Oso and Colgate-Rio Oso 230 kV the Bogue-Rio Oso 115 kV line could overload. Solutions include reconductoring of the remaining portions of this line.

- **Atlantic-Placer Voltage Conversion – Category A, B, C and D**

  Multiple system elements, like the Atlantic 230/60 kV and Placer 115/60 kV transformers, Gold Hill-Placer #1 and #2 and Drum-Higgins-Bell-Placer 115 kV lines, under normal conditions as well as numerous single and multiple contingency could overload. Also the voltages in the Atlantic 60 kV system are low for normal conditions and in Placer 115 and 60 kV systems have high voltage deviations under emergency conditions. Solutions include upgrading the Atlantic-Rocklin-Del Mar-Penryn-Placer system to 115 kV operation. This would be achieved by upgrading the existing Atlantic-Del Mar #1 and #2 60 kV to 115 kV operation as well as rebuilding Placer-Del Mar to a 115 kV DCTL and having the entire system looped through.

- **Horseshoe Taps #1 and #2 Reconductoring – Category A**

  Under normal conditions the Horseshoe tap #1 and/or #2, whichever is used, could overload. Solutions include reconductoring of these two tap that can be done concurrent with the Gold Hill-Horseshoe 115 kV Reinforcement project.

- **Gold Hill-Horseshoe 115 kV Reinforcement – Category B, C**

  Under single and multiple contingency the Gold Hill-Horseshoe portions of the Gold Hill-Placer 115 kV lines could overload. Solutions include reconductoring of these sections and upgrading the Atlantic-Rocklin-Del Mar-Penryn-Placer system to 115 kV operations.

- **Clarksville Area Reinforcement – Category B, C**

  There are a few single and multiple contingencies in the area that could overload the Clarksville tap as well as the Gold Hill-Missouri Flat #1 115 kV line. Also the Clarksville substation has close to 200 MW of load, as such should be looped in. Solutions include

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reconductoring with 477 SSAC and upgrading to 115 kV operations the Gold Hill #1 60 kV line. Another solution would be to upgrade the Clarksville substation to 230 kV operations by looping the Gold Hill-Middle Fork 230 kV line into this substation.

- **Gold Hill #3 230/115 kV Transformer – Category B, C**

  Under single and multiple contingency the Gold Hill #1 and/or #2 230/115 kV transformer could overload. Solutions include the addition of a third 230/115 kV 420 MVA bank at Gold Hill. This solution depends on the options chosen for the Clarksville area reinforcement as well as the upgrade of the Atlantic-Placer system from 60 to 115 kV operations.

- **Drum-Grass Valley-Weimar 60 kV line – Category B, C**

  Under single and multiple contingency the Drum-Grass Valley-Weimar 60 kV line could overload. Also under single and multiple contingency conditions the voltages in this area are very low and have high voltage deviations. Solutions include reconductoring 20 miles of this 60 kV line. Another solution would be to disable the automatics at Grass Valley and to change the configuration at Weimar such that Forest Hill is served from Middle Fork.

- **New Rio Oso-Pleasant Grove 115 kV line – Category C**

  For the simultaneous DCTL loss of the Rio Oso-Gold Hill and Rio Oso-Atlantic the Rio Oso-Lincoln-Pleasant Grove 115 kV lines could overload. Also for the loss of the Rio Oso-Lincoln 115 kV followed by Atlantic Pleasant Grove #1 or #2 the remaining one could overload. There are no resources in this area that could be dispatched to mitigate this problem as such load needs to be dropped pre-contingency (within 30 minutes after the loss of the first element) unless a new SPS is installed to prevent the expected overload after the second contingency. Solutions include a new Rio Oso-Pleasant Grove 115 kV line. Another solution would be the installation of two new SPS for the two particular problems anticipated above. This last solution however will constrain the south of Rio Oso flow much more then the first option.

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- **SPI Lincoln Voltage Support – Category B**

  For the loss of the SPI Lincoln generator de SPI Lincoln voltages are very low and have very high voltage deviations. This voltage problem is suspect of modeling error. If true the solutions include voltage support at the SPI Lincoln bus.

- **Weber-Mormon 60 kV line Reconductoring – Category A**

  Under normal conditions the Weber-Mormon section of the Weber-Mormon Junction 60 kV line could overload. Solution includes reconductoring 6 miles of the Weber-Mormon Junction 60 kV line from Weber to Mormon. Also another solution would be to move Mormon and/or Linden substation to a 115 or 230 kV service.

- **Linden Area Reinforcement – Category A, B and C**

  The loss of Weber-Mormon Junction 60 kV line transfers Linden to the Valley Springs #1 60 kV line which could overload. Also this transfer could overload the Valley Springs 230/60 kV transformer. One solution includes disabling the automatics at Linden combined with the Weber-Mormon 60 kV reconductoring. Another solution would maintain the automatics and would reconductor the Valley Springs #1 60 kV along with the addition of a new 230/60 kV transformer at Valley Springs. A more elegant solution would be to upgrade Linden to 115 kV operations tapped on any one of the lines near by like: Stockton “A”-Lockeford-Bellota #1, #2

or Gold Hill-Bellota-Lockeford 115 kV. Also a direct 5 mile 115 kV line could be constructed from Bellota to Linden. For these last few alternatives the Weber-Mormon 60 kV does not need to be reconductored.

- **Mosher Area Reinforcement – Category A, B and C**

  Under normal conditions the Stagg-Hummer 60 kV line could overload. Also for the loss of the Country Club-Hummer 60 kV the Mosher substation transfers to the Lockeford #1 60 kV line potentially overloading it. The Mosher substation has over 50 MW of load as such it should have a looped service. Furthermore there are some category C contingencies with very high potential overloads as well as voltage drops in both the Stagg 60 kV as well as Lockeford 60 kV when Mosher is served from either side. There are no generators in this area as such the ISO would have to use pre-contingency load shedding immediately after the first contingency in order to protect the equipment for the loss of the next contingency per WECC and NERC standards in consequence loss of load after a single contingency is very likely in this area. Solution includes upgrading this substation to 115 kV or 230 kV service. Since the Mosher substation is in proximity of the Industrial substation a common project to upgrade both to preferably a new 230 kV service on a double circuit tower line coming from the general Eight Mile area would benefit both and possibly Hummer substation as well. Also it would constitute the third leg (out of four) into achieving a 230 kV ring around the Stockton area.

- **Hammer Area Reliability – Category C**

  Given the Mosher area reinforcement is implemented. There will still be some category C overlapping contingencies with potential overloads in this area. The loss of any two of Stagg-Hammer and Stagg-Country Club #1 and #2 60 kV lines would overload the remaining. There are no generators in this area as such the ISO would have to use pre-contingency load shedding immediately after the first contingency in order to protect the equipment for the loss of the next contingency per WECC and NERC standards in consequence loss of load after a single contingency is very likely in this area. One solution includes upgrading this loop to 115 kV operations. Another will rebuild the Stagg-Hammer 60 kV to a DCTL. A third solution will build a new 230 kV substation north of Hammer 60 kV from the new 230 kV DCTL that serves Mosher and Industrial and will move enough load of the Hammer substation such that overloads are not expected. A last alternative would add two SPS in the area one at Hammer and one at Country Club in order to drop enough load such that and overload is not encountered for any category C contingency.

- **Industrial Area Reinforcement – Category B and C**

  There are a few single and numerous overlapping contingencies with high potential overloads in this area. Designing an SPS that follows the ISO guidelines for this magnitude of different components is more that challenging if at all possible and it does not constitute a long-term solution for the area. All generators in this area have been dispatched at maximum during these studies as such the ISO would have to use pre-contingency load shedding immediately after the first contingency in order to protect the equipment for the loss of the next contingency per WECC and NERC standards; in consequence loss of load after a single contingency is very likely in this area. Further aggravating the situation is that the contingencies with higher voltage drop diverge if the Lodi CT is not on-line suggesting a potential voltage collapse in this area. The biggest substation in this are is Industrial with about 150 MW of load. Solution includes upgrading this substation to 115 kV or 230 kV service. Since the Industrial substation is in proximity of the Mosher substation a common project to upgrade both to preferably a new 230 kV service on a double circuit tower line

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coming from the general Eight Mile area would benefit both and possibly Hummer substation as well. Also it would constitute the third leg (out of four) into achieving a 230 kV ring around the Stockton area.

- **Stagg 230 kV Area Reinforcement – Category B and C**

  There are a few single and numerous overlapping contingencies with potential overloads in this area. This area has an existing LCR requirement as well. Solution includes reconductoring a total of 22 miles of the Tesla-Stagg 230 kV line and the Tesla-Stagg portion of the Tesla-Eight Mile 230 kV line then loops the Tesla-Eight Mile 230 kV line into Stagg and upgrade Stagg 230 kV bus to BAAH. If needed the project can be augmented with a UVLS and/or voltage support such the all category B and C concerns are mitigated.

- **Tesla-Bellota 115 kV Area Reinforcement – Category B and C**

  There are a few single and numerous overlapping contingencies with potential overloads in this area. This area has an existing LCR requirement as well. One of the solutions includes looping the Tesla-Stockton-Co-gen Junction 115 kV into the Vierra, Manteca, Kasson or Tracy substations and additional reconductoring if necessary. Another solution would be to upgrade part of the 60 kV Lee tap to 115 kV operations in order to close a 115 kV loop between the Ripon Co-gen and Ripon substation with additional reconductoring if necessary. Also another solution would be to move some of the substations with higher load like Tracy or Manteca to 230 kV service.

- **Curtis UVLS – Category C**

  Under category C conditions the loss of the Bellota-Riverbank-Melones and Donnells-Curtis 115 kV lines, the voltages around Curtis as well as the Manteca-Riverbank Junction 115 kV line could overload. Solution includes installing a UVLS at Curtis in order to trip load when the voltage is below 105 kV.

- **Stockton "A" Reinforcement – Category B**

  For the loss of the Stockton "A"-Lockeford-Bellota #1 115 kV line the Stockton "A"-Lockeford-Bellota #2 115 kV line could overload and vice versa. The Stockton "A" 115 kV substation has over 90 MW of load and should be looped in not drop and pick-up. Solution includes the reconductoring of 24 miles for both 115 kV lines from Stockton Junction to Stockton "A" and loops the system through.

- **Weber #2 230/60 kV Transformer Replacement – Category B and C**

  For the loss of the Weber #1 230/60 kV transformer the Weber #2&2A 230/60 kV transformer overloads. Under category C this overload is aggravated by any generator loss in this area. All generators in this area have been dispatch as such the ISO would have to use pre-contingency load shedding immediately after the loss of any generator located here in order to protect the equipment for the loss of the next contingency per WECC and NERC standards in consequence loss of load after a single contingency is very likely in this area. Solution includes replacing the Weber #2&2A 230/60 kV transformer with a new 200 MVA 230/60 kV transformer.

- **Stockton "A"-Weber #1 60 kV line Reconductoring – Category B**

  For the loss of the Stockton "A"-Weber #2 60 kV line with Cogeneration Nation unit out of

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service the Weber to Santa Fee Switches of the Stockton “A”-Weber #1 60 kV line could overload. Solution includes reconductoring 3 miles of the Stockton “A”-Weber #1 60 kV line from Weber to Santa Fee Switches.

- **Kasson-Manteca 60 kV System Rearrangement – Category C**

  There are a few overlapping and possible common mode DCTL contingencies with potential overloads in this area. One of the solutions includes de-looping the Kasson-Manteca 60 kV system under normal conditions. Another solution would be to implement a SPS or an operating procedure in order to achieve de-looping.

4.5.4.4 Key conclusions

Based on the ISO assessment Central Valley area had:

- Six overloads and two worst low voltages under normal conditions,
- One contingency with divergent case, 32 overloads caused by 40 critical contingencies as well as five worst buses with low voltages caused by six critical contingencies under single contingency conditions,
- 51 overloads caused by 41 critical contingency conditions, 12 worst buses with low voltages caused by 15 critical contingencies and 11 contingencies with divergent cases under multiple contingency conditions,
- 24 divergent cases (potential voltage collapse) among the extreme contingency studied,

In order to address all the above concerns, the ISO has proposed 27 transmission projects.

During the 2008 Open Request Window the ISO received 21 project proposals:

- Eight have been approved,
- One has been withdrawn,
- Two have been denied,
- Ten are on-going projects – to be approved at a later date

Only four of these projects have matched the ISO proposed solutions. Therefore, there are 23 projects proposed by the ISO that are on-going (i.e., to be considered for approval at a later date).

In brief, there were a total of 44 projects in the ISO 2009 transmission plan for the Central Valley area.

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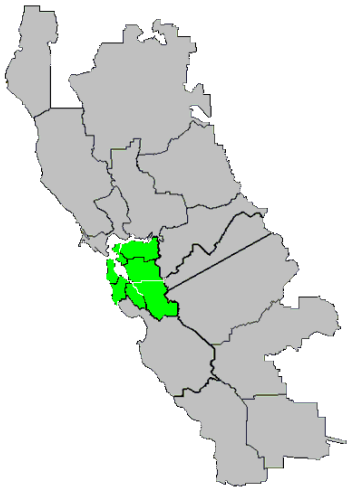
4.5.5 Greater Bay Area

The Greater Bay Area (Bay Area) is at the center of PG&E's service territory. This area includes Alameda, Contra Costa, Santa Clara, San Mateo and San Francisco counties as shown in figure below. In 2008, the Bay Area had a total simultaneous peak electric demand of approximately 9,000 MW. The highest recorded peak demand was in 2006 at 9,300 MW.



For ease of conducting the performance evaluation, the Greater Bay Area is divided into three sub-areas: 1) East Bay, 2) San Francisco-Peninsula and 3) South Bay.

The East Bay sub-area includes cities in Alameda and Contra Costa Counties. Major cities include Concord, Berkeley, Oakland, Hayward, Fremont and Pittsburg. This area primarily relies on its internal generation to serve electricicity customers. New generation planned for the area includes Gateway Generating Station (formerly known as Contra Costa Unit 8). The Gateway project was expected to be in operation in early 2009 and it was reflected in the studies.

The San Francisco-Peninsula sub-area includes the San Francisco and San Mateo Counties. These counties comprise of the cities of San Francisco, San Bruno, San Mateo, Redwood City, and Palo Alto. The San Francisco-Peninsula area relies on internal generation and transmission line import capabilities to serve its electricity demand. One of the recent generation units in the area is the Ox Mountain land-filled gas power plant (10.7 MW) which came on-line in December 2009. Some of the key generation units in the area are the Mirant's Potrero power plant which is capable of generating up to 362 MW and it's located within the city of San Francisco. Electric power is imported from Pittsburg, East Shore, Tesla, Newark, and Monta Vista substations to support the sub-area loads. The amount of transfer capabilities into the area is dependent upon the amount of electricity demand and generation dispatch levels in the sub-area.

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The South Bay sub-area covers approximately 1,500 square miles and includes the Santa Clara County. Major cities include San Jose, Mountain View, Morgan Hill and Gilroy. Los Esteros, Metcalf, Monta Vista and Newark are the key substations that deliver power to the sub-area. The South Bay Area encompasses the De Anza and San Jose divisions, and the City of Santa Clara or Silicon Valley Power (SVP). Internal to the South Bay are units such as the Calpine's Metcalf Energy Center, Los Esteros Energy Center, Gilroy Units, and SVP's Donald Von Raesfeld power plant. In addition, South Bay sub-area has key 500kV and 230kV interconnections to the Moss Landing and Tesla substations.

4.5.5.1 Area-specific assumptions and system conditions

In addition to the general assumptions described in Chapter 3, the following are some of the area-specific assumptions used for the Greater Bay Area studies.

Generation

Approximately 8,400 MW of generation was dispatched in the basecases for the Greater Bay Area. This generation includes the new Gateway plant, San Francisco Airport Peaker, and San Francisco's Electric Reliability Peakers (at Potrero substation). In addition, the generation

Russel City Energy Center (361 MW) and East Shore Energy Facility (118 MW) were also dispatched but only for the 2018 basecase. Hunters Point Power Plant was assumed shut down. Table 4-36 lists major generating plants in the Greater Bay Area.

Table 4-36: Generators in the Greater Bay Area

Power Plant Name	Maximum Capacity (MW)
Alameda Gas Turbines	51
Calpine Gilroy I	182
Contra Costa Power Plant	680
Crockett Co-Generation	243
Delta Energy Center	965
High Winds, LLC	162
Los Esteros Critical Energy Facility	242
Los Medanos Energy Center	678
Metcalf Energy Center	575
Moss Landing Power Plant	1500
Oakland C Gas Turbines	165
Donald Von Raesfeld Power Plant	182
Pittsburg Power Plant	1360
Potrero Power Plant	366
Riverview Energy Center	61
Ox Mountain (Online 2008)	13
San Francisco Airport Peaker (Online 2009)	51
San Francisco Electric Reliability Peakers (Online 2009)	159
Gateway Generating Station (Online 2010)	599

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Load forecast

Loads within the Greater Bay Area reflect a coincident peak load for 1-in-10-year heat wave conditions. Table 4-37 shows the area load levels modeled for each of the PG&E local area studies including the Greater Bay Area.. While the Greater Bay Area loads were evaluated at extreme levels (1-in-10), other PG&E local area loads shown in the table were modeled at normal forecast summer loads (1-in-2). System losses for the Greater Bay Area were estimated at roughly 190 MW, 211 MW and 215 MW for 2009, 2013 and 2018 respectively.

Table 4-37: Summer Peak Load Forecasts for Greater Bay Area Assessment

	MW Load Forecast										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Humboldt	131	132	134	136	138	140	142	144	145	147	149
North Coast	789	802	814	828	841	854	867	880	893	906	918
North Valley	785	796	810	825	842	856	869	883	896	909	922
Sacramento	1046	1058	1071	1086	1097	1111	1124	1137	1150	1162	1175
Sierra	1095	1126	1156	1190	1225	1257	1288	1319	1351	1381	1412
North Bay	701	708	716	725	734	743	752	761	770	779	788
East Bay	947	953	959	967	975	982	989	996	1003	1010	1017
Diablo	1706	1726	1745	1769	1791	1811	1851	1865	1880	1895	1912
San Francisco	955	959	967	977	987	996	1006	1017	1026	1035	1044
Peninsula	1051	1068	1081	1092	1101	1115	1130	1144	1158	1173	1187
Mission	1341	1354	1365	1379	1392	1406	1420	1434	1448	1461	1475
De Anza	963	971	980	991	1001	1013	1023	1035	1045	1056	1067
San Jose	1782	1804	1824	1842	1861	1884	1906	1928	1950	1972	1994
Silicon Valley Power	528	537	547	555	564	572	582	591	601	610	618
Other GBA Muni Loads	352	354	357	359	360	361	362	362	363	363	364
Stockton	1321	1339	1360	1383	1406	1429	1452	1474	1497	1519	1541
Sanislaus	223	230	235	240	245	250	255	260	265	270	275
Yosemite	815	826	837	849	860	872	884	896	908	920	932
Fresno	2035	2063	2092	2124	2156	2185	2214	2242	2271	2298	2326
Kern	1406	1427	1448	1471	1496	1518	1540	1562	1585	1606	1628
Central Coast	731	744	754	765	775	784	792	800	808	816	824
Los Padres	525	534	542	552	562	571	580	589	598	607	616
Total	**21228**	**21511**	**21794**	**22105**	**22409**	**22710**	**23028**	**23319**	**23611**	**23895**	**24184**

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4.5.5.2 Study results and discussions

The Greater Bay Area assessment was focused on the 2013 (year 5) and 2018 (year 10) extreme summer peak load conditions. Normal and emergency contingency conditions were evaluated including Category B (N-1) and Category C (N-2) conditions. Some selected Category D contingencies were also evaluated. The study results showed that the Greater Bay Area system has adequate internal generation resources and import capability to serve its future load reliably under normal operating conditions. No overloaded facilities were found under normal operating conditions (Category A). However, many transmission lines and transformers were found to be overloaded under Category B and Category C contingency conditions. For those overloaded facilities, ISO has proposed mitigation plans to ensure that the system performance meets the NERC and WECC reliability criteria. Table 4-38 summarizes the power flow results and identifies overloaded facilities, contingencies causing such overloads, and ISO proposed mitigation plans.

Table 4-38 Worst line/Equipment Overload Summaries for Summer Peak Load Conditions

San Francisco

Overloaded Facility	Critical Contingency(ies)	Category	Loading		ISO Proposed Solutions
			2013	2018	
Potrero-Larkin #2 115 kV line	Potrero-Mission 115 kV line	B	105%	105%	Develop Short Term Emergency (STE) rating (30 minute) and install SPS to decrease either Potrero generation or Trans Bay Cable output if necessary to relieve overloading. If overloading falls within the STE rating, then manual generation adjustment can b
Potrero-Mission 115 kV line	Potrero-Larkin #2 115 kV line	B	128%	128%	"DC runback scheme" associated with the Trans Bay Cable project (TBC) will decrease DC output on the cable to relieve overload.
Potrero-Larkin #2 115 kV line	Bus fault at Potrero 115 kV 2D	C	136%	135%	Develop STE rating and possibly re-arrange line terminations on buses. If overload exists for this contingency, decrease Potrero generation or TBC output either manually or through SPS
Potrero-Mission 115 kV line	Bus fault at Potrero 115 kV 2E	C	128%	128%	TBC DC runback scheme should mitigate this overload because the bus fault results in outage of the same Potrero-Larkin #2 115 kV line for which the runback scheme is designed

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Table 4-38: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions (cont)

Peninsula

Overloaded Facility	Critical Contingency(ies)	Category	Loading		ISO Proposed Solutions
			2013	2018	
Bay Meadows-San Mateo 115 kV line #1	Bay Meadows-San Mateo 115 kV line #2 out	B	109%	121%	Existing SPS to drop calculated amount of load at Bay Meadows substation will mitigate overload, however, a long term solution will be determined.
Bay Meadows-San Mateo 115 kV line #2	Bay Meadows-San Mateo 115 kV line #1 out	B	109%	121%	Existing SPS to drop calculated amount of load at Bay Meadows substation will mitigate overload, however, a long term solution will be determined.
Jefferson-Emerald Lake 60 kV line	Cooley Landing-Glenwood 60 kV Line and Cardinal Cogen out	B	206%	229%	Short term: Develop STE rating and install SPS to drop load. Long term: Menlo area 60 kV system upgrade including Switch Replacement, reconductoring of 60 kV buses and reconductoring of limiting 60 kV line sections.
Glenwood-S.R.I. 60 kV line	Jefferson-SLAC 60 kV Line out	B	102%	115%	Short term: Re-rate line and develop STE rating. If re-rate is not feasible, install SPS to drop load. Long term: Menlo area 60 kV system upgrade including Switch Replacement, reconductoring of 60 kV buses and reconductoring of limiting 60 kV line sections.
Las Pulgas-Emerald Lake 60 kV Line	Cooley Landing-Glenwood 60 kV Line and Cardinal Cogen out	B	197%	219%	Short term: Develop STE rating and install SPS to drop load. Long term: Menlo area 60 kV system upgrade including Switch Replacement, reconductoring of 60 kV buses and reconductoring of limiting 60 kV line sections.

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Table 4-38: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions (cont)

Peninsula

Overloaded Facility	Critical Contingency(ies)	Category	Loading		ISO Proposed Solutions
			2013	2018	
Menlo-Las Pulgas 60 kV line (all sections)	Cooley Landing-Glenwood 60 kV Line and Cardinal Cogen out	B	198%	219%	Short term: Develop STE rating and install SPS to drop load. Long term: Menlo area 60 kV system upgrade including Switch Replacement, reconductoring of 60 kV buses and reconductoring of limiting 60 kV line sections.
San Mateo-Oracle 60 kV Line	Bair 115/60 kV Txmr	B	97%	113%	Reconductor San Mateo-Bair 60 kV line
Cooley Landing-Westinghous Junction 60 kV line	Los Altos-Monta vista 60 kV line out	B	102%	112%	Reconductor Cooley Landing-Los Altos 60 kV line
Ravenswood-Cooley Landing 115 kV line #2	Ravenswood-Cooley Landing 115 kV line #1 & Cardinal Gen out	B	102%	108%	Reconductor Ravenswood-Cooley Landing 115 kV line #2
Ravenswood-Cooley Landing 115 kV line #1	Ravenswood-Cooley Landing 115 kV line #2 & Cardinal Gen out	B	101%	107%	Reconductor Ravenswood-Cooley Landing 115 kV line #1
Bair 115/60 kV Txmr #1	Bus Fault at Cooley Landing 60 kV bus	C	104%	113%	Re-rate transformer or add cooling fans
Bay Meadows-San Mateo 115 kV line #1	Bus Fault at San Mateo 115 kV bus 2E	C	109%	121%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load
Belmont-San Mateo 115 kV line	Ravenswood-Bair #1 and #2 115 kV lines out	C	109%	122%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load
Belly Haven-Redwood 60 kV line #1	Bus Fault at Cooley Landing 60 kV bus	C	138%	154%	Develop STE rating. Use SPS to drop load
Cooley Landing-Ravenswood E 115 kV line #2	Ravenswood-Palo Alto #1 and #2 115 kV lines out	C	157%	161%	Reconductor Ravenswood – Cooley Landing 115 kV line #1 and #2 with conductor rated at 1100 amps or greater. Use SPS to drop load in the interim.
Jefferson-Emerald Lake 60 kV line	Bus Fault at Cooley Landing 60 kV bus	C	103%	119%	Short term: Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load. Long term: Menlo area 60 kV system upgrade including Switch Replacement, reconductoring of 60 kV buses and reconductoring of limiting 60 kV line sections.

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Table 4-38: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions (cont)

Peninsula

Overloaded Facility	Critical Contingency(ies)	Category	Loading 2013	Loading 2018	ISO Proposed Solutions
Glenwood-S.R.I. 60 kV line	Bus Fault at Jefferson 60 kV bus 1D	C	112%	126%	Short term: Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load. Long term: Menlo area 60 kV system upgrade including Switch Replacement, reconductoring of 60 kV buses and reconductoring of limiting 60 kV line sections.
Las Pulgas-Emerald Lake 60 kV line	Bus Fault at Cooley Landing 60 kV bus	C	94%	109%	Short term: Re-rate line and develop STE rating. If re-rate is not feasible, use SPS or manually drop load when an overload occurs. Long term: Menlo area 60 kV system upgrade including Switch Replacement, reconductoring of 60 kV buses and reconductoring of limiting 60 kV line sections.
Menlo-Las Pulgas 60 kV line	Bus Fault at Cooley Landing 60 kV bus	C	95%	110%	Short term: Re-rate line and develop STE rating. If re-rate is not feasible, use SPS or manually drop load when an overload occurs. Long term: Menlo area 60 kV system upgrade including Switch Replacement, reconductoring of 60 kV buses and reconductoring of limiting 60 kV line sections.
San Mateo-Oracle 60 kV line	Bus Fault at Bair 115 kV bus	C	94%	110%	Reconductor San Mateo-Bair 60 kV line
Palo Alto-Cooley Landing 115 kV line	Ravenswood-Palo Alto #1 and #2 115 kV lines out	C	124%	124%	Develop STE rating. Use SPS to drop load
Palo Alto-Ravenswood E 115 kV line #1	Bus Fault at Ravenswood 115 kV bus 2E	C	132%	135%	Develop STE rating. Use SPS to drop load
Palo Alto-Ravenswood E 115 kV line #2	Ravenswood-Palo Alto #1 and Cooley Landing-Palo Alto #1 115 kV lines out	C	115%	115%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load.

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Table 4-38: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions (cont)

Peninsula

Overloaded Facility	Critical Contingenc(ies)	Category	Loading		ISO Proposed Solutions
			2013	2018	
Redwood Tap1-Bair 60 kV line #1	Bus Fault at Cooley Landing 60 kV bus	C	96%	108%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS or manually drop load when an overload occurs.
Redwood Tap2-Belly Haven 60 kV line #2	Bus Fault at Bair 115 kV bus	C	117%	131%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load.
Cooley Landing-S.R.I. 60 kV line #2	Bus Fault at Jefferson 60 kV bus 1D	C	97%	109%	Long term: Menlo area 60 kV system upgrade including Switch Replacement, reconductoring of 60 kV buses and reconductoring of limiting 60 kV line sections.
San Carlos-Bair 60 kV line	Bus Fault at San Mateo 60 kV bus 2	C	97%	104%	Reconductor San Mateo-Bair 60 kV line

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Table 4-38: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions (cont)

East Bay

Overloaded Facility	Critical Contingenc(ies)	Category	Loading		ISO Proposed Solutions
			2013	2018	
EDES 115 kV tap to Domtar #2 portion of the San Leandro-Oakland J 115 kV Line	Moraga-Station J 115 kV Line out	B	98%	102%	Short term: Re-rate line and develop STE rating. If re-rate is not feasible, use SPS or manually drop load when an overload occurs. Long term: Oakland Area Long Term Plan. Note: This plan is ISO review.
Sobrante-Christie 115 kV line	Sobrante-"G" Nos. 1 & 2 115 kV lines	C	100%	105%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load.
EDES -Domtar #2 115 kV line	Moraga-Oakland "J" 115 kV and Moraga-San Leandro No. 3 115 kV lines	C	100%	105%	Short term: Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load. Long term: Oakland Area Long Term Plan. Note: This plan is under ISO review.
Sobrante-El Cerito 115 kV line #2	Bus Fault at Sobrante 115 kV bus 1	C	116%	121%	Convert Sobrante 115 kV substation into a Breaker And A Half (BAAH) scheme
Sobrante-El Cerito 115 kV Jct	Bus Fault at El Cerito 115 kV bus section D	C	101%	105%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load.
Oakland C-Station L 115 kV line	Bus Fault at Claremont 115 kV bus	C	107%	112%	Short term: Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load. Long term: Oakland Area Long Term Plan. Note: This plan is under ISO review.

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Table 4-38: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions (cont)

Diablo

Overloaded Facility	Critical Contingenc(ies)	Category	Loading		ISO Proposed Solutions
			2013	2018	
Martinez-Alhambra Tap#2 115 kV line	Sobrante-"G" Nos. 1 & 2 115 kV lines	C	104%	111%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load.
Clayton-kirker tap 115 kV line	Bus Fault at Clayton 115 kV bus 2	C	108%	114%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load.
Clayton-Pittsburg 115 kV line	Pittsburg-Clayton # 3 and #4 115 kV lines out	C	128%	135%	Use SPS to drop load.
Kirker tap-Pittsburg 115 kV line	Bus Fault at Clayton 115 kV bus 2	C	95%	101%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load.
Clayton-Lakewood Jct 115 kV line	Bus Fault at Clayton 115 kV bus 1	C	112%	119%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load.
Lakewood-Moraga 115 kV line	Lakewood-Clayton and Lakewood-Meadow Lane-Clayton 115 kV lines	C	127%	133%	Develop STE rating. Use SPS to drop load.
Oleum-Alhambra Tap#2 115 kV line	Sobrante-"G" Nos. 1 & 2 115 kV lines	C	97%	104%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load.
San Leandro-Moraga 115 kV line #1	Bus Fault at San Leandro 115 kV bus D	C	150%	157%	Short term: Develop STE rating. Use SPS to drop load. Long term: Oakland Area Long Term Plan. Note: This plan is under ISO review.
San Leandro-Moraga 115 kV line #2	Bus Fault at Moraga 115 kV bus 1E	C	150%	158%	Short term: Develop STE rating. Use SPS to drop load. Long term: Oakland Area Long Term Plan. Note: This plan is under ISO review.
Moraga-Station J 115 kV line	Bus Fault at San Leandro 115 kV bus E	C	139%	146%	Short term: Develop STE rating. Use SPS to drop load. Long term: Oakland Area Long Term Plan. Note: This plan is under ISO review.

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Table 4-38: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions (cont)

Mission

Overloaded Facility	Critical Contingenc(ies)	Category	Loading		ISO Proposed Solutions
			2013	2018	
Dixon Landing-Newark 115 kV line	Piercy-Metcalf 115 kV line out	B	100%	105%	Convert 60 kV portion of the Mabury substation to 115 kV and rebuild Evergreen-Mabury line to 115 kV circuit
San Leandro-Domtar 115 kV line	Moraga-Station J 115 kV line out	B	100%	104%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load as an interim solution. Oakland Area Long Term Plan may eliminate this overload. Note: This plan is under ISO review
Dumbarton-Newark D 115 kV line	East Shore-San Mateo 230 kV line out	B	19%	109%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load as an interim solution. Oakland Area Long Term Plan may eliminate this overload. Note: This plan is under ISO review
Dixon Landing-Newark 115 kV line	Swift - Metcalf 115 kV and Piercy - Metcalf 115 kV lines out	C	100%	106%	Convert 60 kV portion of the Mabury substation to 115 kV and rebuild Evergreen-Mabury line to 115 kV circuit
San Leandro-Domtar #2 115 kV line	Moraga-Oakland "J" 115 kV and Moraga-San Leandro No. 3 115 kV lines out	C	103%	107%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load as an interim solution. Oakland Area Long Term Plan may eliminate this overload. Note: This plan is under ISO review
Dumbarton-Newark D 115 kV line	Eastshore-San Mateo 230 kV and Pittsburg-San Mateo 230 kV lines out	C	19%	117%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load as an interim solution. Oakland Area Long Term Plan may eliminate this overload. Note: This plan is under ISO review
Newark 230/13.2 Txmr #11	Bus Fault at Newark D 115 kV bus 1	C	106%	102%	Re-rate transformer or add cooling fans

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Table 4-38: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions (cont)

De Anza

Overloaded Facility	Critical Contingenc(ies)	Category	Loading		ISO Proposed Solutions
			2013	2018	
Los Altos-Westinghouse Jct 60 kV line	Los Altos-Monta Vista-Almaden 60 kV line out	B	106%	118%	Reconductor Cooley Landing-Los Altos 60 kV line
Los Altos sub-Los Altos 60 kV Jct	Loyola-Monta Vista 60 kV line	B	100%	111%	Reconductor Cooley Landing-Los Altos 60 kV line
Monta Vista-Los Gatos 60 kV line	Evergreen-Almaden-Los Gatos 60 kV line	B	98%	102%	Re-rate Monta Vista-Los Gatos 60 kV line. If re-rating is not feasible, reconductor Monta Vista-Los Gatos and Evergreen-Los Gatos 60 kV lines
Monta Vista 230/115 kV Txmr #4	Bus Fault at Monta Vista 115 kV bus 1	C	97%	101%	Monta Vista 115 kV substation is being converted into a BAAH scheme. This will eliminateTransformer overload.
Monta Vista 230/60 kV Txmr #5	Bus Fault at Monta Vista 115 kV bus 2	C	95%	101%	Monta Vista 115 kV substation is being converted into a BAAH scheme. This will eliminateTransformer overload.
Saratoga-Vasona 230 kV line	Metcalf - Monta Vista #3 230 kV and Cal MEC - Monta Vista #4 230 kV lines out	C	101%	101%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS to drop load.

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Table 4-38: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions (cont)

San Jose

Overloaded Facility	Critical Contingenc(ies)	Category	Loading		ISO Proposed Solutions
			2013	2018	
Llagas-Morgan Hill 115 kV line	Metcalf-Llagas 115 kV line	B	117%	114%	Existing RAS to drop generation in Gilroy area
Piercy-Metclf E 115 kV line	Dixon Landing-Newark 115 kV line	B	101%	107%	Convert 60 kV portion of the Mabury substation to 115 kV and rebuild Evergreen-Mabury line to 115 kV circuit
Almaden-Senter Tap 60 kV line	Monta Vista-Los Gatos 60 kV line	B	115%	120%	Reconductor Monta Vista-Los Gatos and Evergreen-Los Gatos 60 kV lines
Senter Tap-Evergreen 60 kV line	Monta Vista-Los Gatos 60 kV line	B	103%	108%	Reconductor Monta Vista-Los Gatos and Evergreen-Los Gatos 60 kV lines
Llagas-Morgan Hill 115 kV line	Bus Fault at Metcalf D 115 kV bus 1D	C	117%	114%	Existing RAS to drop generation in Gilroy area
Piercy-Metcalf E 115 kV line	Newark - Dixon Landing 115 kV and Newark - Milpitas #1 115 kV lines out	C	102%	107%	Convert 60 kV portion of the Mabury substation to 115 kV and rebuild Evergreen-Mabury line to 115 kV circuit
Trimble-San Jose B 115 kV line	Metcalf - El Patio #1 and #2 115 kV lines out	C	98%	110%	Re-rate line and develop STE rating. If re-rate is not feasible, use SPS or manually drop load when an overload occurs.

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4.5.5.3 Recommended solutions for reliability criteria violations

For each criteria violation identified in this study, following are proposed mitigations identified by ISO.

San Francisco

TPL 001-System Performance Under Normal Conditions

No overloads were found under normal operating conditions (Category A)

TPL 002-System Performance Following Loss of a Single BES Element

- **Potrero-Larkin #2 115 kV line Overload**

  This line is overloaded when Potrero-Mission 115 kV line is out of service while Potrero substation is receiving 400 MW of generation through Trans Bay Cable (TBC) in addition to Potrero's own generation. The solution is simply to decrease either Potrero generation or ramp down DC output through TBC. If a short term rating is developed for Potrero-Larkin #2 line, then appropriate amount of generation can be decreased manually through operator action, otherwise an SPS should be installed to reduce calculated amount of generation automatically.

- **Potrero-Mission 115 kV line Overload**

  This line is overloaded when Potrero-Larkin #2 line is out of service. This overload is mitigated through an already planned "DC runback scheme" associated with the Trans Bay Cable project. This mitigation scheme will activate upon detection of the outage AND occurrence of the above overload. If the outage occurred but overload did not occur, no action will be taken. If the overload did occur, the TBC output will be decreased from 400 MW to 300 MW.

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TPL 003-System Performance Following Loss of Two or More BES Elements

- **Potrero-Larkin #2 115 kV line Overload**

  This overload occurs upon a bus fault at Potrero 115 kV substation 2D. The overload can be mitigated by re-arranging line terminals on buses and installing SPS to drop generation at Potrero.

- **Potrero-Mission 115 kV line Overload**

  This overload occurs upon a bus fault at Potrero 115 kV substation 2E. This overload can be mitigated through the same "DC runback scheme" mentioned above. The bus fault results in loss of Potrero-Larkin #2 circuit for which the DC runback scheme is designed.

Peninsula

TPL 001-System Performance Under Normal Conditions

No criteria violation has been identified

TPL 002-System Performance Following Loss of a Single BES Element

- **Bay Meadows-San Mateo 115 kV line #1 Overload**

  This overload is caused by loss of the parallel line #2 and can be mitigated through an existing SPS that will drop some calculated amount of load at Bay Meadows substation. This load dropping is allowed under NERC/WECC criteria because it is a radial circuit and only controlled load dropping is exercised without impacting the overall reliability of the transmission systems. However, ISO plans to determine a long term solution to avoid load curtailment.

- **Bay Meadows-San Mateo 115 kV line #2 Overload**

  This overload is caused by loss of the parallel line #1 that is also mitigated through the same existing SPS that will drop some calculated amount of load at Bay Meadows substation. This load dropping is allowed under NERC/WECC criteria because it is a radial circuit and only controlled load dropping is exercised without impacting the overall reliability of the transmission systems. However, ISO plans to determine a long term solution to avoid load curtailment.

- **Jefferson-Emerald Lake 60 kV line Overload**

  This overload is caused by an L-1, G-1 outage (Cooley Landing-Glenwood 60 kV line and Cardinal generation). ISO is recommending Menlo Area 60 kV System Upgrade project proposed by PG&E to mitigate this overload. However, in the interim, ISO is recommending to install an SPS to drop some calculated amount of load.

- **Glenwood-S.R.I. 60 kV line Overload**

  This overload is caused by an outage of Jefferson-SLAC 60 kV line tap. This circuit is in Menlo Park area and can be mitigated through Menlo Area 60 kV System Upgrade project proposed by PG&E. However, in the interim, ISO is proposing to re-rate the line. If re-rate is not possible, then install SPS to drop some calculated amount of load as an interim solution.

- **Las Pulgas-Emerald Lake 60 kV line Overload**

  This overload is caused by an L-1, G-1 outage (Cooley Landing-Glenwood 60 kV line and Cardinal generation). This circuit is in Menlo Park area and can be mitigated through Menlo Area 60 kV System Upgrade project proposed by PG&E. However, in the interim, ISO is recommending to install SPS to drop some calculated amount of load.

- **Menlo-Las Pulgas 60 kV line (all sections) Overload**

  This overload is caused by an L-1, G-1 outage (Cooley Landing-Glenwood 60 kV line and Cardinal generation). This circuit is in Menlo Park area and can be mitigated through Menlo Area 60 kV System Upgrade project proposed by PG&E. However, in the interim, ISO is recommending to install SPS to drop some calculated amount of load.

- **San Mateo-Oracle 60 kV line Overload**

  This overload only appears in the year 2018 and is caused by loss of Bair 115/60 kV transformer. ISO is recommending San Mateo-Bair 60 kV line re-conductoring project proposed by PG&E to mitigate this overload.

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- **Cooley Landing-Westinghous Junction 60 kV line Overload**

  This overload is caused by an outage of Los Altos-Monta Vista 60 kV line. ISO is recommending Cooley Landing-Los Altos 60 kV line reconductoring project proposed by PG&E to mitigate this overload.

TPL 003-System Performance Following Loss of Two or More BES Elements

- **Bair 115/60 kV Txmr #1 Overload**

  This transformer overload is caused by a bus fault at Cooley Landing 60 kV bus. ISO is recommending re-rating the transformer. If re-rating is not possible then add cooling fans to mitigate slightly higher loading. If this does not relieve overload, then drop some calculated amount of customer load fed through this transformer.

- **Bay Meadows-San Mateo 115 kV line #1 Overload**

  This overload is caused by a bus fault at San Mateo 115 kV bus E. This overload also occurs under Category B contingency condition listed above. The mitigation is through an existing SPS that will drop some calculated amount of load at Bay Meadows substation.

- **Belmont-San Mateo 115 kV line Overload**

  This overload is caused by loss of a double circuit tower line carrying Ravenswood-Bair #1 and #2 115 kV lines. ISO is recommending re-rating the line to mitigate overload. If re-rating is not feasible, use SPS to drop calculated amount of load.

- **Belly Haven-Redwood 60 kV line #1 Overload**

  This overload is caused by a bus fault at Cooley Landing 60 kV bus. ISO is recommending using SPS to drop load to mitigate this overload.

- **Cooley Landing-Ravenswood E 115 kV line #2 Overload**

  This overload is caused by loss of a double circuit tower line carrying Ravenswood-Palo Alto #1 and #2 lines. ISO is recommending Ravenswood-Cooley Landing 115 kV Reconductoring project proposed by PG&E to mitigate this overload. Use SPS to drop calculated amount of load as an interim solution.

- **Jefferson-Emerald Lake 60 kV line Overload**

  This overload occurs for a bus fault at Cooley Landing 60 kV bus.This overload also occurs under category B conditions listed above. ISO is recommending Menlo Area 60 kV System Upgrade project proposed by PG&E to mitigate this overload. However, in the interim, ISO is recommending to install an SPS to drop some calculated amount of load.

- **Glenwood-S.R.I. 60 kV line Overload**

  This overload occurs for a bus fault at Jefferson 60 kV bus 1D. This overload also occurs under category B conditions listed above. ISO is recommending Menlo Area 60 kV System Upgrade project proposed by PG&E to mitigate this overload. However, in the interim, ISO is proposing to re-rate the line. If re-rate is not possible, then install an SPS to drop some calculated amount of load.

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- **Las Pulgas-Emerald Lake 60 kV line Overload**

  This overload is caused by a bus fault at Cooley Landing 60 kV bus and occurs only in the year 2019. This overload also occurs under category B conditions listed above. ISO is recommending Menlo Area 60 kV System Upgrade project proposed by PG&E to mitigate this overload.

- **Menlo-Las Pulgas 60 kV line Overload**

  This overload is caused by a bus fault at Cooley Landing 60 kV bus and occurs only in the year 2019. This overload also occurs under category B conditions listed above. ISO is recommending Menlo Area 60 kV System Upgrade project proposed by PG&E to mitigate this overload.

- **San Mateo-Oracle 60 kV line Overload**

  This overload is caused by a bus fault at Bair 115 kV bus and occurs only in the year 2019. This overload also occurs under category B conditions listed above. ISO is recommending San Mateo-Bair 60 kV line reconductoring project proposed by PG&E to mitigate this overload.

- **Palo Alto-Cooley Landing 115 kV line Overload**

  This overload is caused by loss of a double circuit tower line carrying Ravenswood-Palo Alto #1 and #2 115 kV lines. ISO is recommending using SPS to drop calculated amount of load to mitigate this overload.

- **Palo Alto-Ravenswood E 115 kV line #1 Overload**

  This overload is caused by a bus fault at Ravenswood 115 kV bus 2E. ISO is recommending using SPS to drop calculated amount of load to mitigate this overload.

- **Palo Alto-Ravenswood E 115 kV line #2 Overload**

  This overload is caused by loss of a double circuit tower line carrying Ravenswood-Palo Alto #1 and Cooley Landing-Palo Alto #1 115 kV lines. ISO is recommending re-rating the line. If re-rate is not feasible, then use SPS to drop calculated amount of load to mitigate this overload.

- **Redwood Tap1-Bair 60 kV line #1 Overload**

  This overload is caused by a bus fault at Cooley Landing 60 kV bus and occurs only in 2019. ISO is recommending re-rating the line. If re-rate is not feasible, then use SPS to drop calculated amount of load.

- **Redwood Tap4-Belly Haven 60 kV line #2 Overload**

  This overload is caused by a bus fault at Bair 115 kV bus. ISO is recommending to re-rate the line. If re-rate is not feasible, then use SPS to drop calculated amount of load.

- **Cooley Landing-S.R.I. 60 kV line #2 Overload**

  This overload is caused by a bus fault at Jefferson 60 kV bus 1D and occurs only in 2019. ISO is recommending Menlo Area 60 kV System Upgrade project proposed by PG&E to mitigate this overload.

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- **San Carlos-Bair 60 kV line Overload**

  This overload is caused by a bus fault at San Mateo 60 kV bus 2 and occurs only in 2019. ISO is recommending San Mateo-Bair 60 kV reconductoring project proposed by PG&E to mitigate this overload.

East Bay

TPL 001-System Performance Under Normal Conditions

No overloads were found under normal operating conditions (Category A)

TPL 002-System Performance Following Loss of a Single BES Element

- **EDES 115 kV tap to Domtar #2 portion of the San Leandro-Oakland J 115 kV line overload**

  This overload is caused by an outage of Moraga-Station J 115 kV line and occurs only in 2019. ISO is recommending re-rating the line. If re-rate is not feasible, use SPS as an interim solution to drop calculated amount of load. ISO is evaluating Oakland Area Long Term plan to mitigate this and many other overloads in East Bay.

TPL 003-System Performance Following Loss of Two or More BES Elements

- **Sobrante-Christie 115 kV line Overload**

  This overload occurs for loss of a double circuit tower line carrying Sobrante-G #1 and G#2 115 kV lines. The overload occurs only in 2018 and can be mitigated through re-rating the line. If re-rating is not feasible, then SPS can be used to drop calculated amount of load.

- **EDES -Domtar #2 115 kV line Overload**

  This overload occurs for loss of a double circuit tower line carrying Moraga-Oakland J and Moraga-San Leandro #3 115 kV lines. The overload occurs only in 2018 and can be mitigated through re-rating the line. If re-rating is not feasible, then SPS can be used as an interim solution to drop calculated amount of load. ISO is evaluating Oakland Area Long Term plan to mitigate this and many other overloads in East Bay.

- **Sobrante-El Cerito 115 kV line #2 Overload**

  This overload is caused by a bus fault at Sobrante 115 kV bus1. As a result of that bus fault, two 230 kV transmission lines and one 230/115 kV transformer are tripped. ISO is recommending converting Sobrante substation into a Breaker and a Half (BAAH) scheme to minimize number of circuits lost due to a bus fault. ISO and PG&E agree that converting Sobrante substation into BAAH scheme will mitigate this overload.

- **Sobrante-El Cerito 115 kV Jct Overload**

  This overload is caused by a bus fault at El Cerito 115 kV bus section D. ISO is recommending to re-rate the line to mitigate this overload. If re-rate is not feasible, then use

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SPS to drop calculated amount of load.

- **Oakland B-Station L 115 kV line Overload**

  This overload is caused by a bus fault at Claremont 115 kV bus. ISO is recommending re-rating the line to mitigate this overload. If re-rate is not feasible, then use SPS to drop calculated amount of load as an interim solution. ISO is evaluating Oakland Area Long Term plan to mitigate this and many other overloads in East Bay.

Diablo

TPL 001-System Performance Under Normal Conditions

No overloads were found under normal operating conditions (Category A)

TPL 002-System Performance Following Loss of a Single BES Element

No overloads were found under Category B contingency conditions

TPL 003-System Performance Following Loss of Two or More BES Elements

- **Martinez-Alhambra Tap#2 115 kV line Overload**

  This overload occurs for loss of a double circuit tower line carrying Sobrante-G #1 and G#2 115 kV lines. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop calculated amount of load.

- **Clayton-kirker tap 115 kV line Overload**

  This overload occurs for a bus fault at Clayton 115 kV bus 2. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop calculated amount of load.

- **Clayton-Pittsburg 115 kV line Overload**

  This overload is caused by loss of a double circuit tower line carrying Pittsburg-Clayton #3 and #4 115 kV lines. ISO is recommending using SPS to drop calculated amount of load to mitigate this overload.

- **Kirker tap-Pittsburg 115 kV line Overload**

  This overload occurs only in 2018 for a bus fault at Clayton 115 kV bus 2. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop calculated amount of load.

- **Clayton-Lakewood Jct 115 kV line Overload**

  This overload occurs for a bus fault at Clayton 115 kV bus 1. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop calculated amount of load.

- **Lakewood-Moraga 115 kV line Overload**

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This overload is caused by loss of a double circuit tower line carrying Lakewood-Clayton and Lakewood-Meadow Lane-Clayton 115 kV lines. ISO is recommending using SPS to drop calculated amount of load to mitigate this overload.

- **Oleum-Alhambra Tap#2 115 kV line Overload**

  This overload occurs only in 2018 for loss of a double circuit tower line carrying Sobrante-G #1 and G#2 115 kV lines. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop calculated amount of load.

- **San Leandro-Moraga 115 kV line #1 Overload**

  This overload is caused by a bus fault at San Leandro 115 kV bus D. ISO is recommending to use SPS to drop calculated amount of load as an interim solution. ISO is evaluating Oakland Area Long Term plan to mitigate this and many other overloads in East Bay.

- **San Leandro-Moraga 115 kV line #2 Overload**

  This overload is caused by a bus fault at Moraga 115 kV bus 1E. ISO is recommending using SPS to drop calculated amount of load as an interim solution. ISO is evaluating Oakland Area Long Term plan to mitigate this and many other overloads in East Bay.

- **Moraga-Station J 115 kV line Overload**

  This overload is caused by a bus fault at San Leandro 115 kV bus E. ISO is recommending to use SPS to drop calculated amount of load as an interim solution. ISO is evaluating Oakland Area Long Term plan to mitigate this and many other overloads in East Bay.

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Mission

TPL 001-System Performance Under Normal Conditions

No overloads were found under normal operating conditions (Category A)

TPL 002-System Performance Following Loss of a Single BES Element

- **Dixon Landing-Newark 115 kV line Overload**

  This overload is caused by an outage of Piercy-Metcalf 115 kV line and it occurs only in 2019. ISO is recommending Evergreen-Mabury 60 kV to 115 kV Conversion Project proposed by PG&E to mitigate this overload.

- **San Leandro-Domtar 115 kV line Overload**

  This overload is caused by an outage of Moraga-Station J 115 kV line and it occurs only in 2019. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop calculated amount of load as an interim solution. ISO is evaluating Oakland Area Long Term plan to mitigate this and many other overloads in East Bay.

- **Dumbarton-Newark D 115 kV line Overload**

  This overload is caused by an outage of East Shore-San Mateo 115 kV line and it occurs only

in 2019. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop calculated amount of generation at East Shore substation (Russell City Energy Center and East Shore Energy Facility) as an interim solution. ISO is evaluating Oakland Area Long Term plan to mitigate this and many other overloads in East Bay.

TPL 003-System Performance Following Loss of Two or More BES Elements

- **Dixon Landing-Newark 115 kV line Overload**

  This overload is caused by loss of a double circuit tower line carrying Swift-Metcalf and Piercy-Metcalf 115 kV lines. The overload occurs only in 2019. ISO is recommending Evergreen-Mabury 60 kV to 115 kV Conversion Project proposed by PG&E to mitigate this overload.

- **San Leandro-Domtar #2 115 kV line Overload**

  This overload is caused by loss of a double circuit tower line carrying Moraga-Oakland J and Moraga-San Leandro #3 115 kV lines. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop calculated amount of load as an interim solution. ISO is evaluating Oakland Area Long Term plan to mitigate this and many other overloads in East Bay.

- **Dumbarton-Newark D 115 kV line Overload**

  This overload is caused by an outage of a double circuit tower line carrying East Shore-San Mateo and Pittsburg-San Mateo 230 kV lines, and it occurs only in 2019. This overload also occurs under Category B conditions as listed above. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop calculated amount of generation at East Shore substation (Russell City Energy Center and East Shore Energy Facility) as an interim solution. ISO is evaluating Oakland Area Long Term plan to mitigate this and many other overloads in East Bay.

- **Newark 230/13.2 Txmr #11 Overload**

  This transformer overload occurs for a bus fault at Newark D 115 kV bus1. ISO is recommending re-rating the transformer. If re-rating is not possible then add cooling fans to mitigate slightly higher loading. If this does not relieve overload, then drop some calculated amount of customer load fed through this transformer.

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TPL 001-System Performance Under Normal Conditions

No overloads were found under normal operating conditions (Category A)

TPL 002-System Performance Following Loss of a Single BES Element

- **Los Altos-Westinghouse Jct 60 kV line Overload**

  This overload occurs for an outage of Los Altos-Monta Vista-Almaden 60 kV line. ISO is

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recommending Cooley Landing-Los Altos 60 kV line re-conductoring project proposed by PG&E to mitigate this overload.

- **Los Altos sub-Los Altos 60 kV Jct Overload**

  This overload occurs for an outage of Loyola-Monta Vista 60 kV line. The overload occurs in 2019. ISO is recommending Cooley Landing-Los Altos 60 kV line re-conductoring project proposed by PG&E to mitigate this overload.

- **Monta Vista-Los Gatos 60 kV line Overload**

  This overload occurs for an outage of Evergreen-Almaden-Los Gatos 60 kV line. The overload occurs in 2019. ISO is recommending Monta Vista-Los Gatos-Evergreen 60 kV line re-conductoring project proposed by PG&E to mitigate this overload.

TPL 003-System Performance Following Loss of Two or More BES Elements

- **Monta Vista 230/115 kV Txmr #4 Overload**

  This transformer overload occurs for a bus fault at Monta Vista 115 kV bus 1 in the year 2019. PG&E has reported that the Monta Vista substation is being converted into a BAAH scheme which will eliminate this overloading.

- **Monta Vista 230/60 kV Txmr #5 Overload**

  This transformer overload occurs for a bus fault at Monta Vista 115 kV bus 2 in the year 2019. PG&E has reported that the Monta Vista substation is being converted into a BAAH scheme which will eliminate this overloading.

- **Saratoga-Vasona 230 kV line Overload**

  This overload occurs for loss of a double circuit tower line carrying Metcalf-Monta Vista #3 and Cal MEB-Monta Vista #4 230 kV lines. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop some calculated amount of load.

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San Jose

TPL 001-System Performance Under Normal Conditions

No overloads were found under normal operating conditions (Category A)

TPL 002-System Performance Following Loss of a Single BES Element

- **Llagas-Morgan Hill 115 kV line Overload**

  This overload occurs for outage of Metcalf-Liagas 115 kV line. Currently an existing RAS mitigates this overload by dropping appropriate amount of generation in Gilroy area. ISO recommends maintaining the existing RAS to mitigate this overload.

- **Piercy-Metclf E 115 kV line Overload**

This overload occurs for outage of Dixon Landing-Newark 115 kV line. ISO is recommending Evergreen-Mabury 60 kV to 115 kV Conversion Project proposed by PG&E to mitigate this overload.

- **Almaden-Senter Tap 60 kV line Overload**

  This overload occurs for outage of Monta Vista-Los Gatos 60 kV line. ISO is recommending Monta Vista-Los Gatos-Evergreen 60 kV reconductoring Project proposed by PG&E to mitigate this overload.

- **Senter Tap-Evergreen 60 kV line Overload**

  This overload occurs for outage of Monta Vista-Los Gatos 60 kV line. ISO is recommending Monta Vista-Los Gatos-Evergreen 60 kV reconductoring Project proposed by PG&E to mitigate this overload.

TPL 003-System Performance Following Loss of Two or More BES Elements

- **Llagas-Morgan Hill 115 kV line Overload**

  This overload occurs for a bus fault at Metcalf D 115 kV bus 1D. This overload also appears under category B contingency conditions listed above. Currently an existing RAS mitigates this overload by dropping appropriate amount of generation in Gilroy area. ISO recommends maintaining the existing RAS to mitigate this overload.

- **Piercy-Metcalf E 115 kV line Overload**

  This overload occurs for loss of a double circuit tower line carrying Newark-Dixon Landing and Newark-Milpitas #1 115 kV lines. This overload also appears under category B contingency conditions listed above. ISO is recommending Evergreen-Mabury 60 kV to 115 kV Conversion Project proposed by PG&E to mitigate this overload.

- **Trimble-San Jose B 115 kV line Overload**

  This overload occurs for loss of a double circuit tower line carrying Metcalf-El Patio #1 and #2 115 kV lines. The overload occurs in the year 2019. ISO is recommending re-rating the line to mitigate this overload. If re-rating is not feasible, then use SPS to drop calculated amount of load.

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4.5.5.4 Key conclusions

Based on the ISO study assessment, the Greater Bay Area has:

- No overloads under normal conditions,
- 23 overloads caused by 20 critical single contingencies under summer peak conditions
- 44 overloads caused by 33 critical multiple contingencies under summer peak conditions

Among those studied, there are no extreme contingency conditions with potential voltage collapse,

In order to address all these concerns ISO has proposed 45 transmission solutions.

During the 2008 Open Request Window the ISO received 16 project proposals:

- Nine were approved,
- None were withdrawn,
- None were denied,
- Seven are on-going projects (i.e., to be considered for approval at a later date).

There are a total of 48 projects in the 2009 transmission plan for the Greater Bay Area including 45 proposed by the ISO

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4.5.6 Greater Fresno Area

The Greater Fresno Area is located in the Central to Southern PG&E's service territory. This area includes Madera, Mariposa, Merced, and Kings Counties located within the San Joaquin Valley Region. The figure below depicts the geographical location of the Fresno area.

The Greater Fresno area electric transmission system is comprised of 70 kV, 115 kV, and 230 kV transmission facilities. Electric supply to the Greater Fresno area is provided primarily by area Hydro generation (largest of which is Helms Pump/Gen), a number of market, and few QF units. It is supplemented by transmission imports from the North Valley and the 500 kV along the West and South parts of the Valley. Greater Fresno Area is comprised of two primary load pockets, one being the Yosemite area in the Northwest portion of the shaded region in Figure 4-6. The rest of the shaded region represents the Fresno area.

The Greater Fresno area interconnects to the bulk PG&E transmission system by thirteen transmission circuits which are ten (10) 230 230 kV lines, one (1) 230/115 kV bank, two 230/70 kV banks, and one (1) 70 kV line served from the Gates substation in the south, Moss Landing in the West, Los Banos in the Northwest, Bellota in the Northeast, and Templeton in the Southwest. Historically, the Greater Fresno area experiences its highest demand during the summer season but also experience high loading due to the potential of 1,200 MW of pump load at Helms during off-peak. Load forecasts indicate the Greater Fresno area should reach its summer peak demand of approximately 3,650 MW and summer off-peak of load exceeding 1,600 MW (excluding the Helms pump load) by 2018 assuming load is increasing at a rate of 48 MW per year (MW/year). In addition, this area has a rated capacity of about 3,000 MW of local generation. The largest generation facility within the area is the Helms Pump Storage Plant (PSP) with 1,212 MW of generation capability. Accordingly, system assessments in this area include the technical studies for the scenarios under summer-peak and off-peak conditions that reflect different operating conditions of the Helms pump-storage plant.

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4.5.6.1 Area-specific assumptions and system conditions

The Greater Fresno area study was performed consistent with the general study assumptions and methodology described in Chapter 3 and appendix A. The ISO secured website provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions and methodology applied to Fresno area study are provided below in this section.

Generation

Generation resources in the Greater Fresno area consist of market, QF and self-generating units. Table 4-39 list all generating plants in Greater Fresno and Yosemite areas modeled in the study.

Table 4-39: Generation units in the Greater Fresno – 2013 peak analysis

Plant Name	Max Capacity (MW)
Fresno Cogen-Agrico	79.9
Balch 1 PH	31
Mendota Biomass Power	25
Balch 2 PH	107
Chow 2 Peaker Plant	52.5
Chevron USA (Coalinga)	25
Chow II Biomass to Energy	12.5
Coalinga Cogeneration Company	46
CalPeak Power – Panoche LLC	49
Dinuba Generation Project	13.5
El Nido Biomass to Energy	12.5
Exchequer Hydro	94.5
Fresno Waste Water	9
Friant Dam	27.3
GWF Henrietta Peaker Plant	109.6
HEP Peaker Plant Aggregate	102
Hanford L.P.	23
Haas PH Unit 1 & 2 Aggregate	146.2
Helms Pump-Gen	1212
Herndon Synch Condenser	0
J.R. Wood	10.8
Kerkhoff PH 1	32.8
Kerkhoff PH 2	142
Kingsburg Cogen	34.5
Kings River Hydro	51.5
Kings River Conservation District	112
Madera	28.7
McCall Synch Condensers	0
Mc Swain Hydro	10
Merced Falls	4
O'Neill Pump-Gen	11
Panoche Energy Center	410
Pine Flat Hydro	189.9
Sanger Cogen	38
San Joaquin 2	3.2
San Joaquin 3	4.2
Rio Bravo Fresno (AKA Ultrapower)	26.5
Wellhead Power Gates, LLC	49
Wellhead Power Panoche, LLC	49
Wishon/San Joaquin #1-A Aggregate	20.4
Generation Total	**3405**

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Load forecast

Loads within the Fresno and Yosemite area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 4-40 shows the substation loads assumed in these studies under summer peak and off-peak conditions. These tables also show loads modeled for neighboring local areas in PG&E system in the Fresno and Yosemite area assessment as well.

Table 4-40: Load Forecasts modeled in Fresno and Yosemite area assessment

	MW Summer Load Forecast											
	Peak											Off-Peak
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2013
Humboldt	131	132	134	136	138	140	142	144	145	147	149	89
North Coast	715	726	737	750	762	774	786	797	809	821	832	334
North Valley	840	852	866	882	900	915	929	944	958	972	986	373
Sacramento	1,009	1,021	1,033	1,047	1,059	1,071	1,084	1,097	1,109	1,121	1,134	465
Sierra	1,198	1,231	1,264	1,301	1,340	1,374	1,408	1,443	1,477	1,511	1,544	481
North Bay	642	649	656	664	672	681	689	698	706	714	722	365
East Bay	836	841	847	854	861	867	873	880	886	892	898	616
Diablo	1,591	1,608	1,625	1,646	1,666	1,685	1,703	1,722	1,740	1,758	1,776	771
San Francisco	855	862	870	879	887	896	904	913	922	930	939	499
Peninsula	866	880	890	899	907	919	931	943	954	966	978	574
Stockton	1,336	1,354	1,375	1,399	1,422	1,446	1,468	1,491	1,514	1,536	1,558	710
Stanislaus	225	232	237	242	248	253	258	263	268	273	278	122
Yosemite	913	925	938	951	964	977	990	1,004	1,017	1,031	1,044	454
Fresno	2,280	2,311	2,343	2,379	2,416	2,448	2,480	2,512	2,544	2,575	2,606	1139
Kern	1,548	1,571	1,595	1,620	1,647	1,672	1,696	1,721	1,745	1,769	1,793	1071
Mission	1,253	1,265	1,276	1,289	1,301	1,314	1,327	1,340	1,353	1,366	1,378	589
De Anza	875	883	891	900	910	920	930	940	950	960	969	525
San Jose	1,601	1,620	1,639	1,655	1,671	1,692	1,711	1,731	1,752	1,771	1,791	731
Central Coast	700	713	723	733	743	751	759	767	775	782	790	466
Los Padres	504	512	520	530	539	548	557	566	574	583	592	302
Total	19,918	20,188	20,459	20,758	21,054	21,343	21,626	21,913	22,199	22,478	22,757	10,676

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4.5.6.2 Study results and discussions

In this section, study results and proposed mitigation plans for the Greater Fresno area under each category of the planning standards are shown below. Table 4-41 through 4-42 also provide a summary of the study results and ISO proposed solutions.

TPL 001-System Performance Under Normal Conditions

There were three (3) overloads under summer peak conditions and two (2) overloads under summer off-peak conditions that did not meet Category A performance requirements as summarized in tables 4-41 and 4-42 respectively. There were no voltage criteria violation identified under system normal conditions.

TPL 002-System Performance Following Loss of a Single BES Element

There were seven (7) overloads caused by six (6) contingencies under the summer peak conditions and four (4)overloads caused by four (4) contingencies under summer off-peak conditions that did not meet Category B performance requirements as summarized in tables 4-41 and 4-42 respectively.

TPL 003-System Performance Following Loss of Two or More BES Elements

There were eleven (11) overloads driven by six (6) contingencies under summer peak conditions, and fourteen (14) overloads driven by six (6) contingencies under summer off-peak conditions that did not meet Category C (TPL 003) performance requirements as summarized in Tables 4-41 and 4-42 respectively.

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Table 4-41: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Atwater - Cressey 115kV Line	Wilson - Atwater #2 115kV and El Capitan - Wilson 115kV Lines	C	191%	217%	Reinforce the Wilson-Merced-Atwater 115kV System
Atwater - Merced 115kV Line		C	162%	183%	
Wilson - Merced #1 & #2 115kV Line		C	151%	171%	
			136%	154%	
Cal Ave - McCall 115kV Line	McCall - West Fresno 115kV Line	B		105%	Reinforce the Cal Ave, West Fresno, Reedley system by
				102%	
Coppermine - Reedley 70kV Line	Borden - Coppermine 70kV Line + Friant gen	B	119%	138%	Reconductor Coppermine - Reedley 70kV Line or De-Loop the 70kV System
Corcoran 115/70kV Bank#2	Base Case	A	110%	111%	Add second bank
Gregg - Ashlan 230kV Line	Gregg-Herndon #1 and #2 230kV Lines	C	183%	191%	Reconductor Gregg - Ashlan 230kV Line
			168%	174%	
Gregg - Borden 230kV Line	Base Case	A		102%	Reconductor the Gregg-Borden 230kV Line as prescribed by all C3ETP alternatives
Helm - McCall 230kV Line	Gates - Gregg 230kV and Gates - McCall 230kV Lines, Helms Unit #3 based on HRAS action, and Henrietta 70kV Load based on SPS	C		116%	Reconductor the Helm-McCall 230kV Line as prescribed by all C3ETP alternatives
GWF - Kingsburg 115kV Line	Helm - McCall and Gates - McCall 230kV Lines	C		105%	Reconductor the GWF - Kingsburg 115kV Line or develop SPS to drop area generation.
	Helm - McCall and Gates - McCall 230kV Lines	C		101%	
Herndon 230/115kV Bank #1 and #2	Herndon 230/115kV Bank #1 or #2	B	107%	111%	Add additional 230/115kV Bank
Kingsriver - Sanger - Reedley 115kV Line	McCall - Reedley 115kV Line + Kingsriver gen	B		113%	Reconductor the Sanger - Reedley 115kV Line
	McCall - Reedley 115kV Line + Sanger Cogen	B		117%	

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Table 4-41 Worst line/Equipment Overload Summaries for Summer Peak Load Conditions (cont)

Overloaded Transmission Equipment	Worst system contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Le Grand - Chowchilla 115kV Line	Kerckhoff - Clovis -Sanger #1 and #2 115kV Lines	C	117%	108%	Reconductor LeGrand - Chowchilla 115kV Line or develop SPS
Los Banos - Canal - Oro Loma 70kV Line	Los Banos - Livingston Jct - Canal 70kV Line	B		112%	Reconductor the Los Banos - Canal - Oro Loma 70kV Line or add additional source into Canal.
Oakhurst Tap 115kV	Base Case	A		112%	Reconductor the Oakhurst Tap or add additional source to Oakhurst.
Oro Loma - Dos Palos 70kV Line	Los Banos - Livingston Jct - Canal 70kV Line	B		103%	Reconductor the Oro Loma - Dos Palos 70kV Line or add additional source into Canal.
Panoche - Helm 230kV Line	Gates - Gregg 230kV and Gates - McCall 230kV Lines, Helms Unit #3 based on HRAS action, and Henrietta 70kV Load based on SPS	C		107%	Reconductor the Panoche - Helm 230kV Line as prescribed by all C3ETP alternatives.
Panoche - Kearney 230kV Line	Helms - Gregg #1 and #2 230kV Lines	C		108%	Reconductor the Panoche - Kearney 230kV Line as
	Helms - Gregg #1 and #2 230kV Lines	C		103%	
Sanger - Reedley 70kV Line	McCall - Reedley 115kV Line + Kingsriver gen	B	112%	117%	Reconductor Sanger - Reedley 70kV Line
	McCall - Reedley 115kV Line + Sanger Cogen	B	102%	102%	
Warnerville - Wilson 230kV Line	Helms - Gregg #1 and #2 230kV Lines	C	103%		Reconductor the Warnerville - Wilson 230kV Line as prescribed by all C3ETP alternatives
Wilson – Le Grand 115kV Line	Kerckhoff - Clovis -Sanger #1 and #2 115kV Lines	C	101%	103%	Reconductor the Wilson – Le Grand 115kV Line or develop SPS

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Table 4-42: Worst line/Equipment Overload Summaries for Summer Off-Peak Conditions

Overloaded Transmission Equipment	Worst system Contingency	Category	Loading	Proposed Solution
Gates-Gregg 230kV Line	Melones - Wilson 230kV and Warnerville - Wilson 230kV Lines and Helms Unit #3 based on HRAS action	C	101%	1. Build Raisin City Junction Sub 2. Modify to remove Bellota-Gregg corridor lines from HRAS and add to the HTT-RAS to trip pumps in 1, 2, or 3 pump modes
Gates-McCall 230kV Line (Henrietta - McCall)	Base Case	A	101%	Reconductor Gates-McCall 230kV Line as prescribed by all C3ETP alternatives
	Helm - McCall 230kV Line	B	103%	1. Reconductor Gates-McCall 230kV Line as prescribed by all C3ETP alternatives 2. Add Helm - McCall 230kV Line to HTTRAS
	Panoche-Kearney and Helm-McCall 230kV Lines, and Helms Unit #2 based on HTT-RAS action	C	106%	Reconductor Gates-McCall 230kV Line as prescribed by all C3ETP alternatives
Gates-Midway 230kV Line	Gates 500/230kV Bank #11, and Helms Unit #2 based on HTT-RAS action	B	104%	Reconductor the Gates - Midway 230kV Line
Helm-McCall 230kV Line	Gates - Gregg 230kV and Gates - McCall 230kV Lines, Helms Unit #2 based on HTT-RAS action, and Henrietta 70kV Load based on SPS	C	123%	Reconductor the Helm-McCall 230kV Line as prescribed by all C3ETP alternatives
Helm-Stroud SW STA 70kV Line	Panoche-Kearney and Panoche-Helm 230kV Lines, and Helms Unit #2 based on HTT-RAS action	C	102%	Reconductor the Helm-Stroud SW STA 70kV Line or De-Loop 70kV System
Henrietta - GWF 115kV Line	Helm - McCall and Gates - McCall 230kV Lines, and Helms Unit #2 based on HTT-RAS action	C	116%	Reconductor the Henrietta-GWF 115kV Line
Herndon-Kearney 230kV Line	Gates - Gregg 230kV and Gates - McCall 230kV Lines, Helms Unit #2 based on HTT-RAS action, and Henrietta 70kV Load based on SPS	C	114%	Reconductor Herndon-Kearney 230kV Line
McCall-Sanger #2 and #3 115kV Line	McCall - Sanger #1 and #2 115kV Lines	C	125%	Reconductor McCall-Sanger #2 and #3 115kV Lines

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Table 4-42 Worst line/Equipment Overload Summaries for Summer Off-Peak Conditions (cont)

Overloaded Transmission Equipment	Worst system Contingency	Category	Loading	Proposed Solution
Panoche-Gates #1 230kV Line	Gates - Gregg 230kV and Gates - McCall 230kV Lines, Helms Unit #2 based on HTT-RAS action, and Henrietta 70kV Load based on SPS	C	117%	Reconductor Panoche-Gates #1 and #2 230kV Lines
Panoche-Helm 230kV Line	Gates - Gregg 230kV and Gates - McCall 230kV Lines, Helms Unit #2 based on HTT-RAS action, and Henrietta 70kV Load based on SPS	C	117%	Reconductor the Panoche - Helm 230kV Line as prescribed by all C3ETP alternatives.
Panoche-Kearney 230kV Line	Base Case	A	108%	Reconductor the Panoche - Kearney 230kV Line as prescribed by all C3ETP alternatives.
	Gates - Gregg 230kV Line and Helms Unit #2 based on HTT-RAS action	B	105%	
	Gates - Gregg 230kV and Gates - McCall 230kV Lines, Helms Unit #2 based on HTT-RAS action, and Henrietta 70kV Load based on SPS	C	128%	
Schindler-Huron-Gates 70kV Line (Huron-Calflax)	Gates - Gregg 230kV and Gates - McCall 230kV Lines, Helms Unit #2 based on HTT-RAS action, and Henrietta 70kV Load based on SPS	C	107%	Reconductor the Schindler-Huron-Gates 70kV Line or De-Loop 70kV System
Stroud SW STA-Schindler 70kV Line	Panoche - Helm 230kV Line	B	100%	1. Reconductor the Schindler-Stroud-Helm-Gates 70kV System or De-Loop 70kV System 2. Add Panoche-Helm 230kV Line to HTT-RAS
	Panoche-Kearney and Panoche-Helm 230kV Lines, and Helms Unit #2 based on HTT-RAS action	C	112%	Reconductor the Schindler-Stroud-Helm-Gates 70kV System or De-Loop 70kV System
Wilson-Oro Loma 115kV Line (Oro Loma - El Nido)	Melones - Wilson 230kV and Warnerville - Wilson 230kV Lines	C	104%	Reconductor Wilson-Oro Loma 115kV Line as prescribed by all C3ETP alternatives.
Wilson-Oro Loma 115kV Line (Wilson - El Nido)			120%	

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4.5.6.3 Recommended solutions for reliability criteria violations

Thermal overload mitigations

- **Arco-Twisselman kV line**

  This normal overload (Category A) was identified starting in the 2013 Summer Peak conditions. As this is a radial line the overload is strictly caused the load modeled as a result of the Fresno area anticipated load growth. With this limitation increasing over time a mitigation plan for this overload is needed. The proposed solutions are:

  - Explore the possibility of re-rating this line.
  - If re-rate is not possible, reconductor the line with the higher rating conductors or upgrade the limiting facility of this line.
  - Add additional source to Area

- **Arco 230/70 kV Bank #2 [Does not belong to the Fresno area]**

  This normal overload (Category A) was identified starting in the 2018 Summer Peak conditions. As this is a radial system the overload is strictly caused the load modeled as a result of the Fresno area anticipated load growth. With this limitation increasing over time a mitigation plan for this overload is needed. The proposed solutions are:

  - Add a second bank
  - Investigate load transfer option.

- **Atwater – Cressey, Atwater – Merced, and Wilson – Merced #1 & #2 115 kV lines**

  These significant overloads were identified starting in the 2013 summer peak conditions caused by the outage of Wilson – Atwater #2 115 kV and El Capitan – Wilson 115 kV lines (Category C). With these significant limitations increasing over time a mitigation plan for these overloads is required. The proposed solution is to reinforce the Wilson-Merced-Atwater 115 kV System which should include:

  - Reconductor the Atwater – Cressey 115 kV line with the higher rating conductors or upgrade the limiting facility of this line.
  - Reconductor the Atwater-Merced 115 kV line with the higher rating conductors or upgrade the limiting facility of this line.
  - Reconductor the Wilson – Merced #1 & #2 115 kV lines with the higher rating conductors or upgrade the limiting facility of this line.
  - Operate Atwater CB 162 or Atwater Jct SW 145 Normally open during Summer Months.
  - Add additional source into Atwater Substation.

- **California Ave – McCall 115 kV line**

  This overload was identified starting in the 2018 Summer Peak conditions caused by the outage of McCall – West Fresno 115 kV line (Category B). The proposed solution is to reinforce the California Ave, West Fresno, Reedley system by tying the two systems together over a converted 115 kV system from the current idle 70 kV lines.

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- **Coppermine – Reedley 70 kV line**

  This overload was identified starting in the 2013 summer peak conditions caused by the outage of Borden – Coppermine 70 kV line (Category B). The proposed solutions are reconductoring Coppermine – Reedley 70 kV line or De-Loop the 70 kV System during the summer months.

- **Corcoran 115/70 kV Bank #2**

  This overload was identified starting in the 2013 Summer Peak conditions given as a normal overload (Category A). With this being a radial system the overload is strictly caused by anticipated load growth. With this limitation increasing over time a mitigation plan for this overload is needed. The proposed solution is to add a second 115/70 kV Bank at Corcoran.

- **Gates-Gregg 230 kV line**

  This overload was identified starting in the 2013 off-peak conditions caused by the outage of Melones–Wilson 230 kV and Warnerville–Wilson 230 kV and Helms Unit #3 based on HRAS action (Category C). The proposed solution: Since this line was recently reconductored the only reasonable recommendation is to have the have Raisin City Junction built which would electrically tie the Gates-Gregg, Gates-McCall, Helm-McCall, and Panoche-Kearney 230 kV lines together. This configuration would help off-load all the associated lines but still would also require reconductoring of the Gates-McCall, Helm-McCall, and Panoche-Kearney lines.

- **Gates-McCall 230 kV line (Henrietta – McCall)**

  This overload was identified starting in the 2013 off-peak conditions caused by the following

  - Outage of the Helm – McCall 230 kV line (Category B)
  - Outage of the Panoche – Kearney and Helm – McCall 230 kV lines, and Helms Unit #2 based on HTT-RAS action.

  The proposed solutions are:

  - Reconductor the Gates – McCall 230 kV line from Henrietta – McCall as prescribed by all C3ETP alternatives
  - Add Helm – McCall 230 kV line to HTTRAS.
  - Gates-Midway 230 kV line

  This overload was identified starting in the 2013 off-peak conditions caused by Gates 500/230 kV Bank #1 and Helms Unit #2 based on HTT-RAS action. The proposed solution is to reconductor the Gates – Midway 230 kV line

- **Gregg – Ashlan 230 kV line**

  This significant overload was identified starting in the 2013 summer peak conditions caused by the outage of Gregg-Herndon #1 and #2 230 kV lines (Category C). The proposed solution is to reconductor the Gregg – Ashlan 230 kV line.

- **Gregg – Borden 230 kV line**

  This overload was identified starting in the 2018 Summer Peak conditions given as a normal overload. (Category C). The proposed solution is to reconductor the Gregg – Borden 230 kV line as prescribed by all C3ETP alternatives.

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- **Helm – McCall 230 kV line**

  This overload was identified starting in the 2018 summer peak and the 2013 off-peak conditions caused by the outage of Gates – Gregg 230 kV and Gates – McCall 230 kV lines, along with Helms Unit #3 based on HRAS action for summer peak conditionsand Helms Unit #2 based on HTT-RAS action for off-peak conditions (Category C). The proposed solution is to reconductor the Helm-McCall 230 kV line as prescribed by all C3ETP alternatives.

- **Helm – Stroud SW STA 230 kV line**

  This overload was identified starting in the 2013 off-peak conditions caused by the outage of Panoche-Kearney and Panoche-Helm 230 kV lines, and Helms Unit #2 based on HTT-RAS action (Category C). The proposed solution is to reconductor the Helm-Stroud SW STA 70 kV line or De-Loop 70 kV System during the summer months.

- **Henrietta – GWF 115 kV line**

  This overload was identified starting in the 2013 off-peak conditions caused by the outage of Helm-McCall and Gates-McCall 230 kV lines, and Helms Unit #2 based on HTT-RAS action (Category C). The proposed solution is to reconductor Henrietta-GWF 115 kV line.

- **Herndon – Kearney 230 kV line**

  This overload was identified starting in the 2013 off-peak conditions caused by the outage of Gates – Gregg and Gates – McCall 230 kV line, Helms Unit #2 based on HTT-RAS action and Henrietta 70 kV load based on SPS (Category C). The proposed solution is to reconductor Herndon – Kearney 230 kV line.

- **GWF – Kingsburg 115 kV line**

  This overload was identified starting in the 2018 summer peak conditions caused by the outage of Helm – McCall and Gates – McCall 230 kV lines (Category C). The proposed solutions are reconductoring the GWF-Henrietta 115 kV line or developing SPS to drop area generation during peak conditions only.

- **Kings River – Sanger – Reedley 115 kV line**

  This overload was identified starting in the 2018 summer peak conditions caused by the outage of McCall – Reedley 115 kV line and Kingsriver PH or Sanger Cogen (Category B). The proposed solution is to reconductor the Kingsriver – Sanger – Reedley 115 kV line or reconductor and converts the Sanger-Reedley 70 kV line to 115 kV service.

- **Le Grand – Chowchilla 115 kV line**

  This overload was identified starting in the 2013 summer peak conditions caused by the outage of Kerckhoff – Clovis – Sanger #1 and #2 115 kV lines (Category C). The proposed solution is to reconductor the Le Grand – Chowchilla 115 kV line or develops an SPS.

- **Los Banos – Canal – Oro Loma 70 kV line**

  This overload was identified starting in the 2018 summer peak conditions caused by the outage of Los Banos – Livingston Jct – Canal 70 kV line (Category B). The proposed solution is to reconductor the Los Banos – Canal – Oro Loma 70 kV line or add additional source into Canal

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- **McCall – Sanger #2 and #3 115 kV lines**

  This overload was identified starting in the 2013 off-peak conditions caused by the outage of McCall – Sanger #1 and #2 115 kV lines or McCall – Sanger #1 and #3 lines (Category C). The proposed solutions are to reconductor McCall – Sanger #2 and #3 115 kV lines.

- **Oakhurst Tap 115 kV**

  This overload was identified starting in the 2018 summer peak conditions given as a normal overload (Category A). With this being a radial line the overload is strictly caused by anticipated load growth. With this limitation increasing over time a mitigation plan for this overload is needed. The proposed solutions are:

  - Explore the possibility of re-rating this line.
  - If re-rate is not possible, reconductor the line with the higher rating conductors or upgrade the limiting facility of this line.
  - Add additional source to Area

- **Oro Loma – Dos Palos 70 kV line**

  This overload was identified starting in the 2018 summer peak conditions caused by the outage of Los Banos – Livingston Jct – Canal 70 kV line (Category B). The proposed solution is to reconductor the Oro Loma – Dos Palos 70 kV or add additional source into Canal.

- **Panoche-Gates #1 and #2 230 kV lines**

  This overload was identified starting in the 2013 off-peak conditions caused by the outage of Gates – Gregg and Gates – McCall 230 kV line, Helms Unit #2 based on HTT-RAS action and Henrietta 70 kV load based on SPS (Category C). The proposed solution is to reconductor Panoche – Gates #1 and #2 230 kV line.

- **Panoche – Helm 230 kV line**

  This overload was identified starting in the 2018 summer peak and 2013 off-peak conditions caused by the outage of Gates – Gregg 230 kV and Gates – McCall 230 kV lines, Henrietta 70 kV load based on SPS, Helms unit #3 based on HRAS action for summer peak and Helms unit #2 based on HTTRAS action for off-peak conditions (Category C). The proposed solution is to reconductor the Panoche – Helm 230 kV line as prescribed by all C3ETP alternatives.

- **Panoche – Kearney 230 kV line**

  This overload was identified starting in the 2018 summer peak and 2013 off-peak conditions caused by the following:

  - Outage of Helms-Gregg #1 and #2 230 kV for 2018 summer peak conditions (Category C)
  - Normal overload (Category A) for Off-peak.
  - Outage of Gates – Gregg 230 kV line and Helms Unit #2 based on HTT-RAS Action for Off-peak.
  - Outage of Gates – Gregg and Gates – McCall 230 kV lines, Helms Unit #2 based on HTT-RAS action, and Henrietta 70 kV load based on SPS for Off-peak.

  The proposed solution is to reconductor the Panoche – Kearney 230 kV line as prescribed by

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all C3ETP alternatives.

- **Sanger – Reedley 70 kV line**

  This overload was identified starting in the 2013 summer peak conditions caused by the outage of McCall – Reedley 115 kV line and Kingsriver PH or Sanger Cogen (Category B). The proposed solution is to reconductor and convert the Sanger – Reedley 70 kV line to 115 kV service.

- **Schindler – Huron – Gates 70 kV line (Huron – Calflax)**

  This overload was identified starting in the 2013 off-peak conditions caused by the outage of Gates – Gregg 230 kV and Gates – McCall 230 kV lines, Helms Unit #2 based on HTT-RAS action, and Henrietta 70 kV load based on SPS (Category C). The proposed solutions are to reconductor the Schindler-Huron-Gates 70 kV line (Huron-Calflax section) or De-Loop 70 kV System during the summer months.

- **Stroud SW STA – Schindler 70 kV line**

  This overload was identified starting in the 2013 off-peak conditions caused by the following:

  - An outage of the Panoche – Helm 230 kV line (Category B).
  - An outage of the Panoche – Kearney and Panoche – Helm 230 kV lines, and Helms Unit #2 based on HTT-RAS action

  The proposed solutions are

  - Reconductor the Stroud SW STA-Schindler 70 kV line or De-Loop 70 kV System during the summer months.
  - Add Panoche – Helm 230 kV line to HTT-RAS

- **Warnerville – Wilson 230 kV line**

  This overload was identified starting in the 2013 summer peak conditions caused by the outage of Helms – Gregg #1 and #2 230 kV lines (Category C). This is the same overload identified in the local capacity requirement (LCR) studies. The proposed solution is to reconductor the Warnerville – Wilson 230 kV line as prescribed by all C3ETP alternatives.

- **Wilson – Le Grand 115 kV line**

  This overload was identified starting in the 2013 summer peak conditions caused by the outage of Kerckhoff – Clovis – Sanger #1 and #2 115 kV lines (Category C). The proposed solution is to reconductor the Wilson – Le Grand 115 kV line or develops SPS.

- **Wilson – Oro Loma 115 kV line**

  This overload was identified starting in the 2013 off-peak conditions caused by the outage of Melones – Wilson 230 kV and Warnerville – Wilson 230 kV lines (Category C). The proposed solution is to reconductor the Wilson – Oro Loma 115 kV line as recommended in the C3ETP alternatives.

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4.5.6.4 Key conclusions

Based on the ISO study assessment, the Fresno area has:

- Five (5) overloads under normal conditions,
- Seven (7) overloads caused by six (6) critical single contingencies under summer peak conditions and four (4) overloads caused by four (4) single contingencies under summer off-peak conditions,
- Eleven (11) overloads caused by six (6) critical multiple contingencies under summer peak conditions and fourteen (14) overloads driven by six (6) multiple contingencies under summer off-peak conditions,

In order to address all these concerns ISO has proposed 32 transmission solutions.

During the 2008 Open Request Window the ISO received 22 project proposals:

- Seven were approved,
- Three were withdrawn,
- Two were denied,
- Ten are on-going projects (i.e., to be considered for approval at a later date).

This gives a total of seventeen (17) projects in the 2009 transmission plan for the Fresno area

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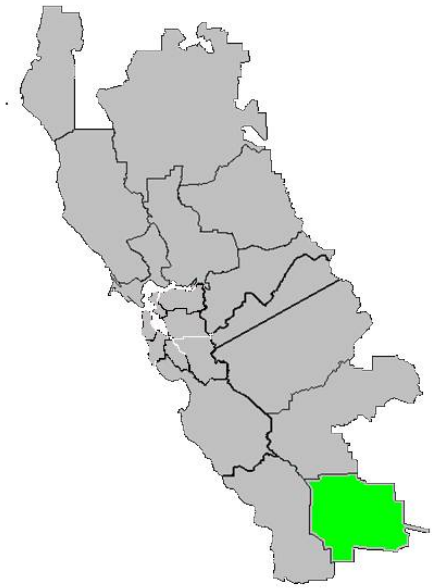
4.5.7 Kern area

The Kern area is located south of the Yosemite-Fresno area and north of Southern California Edison's (SCE) service territory. Midway Substation, one of the largest substations in the PG&E system is located in Kern Division and has connections to PG&E's Diablo Canyon, Gates, and Los Banos substations as well as SCE's Vincent Substation. The figure below depicts the geographical location of Kern area.



The bulk of the power that interconnects at Midway Substation transfers onto the 500 kV systems. A substantial amount also reaches neighboring transmission systems through Midway's 230 and 115 kV interconnections to the local areas. These interconnections include 115 kV lines to Yosemite-Fresno (north) as well as 115 and 230 kV lines to Los Padres (west). Electric customers in Kern area are served primarily through the 230/115 kV transformers at Midway and Kern Power Plant substations and through local generation power plants connected to the lower voltage transmission network.

Load forecasts indicate that the Kern area should reach its summer peak demand of 1672 MW by 2013 respectively. By 2018 the loading for this area would be 1793 MW. Load is increasing at a rate of about 24 MW per year (MW/year). Accordingly, system assessments in this area include the technical studies for the scenarios under these load assumptions for summer-peak condition

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4.5.7.1 Area-specific assumptions and system conditions

The Kern area study was performed in a manner consistent with the general study methodology and assumptions described in Chapter 3 and appendix A. The ISO secured website lists the contingencies that were studied as part of this assessment. In additional, specific assumptions and methodology applied to Kern area study are provided below in this section

Generation

Generation resources in Kern area consist of market, QF and self-generating units. Table 4-43 lists all generating plants in Kern area and modeled parameters for the 2013 and 2018 Peak Analysis respectively.

Table 4-43: Generator in Kern Area

Plant Name	Max Capacity (MW)
Badger Creek (PSE)	49
Chalk Cliff	48
Cymric Cogen (Chevron)	20.8
Cadet (Chev USA)	11.6
Dexzel	33
Discovery	44
Double C (PSE)	45.4
Elk Hills	623
Frito Lay	7.5
Hi Sierra Cogen	49
Kern	177
Kern Canyon Power House	11.2
Kernfront	49
Kern Ridge (South Belridge)	76
La Paloma Generation	926
Midsun	25
Mt. Poso	56
Navy 35R	65
Oildale Cogen	40
Bear Mountain Cogen (PSE)	68.8
Live Oak (PSE)	48
McKittrick (PSE)	45.4
Rio Bravo Hydro	10.5
Shell S.E. Kern River	27
Solar Tannenhill	17.6
Sunset	225
North Midway (Texaco)	24
Sunrise (Texaco)	338
Sunset (Texaco)	239
Midset (Texaco)	42
Lost Hills (Texaco)	9
Ultra Power (OGLE)	45
University Cogen	36.3
Total	3532.1
Kern Area Pumping Plants	
Wheeler Ridge Pumping Plant	22.5
Wind Gap Pumping Plant	15.9
Total	38.4

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Load forecast

Loads within the Kern area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 4-44 shows loads modeled for neighboring local areas in PG&E system in the Kern area assessment as well.

Table 4-44: Summer Peak Load Forecasts modeled in Kern area assessment

	MW Load Forecast										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Humboldt	131	132	134	136	138	140	142	144	145	147	149
North Coast	715	726	737	750	762	774	786	797	809	821	832
North Valley	840	852	866	882	900	915	929	944	958	972	986
Sacramento	1,009	1,021	1,033	1,047	1,059	1,071	1,084	1,097	1,109	1,121	1,134
Sierra	1,198	1,231	1,264	1,301	1,340	1,374	1,408	1,443	1,477	1,511	1,544
North Bay	642	649	656	664	672	681	689	698	706	714	722
East Bay	836	841	847	854	861	867	873	880	886	892	898
Diablo	1,591	1,608	1,625	1,646	1,666	1,685	1,703	1,722	1,740	1,758	1,776
San Francisco	855	862	870	879	887	896	904	913	922	930	939
Peninsula	866	880	890	899	907	919	931	943	954	966	978
Stockton	1,336	1,354	1,375	1,399	1,422	1,446	1,468	1,491	1,514	1,536	1,558
Stanislaus	225	232	237	242	248	253	258	263	268	273	278
Yosemite	913	925	938	951	964	977	990	1,004	1,017	1,031	1,044
Fresno	2,280	2,311	2,343	2,379	2,416	2,448	2,480	2,512	2,544	2,575	2,606
Kern	1,548	1,571	1,595	1,620	1,647	**1,672**	1,696	1,721	1,745	1,769	**1,793**
Mission	1,253	1,265	1,276	1,289	1,301	1,314	1,327	1,340	1,353	1,366	1,378
De Anza	875	883	891	900	910	920	930	940	950	960	969
San Jose	1,601	1,620	1,639	1,655	1,671	1,692	1,711	1,731	1,752	1,771	1,791
Central Coast	700	713	723	733	743	751	759	767	775	782	790
Los Padres	504	512	520	530	539	548	557	566	574	583	592
Total	19,918	20,188	20,459	20,758	21,054	21,343	21,626	21,913	22,199	22,478	22,757

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4.5.7.2 Study results and discussions

In this section, study results and proposed mitigation plans for the Kern area under each category of the planning standards are shown below.

TPL 001-System Performance Under Normal Conditions

Study results show the Arco-Twisselman 70 kV line and the Arco 230/70 kV Bank #2 can be overloaded during normal conditions. Table 4-45 provides the summary of these overloads.

TPL 002-System Performance Following Loss of a Single BES Element

There were two overloads caused by two contingencies that did not meet Category C performance requirements. Table 4-45 documents the worst overloads for the summer peak conditions and ISO-proposed solutions to mitigate these criteria violations.

TPL 003-System Performance Following Loss of Two or More BES Elements

There is 3 overload caused by 1 contingency that do not meet Category C performance. This overload is shown in Table 4-45.

Table 4-45: Worst line/Equipment Overload Summaries for Summer Peak Load Conditions

Overloaded Transmission Equipment	Worst system contingency	Category	Loading		Proposed Solutions
			2013	2018	
Arco – Twisselman 70kV Line	Base Case	A	100%	101%	Re-rate of reconductor or explore switching options
Arco 230/70kV Bank#2	Base Case	A	-	101%	Upgrade or Reinforce the bank
Kern Power 115/70kV Bank#1	Kern 115/70kV Bank #2	B	107%	119%	Upgrade or Reinforce the banks
Midway – Temblor 115kV Line	Kernridge gen	B	114%	-	Re-rate or reconductor or explore switching options
Kern – Magunden – Witco 115kV Line	Kern – Westpark #1 and #2 115kV Lines	C	-	111%	Re-rate or reconductor or explore switching options

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4.5.7.3 Recommended solutions for reliability criteria violations

Thermal overload mitigations

- **Arco – Twisselman 70 kV line**

  Base case overload is observed on Arco – Twisselman 70 kV line in 2013 and 2019. The recommendation is re-rating or reconductoring the Aco – Twisselman 70 kV line or exploring switching solutions.

- **Arco 230/70 kV Bank#2**

  This overload on Acro 230/70 kV Bank#2 was observed in the base case for 2019. The recommendation is to upgrade or reinforce the bank capacity.

- **Kern – Magunden-Witco 115 kV line**

  This overload was identified in the 2018 summer peak conditions caused by the outage of Kern – Westpark #1 and #2 115 kV lines. (Category C). The recommendation is to re-rate or reconductor the Kern – Magunden-Witco 115 kV line or explore switching solutions.

- **Kern Power 115/70 kV Bank#1**

  This overload was identified in the 2013 and 2018 summer peak conditions caused by the outage of Kern Power 115/70 kV Bank#1. (Category B). The recommendation is to upgrade or reinforce the bank capacity.

- **Midway – Temblor 115 kV line**

  This overload was identified in the 2013 summer peak conditions caused by the outage of Kernridge generation. (Category B). The recommendation is to reconductor or re-rates the line. Investigate generation dispatch pattern.

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4.5.7.4 Key conclusions

Based on the ISO assessment, the Kern area has:

- Two overloads under normal conditions,
- Two overloads caused by two critical single contingency conditions,
- One overload caused by one critical multiple contingency

Among those studied, there were no extreme contingency conditions with potential voltage collapse,

In order to address all these concerns ISO has proposed five transmission solutions.

During the 2008 Open Request Window the ISO received seven project proposals:

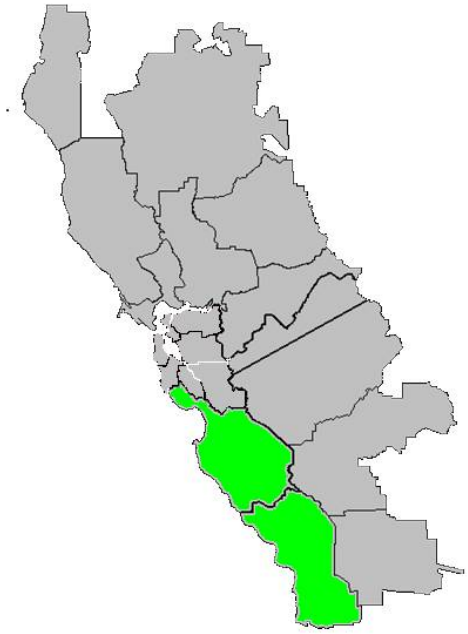
- Two have been approved,
- Five are on-going project (i.e., to be considered for approval at a later date).

Only one of the above projects matched two of the ISO proposed solutions. The remaining three ISO proposed solutions are under further investigation. This gives a total of seven projects in the 2009 ISO transmission plan for the Kern area.

4.5.8 Central Coast and Los Padres area

The Central Coast Area is located south of Bay Area and extends along the Central Coast from Santa Cruz to King City. The Central Coast transmission system serves the Santa Cruz, Monterey and San Benito counties. A figure below depicts the geographical location of Central Coast and Los Padres area.

Central Coast Area electric transmission system is comprised of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. Central Coast's transmission system is tied to the San Jose and De Anza systems in the north, and the Greater Fresno system in the east.



The Los Padres Division is located in the southwestern portion of PG&E's service territory (south of Central Coast Division). San Luis Obispo, Santa Maria, Paso Robles and Atascadero are among the cities PG&E provides electric service to within this Division. The City of Lompoc, a member of NCPA is also located here. Counties in the area include San Luis Obispo and Santa Barbara. Diablo Canyon Nuclear Power Plant is also located in Los-Padres. Most of the power generated from Diablo Canyon Power Plants is exported to the north and the east through bulk 230 kV and 500 kV transmission lines hence it has very little impact on the Los Padres area operation. There are several transmission ties to the Fresno and Kern systems, with the majority of these interconnections made at Gates and Midway substations. Local customer demand is served through a network of 115 kV and 70 kV circuits.

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Load forecasts indicate that the Central Coast and Los Padres areas should reach its summer peak demand of 751 MW and 548 MW by 2013 respectively. By 2018 the loading for these 2 areas would be 790 MW and 592 MW respectively. Load is increasing at a rate of 9 to 10 MW per year (MW/year). Accordingly, system assessments in this area include the technical studies for the scenarios under these load assumptions for summer-peak peak conditions

4.5.9.1 Area-specific assumptions and system conditions

The Central Coast and Los Padres area study was performed consistent with the general study methodology and assumptions that are described in sections 2.4. The ISO secured website lists the contingencies that were studied as part of this assessment. Additionally, specific methodology and assumptions that were applicable to the Central Coast and Los Padres area study are provided below.

Generation

Generation resources in Central Coast and Los Padres area consist of market, QF and self-generating units. Table 4-46 lists all generating plants in Central Coast and Los Padres area and modeled parameters for the 2013 and 2018 Peak Analysis respectively.

Table 4-46: Generator in Central Coast and Los Padres Area

Plant Name	Max Capacity (MW)
King City Energy Cogen	60.5
Soledad Energy	16
Moss Landing PP	2600
CIC	28.5
Sargent Canyon	49.6
Salinas River	49.6
Basic Energy	120
Vandenberg Air Force Base	15
Morro Bay PP	1014
Santa Maria Cogen	8
Union Oil	5.6
City of Lompoc	119
Generation Total	**4086**

Load forecast

Loads within the Central Coast and Los Padres area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 4-47 shows loads modeled for neighboring local areas in PG&E system in the Central Coast and Los Padres area assessment as well.

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Table 4-47: Summer Peak Load Forecasts modeled in Central Coast and Los Padres assessment

	MW Load Forecast										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Humboldt	131	132	134	136	138	140	142	144	145	147	149
North Coast	715	726	737	750	762	774	786	797	809	821	832
North Valley	840	852	866	882	900	915	929	944	958	972	986
Sacramento	1,009	1,021	1,033	1,047	1,059	1,071	1,084	1,097	1,109	1,121	1,134
Sierra	1,198	1,231	1,264	1,301	1,340	1,374	1,408	1,443	1,477	1,511	1,544
North Bay	642	649	656	664	672	681	689	698	706	714	722
East Bay	836	841	847	854	861	867	873	880	886	892	898
Diablo	1,591	1,608	1,625	1,646	1,666	1,685	1,703	1,722	1,740	1,758	1,776
San Francisco	855	862	870	879	887	896	904	913	922	930	939
Peninsula	866	880	890	899	907	919	931	943	954	966	978
Stockton	1,336	1,354	1,375	1,399	1,422	1,446	1,468	1,491	1,514	1,536	1,558
Stanislaus	225	232	237	242	248	253	258	263	268	273	278
Yosemite	913	925	938	951	964	977	990	1,004	1,017	1,031	1,044
Fresno	2,280	2,311	2,343	2,379	2,416	2,448	2,480	2,512	2,544	2,575	2,606
Kern	1,548	1,571	1,595	1,620	1,647	1,672	1,696	1,721	1,745	1,769	1,793
Mission	1,253	1,265	1,276	1,289	1,301	1,314	1,327	1,340	1,353	1,366	1,378
De Anza	875	883	891	900	910	920	930	940	950	960	969
San Jose	1,601	1,620	1,639	1,655	1,671	1,692	1,711	1,731	1,752	1,771	1,791
Central Coast	**700**	713	723	733	743	**751**	759	767	775	782	**790**
Los Padres	**504**	512	520	530	539	**548**	557	566	574	583	**592**
Total	19,918	20,188	20,459	20,758	21,054	21,343	21,626	21,913	22,199	22,478	22,757

4.5.9.2 Study results and discussions

For all study scenarios, the studies were performed under normal and emergency conditions. Under system normal conditions, the base cases were evaluated to facilities with normal overloads. In addition, the contingency analysis were performed to identify overloads under single contingency (N-1) and double contingency (N-2) conditions.

TPL 001-System Performance Under Normal Conditions:

For all summer peak cases, there is no overload or voltage violation under Category A and Category B performance requirement.

Emergency Conditions (TPL 002 – TPL 004):

There are six overloads caused by six contingencies that did not meet Category C performance. Table 4-48 documents the worst overloads for the summer peak conditions and ISO-proposed solutions to mitigate these criteria violations.

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Table 4-48: Worst line/equipment overload summaries for summer peak load conditions

Overloaded Transmission Equipment	Worst system contingency	Category	Loading		Proposed Solutions
			2013	2018	
Moss Landing – Salinas – Soledad #1	Moss Landing _ Salinas #1 and #2 115kV Lines	C	154%	170%	Upgrade the line sections near Natividad Sw. St.
Moss Landing – Salinas – Soledad #2	Moss Landing _ Salinas #1 and #2 115kV Lines	C	155%	171%	Upgrade the line sections near Natividad Sw. St.
Atascadero – San Louis Obispo 70kV Line	Morro Bay – Gates #2 230kV and Morro Bay – Templeton 230kV Lines	C	-	107%	Reconductor or explore switching options
San Luis Obispo – Santa Maria 115kV Line	Mesa – Santa Maria and Santa Maria – Sisquoc 115kV Lines + Load transfer from Fairway to Santa Maria	C	-	125%	Reconductor or re-rate
Mesa – Sisqouc 115kV Line	Mesa – Santa Maria and San Luis Obispo – Santa Maria 115kV Lines + Load transfer from Fairway to Santa Maria	C	-	121%	Reconductor or re-rate
Santa Maria – Sisquoc 115kV Line	Mesa – Santa Maria and San Luis Obispo – Santa Maria 115kV Lines + Load transfer from Fairway to Santa Maria	C	-	137%	Reconducto or re-rate

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4.5.9.3 Recommended solutions for reliability criteria violations

The following are proposed solutions for the identified criteria violations

Thermal Overload Mitigations

- **Moss Landing – Salinas – Soledad #1 115 kV line**
- **Moss Langing – Salinas – Soledad #2 115 kV line**

  These overloads on line sections near Natividad Switching Station were observed for Category C contingency of Moss Landing – Salinas #1 and #2 115 kV lines. The recommendation is to rerate or reconductor Crazy Horse – Natividad – Salinas sections.

- **Atascadero – San Louis Obispo 70 kV line**

  This overload was identified in the 2018 summer peak conditions caused by the outage of Morro Bay – Gates #2 and Morro Bay – Templeton 230 kV lines. (Category C). The recommendation if to reconductor or re-rate the line or explore switching options to mitigate the overload.

- **San Luis Obispo – Santa Maria 115 kV line**

  This overload was identified in the 2018 summer peak conditions caused by the outage of Mesa – Santa Maria and Santa Maria – Sisquoc 115 kV lines. (Category C). The recommendation is to reconductor or re-rates the line.

- **Mesa-Sisquoc 115 kV line**

  This overload was identified in the 2018 summer peak conditions caused by the outage of Mesa – Santa Maria and San Luis Obispo-Santa Maria 115 kV lines. (Category C). The recommendation is to reconductor or re-rates the line.

- **Santa Maria-Sisquoc 115 kV line**

  This overload was identified in the 2018 summer peak conditions caused by the outage of Mesa – Santa Maria and San Luis Obispo-Santa Maria 115 kV lines. (Category C). The recommendation is to reconductor or re-rates the line.

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4.5.9.4 Key conclusions

Based on the ISO assessment Central Coast and Los Padres area has:

- Six overloads caused by five critical multiple contingency conditions,
- Among those studied, there were no extreme contingency conditions with potential voltage collapse,

In order to address all the concerns ISO has proposed five transmission projects.

During the 2008 Open Request Window the ISO received twelve (12) project proposals:

- Four were approved,
- Eight are on-going project (i.e., to be considered for approval at a later date)

Only one of these projects matched one ISO proposed solution. The remaining four ISO proposed solutions are under further investigation due to RAS modeling issues.

This gives a total of 12 projects in the 2009 ISO transmission plan for the Central Coast and Los Padres areas.

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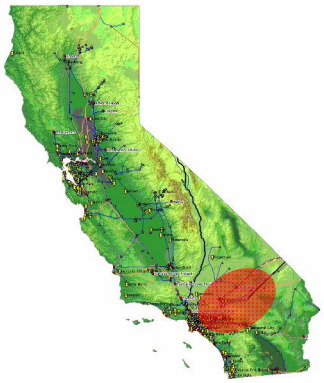
Chapter 5 – SCE Service Area Reliability Assessment

Southern California Edison (SCE) serves over 13 Million people in a 50,000 sq. mile area of central, coastal and southern California, excluding the city of Los Angeles, and certain other cities. In 2008, the SCE system load peaked at 22,405 MW on June 20. The transmission system consists of 500 kV and 230 kV transmission facilities. Most of the SCE load is located within the Los Angeles Basin, however the highest load growth occurs in the Inland Empire area. The SCE service area is shown in map on the left. The California Energy Commission (CEC)'s load forecast for the entire SCE and Inland Empire area are 400 MW per year and 180 MW per year respoectively.



The CEC's 1-in-10 heat wave load forecast includes the SCE service area, Pasadena Water and Power Department and the California Department of Water Resources pump load. The 2013 and 2018 summer peak forecast loads are 28,039 MW and 30,042 MW respectively. Most of the SCE area load is served by local generation that includes nuclear, QFs, hydro, and oil/gas-fired power plants. The remaining demand is served by power transfers into Southern California on AC and DC transmission lines from the Pacific Northwest and Desert Southwest.

Consistent with the ISO planning assumptions outlined in its tariff, the performance of the SCE main 500 kV and 230 kV transmission system under the 2009 through 2018 heavy summer conditions was evaluated using applicable reliability criteria as outlined in Chapter 3.

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5.1 General Assessment Summary

The following transmission upgrades were identified by the ISO as needed to maintain NERC and WECC Reliability Criteria in the SCE service area. Further details are provided in sections 5.5 and 5.6.

5.1.1 2013 SCE transmission system assessment summary

The following recommended solutions are based on the ISO 2013 studies:

- Upgrade Barre–Ellis 230 kV line terminal equipment,
- Relieve loading on the Antelope 230/66 kV Transformer Bank,
- Upgrade Chino–Mira Loma 230 kV Line No. 3,
- Install reactive support for Big Creek area,
- Increase load serving capability to Valley Substation,
- Optimize dynamic and static reactive support to the Tehachapi Transmission Project.

5.1.2. 2018 SCE transmission system assessment summary

- Relieve Antelope–Bailey 66 kV loading concerns,
- Upgrade Chino–Mira Loma 230 kV lines Nos. 2 & 3,

- Upgrade Redondo–La Fresa 230 kV line.

Table 5-1 provides a list of on-going projects or study requests that will be further evaluated.

Table 5-1: List of on-going projects or study requests that require further evaluation.

Project No.	Name of Proposed Project*	Project Sponsor*	Description of Proposed Project	Project Category	Proposed On-Line Date
1	Antelope – Bailey – Windhub System Re-configuration	SCE	Place 4th transformer in service; split Antelope 66kV bus; re-arrange 66-kV transmission lines	Reliability	Dec. 2011
2	Cal Cement Interim Solution	TTS	Project Proponent wants to propose service contract/lease option for connecting SVC at 66kV subtransmission system in the Tehachapi Area	Reliability	Nov. 2010
3	Alberhill 500./115kV Substation	SCE	Connect new substation to the existing Valley – Serrano 500kV line	Reliability	June 2012
4	West of Devers 230kV Lines Rebuild	SCE	Rebuild existing 4-230kV lines to mitigate NERC reliability and resolve the Right of Way issue with the Morongo Indian	Reliability	June 2012
5	Construct new transmission to connect new renewable generation in the Ivanpah area	SCE	-Construct new 230/115kV substation -Construct new double circuit 230kV line	Transmission for connecting new renewable generation	July 2013

5.2 Transmission System Description

In general, the SCE transmission system includes 500 kV and 230 kV facilities, with small pockets of 115 kV and 66 kV network transmission in the Devers-Mirage and Tehachapi areas, respectively. The bulk 500 kV and 230 kV transmission systems include the following:

- WECC Path 26 (Midway–Vincent 500 kV lines) linking PG&E and SCE transmission systems,
- Various 500 kV lines which are part of WECC Path 49 (East of River) and Path 46 (West of River) linking Southern California to Arizona and Southern Nevada,
- Major 500 kV Substations: Vincent, Lugo, Mira Loma, Rancho Vista, Serrano, Devers and Valley,
- 230 kV transmission network in the Los Angeles Basin, Big Creek and West of Devers areas.

5.3 Study Assumptions and System Conditions

The SCE area study was performed consistent with the general study methodology and

assumptions described in section 3.4. The ISO secured website lists the contingencies that were performed as part of this assessment. In additional, specific assumptions and methodology applied to the SCE area study are provided below.

5.3.1 Generation

Table 5-2 lists the major generation plants in the SCE area.

Generation Plants	Max. Capacity (MW)
Alamitos	1950
Big Creek Hydro	1020
El Segundo	670
Long Beach	260
Mohave[1]	1580
Mountain Vista	640
Mandalay	430
Ormond Beach	1500
Redondo Beach	1280
Cool Water	628
Pastoria	750
Mountain View	1072
IEEC	810
San Onofre Nuclear Generating Station (SONGS)	2150 MW (SCE's Share = 1720 MW)

[1] Per SCE, there are on-going efforts to bring the plant back in-service in the future with full compliance of environmental mandates.

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5.3.2 Load forecast

The ISO base case assumes the CEC's 1-in-10 year heat wave load forecast for SCE. This forecast load includes system losses. The CEC's 1-in-10 year heat wave load forecast for SCE, Pasadena Water and Power Department and California Department of Water Resources pump load is 28,039 MW and 30,042 MW for summer 2013 and 2018 respectively.

Table 5-3 provides a summary of the load, losses, generation and imports modeled in the power flow base cases for 2013 and 2018. Two base cases were used for each study year (1) the dispatch of all thermal and hydro units, and (2) the loss of the largest generating unit (SONGS). System readjustment was performed for the base case with the largest generating unit out-of-service. Case 1 was utilized for performing double element contingencies (N-2) and beyond, while case 2 was utilized for assessment of single element contingencies (N-1).

The power flow base case assumptions are consistent with the ISO Grid Planning Standards. The loads for external systems were maintained from the WECC 2018 HS1A (posted June 12, 2008) and WECC 2012 HS2A (posted November 14, 2007). These base cases were utilized as

starting power flow cases, with transmission, generation and load updated for the ISO Balancing Authority Area.

Table 5-3: Summer peak load forecasts modeled in the SCE area assessment

	Conforming Load (MW)	Pump Load (MW)	Losses (MW)	Imports (MW)
2013 Heavy Summer				
All Generation In Service	26759	723	515	6742
G-1 SONGS,System Readjusted	26759	723	553	7871
2018 Heavy Summer				
All Generation In Service	28732	723	570	7965
G-1 SONGS,System Readjusted	28732	723	517	9089

5.3.3 Power factor

In SCE area assessment an active to reactive power (MW/MVAr) ratio of 25 to 1 or a power factor of 0.999 measured at the high side of the A-Bank (230/115 kV or 230/66 kV) was assumed for the SCE transmission substation loads. The value of this ratio recorded during the annual peak loads for the last six years ranges from 12.2 in 2000 to 38.0 in 2005.

The increase in the MW/MVAr ratio was the result of SCE's commitment to its program to optimize reactive power planning and capacitor bank availability during heavy summer peak load periods in its distribution and sub-transmission systems. The objective of the SCE's reactive power program was to ensure a MW/MVAr ratio of 25 to 1. Table 5-4 shows the MW to MVAr ratio recorded for the SCE transmission substation loads during the annual peak loads for the last five years.

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Table 5-4:Active to reactive (MW/MVAr) power ratios recorded for SCE transmission substation loads during annual non-coincidental peak loads. Inserted by CMB to replace the bulleted format-to be discussed and filled in

Year of peak substation load	MW/MVAr (-)
2008	42
2007	52
2006	28.9
2005	38
2004	Leading power factor

5.4 Study Results and Discussions

Based on the reliability assessment performed for 2013 and 2018, the ISO identified the need to:

- Upgrade the 230 kV lines in the LA Basin,
- Relieve overloading concerns on existing sub-transmission facilities in the Tehachapi area due to load growth,

- Increase load serving capability to areas served by Valley substation,
- Provide additional reactive support in the Big Creek area to maintain the WECC reliability criteria,
- Optimize the mixture of dynamic and static reactive support as part of the Tehachapi Transmission Project for delivery of up to 4,500 MW of generation (approximately 4,200 MW of wind resources). Refer to Chapter 9 for more details.

Tables 5-5 and 5-6 provide further details on the ISO identified reliability concerns for the 2013 and 2018 summer peak assessments. Table 5-7 provides further details on transient stability analyses for the bulk transmission system and the Big Creek area. Further details on recommended mitigation measures are listed in Section 5.5.

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5.4.1 Power flow analyses

Table 5-5: Facility overloads for 2013 base case, G-1(one SONGS)/N-1, and N-2 contingencies

Overloaded Transmission Equipment	Worst system contingency	Category	2013 Loading (%)
Antelope 230/66 kV Bank #2	Base Case	A	101%
Antelope 230/66 kV Bank #4	Base Case	A	100%
Barre-Ellis 230 kV Line #1	Hassayampa - N.Gila 500 kV Line #1	B	121%
	Imperial Valley - N.Gila 500 kV Line #1	B	115%
	Imperial Valley- Miguel 500 kV Line #1	B	102%
	S.Onofre- Santago #1 & S.Onofre-Santiago 230 kV #2	C	111%
Chino - Mira Loma 230 kV Line #3	Chino - Mira Loma 230 kV Line #2	B	112%
	Hassayampa - N.Gila 500 kV Line #1	B	111%
	Imperial Valley - N.Gila 500 kV Line #1	B	107%
Valley500/115 kV Bank #1	Valley500/115 kV Bank #2	B	124%
Valley500/115 kV Bank #2	Valley500/115 kV Bank #1	B	123%
Valley500/115 kV Bank #3	Valley500/115 kV Bank #4	B	121%
Valley500/115 kV Bank #4	Valley500/115 kV Bank #3	B	121%
Valley500/115 kV Bank #1	Base Case	A	106
Valley500/115 kV Bank #2	Base Case	A	106
Valley500/115 kV Bank #3	Base Case	A	105
Valley500/115 kV Bank #4	Base Case	A	105
Antelope 230/66 kV Bank #1	Base Case	A	122
Antelope 230/66 kV Bank #2	Base Case	A	126
Antelope 230/66 kV Bank #4	Base Case	A	125
Del Sur - Antelope 66 kV Line #1	Base Case	A	122
Oasis SC - Tap 68 66 kV Line#1	Base Case	A	107
Tap 60 - Helijet 66 kV Line#1	Base Case	A	118
Barre-Ellis 230 kV Line #1	Hassayampa - N.Gila 500 kV Line #1	B	119
	Imperial Valley - N.Gila 500 kV Line #1	B	117
	S.Onofre - Santiago 230 kV #1 and S.Onefre - Santiago 230 kV #2	C	100

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Table 5-6: Facility overloads for 2018 for base case, G-1(1 SONGS)/N-1, and N-2 contingencies

Overloaded Transmission Equipment	Worst system contingency	Category	2013 Loading (%)
Chino - Mira Loma 230 kV Line #2	Chino - Mira Loma 230 kV Line #3	B	118
	Chino - Mira Loma 230 kV Line #1 and Chino - Mira Loma 230 kV Line #3	C	115
Chino - Mira Loma 230 kV Line #3	Chino - Mira Loma 230 kV Line #2	B	132
	Hassayampa - N.Gila 500 kV Line #1	B	123
	Imperial Valley - N.Gila 500 kV Line #1	B	122
	Mira Loma 500/230 kV Bank #1	B	110
	Mira Loma 500/230 kV Bank #2	B	109
	Mira Loma - Olinda 230 kV #1	B	103
	Rancho Vista - Serrano 500 kV #1	B	100
	Chino - Mira Loma 230 kV Line #1 and Chino - Mira Loma 230 kV Line #2	C	120
	Mira Loma - Walnut 230 kV #1 and Chino - Mira Loma 230 kV #2		111
	Mira Loma - Wilderness 230 kV #1 and Chino - Mira Loma 230 kV #2	C	109
	Mira Loma - Serano 500 kV #1 and Redondo - Lithhipe 230 kV #1	C	102
Redondo - La Fresa 230 kV #1	La Fresa - Redondo 230 kV #1 and Redondo - Lithhipe 230 kV #1	C	109
	La Fresa - Redondo 230 kV #1 and La Fresa - Hinson 230 kV #1	C	104
	La Fresa - Redondo 230 kV #1 and Redondo - Mesa 230 kV #1	C	102
Redondo - La Fresa 230 kV #2	La Fresa - Redondo 230 kV #1 and Redondo - Lithhipe 230 kV #1	C	109
	La Fresa - Redondo 230 kV #1 and La Fresa - Hinson 230 kV #1	C	104
	La Fresa - Redondo 230 kV #1 and Redondo - Mesa 230 kV #1	C	102
Neenach - Antelope 66 kV #1	Pardee - Bailey 230 kV #1 and Bailey - Pastoria 230 kV #1	C	122

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5.4.2 Transient stability analyses for 2013 and 2018

Transient stability studies of the Bulk 500 kV and 230 kV system were performed using the list of contingencies (switching file) in Table 5-7.

Table 5-7: Transient stability analyses and study results

Switching File	Voltage Violations	Frequency Violations
No-fault	No Violations	No Violations
G-1: Palo Verde Unit # 2	No Violations	No Violations
N-1: Palo Verde – Devers 500kV Line	No Violations	No Violations
G-1: SONGS Unit # 3	No Violations	No Violations
N-2: Double Line Outage on Eldorado – Lugo & Mohave – Lugo 500kV Lines	No Violations	No Violations
N-2: Double Line Outage on Lugo South (Lugo – Mira Loma # 2 & 3 500kV Lines)	No Violations	No Violations
N-2: Double Line Outage on Lugo – Vincent 500kV Lines	No Violations	No Violations
Lugo Substation Category D (Lugo 500/230kV Transformers and Six 230kV Lines)	Unstable *(Further evaluation will be performed to determine effective mitigation plan for next steps. NERC Standards only requires evaluation to identify risk and consequences at this time)*	Unstable *(Further evaluation will be performed to determine effective mitigation plan for next steps. NERC Standards only requires evaluation to identify risk and consequences at this time)*
N-2: Midway-Vincent #1 & 2 500kV Double Line Outage	No Violations	No Violations
N-2: Pacific DC Intertie (PDCI) Bi-polar Outage	No Violations	No Violations
T-2: Devers 500/230kV banks	No Violations	No Violations
T-2: MIRALOMA E_500/230kV banks	No Violations	No Violations
T-2: MIRALOMA W 500/230kV banks	No Violations	No Violations
N-2: Vestal – Rector 230kV Lines (No fault), followed by Big Creek generation tripping	No Violations	No Violations
N2: Magunden – Sringville 230kV Lines (No fault), followed by Big Creek generation tripping	No Violations	No Violations
T-2: SERRANO 500/230kV banks	No Violations	No Violations
T-2: Vincent 500/230kV banks	No Violations	No Violations
G-2: PaloVerde Units # 1 & 2	No Violations	No Violations
G-2: SONGS Units # 2 & 3	No Violations	No Violations

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Table 5-7 Transient stability analyses and study results (cont)

Switching File	Voltage Violations	Frequency Violations
N-2: SONGS – Santiago 230kV Lines #1&2	No Violations	No Violations
T-2: Valley 500/115kV banks	**Valley 115kV voltage dips** *(CAISO is considering various options for mitigating thermal constraints on Valley transformers, including a potential new substation to be connected to* ***existing*** *Valley – Serrano 500kV line. This option to relieve loading at Valley Substation would also mitigate this contingency voltage dip concern)*	No Violations

5.4.3 Big Creek transient stability analyses for 2013 and 2018

In addition to the analyses of critical infrastructures listed in Table 5-7, the ISO also evaluated mitigations for identified for Big Creek transient voltage and frequency dip concerns in the 2013 and 2018 studies. The objective was to evaluate the recommended mitigations for its effectiveness for the 2018 summer peak load conditions. The preferred mitigations are listed below for convenience:

Option # 4 requires installation of 100 MVAR SVC at Rector 66 kV bus (or equivalent effective amount if installed on the 230 kV bus), implementation of fast fault clearing and generation tripping (4 cycles). The amount of generation tripping is 397 MW under N-2 contingency condition.

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5.4.4 Transient Stability Analyses

Transient stability studies were performed for the following contingencies:

Table 5-8 Transient stability analyses and study results

Switching File	Voltage Violations	Frequency Violations
No-fault	No Violations	No Violations
N-2: Double Line Outage on El Dorado – Lugo & Mohave – Lugo 500kV Lines	No Violations	No Violations
N-2: Double Line Outage on Lugo South (Lugo – Mira Loma # 2 & 3 500kV Lines)	No Violations	No Violations
N-2: Double Line Outage on Lugo – Vincent 500kV Lines	No Violations	No Violations

Table 5-8 Transient stability analyses and study results (cont)

Switching File	Voltage Violations	Frequency Violations
Lugo Substation Category D (Lugo 500/230kV Transformers and Six 230kV Lines)	Unstable *(Further evaluation will be performed to determine effective mitigation plan for next steps. NERC Standards only requires evaluation to identify risk and consequences at this time)*	Unstable *(Further evaluation will be performed to determine effective mitigation plan for next steps. NERC Standards only requires evaluation to identify risk and consequences at this time)*
N-2: Midway-Vincent #1 & 2 500kV Double Line Outage	No Violations	No Violations
N-2: Pacific DC Intertie (PDCI) Bi-polar Outage	No Violations	No Violations
T-2: Devers 500/230kV banks	No Violations	No Violations
T-2: MIRALOMA E_500/230kV banks	No Violations	No Violations
T-2: MIRALOMA W 500/230kV banks	No Violations	No Violations
N-2: Vestal – Rector 230kV Lines (No fault), followed by Big Creek generation tripping	No Violations	No Violations
N2: Magunden – Sringville 230kV Lines (No fault), followed by Big Creek generation tripping	No Violations	No Violations
T-2: SERRANO 500/230kV banks	No Violations	No Violations
T-2: Valley 500/115kV banks	No Violations	No Violations
T-2: Vincent 500/230kV banks	No Violations	No Violations
G-1: Palo Verde Unit # 2	No Violations	No Violations
G-2: PaloVerde Units # 1 & 2	No Violations	No Violations
N-1: Palo Verde – Devers 500kV Line	No Violations	No Violations
G-1: SONGS Unit # 3	No Violations	No Violations
G-2: SONGS Units # 2 & 3	No Violations	No Violations
N-2: SONGS – Santiago 230kV Lines # 1 & 2	No Violations	No Violations
N-1: Big Creek 3 – Rector 230kV Line #1	**ΔV≥ 25% at Load Bus:** Rector 66 kV Springville 66 kV Stable, Positively Damped	**f ≤ 59.6 Hz for More Than 6 Cycles:** 6.8 Cycles at Rector 66 kV Bus
N-2: Big Creek 3 – Rector 230kV Lines #1 & 2	**ΔV≥ 30%:** All buses north of Magunden Unstable	Unstable

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Based on the results listed in Table 1D-3, the following is the summary of results which exceed the WECC transient stability criteria:

- Rector and Springville loads are subject to transient voltage dip of more than 25% under N-1 contingency conditions
- Rector 66kV bus is subject to transient frequency dip below 59.6 Hz for more than 6 cycles under N-1 contingency conditions
- All buses north of Magunden are subject to transient voltage dip more than 30% under N-2 contingency conditions
- Unstable results under N-2 contingency conditions

Figs. 5-2 and 5-3 show the plots of the Rector 66kV bus's transient voltage response and Big Creek Power House 3 Unit 1 generator angle under a 3-phase to ground fault at Rector 230kV bus, followed by tripping Big Creek – Rector 230kV lines # 1 and 2. This shows unstable response for the Rector 66kV bus voltage and tripping of the Big Creek P.H. 3 Unit 1 generating unit. This is due to the outage on the double line from Big Creek to load center (Rector). The double-line outage reduces the transfer or delivery capability from generation to load center.

Figure 5-2. Transient Stability Plot of Rector 66kV Bus Voltage Under N-2 Contingency Condition (Summer 2013 Peak Load Case)

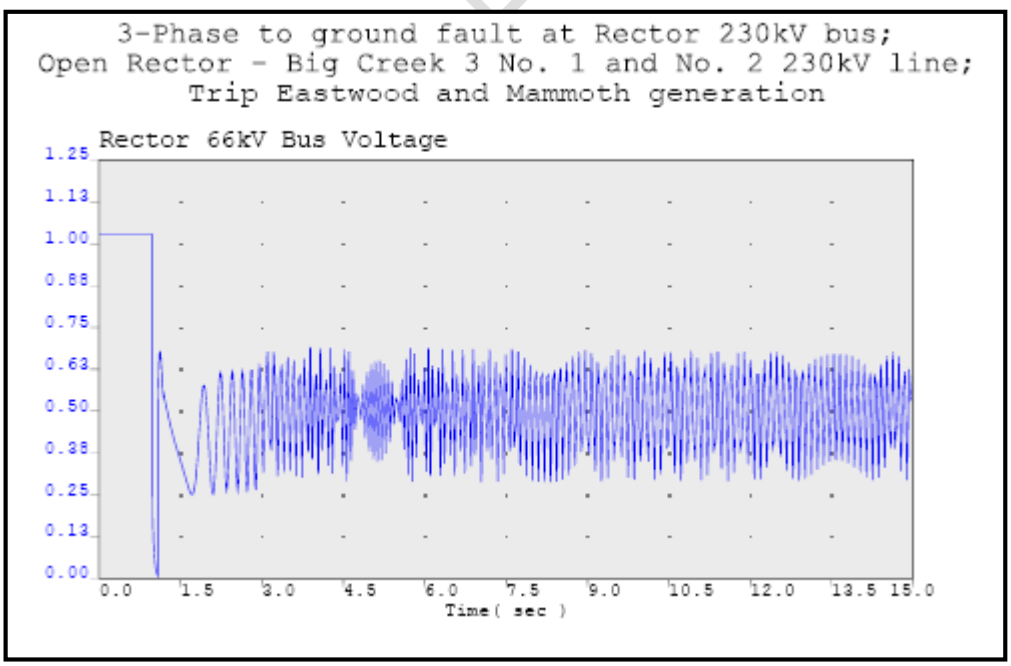
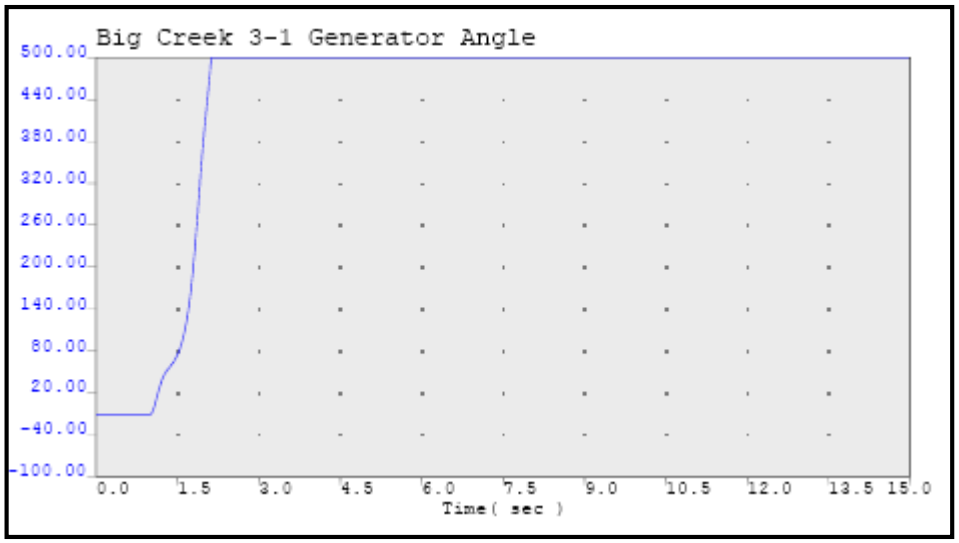


Figure 5-3 Transient Stability Plot of Big Creek P.H. Unit 3 Under the N-2 Contingency Condition (Summer 2013 Peak Load Case)



Preferred Recommending Mitigation: The CAISO evaluated six different options, as summarized in the Table 5-9 below. Of these six options, Option # 4 is the effective solution to mitigate transient voltage dip and frequency concerns. Option # 4 requires installation of 100 MVAR SVC at Rector 66kV bus (or equivalent effective amount if installed on 230kV bus), implementation of fast fault clearing and generation tripping (4 cycles). The amount of generation tripping is 397 MW under N-2 contingency condition. Figures 5-4 and 5-5 show the transient stability plot results with this recommended option. ***Please note that these recommended mitigations will also be evaluated in the Central California Clean Energy Transmission Project (C3ETP) to compare with other options that were proposed previously for the Big Creek Area.***

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Table 5-9. Summary of Evaluated Alternatives for Mitigating Big Creek Transient Voltage and Frequency Dip Concerns

2013hs_sce_v3.sav				
	Big Creek 3 - Rector N-1		Big Creek 3 - Rector N-2	
	Transient Voltage Dip and Damping	Transient Frequency at Load Bus	Transient Voltage Dip and Damping	Transient Frequency at Load Bus
No Mitigation	Max ?V = 38.2% at Rector 66 kV 20% = ?V = 25% for more than 20 cycles	f < 59.6 for 6.8 cycles at Rector 66 kV bus	Unstable	Unstable
1) Fast fault clearing and generation tripping	Max ?V = 22.9% at Rector 66 kV 20% = ?V = 25% for less than 20 cycles	No violation	Max ?V = 31.5% at Rector 66 kV Stable	No violation
2) Increase SVC size to 600MVAR at Rector 230 kV	Max ?V = 20.2% at Rector 66 kV 20% = ?V = 25% for less than 20 cycles	f < 59.6 for 6.8 cycles at Rector 66 kV bus	Max ?V = 28.1% at Rector 66 kV 20% = ?V = 30% for less than 20 cycles; Stable	No violation
3) Install new 100 MVAR SVC at Rector 66 kV	Max ?V = 32.7% at Rector 66 kV	f < 59.6 for 6.8 cycles at Rector 66 kV bus	Unstable	Unstable
4) Install new 100 MVAR SVC at Rector 66 kV and fast fault clearing and generation tripping	Max ?V = 18.4% at Rector 66 kV	No violation	Max ?V = 24.7% at Rector 66 kV; 20% = ?V = 30% for less than 20 cycles; Stable	No violation
5) Install new generator near Rector	Max ?V = 28.5% > 25% at Rector 66 kV	f < 59.6 for 6.8 cycles at Rector 66 kV bus	Max ?V = 32.3% > 30% at Rector 66 kV; Stable	No violation
6) New 500kV line from Rector to Whirlwind	Max ?V = 18.1% < 20% at Rector 66 kV	f < 59.6 for 6.8 cycles at Rector 66 kV bus	Max ?V = 18.9% < 20% at Springville 66 kV; Stable	No violation

Slide 1

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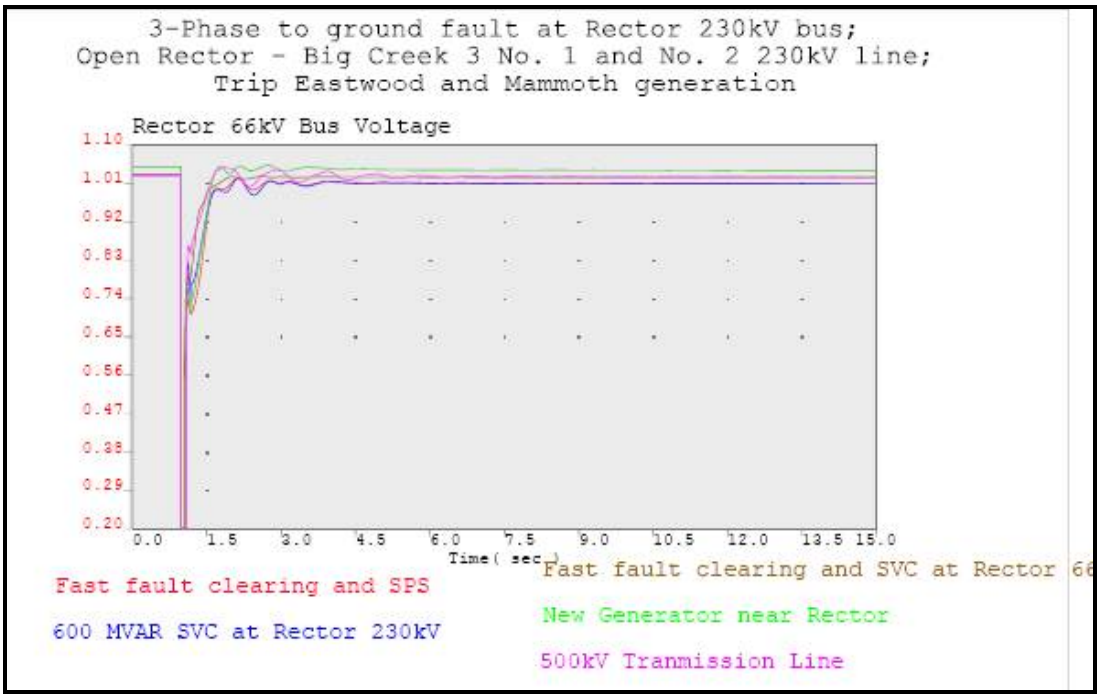

Figure 5-4. Transient Stability Plots for Various Solutions In Mitigating Transient Voltage Dip Concern

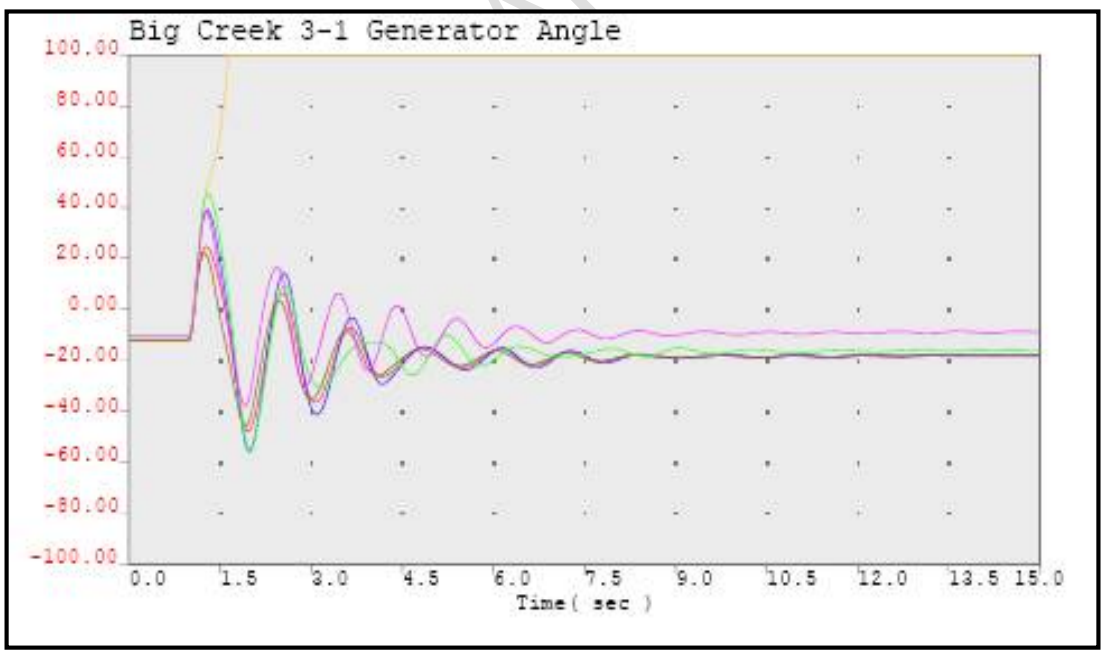

Figure 5-5 Transient Stability Plots of Big Creek P.H. 3 Unit 1 Generator Angle for Various Solutions

5.5 Recommended Solutions for Reliability Criteria Violations

This section describes the study results and proposed mitigation plans for the SCE area under each category of the planning standards.

TPL 001-System Performance Under Normal Conditions

For the 2013 peak load conditions, the following overload concerns were identified:

- **Antelope 230/66 kV Transformer Bank No. 2**

The transformer was slightly overloaded (1% above its normal rating) and Bank No. 4 reached 100% of its normal rating.

Recommendation: Energize the fourth spare transformer bank at Antelope substation. Short circuit evaluation is needed to determine potential impact to the existing circuit breakers at Antelope substation and replace if necessary.

For 2018 peak load conditions, the following overloading concerns were identified:

- **Antelope 230/66 kV Transformer Bank No. 2**

- **Antelope 230/66 kV transformer bank No. 1, 2 and 4 were loaded to 121%, 125% and 124% of its normal rating, respectively.**

Recommendation: Energize the fourth spare transformer bank at Antelope substation. Short circuit evaluation is needed to determine potential impact to the existing circuit breakers at Antelope Substation and replacement if necessary.

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- **Valley Transformer Bank No. 1, 2, 3 and 4**

Valley 500/115 kV Transformer Bank Nos. 1, 2, 3 and 4 were loaded to 106%, 106%, 105% and 105% of its normal rating, respectively.

Recommendation: Evaluate the feasibility and effectiveness of three mitigation options: (a) install a new transformer; (b) replace the existing transformers with larger transformer capacity, and (c) construct a new substation and transfer some existing load to new substation to relieve overloading concerns.

- **Antelope – Bailey 66 kV sub-transmission overloads**

The following 66 kV transmission lines are projected to be overloaded under normal peak load conditions in 2018:

- Del Sur–Antelope 66 kV line, overloaded by 22% over its normal rating,
- Oasis SC–Tap 68 66 kV line, overloaded by 7% over its normal rating,
- Tap 60–Helijet 66 kV line, overloaded by 18% over its normal rating,

Recommendation: Evaluate the feasibility and effectiveness of two mitigation options: (a) line re-conductoring, and (b) sectionalizing Antelope 66 kV bus and re-arranging 66 kV lines,

TPL 002-System Performance Following Loss of a Single BES Element

For 2013 peak load conditions, two overloading concerns were identified which did not meet Category B performance requirement. The following lines were overloaded:

- **Barre-Ellis 230 kV line**

The overloading of the Barre-Ellis 230 kV line is caused by an outage of :

- Hassayampa – North Gila 500 kV line,
- Imperial Valley – North Gila 500 kV line.

Recommendation: Eliminate the ground clearance limitations in order to mitigate this overload concern.

- **Chino–Mira Loma 230 kV line # 3**

The overloading of the Chino–Mira Loma 230 kV line # 3 is caused by the following individual contingencies:

- Chino–Mira Loma 230 kV line # 2,
- Hassayampa–North Gila 500 kV,
- Imperial Valley–North Gila 500 kV.

Recommendation: Increase the emergency rating by re-conductoring. As part of the ISO-approved Tehachapi Transmission Project, the Chino–Mira Loma No. 3 230 kV line will be re-conductored to mitigate the identified overload concern. The ISO recommends that the line be re-conductored with 2-2156 kcmil Al conductor, if feasible. Terminal equipment will also need to be replaced, if necessary, to increase the emergency rating to 3,350 Amps.

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- **Valley 500/115 kV Transformers**

The overloading of the Valley 500/115 kV transformers is caused by the T-1 outage of the parallel transformer bank.

Recommendation: Evaluate for feasibility and effectiveness of three mitigation options: (a) install new additional transformer, (b) replace existing transformers with larger transformer capacity; and (c) construct a new substation and transfer some existing load to the new substation to relieve overloading concerns.

For the 2018 peak load conditions, the following overloading concerns were identified which do not meet Category B performance requirement. Some of these overloading concerns were identified for the 2013 summer peak load case and are exacerbated further under 2018 summer peak load conditions. It is the ISO's goal to implement the proposed mitigation plans to meet NERC/WECC reliability criteria for the 2013 as well as the 2018 summer peak conditions.

- **Barre-Ellis 230 kV line**

The overloading of the Barre-Ellis 230 kV line is caused by an outage of any one of these lines :

- Hassayampa–North Gila 500 kV line
- Imperial Valley–North Gila 500 kV line

Recommendation: Eliminate the ground clearance limitations in order to mitigate the overload

concern.

- **Chino–Mira Loma 230 kV line # 2**

The overloading of the Chino–Mira Loma 230 kV line # 2 was caused by the parallel Chino–Mira Loma 230 kV line #3.

Recommendation: Increase the emergency rating by re-conductoring. As part of the ISO-approved Tehachapi Transmission Project, the Chino–Mira Loma No. 3 230 kV line will be re-conductored to mitigate the identified overloading concern. The ISO recommends that the line be re-conductored with 2-2156 kcmil Al conductor, if feasible. Terminal equipment will also need to be replaced, if necessary, to increase the emergency rating to 3,350 Amps.

- **Chino – Mira Loma 230 kV line # 3**

The overloading of the Chino–Mira Loma 230 kV line # 3 is caused by the respective following N-1 contingencies:

- Chino – Mira Loma 230 kV line # 2
- Hassayampa – North Gila 500 kV line
- Imperial Valley – North Gila 500 kV line
- Mira Loma 500/230 kV Bank No. 1
- Mira Loma 500/230 kV Bank No. 2
- Mira Loma – Olinda 230 kV line
- Rancho Vista – Serrano 500 kV line

Recommendation: Increase the emergency rating by re-conductoring. As part of the ISO-approved Tehachapi Transmission Project, the Chino–Mira Loma No. 3 230 kV line will be re-conductored to mitigate the identified overloading concern. The ISO recommends that the line be re-conductored to 2-2156 kcmil Al conductor, if feasible. Terminal equipment will also need to be replaced, if necessary, to increase the emergency rating to 3350 Amps.

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TPL 003-System Performance Following Loss of Two or More BES Elements

For the 2013 peak load conditions

- **The Barre-Ellis 230 kV line overloaded.The overload was caused by the N-2 contingency of San Onofre–Santiago 230 kV lines # 1 and 2.**

Recommendation: Eliminate the ground clearance limitations in order to mitigate this overload concern.

For the 2018 peak load conditions, the following overload concerns were identified which did not meet Category C performance requirements. Some of these overload concerns were identified for the 2013 summer peak load case, and were exacerbated further under 2018 summer peak load conditions. It is the ISO's goal to implement the proposed mitigation plans to meet the NERC/WECC reliability criteria for the 2013 as well as the 2018 summer peak conditions.

- **Barre-Ellis 230 kV line**

The overloading of the Barre-Ellis 230 kV line is caused by the outage of the San Onofre – Santiago # 1 and # 2 230 kV lines.

Recommendation: This overload was also identified for Category B (single) contingency. Proposed mitigation for eliminating single element contingency overload was also effective for double line contingencies. The proposed mitigation includes the elimination of ground clearance limitations. An N-2 SPS (shedding load at Santiago under an N-2 contingency condition) can also be effective in mitigating this overload. An N-2 SPS is allowed under NERC Planning Standards. The N-2 SPS was already approved by the ISO under Local Capacity Requirements (LCR) studies.

- **Chino–Mira Loma 230 kV line # 2**

The overloading of the Chino–Mira Loma 230 kV line # 2 was also identified due to a Category B contingency (i.e., N-1 of the parallel Chino–Mira Loma 230 kV line #3). This line overload was also caused by the N-2 contingency of the Chino–Serrano 230 kV # 1 and the Chino–Mira Loma 230 kV line # 3.

Recommendation: Increase the emergency rating by re-conductoring. This was also proposed to mitigate the overload identified for the 2013 summer peak conditions. As part of the ISO's approved Tehachapi Transmission Project, the Chino–Mira Loma No. 3 230 kV line will be re-conductored to mitigate the identified overload. The ISO recommends that the line be re-conductored with 2-2156 kcmil Al conductor. Terminal equipment will also need to be replaced, if necessary to increase the emergency rating to 3,350 Amps.

- **Chino–Mira Loma 230 kV line # 3**

The overload of the Chino–Mira Loma 230 kV line # 3 was caused by the following N-2 contingencies:

- Chino – Serrano 230 kV line # 1 and Chino – Mira Loma 230 kV line # 2,
- Mira Loma – Walnut 230 kV line # 1 and Chino – Mira Loma 230 kV line # 2,
- Mira Loma – Wilderness 230 kV line # 1 and Chino – Mira Loma 230 kV line # 2,
- Mira Loma – Serrano 500 kV line # 1 and Rancho Vista – Serrano 500 kV line # 1.

Recommendation: Increase the emergency rating by re-conductoring. This was also proposed to mitigate the overload identified for the 2013 summer peak conditions. As part of the ISO's approved Tehachapi Transmission Project, the Chino–Mira Loma No. 3 230 kV line will be re-conductored to mitigate the identified overload concern. The ISO recommends that the line be re-conductored with 2-2156 kcmil Al conductor. Terminal equipment will also need to be replaced, if necessary, to increase the emergency rating to 3,350 Amps.

- **Redondo–La Fresa 230 kV Line # 1 or # 2**

The overloading of the Redondo–La Fresa 230 kV line # 1 or # 2 was caused by the following N-2 contingencies:

- For Redondo – La Fresa 230 kV Line #1:
- La Fresa–Redondo 230 kV # 1 and Redondo–Lighthipe 230 kV # 1 lines,
- La Fresa–Redondo 230 kV # 2 and La Fresa–Hinson 230 kV # 1,
- La Fresa–Redondo 230 kV # 2 and Redondo–Mesa 230 kV # 1,

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- For Redondo–La Fresa 230 kV Line # 2,
- La Fresa–Redondo 230 kV # 1 and Redondo–Lighthipe 230 kV # 1,
- La Fresa–Redondo 230 kV # 1 and La Fresa–Hinson 230 kV # 1,
- La Fresa–Redondo 230 kV # 1 and Redondo–Mesa 230 kV # 1,

Recommendation: Increase the emergency rating by replacing terminal equipment at La Fresa to achieve higher rating. Replace terminal equipment at La Fresa for similar rating as the terminal equipment at Redondo substation would mitigate the contingency overloading concern (i.e., 3,360 Amps).

- **Antelope–Bailey 66 kV subtransmission system**

The following 66 kV transmission lines were projected to be overloaded under N-2 contingency conditions at peak load in 2018:

- Del Sur–Antelope 66 kV line
- Neenach–Antelope 66 kV line

Recommendation: Evaluate the feasibility and effectiveness of two mitigation options: (a) line re-conductoring, and (b) sectionalizing Antelope 66 kV bus and re-arranging 66 kV lines. These are also mitigation plans proposed for 2013 summer peak load conditions.

TPL 004-System Performance Following Extreme BES Events

A critical Category D contingency that included the loss of Lugo 500/230 kV transformers and all 500 kV transmission lines connected to 500 kV bus in the SCE Area was performed. This contingency is simulated to satisfy NERC Category D-8 (loss of a substation, one voltage level plus transformers) for the Lugo substation. This contingency resulted in the loss of two 500/230 kV transformers and eight 500 kV transmission lines. Both transient stability and post-transient analyses were performed. Transient stability analysis resulted in unstable system performance.

For post-transient analyses, the case diverged indicating voltage instability in the local bulk transmission system within the SCE Area. Although NERC standards only require evaluation and documentation of results for Category D contingency, the ISO will evaluate potential mitigation including load tripping as part of an SPS to determine if this would be an effective solution. This evaluation will be performed in greater details in the transmission planning cycle in 2009.

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5.6 Key Recommendations

Based on the study results for the reliability assessment for 2013 and 2018 summer peak load conditions, as well as the assessment for the dynamic and static reactive support requirements for the Tehachapi Transmission Project (refer to Chapter 9), the ISO has the following recommendations:

5.6.1. Transmission upgrades before summer 2013

- **Barre–Ellis 230 kV Line Upgrade**

Recommendation: Improve the line's emergency rating by eliminating ground clearance constraint, or re-conductor with higher capacity conductor (SSAC conductor) before the 2013 summer peak load conditions. The ISO Staff recommends achieving an emergency rating higher than 3,000

Amps (or 1,133 MVA).

- **Antelope 230/66 kV Transformer Bank Overloading Relief**

Recommendation: Energize 4th spare transformer bank at Antelope Substation, subject to feasibility of upgrades to circuit breakers and other substation equipment to withstand new higher short circuit duty.

- **Chino – Mira Loma 230 kV Line No. 3 Upgrade**

Recommendation: Upgrade this line to have higher emergency rating. This work is part of the Tehachapi Transmission Project, which was approved by the ISO Board of Governors in January 2007.

- **Big Creek Transient Voltage and Frequency Dip Mitigation**

Recommendation: To mitigate the transient voltage and frequency dip concerns, the ISO recommends installation of 100 MVAR SVC at Rector 66 kV Substation, or equivalent effective amount if installed at other nearby bus, and re-setting the fault clearance and associated generation tripping under contingency to 4 cycles.

- **Valley Substation Capacity Increase**

Recommendation: To mitigate the thermal contingency overloading concerns for Valley 500/115 kV transformer banks, the ISO recommends evaluation for feasibility and most effective solution from the three transmission alternatives: (a) install new transformer at Valley Substation; (b) replace existing transformers with higher capacity transformers; (c) construct a new substation to be connected to the existing Serrano – Valley 500 kV line .

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- **Engineering Redesign of Proposed Installation of Dynamic/Static Reactive Support for the Tehachapi Transmission Project**

Recommendation: The ISO, after re-evaluation of the dynamic and static reactive need associated with the Tehachapi Transmission Project, has the following recommendations:

- **Relocate the proposed SVC installation at Vincent Substation and to the new Windhub 500 kV Substation.**

The size of the SVCs at Windhub and Antelope Substation was evaluated to have 300 MVAR and 250 MVAR at Windhub and Antelope Substation, respectively. This represents a saving of 250 MVAR of dynamic reactive support that was determined not needed, and therefore represented a saving of approximately $25 million.

Recommendation: The ISO Staff will work with SCE for final review of the proposed static reactive support at various 500 kV buses to ensure that the Tehachapi transmission system is not overly compensated. Overly compensated system runs the risk of having voltage collapse point (nose point) within operating voltage range.

5.6.2. Transmission upgrades before Summer 2018

- **Antelope – Bailey 66 kV Sub-Transmission Overload Mitigation**

Recommendation: The ISO recommends SCE evaluate the feasibility and effectiveness of these two mitigation options: (a) line re-conductoring; and (b) sectionalizing Antelope 66 kV bus and re-arranging 66 kV lines. These upgrades may be continued from the Valley transformer upgrade as

identified earlier (see A.2 above).

- **Chino– Mira Loma 230 kV Lines Nos. 2 & 3 Upgrades**

Recommendation: Upgrade these lines to have higher emergency rating. This work is part of the Tehachapi Transmission Project, which was approved by the ISO Board of Governors in January 2007.

- **Redondo–La Fresa 230 kV Transmission Lines Upgrade**

Recommendation: Increase the emergency rating of these lines by replacing terminal equipment at La Fresa to achieve higher emergency rating. Replacing terminal equipment at La Fresa for similar rating as the terminal equipment at Redondo Substation would mitigate the contingency overloading concern (i.e., 3,360 Amps).

5.7 Key Conclusions

The ISO proposes a total of 9 upgrades (see Section 5.5 and 5.6) to address identified reliability concerns to meet the ISO Planning Standards for the SCE service area.

In response to the ISO study results and proposed solutions:

- 19 project submissions were received through the 2008 Request Window. These submittals included not only reliability transmission projects, but also other network transmission to connect renewable generation, merchant transmission and competing generation projects (for meeting reliability concerns)

The project statuses after review by the ISO are:

- Seven submitted projects had sufficient information that met the ISO reliability concerns, and are recommended for management approval,
- Two projects are being recommended by the ISO Board of Governors as location constrained resource interconnection facility (LCRIF) projects.
- Ten projects will be further reviewed. Some of these projects will require ISO policy review in regards to renewable network transmission and project leasing options.

The following list of transmission projects are being recommended by the ISO for management approval. For further details, refer to the presentation at the ISO website location http://www.caiso.com/2360/2360f68726230.pdf):

- Barre–Ellis 230 kV line upgrade project,
- Rector static VAR system (SVS) project,
- Redondo–La Fresa 230 kV line upgrade,
- Antelope 66 kV circuit breaker upgrade,
- Bailey 66 kV circuit breaker upgrade,
- Devers 115 kV circuit breaker upgrade,
- Kramer 115 kV circuit breaker upgrade,

The following two LCRIF projects are being recommended by the ISO for the Board of Governors approval in May 2009. For more information, refer to the presentation posted at

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http://www.caiso.com/2360/2360f68726230.pdf)

- Drycreekwind LCRIF project,
- Highwind LCRIF project.

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Chapter 6 – SDG&E Service Area Reliability Assessment

San Diego Gas and Electric (SDG&E) is a subsidiary of Sempra Energy Utilities which is a Fortune 500 energy services holding company based in San Diego. SDG&E is a regulated public utility that provides energy service to 3.4 million consumers through 1.4 million electric meters and more than 830,000 natural gas meters in San Diego and southern Orange counties. The utility's area encompasses 4,100 square miles.

6.1 Bulk System Description

SDG&E's transmission system consists of bulk 500 kV and 230 kV facilities, as well as sub-transmission 138 kV and 69 kV network transmission systems. The bulk transmission includes the Southwest Power Link (SWPL) that connects Arizona to SDG&E, as well as the South of San Onofre (SONGS) 230 kV transmission lines that link SCE and SDG&E. SDG&E is an importing system. The existing points of import are South of SONGS transmission path (Path 44) and the Miguel 500/230 kV Substation. The geographical location of the SDG&E system is shown in Figure 6-1.

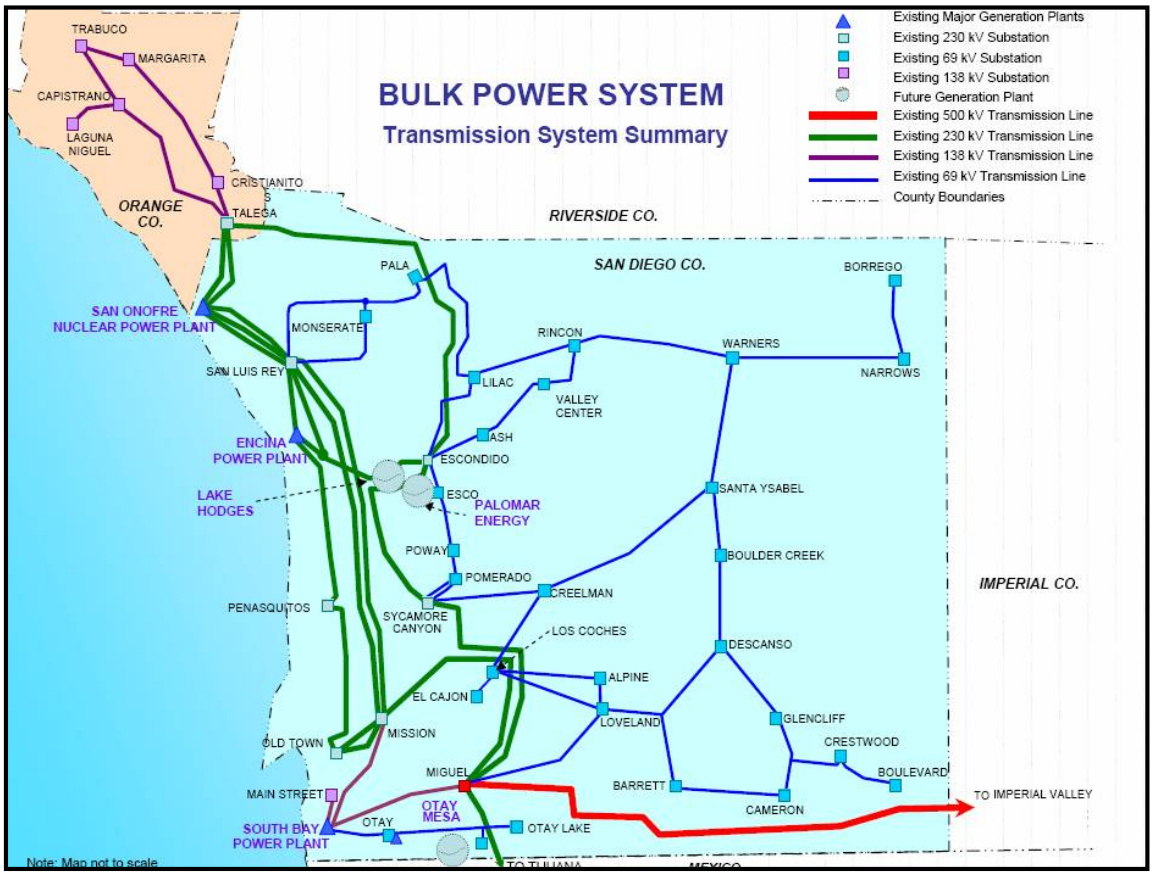

Figure 6-1: SDG&E Transmission System

The SDG&E system import capability is 2,850 MW with all facilities in service and 2,500 MW with SWPL out of service. When the proposed Sunrise Power Link is completed in 2012, the import capability will be increased by at least 1,000 MW and the points of import will change: Imperial Valley-Central 500 kV line flow will be added to the import. Also, with the Otay Mesa Power plant

coming into service, the import point will be moved from the Tijuana-Miguel 230 kV transmission line to the Tijuana-Otay Mesa 230 kV line. Figures 6-2, 6-3 and 6-4 illustrate the present and future SDG&E import cut-planes.

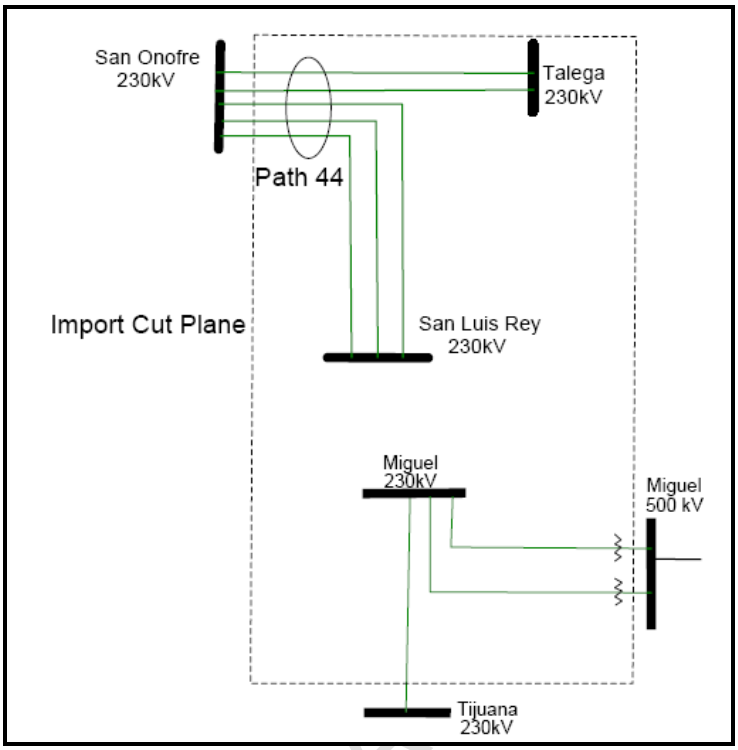

Figure 6-2: Existing SDG&E Import Cut Plane

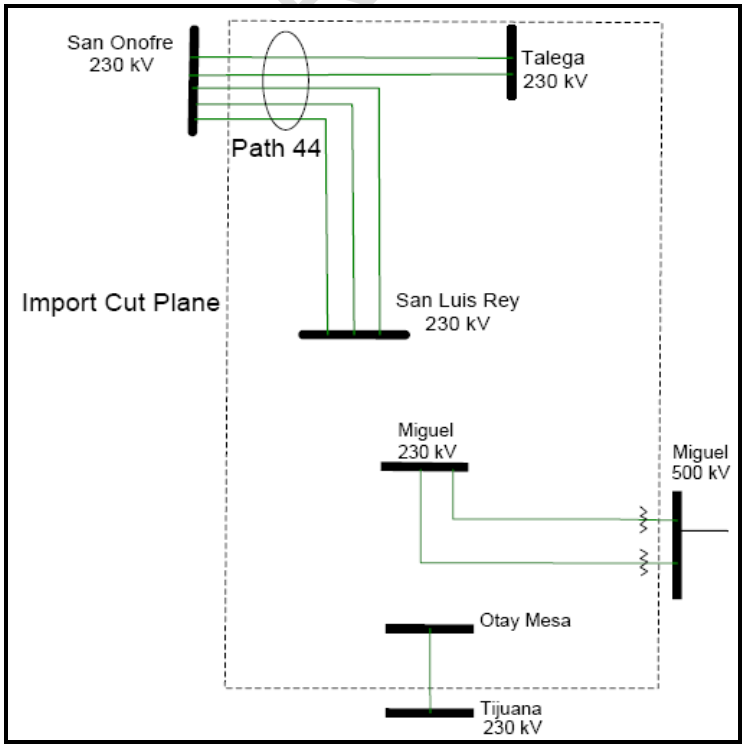

Figure 6-3: SDG&E Import Cut Plane with the Otay Mesa Power Plant

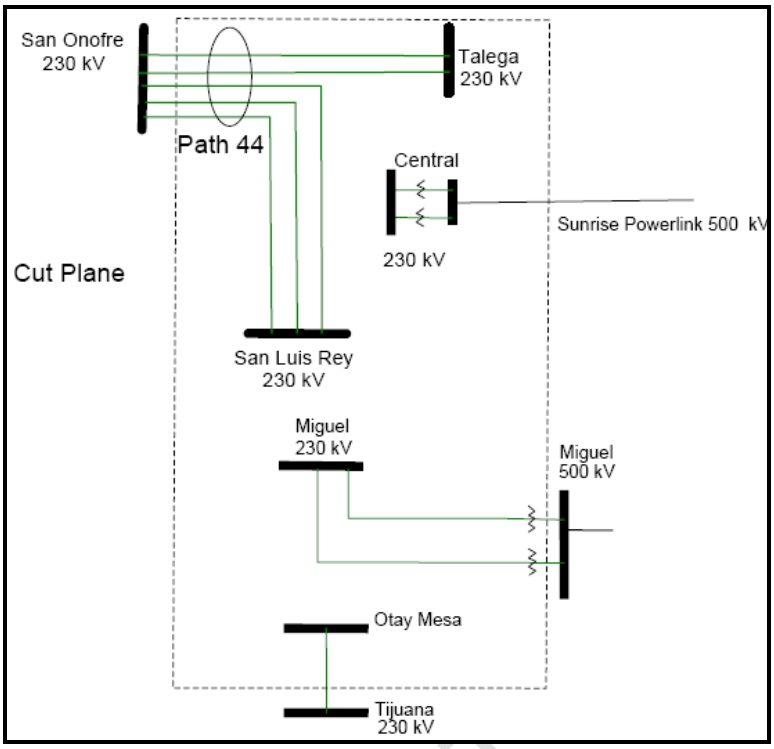

Figure 6-4: SDG&E Import Cut Plane with the Sunrise Power Link

Existing generation within the SDG&E system is comprised of combustion turbines (CT), qualifying facilities (QF), steam turbines (ST), the Palomar Energy combined cycle plant (PEN), and one wind farm. The total capacity of the existing units is based on the Pmax values shown in ISO Generating Procedure G-206. Only generation under construction or with an interconnection agreement was modeled in the Transmission Plan studies.

6.2 Major Transmission Projects

In the SDG&E system, the most significant transmission project modeled in the study period was the proposed 500 kV Sunrise Power Link, which when completed, will be the largest upgrade to the SDG&E's transmission system in over two decades. This project will enhance system reliability in the SDG&E system, provide economic access to the renewable energy needed to comply with the State's Renewable Portfolio Standards, and potentially lower energy costs. The Sunrise Power Link project will also significantly increase the SDG&E's import capability and provide access to needed generation resources to meet load growth. This project received the Certificate of Public Convenience and Necessity (CPCN) from the California Public Utility Commission (CPUC) in December 2008. Tentatively, the operational date is scheduled for summer 2012.

The Sunrise Power Link project was modeled as originally approved by the ISO. The reason for modeling and incorporating the project as approved by the ISO was because at the time the studies were done, it was not apparent which alternative of the project would be approved by the CPUC. However, the final modeling and subsequent inclusion of the Sunrise Power Link will be updated in the studies for the 2010 TP to be consistent with the project alternative approved by the CPUC.

The project alternative modeled in the studies included the following:

Transmission

- A new 100-mile Imperial Valley-Central 500 kV line,
- Two new Central-Sycamore Canyon 230 kV lines,
- A Sycamore Canyon-Penasquitos 230 kV line,
- Reconductoring of the TL639, Sycamore Canyon-Elliott 69 kV line.

Substation

- A new Central 500/230 kV substation,
- Two 500/230 kV transformers at the Central substation,
- Eight 45MVAr 12 kV reactors,
- 240 MVAr Static Var Devices (SVDs) at Central, San Luis Rey, and South Bay substations,
- A third 230/69 kV transformer at San Luis Rey substation

In addition, SDG&E is developing the Orange County long-term expansion plan (Capistrano-Talega Reliability Upgrade) to add a second 230 kV source in the county. This project will potentially address the expected load growth and aging infrastructure as well as improve reliability in the Orange County area. As the Orange County plan is expected to cost more than US $50 Million, it will require the ISO Board of Governor's approval. With the approval of the Orange County expansion plan, projects P061XY (Reconductor TL-13812 Talega-San Mateo) and P00153 (Reconductor TL 13837, Capistrano-Laguna Niguel) could be canceled. SDG&E has already submitted this project to the ISO during the ISO Project Request Window for approval.

Other significant projects in SDG&E include the completion of Miguel-Sycamore Canyon and Miguel-Old Town portions of the Otay Metro Powerloop in 2007, and construction of the Silvergate 230/69 kV substation in December 2008.

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6.3 Study Assumptions and System Conditions

The ISO performed assessment of the SDG&E transmission system for the years 2013 and 2018. The primary objective of the studies was to identify potential problems on the Transmission System and develop a Transmission Plan of Service for the SDG&E area for up to ten years in the future. The studies included power flow and post-transient and transient stability analysis.

The SDG&E system study was performed consistent with the general study assumptions and methodology described in Chapter 3 and appendix A. The ISO secured website lists the contingencies that were performed as part of this assessment. In addition, specific assumptions and methodology applied to the SDG&E system study are provided below.

6.3.1 Generation

High import into the San Diego system and low internal generation were studied since historic data shows that these conditions are the most limiting. Existing generation included all five Encina steam units. They were assumed to be available during peak loads, although not fully dispatched in all power flow cases. A total of 946 MW of generating capacity can be dispatched based on the maximum capacity of each generating unit.

Palomar Energy is a new 541 MW combined cycle generation plant, owned by SDG&E, which began commercial operation in April of 2006. In September 2008, due to the addition of new chillers, its capacity was increased by 34 MW. The two combustion turbines (CTs) are now rated at 173 MW maximum output each, and the steam turbine (ST) is rated at 229 MW maximum output. For the summer months, this plant is modeled at a maximum output of 558 MW, to reflect the reduced capacity during high temperature periods.

South Bay Power plant (689 MW) was assumed to be retired, but its retirement depends on the new Otay Mesa Power plant (561 MW) and on the Sunrise Power Link Transmission Project being in service. Both Otay Mesa and the Sunrise Power Link projects were modeled. The Otay Mesa combined cycle power plant is under construction and is scheduled to begin operation in 2009.

A total of 200 MW of Combustion Turbines (CTs) were modeled in the SDG&E system. Cabrillo II owns and operates all but two of the small CTs in the SDG&E service area. Cabrillo I operates the Encina CT while LS Power operates the South Bay CT. The South Bay CT was not modeled since it is slated for retirement.

A total of 191 MW of Qualifying Facilities (QFs) were modeled in the studies. Power contract agreements with the QFs do not obligate them to generate reactive power so all QFs were modeled at unity power factor.

Existing peaking generation modeled in the power flow cases included Calpeak Peakers (42 MW), Border (42 MW), El Cajon (42 MW), two Larkspur units (46 MW each), Otay (42 MW), Escondido (49 MW), and SDG&E Miramar peaker (46 MW). Future peaking generation modeled in the studies included 49 MW at the Margarita 138 kV substation, 49 MW at Pala Substation, and 99 MW at Orange Grove adjacent to Pala. Margarita construction is planned to resume in 2009. Orange Grove is scheduled to start operation in August 2009. After the studies were performed, the Pala peaking project was cancelled so this change will be reflected in the 2009 Transmission Plan.

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Renewable generation included in the model is the 50 MW Kumeyaay Wind Farm that began commercial operation in December of 2005, Lake Hodges pump-storage plant (40 MW) currently under construction and the Bull Moose Biomass plant (27 MW) is scheduled to be in service in April 2009.

In addition, 1,070 MW of existing thermal power plants connected to the 230 kV bus at the Imperial Valley Substation area were modeled. The generation plants in Imperial Valley are located outside of the San Diego area; therefore, their capacity is not included in the SDG&E internal generation and counted as an import. Renewable (solar and wind) generation proposed to be developed in this area was not modeled in the studies because none of the new plants is presently under construction and none has received regulatory approval or have Power Purchase Agreements.

The San Onofre Nuclear Generation Station (SONGS) was modeled with two units on-line at maximum output.

Internal generation in San Diego modeled in the case is summarized in Table 6-1.

Table 6-1: Generation Plants in SDG&E area

Generation Plants	Max. Capacity (MW)	Note
South Bay 1	145	assumed retired
South Bay 2	149	assumed retired
South Bay 3	174	assumed retired
South Bay 4	221	assumed retired
Encina 1	106	
Encina 2	103	
Encina 3	109	
Encina 4	299	
Encina 5	329	
Palomar	541	
Otay Mesa	561	
South Bay GT	13	assumed retired
Encina GT	14	
El Cajon GT	13	
Kearny GT1	15	
Kearny 2AB (Kearny GT2)	55	
Kearny 3AB (Kearny GT3)	57	
Miramar GT 1	17	
Miramar GT 2	16	
El Cajon GT	13	
Goalline	48	
Naval Station	47	
North Island	33	
NTC Point Loma	22	
Sampson	11	
NTC Point Loma Steam turbine	2.3	
Ash	0.9	
Cabrillo	2.9	
Capistrano	3.3	
Carlton Hills	1.6	
Carlton Hills	1	
Chicarita	3.5	
East Gate	1	
Kyocera	0.1	
Mesa Heights	3.1	
Mission	2.1	
Murray	0.2	
Otay Landfill I	1.5	
Otay Landfill II	1.3	
Covanta Otay 3	3.5	

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Table 6-1: Generation Plants in SDG&E area (cont)

Generation Plants	Max. Capacity (MW)	Note
Rancho Santa Fe	0.4	
Rancho Santa Fe	0.3	
San Marcos Landfill	1.1	
Shadowridge	0.1	
Miramar	46	
Larkspur Border 1	46	
Larkspur Border 2	46	
MMC - Electrovest (Otay)	42	
MMC - Electrovest (Escondido)	49	
El Cajon/Calpeak	42	
Border/Calpeak	42	
Escondido/Calpeak	42	
Margarita	49	
Pala	49	
Orange Grove	99	
Kumeyaay (NQC)	8.3	
Bullmoose (NQC)	20	
Lake Hodges Pumped Storage	40	

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6.3.2 Load forecast

Loads within the SDG&E system reflect a coincident peak for 1-in-10-year heat wave conditions. The load for the year 2013 was modeled at 5,227 MW and the load for 2018 was modeled at 5,577 MW. SDG&E substation loads were modeled according to the data provided by SDG&E and scaled to represent the expected load forecast. The total load in the power flow cases was modeled based on the load forecast by the California Energy Commission (CEC). Table 6-2 summarizes load in SDG&E and neighboring areas modeled in the study.

Table 6-2: Load and Losses in the SDG&E study

PTO	2013 Summer Peak		2018 Summer Peak	
	Load (MW)	Losses (MW)	Load (MW)	Losses (MW)
SDG&E	5227	102	5577	146
SCE	26759	499	27553	455
IID	1327	46	1362	44
CFE	2594	28	3413	51

The load power factor at nearly all the load busses were modeled at 0.995 lagging. The 0.995 lagging value is based on actual system power factor during system peak conditions. In addition, SCADA-controlled distribution capacitors are installed at each substation with sufficient capacity to compensate for distribution transformer losses. The exceptions listed below were modeled using power factors indicative of historical values, which is consistent with the power factors model used by SDG&E.

Need to show voltage levels at the following busses

- Naval Station 69 kV Metering (bus 22556): 0.707 lagging (this substation has 24 MVAR shunt capacitor)
- Creelman 69 kV (bus 22152): 0.992 leading
- Descanso 69 kV (bus 22168): 0.900 leading
- Rincon 69 kV (bus 22688): Unity
- Loveland 69 kV (bus 22416) Unity
- Santa Ysabel 69 kV (bus 22736) Unity
- Warners 69 kV (bus 22884) Unity

6.3.3 Reactive power margin analyses

The March 30, 2006 WECC TSS approved "Guide to WECC/NERC planning standards: Voltage support and reactive power" was utilized for analyzing the SDG&E transmission system. In this study, the SDG&E load was increased by 5% and all Category B contingencies were studied to determine if there was sufficient reactive margin available. The following two cases were studied for the area:

- Increase in load was compensated by increase in generation from north of San Diego (i.e., increase in South-of-SONGS flow),
- Increase in load was compensated by increase in generation from east of Imperial Valley (i.e., increase in the SWPL and Sunrise Power Link flows).

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6.4 Study Results and Discussions

The studies showed that the power grid in the SDG&E system can experience equipment overload and voltage support problems for NERC/WECC Category A, B, C and D contingencies. .

The following table summarizes problems identified and proposed solutions. Only Category A and B contingencies are included, since for multiple, outages load tripping is an appropriate action.

For some problems, several alternative solutions are proposed. These proposals are being discussed with SDG&E so that the most realistic and economic solution can be selected.

Table 6-3: Identified overloads and proposed solutions

Overloaded Facility	Critical Contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Boulder Creek-Santa Ysabel, voltage instability	Barret-Descanso-Loveland 69 kV	B	133%	184%	1) install 50 MVAR SVD at Descanco and reconductor 4 overloaded lines (52 miles); or 2) built new Barret-Barret tap 69 kV line, reconfigure the system, reconductor 52 miles; or 3) Connect to the future Wind Farms (ECO) 500/69kV substation, install SPS for 69 kV lines switching
Boulder Creek-Descanso, voltage instability	Barret-Descanso-Loveland 69 kV	B	133%	184%	
Descanso-Glencliff tap, voltage instability	Barret-Descanso-Loveland 69 kV	B	114%	164%	
Cameron Tap-Glencliff, voltage instability	Barret-Descanso-Loveland 69 kV	B	92%	154%	
Creelman-Santa Ysabel, voltage instability	Barret-Descanso-Loveland 69 kV	B	101%	127%	
Rincon-Warners, voltage instability	Barret-Descanso-Loveland 69 kV	B	101%	120%	
Felicita - Ash tap 69 kV	Escondido-Ash 69 kV	B	94%	112%	Reconductor the line
Penasquitos-Del Mar 69 kV	Rancho Santa Fe-Penasquitos-Del Mar 69 kV	B	101%	107%	Reconductor the line
Bernardo-Felicita Tap 69 kV	Lake Hodges-Bernardo-Rancho Santa Fe	B	95%	102%	Reconductor the line
Lilac-Rincon 69 kV	Ash-Felicita-Valley Center 69 kV	B	104%	105%	Reconductor the line
Los Coches 138/69 kV Bank #2	parallel Los Coches bank	B	92%	106%	Transformer replacement
San Luis Rey-Melrose Tap 69 kV	San Luis Rey-Melrose 69 kV	B	108%	116%	Reconductor the line
Miguel 230/138 kV Bank #2	Miguel-Proctor Vly 138 kV	B	<100%	102%	Install a larger bank or South Bay Substation relocation
Miguel 500/230 kV Bank	parallel bank	B	<100%	101%	SPS
Sn Luis Rey-Morro Hill Tap 69 kV	Pendleton-San Luis Rey 69 kV	B	94%	104%	Reconductor the line
Old Town 230/69 kV Banks	parallel bank	B	95%	111%	relocate South Bay substation to 230 kV, or upgrade the emergency rating of Bank #2

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Table 6-3: Identified overloads and proposed solutions (cont)

Overloaded Facility	Critical Contingency	Category	Loading 2013	Loading 2018	Proposed Solutions
Otay Lake-Otay Lake Tap 69 kV	Miguel-Border 69 kV	B	107%	116%	1) Upgrade the 69 kV system between Miguel and South Bay; or 2) Constructing 69 kV line between Miguel and Border substations; or 3) Temporary Operating procedure
Sycamore 230/69 kV Bank # 2	parallel bank	B	<100%	101%	Re-rate the Sycamore Canyon Bank #2 or new Bank
Rose Canyon-East Gate 69 kV	Rose Canyon-Penasquitos 69 kV	B	104%	104%	Re-arrange 69 kV lines in the Rose Canyon-East Gate area
Pala-Monserate Tap 69 kV line	Lilac-Pala 69 kV	B	179%	179%	Line needs to be upgraded, or SPS to trip Pala generation is needed
Cannon-Calavera Tap 138 kV	Encina-Batiguitos-Penasquitos 138 kV with high Encina generation	B	115%	100% (depends on Encina generation	Install an SPS that would trip a portion of Encina 138 kV generation for the Encina-Batiquitos-Penasquitos 138 kV line outage in case of the overload on the Cannon-Calavera Tap line
San Luis Rey 138/69 kV bank	Encina-Batiguitos-Penasquitos 138 kV with high Encina generation	B	107%		The same SPS proposed to trip Encina generation to mitigate Cannon-Calavera Tap overload will mitigate overload on the San Luis Rey transformer.
Sycamore -Chicarita 138 kV	Encina-Batiguitos-Penasquitos 138 kV with low Encina generation	B	120%	130%	Reconductor the line

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Table 6-3: Identified overloads and proposed solutions (cont)

Overloaded Facility	Critical Contingency	Category	Loading		Proposed Solutions
			2013	2018	
Sycamore -Creelman 69 kV	SWPL out and generation adjusted to SDG&E import of 3500 MW	A	102%	119%	Upgrade the line, or limit the SDG&E import limit capability to allow for the outage of SWPL
IID system (multiple facilities)					IID is planning to implement upgrades on their system: installation of the 4th El Centro 230/92 kV transformer in December 2008, construction of the Imperial Valley-Dixieland 230kV line and associated 230/92kV Dixieland transformer and relocation of the El Centro 230/161kV transformer in 2009. Mitigation of the overloads in IID is studied as a part of the East-of-River upgrade project

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In addition to the solutions proposed for overloads, an additional shunt capacitor needs to be installed at the Borrego 69 kV Substation to mitigate voltage violations.

6.4.1 TPL 004 – System Performance Following Extreme BES Events

As a Category D contingency, a common corridor outage of the transmission lines north of Miguel was studied. This outage is a credible, even if unlikely, contingency since the lines are in a common corridor. Transmission lines in the North-of-Miguel corridor include:

- Miguel-Sycamore Canyon 230 kV,
- Miguel-Mission # 1 and 2 230 kV,
- Otay Mesa-Sycamore Canyon 230 kV,
- Miguel-Los Coches 138 kV and 69 kV,
- Miguel-Jamacha #1 and #2 69 kV.

Power Flow, Transient Stability and Voltage Stability analyses were performed using the heavy summer of 2018 since it is the worst case due to high load. The studies did not show possibility of cascading outages. However, overloads of the following lines were observed.

Table 6-4: Overloaded facilities for North of Miguel Outage

Transmission Facility	Contingency	Loading (%)
Miguel-Granite Tap 69 kV	A common corridor outage of the transmission lines north of Miguel	131%
Miguel-Miguel Tap 69 kV		117%
Miguel 230/138 # 1		114%
Miguel-Proctor Valley 138		110%
Chollas-Paradise 69 kV		105%
Miguel-Paradise 69 kV		100%

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6.4.2 Reactive margin results – Eastern San Diego County

The power flow studies identified insufficient reactive margin for an outage of the Barrett-Descanso-Loveland 69 kV line, in 2018. Post transient studies for the year 2013 with the SDG&E load increased by 5% also identified insufficient reactive margin for this outage. The study results show the 69 kV system in this area will need upgrade due to overloads.

In order to find solutions for the identified problems, the ISO performed several technical studies to identify the size, optimal location, type (static or dynamic) and amount of reactive support and the timeframe to install equipment (prior to 2013). In our estimate, at least 50 MVAR of reactive support is needed to provide for sufficient reactive margin in the 2018 power flow case. The following locations for reactive support were studied:

- 50 MVAR SVC on the Crestwood 69 kV bus. This SVC will also mitigate problems associated with the new wind generation planned to connect to this area. The timeframe for the reactive support is prior to 2013 depending on the load growth in the area,
- 50 MVAR SVC on Barrett 69 kV substation,
- 50 MVAR SVC on Descanso Substation.

The study results are presented in Table 6-6.

Table 6-5: Overloaded facilities following the Barrett-Descanso-Loveland outage

Transmission Facility	Length (Miles)	Loading (%)			
		2013	2018		
			50 MVAR @ Descanso	50 MVAR @ Barrett	50 MVAR @ Crestwood
Boulder Creek-Santa Ysabel 69 kV	7 mi	133	171	201	184
Boulder Creek-Descanso 69 kV	12 mi	133	171	201	184
Descanso-Glencliff tap 69 kV	11 mi	114	95	180	164
Cameron Tap-Glencliff tap 69 kV	6 mi	93	77	169	154
Cameron Tap-Cameron 69 kV	4.5 mi	51	42	141	41
Creelman-Santa Ysabel 69 kV	13 mi	101	115	137	127
Rincon-Warners 69 kV	20 mi	101	114	125	120
Barrett-Cameron 69 kV	14 mi	19	16	102	15

As shown in Table 6-5, the line loading depends on the size and location of the SVC. Since the overloads are high (and the loading is not just reactive, but also real power) the problem can show-up earlier than 2013. This will significantly depend on the load growth in the eastern San Diego area.

It appeared that the optimal placement of the SVC will be Descanso Substation. This location causes minimum amount of overloading (4 transmission lines versus 8 lines if the reactive support is installed at Barrett Substation). In addition, voltage stability studies showed that if the reactive support is installed on any substation other than Descanso, the system will not satisfy WECC reactive margin criteria.

The proposed solution to solve both reactive margin and overload problem is to install a 50 MVAR SVC at Descanso Substation and reconductor four overloaded 69 kV lines (about 52 miles).

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Another solution to solve both reactive margin and overload problem is to construct a new 69 kV line section from the Barret Substation to the Barret Tap (approximately 7 miles) and reconfigure the existing Barret-Loveland-Descanso 69 kV transmission line. With the new Barret–Barret Tap section, two transmission lines will be formed: Barret-Descanso and Barret-Loveland. A single line outage, would result in either Barret-Descanso or Barret-Loveland transmission line to be out. The studies showed no voltage or reactive margin problems even without additional reactive support. However, the following overloads were observed in the 2018 studies for the Barret-Loveland outage. These are the same lines that were overloaded in the case of SVC on Descanso and they will need to be reconductored.

- Boulder Creek-Descanso 135%
- Boulder Creek-Santa Ysabel 135%
- Creelman-Santa Ysabel 109%
- Rincon-Warners 102%

An alternative solution to avoid extensive reconductoring will be the construction of a second Barett-Loveland transmission line (approximately 13 miles) or a second Descanso-Loveland 69 kV line (approximately 15 miles). This may be more cost effective than line reconductoring. These alternatives need to be studied in more details.

Building a new 500/69 kV substation for renewable generation and connecting Crestwood substation to it as an interconnection plan for one of the generation projects may create an additional source for this area. Addition of this substation and connecting it to the Boulevard Substation may eliminate the need for reconductoring, although reactive support may still be required.

SDG&E recommended four measures to mitigate the problems associated with the Barret-Descanso-Loveland 69 kV outage:

- A SCADA sectionalizing switch to be installed at the tap point so that the possibility of a three-terminal line outage will be eliminated (June 2009),
- 12 kV capacitors are being added as part of a long-term power quality initiative for a net of 3 MVAR at Cameron, 7.2 MVAR at Barrett (2009),
- Active replacement of wood poles and associated conductor for all East County 69 kV transmission will lower losses and possibly raise capacity (2009, 2010),
- ECO substation will allow some East County load to be fed from the new substation.

The 2009 Transmission Plan will evaluate if the measures proposed by SDG&E will be sufficient to mitigate the problems. Even with these measures, some additional reactive support and reconductoring of some transmission lines may still be necessary in the future.

6.4.3 Transient stability studies

All major 500 kV and 230 kV outages were studied for the year 2018. Scenarios analyzed included critical Category B, C, and D contingencies based on historical and expected operation. Three-phase faults were modeled on the sending bus of transmission lines. Duration of the fault was modeled as 4 cycles for 500 kV and 5 cycles for 230 kV. The faults were cleared by opening the lines. These outages included:

- Imperial Valley-Miguel 500 kV with and without CFE cross trip
- Hassayampa-North Gila 500 kV
- Imperial Valley-North Gila 500 kV
- Palo Verde-Devers 500 kV
- Imperial Valley-Central 500 kV (planned)
- Intermountain-Adelanto DC
- Pacific DC Inter-tie bipolar
- Sycamore-Central 230 kV (planned) #1 and #2
- Otay Mesa-Sycamore 230 kV
- Otay Mesa-Silvergate 230 kV
- Palomar-Escondido # 1 230 kV
- Palomar-Escondido # 1 and # 2 230 kV
- Palomar-Encina 230 kV
- SONGS generator # 2
- Palo Verde generator #2

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- Diablo generators # 1 and 2
- SONGS generators #2 and #3
- Palo Verde generator #1 and #2
- Miguel-Mission #1 and #2
- North of Miguel corridor

No WECC/NERC criteria violations were found. The analysis indicates acceptable transient stability performance for all of the above contingencies.

A Category D, 3-phase, 6-cycle fault at the Miguel 230 kV bus was simulated and cleared by opening all transmission lines north of Miguel: Miguel-Sycamore Canyon 230 kV, Miguel-Mission # 1 and # 2 230 kV, Otay Mesa-Sycamore Canyon 230 kV, Miguel-Los Coches 138 kV and 69 kV and Miguel-Jamacha #1 and #2 69 kV. The study showed that the system was stable with no transient stability criteria violations.

6.4.4 Post transient and voltage stability studies

Post-transient studies for the Imperial Valley-Miguel 500 kV outage did not show any problems for the cases studied including the cases without RAS. This can be explained by addition of the Sunrise Power Link Transmission Project. Studies of all Category B contingencies within the SDG&E system with load and imports both increased by 5% in 2018 did not show any need for additional reactive support (with the exception of the outage in the eastern San Diego system described above).

The studies showed low voltage on the Borrego 69/12 kV substation for numerous single contingencies. The ISO recommend installing additional shunt capacitor at this substation. Presently, there is 6 MVAR of Static VAR Device on the Borrego 12 kV bus. It is recommended to at least double this amount.

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For 2018, voltage stability analysis was also performed for a Category D outage North of Miguel with a 5% increase in the SDG&E load. The following two scenarios were studied:

- Increase in load was compensated by increase of generation in Arizona. Thus, the transfer from Imperial Valley increased by 7% and from San Onofre by 10%, and
- Increase in load was compensated by increase of generation in PG&E and SCE. Thus, the transfer from San Onofre to SDG&E increased by 13%, and the transfer from Imperial Valley increased by 4%.

The studies showed that there is sufficient voltage stability margin in both cases.

6.4.5 Power flow studies with SWPL out-of-service

For the 2013 and 2018 heavy summer cases, SWPL (Imperial Valley-Miguel 500 kV line) was taken out of service and internal generation readjusted to maintain SDG&E import limit at 3,500 MW. The studies showed numerous additional overloads for different outages (Category B): Carlton Hills tap-Sycamore 138 kV, Bernardo tap-Lake Hodges 69 kV, Kettner-B 69 kV, Old Town-Kettner 69 kV, Murray-Garfield 69 kV, Rincon-Warners 69 kV and others as shown in Table 6-6, as well as overloads in CFE.

Sycamore-Creelman 69 kV line can overload under normal conditions when SWPL is out of service and generation readjusted. Thus, this line needs to be upgraded in order to maintain SDG&E import limit on SWPL at 3,500 MW.

Table 6-6 summarizes power flow study results for 2018 with and without SWPL in service. Only loadings higher than 97% of emergency rating are shown.

Table 6-6: Comparison of study results for 2018 scenarios with and without SWPL

Critical Equipment	Loading (%)		Contingency
	SWPL in	SWPL out	
ASH TAP - FELICITA 69 kV	112%	116%	ESCNDIDO-ASH 69 kV
BERNARDO -FELCTA TAP 69 kV	102%	113%	LK HDGS-BERNRD-RNCH SFE 69 kV
	101%	109%	POWAY-R.CARMEL 69 kV
	92%	103%	ESCNDIDO-ESCO 69 kV
	92%	103%	SYCAMORE 230/69 # 2
	92%	103%	OLIVENHAIN-ESCNDIDO 69 kV
	91%	102%	SYCAMORE 230/69 # 1
	<90%	101%	IMPRLVLY-CENTRAL 500 kV
	<90%	101%	LK HDGS -OLIVENHN 69 kV
	<90%	100%	ESCO-WARREN CYN-POWAY 69 kV
	<90%	100%	ARTESN-SYCAMORE 69 kV
	<90%	98%	POWAY-POMERADO 69 kV
BERNDOTP - Lkhodges 69 kV	<90%	102%	BERNRDO-FELICITA-ESCNDIDO 69 kV
CARLTHT2 - SYCAMORE 138 kV	<90%	108%	MIGUEL-SYCAMORE 230 kV
	<90%	108%	OTAYMESA-SILVERGATE 230 kV
	<90%	101%	PENSQTOS-SYCAMORE 230 kV
	<90%	99%	PENSQTOS-OLD TOWN 230 kV
DEL MAR - PENSQTOS 69 kV #1	107%	109%	RNCH SFE-DEL MAR-PENSQTOS 69 kV
	100%	101%	NORTHCTY-PENASQUITOS 69 kV
ESCNDIDO 230/ 69 kV #2	94%	98%	ESCONDIDO 230/69 # 3
ESCNDIDO 230/ 69 kV #1	94%	97%	ESCONDIDO 230/69 # 3

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Table 6-6: Comparison of study results for 2018 scenarios with and without SWPL (cont)

Critical Equipment	Loading (%) SWPL in	SWPL out	Contingency
LILAC - RINCON 69 kV	105%	120%	ASH-FELICITA-VALLEY CENTER 69 kV
MELROSE - MELRSETP 69 kV	99%	100%	MELROSE-SANLUSRY 69 kV
MELROSE - SANLUSRY 69 kV	96%	97%	MLROSE-SN LUISREY-SN MARCOS 69 kV
MELRSETP - SANLUSRY 69 kV	116%	124%	MELROSE-SANLUSRY 69 kV
	104%	105%	ESCNDIDO-SANMRCOS 69 kV
KETTNER - B 69 kV	97%	126%	SILVERGATE 230/69 # 1
	97%	126%	SILVERGATE 230/69 # 2
	91%	109%	SOUTH BAY 138/69
	<90%	102%	MIGUEL-SYCAMORE 230 kV
	<90%	101%	PACFCBCH-OLD TOWN 69 kV
	<90%	100%	MIGUEL 230/69 # 1
	<90%	100%	MIGUEL 230/69 # 2
	<90%	98%	DIVISION GENERATOR
	<90%	97%	NOISLMTR GENERATOR
MIRAMRTP - PENSQTOS 69 kV	<90%	99%	ROSE CYN-PENSQTOS 69 kV
	<90	99%	PENSQTOS-MESA RIM 69 kV
MORHILTP - SANLUSRY 69 kV	104%	109%	PENDLETN-SANLUSRY 69 kV
MURRAY - GARFIELD 69 kV	<90%	103%	MIGUEL-GRANITE-LOS COCHES 69 kV
	<90%	99%	MIGUEL-SYCAMORE 230 kV
	<90%	98%	MIGUEL 230/69 # 1
	<90%	98%	MIGUEL 230/69 # 2
OLD TOWN 230/69 kV #2	111%	120%	OLD TOWN 230/69 # 1
OLD TOWN 230/69 kV #1	101%	109%	OLD TOWN 230/69 # 2
OLD TOWN - KETTNER 69 kV	97%	122%	SILVERGATE 230/69 # 1
	97%	122%	SILVERGATE 230/69 # 2
	91%	108%	SOUTH BAY 138/69
	<90%	101%	MIGUEL-SYCAMORE 230 kV
	<90%	100%	PACFCBCH-OLD TOWN 69 kV
	<90%	100%	MIGUEL 230/69 # 1
	<90%	100%	MIGUEL 230/69 # 2
	<90%	98%	DIVISION QF GENERATOR
	<90%	98%	NOISLMTR GENERATOR
	<90%	97%	MIGUEL-BORDER 69 kV
OTAYLKTP - OTAY 69 kV	116%	121%	MIGUEL-BORDER 69 kV
PENDLETN - SANLUSRY 69 kV	93%	98%	MONSERAT-MORRO HL-SAN LUIS REY 69 kV
PENSQTOS 230/69 #2	100%	100%	PENASQUITOS 230/69 # 1

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Table 6-6: Comparison of study results for 2018 scenarios with and without SWPL (cont)

Critical Equipment	Loading (%) SWPL in	SWPL out	Contingency
RINCON - WARNERS 69 kV	95%	127%	CREELMAN-SYCAMORE 69 kV
	<90%	111%	SANTA YSABEL-CREELMAN 69 kV
	<90%	101%	SYCAMORE-CARLTON HLS-MISSN 138 kV
	<90%	101%	MISSION-CARLTNHS 138 kV
	<90%	100%	MIGUEL 230/138 # 2
	<90%	99%	MIGUEL-SYCAMORE 230 kV
	<90%	98%	IMPRLVLY-CENTRAL 500 kV
	<90%	98%	OTAYMESA-SILVERGATE 230 kV
LA ROSITA - IMPRLVLY 230 kV	<90%	106%	IMPRLVLY-CENTRAL 500 kV
ROSE CYN - EASTGATE 69 kV	92%	142%	ROSE CYN-PENSQTOS 69 kV
	<90%	119%	PENSQTOS-OLD TOWN 230 kV
	<90%	116%	PACFCBCH-OLD TOWN 69 kV
	<90%	109%	FENTON-MIRAMAR-MIRAMAR GT 69 kV
	<90%	108%	OTAYMESA-SILVERGATE 230 kV
	<90%	105%	MIGUEL-SYCAMORE 230 kV
	<90%	104%	OLD TOWN 230/69 # 1
	<90%	104%	OLD TOWN 230/69 # 2
ROSE CYN - EASTGATE 69 kV	<90%	100%	MESAHGTS-MISSION 69 kV
	<90%	99%	MISSION 138/69 #1
	<90%	99%	MISSION 138/69 #2
	<90%	97%	SYCAMORE-CARLTN HLS-MISSION 138 kV
	<90%	97%	MISSION-CARLTNHS 138 kV
SANYSDRO - OTAY TP 69 kV	94%	97%	BORDER-OTAY-SAN YSIDRO 69 kV
SYCAMORE 230/69 kV #2	101%	109%	SYCAMORE 230/69 # 1
SYCAMORE 230/69 kV #1	97%	104%	SYCAMORE 230/69 # 2
COACHELV 230/92 #1	122%	98%	HASSYAMP-N.GILA 500 kV
COACHELV 230/92 #2	122%	98%	HASSYAMP-N.GILA 500 kV
HRA-115 - LDA-115 115 kV	<90%	96%	IMPRLVLY-CENTRAL 500 kV
HRA -230/115 #1	<90%	96%	IMPRLVLY-CENTRAL 500 kV
HRA -230/115 #2	<90%	96%	IMPRLVLY-CENTRAL 500 kV
ROA-230 - HRA-230 230 kV	<90%	138%	IMPRLVLY-CENTRAL 500 kV
RUM-230 - ROA-230 230 kV	<90%	149%	IMPRLVLY-CENTRAL 500 kV
RUM-230 - HRA-230 230 kV	<90%	133%	IMPRLVLY-CENTRAL 500 kV
RUM-230 - ROA-230 230 kV	<90%	103%	BASE CASE
	<90%	102%	CENTRAL-SYCAMORE 230 # 1
	<90%	102%	CENTRAL-SYCAMORE 230 # 2

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Table 6-6: Comparison of study results for 2018 scenarios with and without SWPL (cont)

Critical Equipment	Loading (%) SWPL in	SWPL out	Contingency
SYCAMORE - CREELMAN 69 kV	<90%	107%	MIGUEL-SYCAMORE 230 kV
	<90%	107%	SYCAMORE-CARLTN HLS-MISSION 138 kV
	<90%	107%	MISSION-CARLTNHS 138 kV
	<90%	106%	MIGUEL 230/138 # 2
	<90%	105%	WARNERS-RINCON 69 kV
	<90%	104%	OTAYMESA-SILVERGATE 230 kV
	<90%	102%	LOS COCHES 138/69 # 1
	95%	101%	CREELMAN-LOSCOCHS 69 kV
	<90%	101%	LOS COCHES 138/69 # 2
	<90%	101%	CARLTNHS-SANTEE 138 kV
	<90%	101%	SYCAMORE-ELLIOTT 69 kV
	<90%	101%	SYCAMORE-SCRIPPS 69 kV
	<90%	100%	PENSQTOS-OLD TOWN 230 kV
	<90%	99%	MURRAY-GARFIELD 69 kV
	<90%	99%	PENSQTOS-SYCAMORE 230 kV
	<90%	99%	LOSCOCHS-ELLIOTT 69 kV
	<90%	99%	ASH-FELICITA-VALLEY CENTER 69 kV
	<90%	98%	SYCAMORE 230/138
	<90%	97%	GARFIELD-EL CAJON 69 kV
	<90%	97%	ESCNDIDO-LILAC 69 kV
	<90%	97%	POWAY-POMERADO 69 kV
	92%	120%	BASE CASE (Normal Rating)

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One potential solutions may be to limit the flow on the Sunrise Power Link to protect for an outage of SWPL by either dispatching more internal San Diego generation or limiting import from Arizona. Also, the South Bay Substation relocation project proposed by SDG&E will mitigate emergency overloads in downtown San Diego that are expected with the SWPL outage.

6.4.6 Impact of SDG&E area outages on neighboring systems

Mitigation of the overloads in IID was studied as a part of the East-of-River upgrade project.

An outage of either one of the North Gila-Imperial Valley or Hassaympa-North Gila 500 kV lines can cause overloads in the IID system. The Coachela 230/92 transformers can overload by 10% in 2013 and up to 22% in 2018; the Blythe-Niland 161 kV line can overload up to 7% and the Coachela-Avenue 58 92 kV line can overload by 1%.

IID is planning to implement upgrades on their system that include the following:

- Installation of the 4th El Centro 230/92 kV transformer,
- Construction of the Imperial Valley-Dixieland 230 kV line and associated 230/92 kV Dixieland transformer, and

- Relocation of the El Centro 230/161 kV transformer in 2009.

Historically, an outage of Imperial Valley-Miguel 500 kV caused overloads in the CFE system. These overloads are mitigated by cross tripping either the Imperial Valley-La Rosita or the Otay Mesa-Tijuana 230 kV lines. Addition of the Sunrise Power Link Transmission Project will reduce loading in the CFE system for the Imperial Valley-Miguel outage. Power flow and post-transient (governor power flow) studies for 2013 and 2018 did not show overloads in the CFE system for the Imperial Valley-Miguel outage. Existing Remedial Action Scheme (RAS) for the Imperial Valley-Miguel outage also trips all generating units connected to the Imperial Valley 230 kV bus. It is recommended to revise the existing RAS when Sunrise Power Link is operational because such extensive generation tripping may not be required.

6.5 Recommended Solutions for Reliability Criteria Violations

Study results and proposed mitigation plans for the SDG&E system under each category of the planning standards are shown below.

TPL 001-System Performance Under Normal Conditions

Under both the summer and winter peak conditions, there is no overload or voltage violation under Category A performance requirement.

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TPL 002-System Performance Following Loss of a Single BES Element

Power flow studies were performed for N-1 conditions (Category B) with all major power plants in service and also for N-1, G-1 conditions with the Otay Mesa generation out. Outage of the Otay Mesa power plant is the largest G-1 contingency in San Diego. Each Category B outage was studied for 2013 and 2018. Also, different generation dispatch patterns such as low/high Encina and/or Palomar generation were studied,. The studies of Category B contingencies identified the following overloads.

500/230 kV System

- **Overload of Miguel 500/230 kV bank with a parallel bank outage.**

The overload observed in the studies was 1% in 2018, but it depended on the Imperial Valley-Miguel flow. The proposed solution is to install SPS that would trip the overloaded bank.

- **Overload of the new Miguel 230/138 kV transformer bank # 2 (its installation was approved by the ISO) for an outage of the parallel bank or Miguel-Proctor Valley 138 kV line.**

One solution to mitigate the overload is to install a larger bank (The proposed 230/138 kV bank is 392 MVA normal rating, 477 MVA emergency). Also, relocating/upgrading South Bay substation to 230 kV that was proposed by SDG&E as a maintenance project will mitigate the overload. The overload is expected to be 2% in 2018.

- **Old Town 230/69 # 1 or 2 kV transformer overload with an outage of the parallel bank,**

up to 11% in 2018 (In 2013 loading of the bank # 2 is 95%).

Relocating South Bay Substation to 230 kV will mitigate the overload (99% loading of the bank # 2 in 2018). The ISO recommends upgrading the emergency rating of Old Town 230/69 kV bank # 2, if possible. The emergency rating of bank # 2 modeled in the studies was 239 MVA and bank # 1 is 263 MVA. The normal rating of both banks is 224 MVA. According to SDG&E data, the 24-hour emergency rating of each of the Old Town banks is 269 MVA and the half-hour emergency rating is 310 MVA. The observed overloads were under the 24-hour emergency ratings.

- **Sycamore Canyon 230/69 kV bank may overload with an outage of the parallel bank (1% in 2018, but depends on the Sunrise Power Link flow and generation dispatch).**

With a G-1 (Palomar Energy Center) outage and an outage of the Sycamore Canyon 230/69 kV transformer # 1, the parallel bank can overload by up to 3% in 2018. The emergency rating of the Sycamore Canyon 230/69 kV transformer # 2 is 269 MVA, and the rating of the transformer # 1 is 285 MVA. Due to a relatively small overload, the ISO recommends a possible re-rate of the Sycamore Canyon 230/69 kV transformer bank. In the future, a second 230/138 kV bank may be added to accommodate new generation in the Sycamore Canyon area, Also, the alternative of the Sunrise Power Link Transmission Project approved by the CPUC, includes installation of the third Sycamore Canyon 230/69 kV transformer.

138 kV System

- **Los Coches 138/69 kV bank #2 overloads with a parallel bank outage, up to 6% in 2018 (92% loading in 2013).**

This transformer bank needs to be upgraded. SDG&E is considering a plan to replace the Los Coches bank as part of its maintenance program. However, no date for the transformer replacement has been set. The bank needs to be replaced by one with a higher rating. Presently, Los Coches bank # 1 has a normal rating of 150 MVA and an emergency rating of 180 MVA. Bank # 2 has a normal rating of 140 MVA and an emergency rating of 155 MVA.

- **Cannon-Calavera Tap 138 kV line can overload for the Encina-Batiquitos-Penasquitos 138 kV line outage and high Encina generation.**

The observed overload was 5% in the 2013 case with Encina generation at full output. Under the same conditions in 2018, the loading of this line was 100%. With high load at the Cannon 138 kV substation, the loading on the Cannon-Calavera tap line will be lower. This 7 mile long line has a rating of 274 MVA. The overload is generation-related and is not expected to occur with higher load at the Cannon Substation, or with generation project in the ISO queue that would replace Encina generation with lower amounts of generation. Therefore, the proposed solution is to install an SPS that would trip a portion of Encina generation output for the Encina-Batiquitos-Penasquitos 138 kV line. The alternative of the Sunrise Power Link Transmission Project approved by the CPUC may mitigate this overload. It will be studied in the 2010 Transmission Plan.

- **San Luis Rey 138/69 kV transformer overload with an outage of the Encina-Batiquitos-Penasquitos 138 kV line is also dependant on Encina 138 kV generation.**

Overload observed in the studies was 7% in the 2013 case with Encina 138 kV generation at full output. Also, this outage creates high voltage on the San Luis Rey 138 kV bus, and the large

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portion of the transformer flow is reactive power that will be mitigated with adjustment of the existing SVC on the San Luis Rey 138 kV bus. The transformer rating is 140 MVA normal, 160 MVA emergency. The same SPS proposed to trip Encina generation to mitigate Cannon-Calavera Tap overload will mitigate overload on the San Luis Rey transformer. Also, the alternative of the Sunrise Power Link Transmission Project approved by the CPUC may impact this overload. It will be studied in the 2010 Transmission Plan.

- **Sycamore Canyon-Chicarita 138 kV line overload may occur with an outage of the Encina-Batiquitos-Penasquitos 138 kV line or Penasquitos 230/138 kV transformer and with low Encina 138 kV generation.**

The overload observed in the studies was 20% in 2013 and 30% in 2018 (in assumption of no generation at Encina 138 kV). The Sycamore Canyon-Chicarita 138 kV line has normal rating of 204 MVA and no emergency rating. The proposed solution is to reconductor the Sycamore Canyon-Chicarita 138 kV line or install a 230/138 kV transformer bank at Encina. Installation of this bank is part of the alternative of the Sunrise Power Link approved by the CPUC.

69 kV System

- **Felicita-Ash 69 kV Tap may overload for up to 12% for a single line outage (Escondido-Ash 69 kV) in 2018.**

In the 2013 case, loading of this line was 94%. The loading will be higher if SWPL is out of service (116% in 2018). The solution is to reconductor the line (6 miles, current rating is 97.5 MVA normal, 102.1 MVA emergency)

- **Penasquitos-Del Mar 69 kV overload of up to 7% with two single outages (Penasquitos -Rancho Santa Fe-Del Mar or Penasquitos-North City) in 2018, 1% in 2013.**

Overload may be even higher if the Lake Hodges generation is not dispatched. The normal rating of this 6 mile line is 50.3 MVA with no emergency rating. As the line is partially underground, a potential solution will be to reconductor the overhead limiting section of the line.

- **Bernardo-Felicita 69 kV Tap is heavily loaded with numerous single outages, may overload up to 3% in 2018 for an outage of Lake Hodges-Rancho Santa Fe-Bernardo (95% loading in 2013).**

With SWPL out of service, loading of this line may be as high as 113% in 2018. This 6-mile long line has a normal rating of 102 MVA and no emergency rating. This line needs to be reconductored.

- **Lilac-Rincon 69 kV line may overload for a single line outage (Ash-Felicita-Valley Center) by 5% in 2018, 4% in 2013.**

This line may overload sooner due to the new Pala peaking generators. The line is 12 miles long and has a rating of 55 MVA. SDG&E plans to replace the conductor during the wood-to-steel-pole replacement for this transmission line. The new rating will be 137 MVA normal and emergency.

- **69 kV lines between San Luis Rey and Melrose may overload for a single outages.**

SDG&E proposed to move part of the load to the Shadowridge substation or maintain the present operator action of opening the San Marcos-Melrose Tap line pre-contingency for high

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load. However, it appears that the system upgrade will be a better solution. The most heavily loaded section is the San Luis Rey-Melrose Tap. Overload is up to 16% in 2018, 8% in 2013 for an outage of the parallel line (San Luis Rey-Melrose) and is higher for the Otay Mesa generation outage. The solution is to reconductor 4.6 miles of the San Luis Rey-Melrose 69 kV tap line. The line has a normal rating of 97 MVA and an emergency rating of 102 MVA.

- **San Luis Rey-Morro Hill 69 kV tap section may overload following a single outage (San Luis Rey-Pendleton). The overload was 4% in 2018 (94% loading in 2013).**

The overload is related to load growth. This 6-mile long line has a normal rating of 97 MVA and an emergency rating of 102. One proposed solution is to reconductor the line. The overload can also be mitigated with the dispatch of new peaking generation at Pala. Temporary operational solution will be to dispatch Pala generation under peak load conditions.

- **Otay-Otay Lake 69 kV Tap line section may overload for a single outage (Miguel-Border 69 kV) by 16% in 2018, and 7% in 2013 if the Border peakers are not generating.**

The rating of this line is 50.3 MVA with no emergency rating. When the Border peakers are not generating, power flows from Otay to Otay Lake Tap and farther to Border substation. Depending on the amount of generation at Border, power on this line may flow in either direction. If all three peaking units at Border are at full output, Otay-Otay Lake Tap section may also overload following an outage of the Border-Miguel line, but in this case, flows on this section is from Border to Otay. There is an existing SPS that trips Border peakers for this overload. The 69 kV system between Miguel and South Bay needs to be upgraded. This upgrade will also eliminate the Border generation SPS. One solution may be to construct a 2nd 69 kV line between Miguel and Border substations (11 miles). A temporary operational solution would be to dispatch peaking generation at the Border 69 kV substation under heavy load conditions and use the existing SPS when generation at Border is high.

- **Rose Canyon-East Gate 69 kV line may overload for an outage of the Penasquitos-Rose Canyon 69 kV line or an outage of SWPL with low Otay Mesa generation and Miramar peaking generator on.**

The observed overload was up to 4% in the 2018 case. The 69 kV line rearrangements proposed as part of the generation interconnection studies for the Miramar peaking generation will mitigate this overload. The rearrangement involves two transmission lines: Penasquitos-Rose Canyon (TL 661) and Penasquitos-Miramar GT-East Gate (TL 664). TL661 will be segmented, and will become Penasquitos–Eastgate and Miramar Tap–Rose Canyon. The connection between the Miramar Tap and Eastgate substation will be removed. The Miramar Tap will be configured to connect to Rose Canyon Substation instead of the Eastgate substation The existing and proposed system configurations are shown in Figures 6-5 and 6-6.

SDG&E proposed to install a new underground tap line from the East Gate Substation to the TL664 (East Gate-Miramar 69 kV Tap) and cutover the existing overhead tap from TL664 to TL661 (Penasquitos-East Gate-Rose Canyon) near the East Gate substation. It will also mitigate the observed overload, however at a higher cost. At this time, it is not clear which alternative will be preferable.

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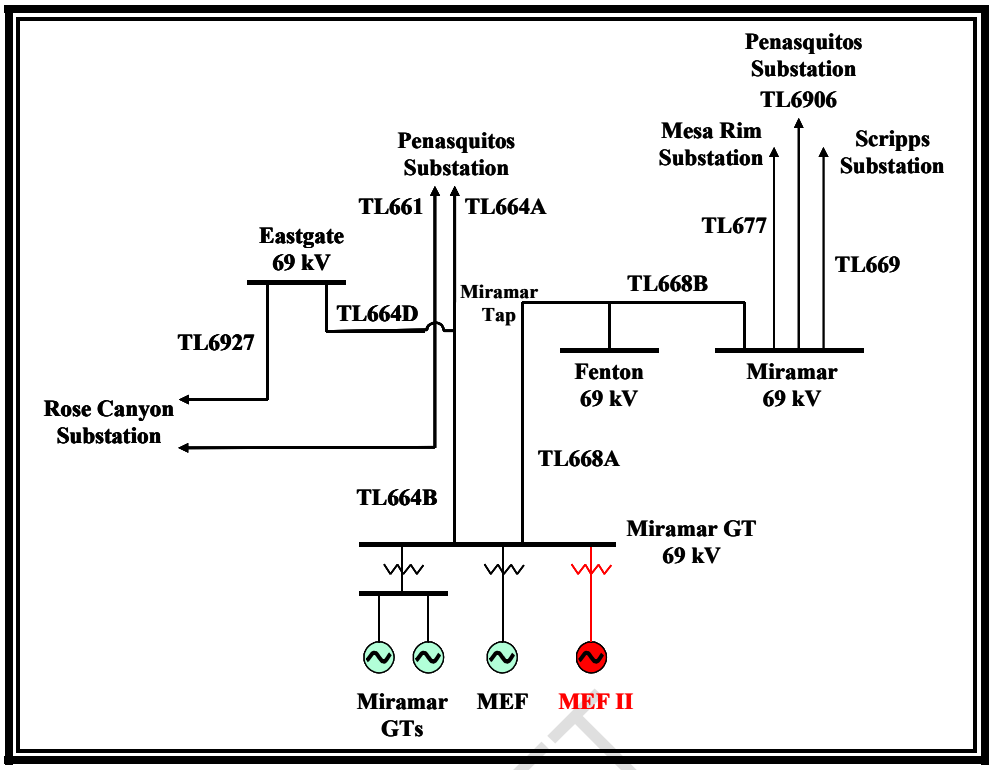

Figure 6-5: Miramar-East Gate-Rose Canyon Existing Configuration

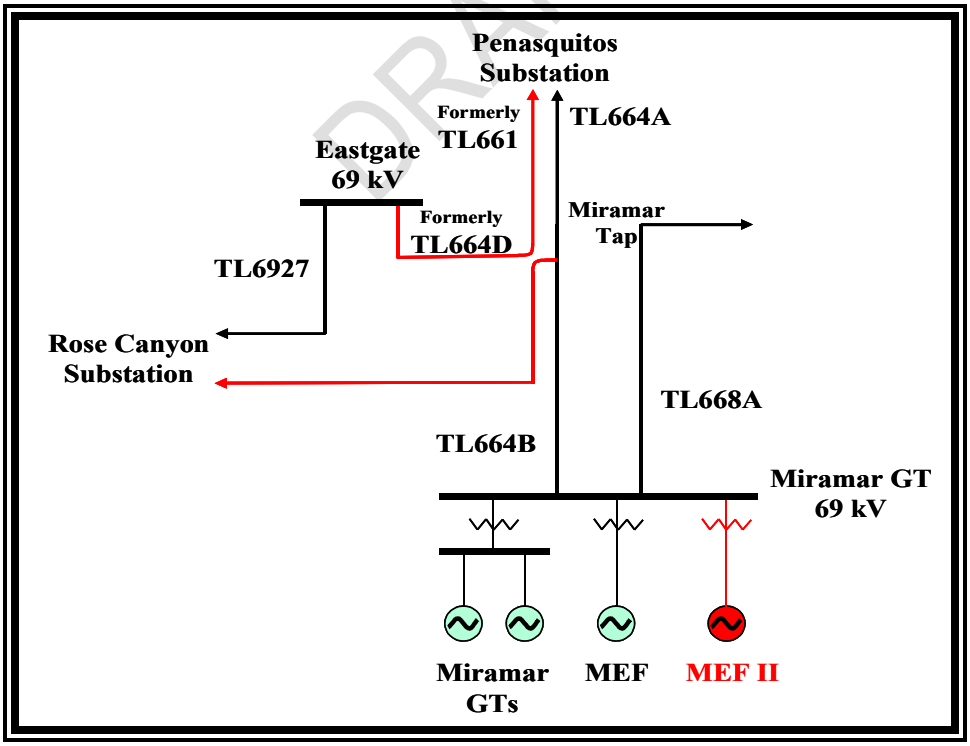

Figure 6-6: Miramar-East Gate-Rose Canyon Proposed Configuration

- **Pala-Monserate 69 kV tap line may overload for Lilac-Pala 69 kV line outage.**

This overload depends on the peaking generation at Pala. With all 144 MW (3 units, including the one that was withdrawn after these studies were performed) of peaking generation at full output, the loading may be as high as 179% above normal both in 2013 and 2018. The line needs to be upgraded, or SPS needed to trip Pala generation. Presently, this 8-mile long line has a normal rating of 68 MVA with no emergency rating.

- **Sycamore Canyon-Creelman 69 kV line may overload under normal conditions in case of the SWPL outage and generation adjusted and with numerous outages when SWPL is out of service.**

This overload depends on the total flow on the Imperial Valley-Miguel and Imperial Valley-Central 500 kV lines. Overload may be as high as 20% in 2018. The normal rating of the Sycamore Canyon-Creelman 69 kV 16-mile line is 71 MVA and its emergency rating is 90 MVA. If this line is not upgraded, SDG&E import limit capability will have to be limited to allow for an outage of SWPL. The proposed solution is to upgrade the line. By replacing the disconnect on the line, the normal rating can be increased to 97 MVA.

- **69 kV downtown San Diego system (Kettner-B and Old Town-Kettner) with an outage of the Silvergate 230/69 kV transformer.**

This overload was observed in the studies for 2018 with high South of SONGS flow and lower flow on the Imperial Valley-Miguel and Sunrise Power Link 500 kV lines. The overload can start when the South of SONGS flow is 1,490 MW or higher under normal conditions with all transmission facilities in service. These transmission lines may also overload with single contingencies when SWPL is out of service. Possible solutions will be relocating the South Bay substation to 230 kV or reconductoring the overloaded 69 kV lines (4.6 miles).

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TPL 003-System Performance Following Loss of Two or More BES Elements

In addition to the transmission facilities that would overload for Category B contingencies, there were additional transmission lines that might overload for Category C contingencies.

Table 6-7: Summary of Category B and C overloads in SDG&E area for the 2018

Transmission Facility	Loading (%) Category B	Loading (%) Category C	CAISO Proposed Solution
Felicita-Ash Tap 69 kV	112%	< 100%	reconductor
Penasquitos-Del Mar 69 kV	107%	108%	reconductor
Del Mar-Del Mar Tap 69 kV	< 100%	135%	Trip part of Del Mar load
Del Mar Tap-Penasquitos 69 kV	< 100%	103%	Trip part of Del Mar load
Bernardo-Felicita Tap 69 kV	103%	124%	reconductor
Bernardo-Rancho Carmel 69 kV	< 100%	65%	Trip part of Rancho Carmel load
Lilac-Rincon 69 kV	105%	< 100%	reconductor
El Cajon-Los Coches 69 kV	< 100%	123%	Trip part of Murray load
El Cajon-Garfield 69 kV	< 100%	131%	Trip part of Murray load
Garfield-Murray 69 kV	< 100%	107%	Trip part of Murray load
Escondido 230/69 # 2	< 100%	143%	Trip load in Escondido area
Escondido-Talega 230 kV	< 100%	107%	Trip some load on the Talega 138 kV system
Escondido-Esco 69 kV	< 100%	105%	Trip part of Poway load
Las Pulgas-Stuart Tap 69 kV	< 100%	108%	Trip part of Jap Mesa and Las Pulgas load
Stuart Tap-Oceansd Tap 69 kV	< 100%	113%	Trip part of Jap Mesa and Las Pulgas load
Los Coches 138/69 kV # 2	106%	112%	Replace transformer
Sn Luis Rey-Melrse Tap 69 kV	116%	119%	reconductor
San Luis Rey-Melrose 69 kV	< 100%	109%	Trip part of Melrose or San Marcos load
San Luis Rey-Pendleton 69 kV	< 100%	106%	Trip part of Monserate load
Mesa Heights-Mission 69 kV	< 100%	106%	Dispatch Kearney generation or trip Mesa Heights load
Miguel 230/138 kV #2	102%	< 100%	Install larger bank or South Bay relocation project
Miguel 500/230 kV # 1 or 2	101%	< 100%	SPS, trip Miguel 500/230 kV
Miguel-Jamacha 69 kV	< 100%	108%	Trip part of Jamacha load
Sn Luis Rey-Morro Hill tap 69 kV	104%	105%	reconductor
Old Town 230/69 kV# 1 or 2	111%	111%	Re-rate or upgrade the bank or South Bay relocation project
Otay Lake-Otay Lake Tap 69 kV	116%	< 100%	2nd Miguel-Border line, or SPS
Rose Canyon-East Gate 69 kV	104%	< 100%	69 kV line re-arrangement
San Mateo-Laguna Niguel 138 kV	< 100%	106%	Trip part of Margarita or Pico load
Sycamore Cyn 230/69 kV # 2	101%	< 100%	Transformer re-rate
Pala-Monserate tap 69 kV	Up to 179%	Up to 179%	Reconductor or SPS
Penasquitos –Miramar tap 69 kV	< 100%	114%	Dispatch Miramar generation or trip some Rose Cyn load
Penasquitos-North City 69 kV	< 100%	102%	Trip part of North City load
Penasquitos 230/69 kV # 2	< 100%	104%	Trip load on 69 kV Penasquitos system
Pomerado-Sycamore # 2 69 kV	< 100%	113%	Trip part of Pomerado load
Cannon-Calavera Tap 138 kV	105%		SPS, trip Encina generation

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Table 6-7: Summary of Category B and C overloads in SDG&E area (cont)

Transmission Facility	Loading (%) Category B	Category C	CAISO Proposed Solution
San Luis Rey 138/69 kV	107%	105%	SPS, trip Encina generation
Sycamore Cyn-Chicarita 138 kV	130%	< 100%	reconductor
Sycamore Cyn -Creelman 69 kV	121%	< 100%	reconductor
Sycamore Cyn-Scripps 69 kV	< 100%	108%	Dispatch Miramar generation or trip some Scripps load
Boulder Creek-Santa Ysabel	184%	136%	reconductor
Boulder Creek-Descanso	184%	136%	reconductor
Descanso-Glencliff tap	164%	< 100%	reconductor
Cameron Tap-Glencliff	154%	< 100%	reconductor
Creelman-Santa Ysabel	127%	10%	reconductor
Rincon-Warners	120%	102%	reconductor

6.6 Key Conclusions

In 2013, only one overload was observed under normal operating conditions and 17 overloads were observed for category B contingencies. Load tripping is an acceptable practice for category C contingencies. In 2018, one overload was observed under normal operating conditions and 21 overloads were observed for Category B contingencies.

The ISO evaluated 41 upgrades to address reliability concerns in meeting the ISO Planning Standards in the SDG&E area. During the 2008 Request Window, the ISO received 8 projects from SDG&E and a third party transmission. One project has sufficient information that meets the ISO needs to address reliability concerns and is being recommended for management approval. One project was denied approval because the ISO did not identify the reliability concerns the project was proposed to mitigate. Six projects will be reviewed further prior to the ISO recommendation.

The ISO recommend the following project for approval:

- **New 138 kV Tap: TL 13835 San Mateo – Laguna Niguel. This project will create a new 138 kV tap from the Talega 138 kV bus to the TL13835 (San Mateo-Laguna Niguel) serving Laguna Niguel and San Mateo areas. The following link gives further details of this project: http://www.caiso.com/2360/2360f6d7296d0.pdf)**

The ISO denied the following project because the ISO studies did not identify the need for this Project:

- **New 230 kV and 138 kV Capacitors for Mission, Telegraph Canyon and Sycamore Substations. The ISO studies did not show insufficient reactive margin that would justify installation of additional reactive support.**

The following projects require further evaluation:

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- **Orange County Transmission Expansion (Capistrano-Talega Reliability Upgrade).** This project plans to upgrade 138/12 kV Capistrano Substation to 230/138/12kV and to construct two new 230kV circuits from Talega to Capistrano by rebuilding the existing TL13835 with double circuit structures. Cost of this project exceeds $50M, therefore it needs to be presented to the ISO Board. Additional information is required prior to the project be approved.

- **Bayfront Transmission Substation.** This project will replace the existing 138/69 kV South Bay Substation with a 230/69 kV substation on a site south of the existing substation and South Bay Power Plant. The new 230/69 kV Bayfront Substation will be connected to the Otay Mesa-Miguel-Silvergate 230 kV transmission line. Cost of this project exceeds $50M. The project was proposed by SDG&E as an aging infrastructure project that is financed from the O&M budget and as such does not require ISO approval in the SDG&E opinion. At this time, the need for the ISO approval is still under discussion.

- **New ECO 500/230/69 kV Substation and New 69 kV Transmission Line to Boulevard Substation**. The project will build a new 500/230/69kV substation between Imperial Valley and Miguel near SWPL and 69kV line from the new substation to the Boulevard Substation. It also includes the rebuild of the Boulevard Substation. The project is required to accommodate future renewable generation. Cost of this project exceeds $50M. At this time it is not clear if the project needs the ISO approval, since it is also considered in the Large Generation Interconnection Process (LGIP)

- **East Gate Tap 69 kV Project.** The project proposes to construct a new 69 kV underground tap from the East Gate Substation to the TL664 (East Gate-Miramar Tap 69 kV) and cutover the existing overhead tap from TL664 to TL661 (Penasquitos-East Gate-Rose Canyon) near the East Gate Substation. At this time, other alternatives are being considered to mitigate the overloads for which this project is proposed.

- **Barrett Interim Solution.** This project proposes to install a -40/+50MVAR SVC at the Barrett 69kV substation. The project is needed to solve voltage problems with the Barret-Descanso-Loveland 69 kV outage. As was discussed above in section 5.4.2., there are other alternatives that can mitigate the observed violations more successfully.

- **Addition of 3rd 500/230 kV Transformer Bank at Imperial Valley.** The project will add a third transformer bank (1120 MVA), parallel to the two existing 500/230 kV banks at the Imperial Valley Substation. The project is needed to mitigate congestion associated with the future renewable generation that plan to be connected to the 230 kV bus at the Imperial Valley Substation. Installation of this transformer is also considered in the LGIP process

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Chapter 7: Transmission Projects and Alternatives

Chapters 4, 5 and 6 of this document describe, in detail, the ISO technical studies and results. Also discussed in these chapters are system violations post contingency, equipment requiring system reinforcements and recommended ISO projects to mitigate the observed violations. In accordance with the ISO Transmission Planning Process, project sponsors may respond to these identified needs by submitting their projects through the Request Window, which spans from August 15 through December 15 each year.

This chapter summarizes the valid transmission projects and other alternatives that were submitted trough the 2008 ISO Request Window and applicable ISO decisions on these submissions.

Overall, the ISO received 134 valid submissions through its 2008 Request Window, which consisted of 63 transmission projects seeking the ISO approval. Of these 63 projects:

- 46 were approved,
- Eight were rejected,
- Two require ISO Board of Governors approval in 2009, and
- Seven were withdrawn.

There will be 11 study requests that will be addressed as part of the 2010 ISO Transmission Planning Process and beyond (2009 planning cycle). The ISO will evaluate the following 11 study requests and coordinate the study with the WECC as necessary:

- One merchant,
- Eight economic transmission projects seeking to be PTO,
- One load interconnection,
- One generation project.

The remaining 60 conceptual transmission projects are being developed by project sponsors.

This chapter provides information about the valid projects that are seeking ISO approval and the conceptual projects received through the 2008 Request Window. Section 7.1 discusses the projects that require ISO management approval. These types of projects have a value of $50 Million or less. Section 7.2 discusses projects costing more than $50 Million. Section 7.3 lists the on-going projects for which project sponsors are developing detailed project scope and projects that the ISO has conceptually agreed with but still require further evaluation or additional information.

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7.1 Projects Requiring ISO Management Approval

In this section, table 7-1 lists new projects that receive ISO management approval as part of this planning cycle.

Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
1	**Humboldt 115/60 kV Transformer Replacements:** This is a project proposal to to replace Humboldt 115/60 kV Banks #1 and #2 banks with higher ratings transformers (200/220 MVA)	PG&E	Humboldt	Overloads of Humboldt 115/60kV Banks #1 and #2 under various B and C contingencies	Dec-10	15	This proposed project is consistent with the CAISO identified solutions to mitigate the overloading problems on these transformers under various category B and C contingency conditions. They also provide operation flexbility in the area.
2	**Maple Creek Reactive Support:** Install approx 10 MVAR of dynamic reactive support (SVC) at this substation	PG&E	Humboldt	Ridge Cabin, Maple Creek, Russ Ranch, Willow Creek, and Hoopa 60 kV	May-11	10	This proposed project is consistent with the CAISO identified solutions to mitigate the low voltage problems at these substations. It also provide dynamic reactive support that increases overall reliability of this system.
3	**Garberville Reactive Support:** Install approx 20 MVAR of dynamic reactive support (SVC) at this substation	PG&E	Humboldt	Bridgeville, Fruitland, Fort Seward, Garberville, Kekawaka, Laytonville, Covelo 60 kV	May-11	10	This proposed project is consistent with the CAISO identified solutions to mitigate the low voltage problems on these substations. It also provide dynamic reactive support that increases overall reliability of this system.

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
4	**Fulton-Fitch Mountain 60 kV Line Reconductor:** The project proposes to Reconductor the limiting 8 Miles section with 715 Al conductor (631/742A)	PG&E	North Coast/Bay	Overload of Fulton-Hopland 60kV #1 following the outage of L-1 Ukiah-Hopland-Cloverdale 115kV and T-1 CORTINA 230/115 Bank #4	May-13	5	This proposed project will increase import capability to the North Geysers area by reconductoring the limiting facility between Fulton-Fitch Mountain 60 kV Line.
5	**Clear Lake 60 kV System Reinforcement:** This is a project proposal to to: 1) Build a new 12-mile 115 kV line (297/345 A) tapping Eagle Rock-Cortina line to Middletown substation. 2) Install 100 MVA 115/60 kV Bank at Middletown substation	PG&E	North Coast/Bay	Overloads of 1) Hopland 115/60kV Bank #2 2) Mendocino-Clear Lake 60kV #1 3) Clear lake-Eagle Rock 60kV #1 4) Clear lake-Hopland 60kV #1 5) Low voltages at several 60 and 115 kV substations in the areas under various B and C contingencies	May-12	30	This project has demonstrated it is a prudent solutions to the identified problem since it will connect 115 kV system from Cortina substation with the 60 kV system at Middletown substation. It will mitigates the overloads, low voltage problems in this are
6	**Lakeville No. 2 60 kV Switch Upgrade:** This is a project proposal to to Replace switch 57 to increase rating of this section from 400 to 440/517A	PG&E	North Coast/Bay	Overload of Lakeville 60kV #2	May-10	1	This proposed project is found to be a better alternative to increase import capability of this line since the limiting facility of this line section is the switch.

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
7	**Glenn #1 60 kV Reconductoring**: This is a proposal to reconductor 5.5 miles of Glenn #1 60 kV Line	PG&E	North Valley	Overloads of Glenn #5 60 kV & Cottonwood-Glenn 230 kV, Glenn #5 60 kV & Colusa #1 gen, and Glenn #5 60 kV under various category B and C contingencies	May-13	6-8	Planning studies demonstrate that the preferred alternative is a prudent and technically sound solution to the CAISO identified reliability criteria violations.
8	**Palermo 115 kV Circuit Breaker & Switch Replacement:** This is a project proposal to replace Palermo circuit breaker 182 and associates switches	PG&E	North Valley	Mitigate NERC category B (G-1/L-1) criteria violation. It also contributes to LCR reduction	May-10	1-5	Planning studies demonstrate that the preferred alternative is a prudent and technically sound solution to the CAISO identified reliability needs. This project is a completion of project T686B and will result in LCR decrease see page 40 in the 2011-13 Lon
9	**Gold Hill-Horseshoe 115 kV Reinforcement:** This is a proposal to reconductor 16 miles of the Gold Hill-Horseshoe #1 & #2 115 kV Lines as well as Horseshoe #1 & #2 taps	PG&E	Central Valley	Overloads of Horseshoe Tap #1 & #2 and Gold Hill-Placer #1 115 kV Lines under normal and emergency (B, C) condtions	May-11	5-10	Planning studies demonstrate that the preferred alternative is a prudent and technically sound solution to the CAISO identified reliability needs.

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
10	**Carbona Reliability:** The is a proposal to 1) Reconductor a portion of the Carbona No. 1 60 KV Tap Line 2) Install a new circuit breaker at Kasson Substation and 3) Upgrade Carbona Switch Nos. 37 and 39 to SCADA controlled switches. Also, a new 60 kV ta	PG&E	Central Valley	Increase system reliability	May-10	1-5	Planning studies demonstrate that the preferred alternative is a prudent and technically sound solution to the identified reliability needs allowing maintenance on the Carbona #2 60 kV Tap without firm load drop.
11	**Kyoho Manufacturing Calfironia 115 kV Interconnection:** This is a project proposal to construct a new 2 mile tap line on to the Stockton "A"-Lockeford-Bellota #2 115 kV Line	PG&E	Central Valley	Interconnect customer	Jun-10	1-5	Planning studies demonstrate that the preferred alternative is a prudent and technically sound solution to interconnect this new customer to the CAISO grid.
12	**Lodi-industrial 60 kV Line Switch Upgrade Project**: This is a proposal to replace switch 29 on the Lodi-Industrial 60 kV Line	PG&E	Central Valley	Increase system reliability	May-10	<1	Planning studies demonstrate that the preferred alternative is a prudent and technically sound solution to the identified reliability needs.

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
13	**Salado-Newman 60 kV Line #2 Reconductor:** This is a project to reconductor 6 spans of the Salado-Newman 60 kV Line #2	PG&E	Central Valley	Increase system reliability	May-10	<1	Planning studies demonstrate that the preferred alternative is a prudent and technically sound solution to the identified reliability needs.
14	**Country Club 60 kV Bus Upgrade:** This is a project to reconductor Country 60 kV Bus and re-rate Hammer-Country Club 60 kV to 4 fps	PG&E	Central Valley	Increase system reliability	May-10	1-5	Planning studies demonstrate that the preferred alternative is a prudent and technically sound solution to the identified reliability needs.
15	**Valley Spring 230/60 kV Transmission Addition:** This is a proposal to add a new Valley Springs 230/60 kV Transformer #2	PG&E	Central Valley	Overload of Valley Springs 230/60 kV Transformer under B contingencies. The project also improve reliability (reduce hours of load potential load dropping) in the area	May-12	8-10	Planning studies demonstrate that the preferred alternative is a prudent and technically sound solution to the CAISO identified reliability needs. It also eliminates load drop ~130 MW for a single transformer outage and it allowes for the existing transfo
16	**Cooley Landing-Los Altos 60 kV line reconductor:** This is a project proposal to reconductor Cooley Landing – Los Altos 60 kV line (~ 11 miles) with a conductor 800 amps or greater. In addition, line terminal equipment may need to be upgraded	PG&E	Greater Bay Area	Overload of Cooley Landing-Westinghous Junction, Los Altos-Westinghouse Jct, and Los Altos sub-Los Altos 60 kV Jct lines following various Category B contingencies	May-13	5-10	This project is the preferred alternative to mitigate Category B overloads and satisfies ISO defined reliability needs

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
17	**Evergreen-Mabury 60 kV to 115 kV conversion:** The scope if this project includes -Convert Mabury Substation from 60 kV to 115 kV -Rebuild Evergreen-Mabury 60 kV line (~6 miles) into a 115 kV circuit with conductors rated 800 amps or greater. In addition, line terminal equipment may need to be upgraded.	PG&E	Greater Bay Area	Overloads of Dixon Landing-Newark and Piercy-Metclf E 115 kV lines following the outage of Piercy-Metcalf 115 kV line out and Swift - Metcalf 115 kV and Piercy - Metcalf 115 kV lines out	May-12	10-15	This project is the preferred alternative to mitigate Category B and Category C overloads and satisfies ISO defined reliability needs
18	**Menlo Area 60 kV System Upgrade:** As part of this project, it includes - Replace fifteen 600 amp switches with 1200 amp switches - Upgrade limited components on the Jefferson-Stanford and Cooley Landing-Stanford 60 kV lines -Reconductor 60 kV buses at Glenwood and Menlo substations.	PG&E	Greater Bay Area	Overloads of Jefferson-Emerald Lake, Glenwood-S.R.I., Las Pulgas-Emerald Lake, Menlo-Las Pulgas (all sections), Jefferson-Emerald Lake, Glenwood-S.R.I., Las Pulgas-Emerald Lake, Menlo-Las Pulgas, and Cooley Landing-S.R.I. 60 kV line #2 following various contingencies.	May-10	5-10	This project mitigates nine different overloaded facilities caused under category B and Category C contingencies. It is a prudent and technically sound solution to ISO defined reliability needs.
19	**Monta Vista-Los Gatos-Evergreen 60 kV Project:** This is a project proposal to - Reconductor limited sections of Monta Vista-Los Gatos (~9 miles) and Evergreen-Los Gatos (~11 miles) 60 kV lines with a conductor rated for 800 amps or greater. Line terminal equipment may need upgrade.	PG&E	Greater Bay Area	Overloads of Monta Vista-Los Gatos, Almaden-Senter Tap, and Senter Tap-Evergreen 60 kV lines following various Category B contingencies	May-18	10-15	This project is the best alternative to mitigate Category B overloads and satisfies ISO defined reliability needs.

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
20	**Daly City Bus Reconfiguration:** The scope of this project include the installation of two new 115 kV line circuit breakers with SCADA, two bus sectionalizing circuit breakers with SCADA, disconnect switches and a low profile 115 kV bus at Daly City substation	PG&E	Greater Bay Area	PG&E proposed: Daly City Bus Reconfiguration	Dec-10	5-10	This project will prevent Category B violations and improve operational flexibility at the Daly City 115 kV substaion to do equipment clearances
21	**Larkin Circuit Breaker No. 192:** This is a proposal to - Operate Larkin CB 192 normally closed - Install CTs and overcurrent relays on distribution transformers at Larkin - Adjust CT ratios at Martin, Potrero and Mission substations	PG&E	Greater Bay Area	PG&E proposed: Larkin Circuit Breaker No. 192	Mar-09	1-5	This project will require operating the circuit breaker No. 192 at Larkin substation normally closed, which will balance the loading on 115 kV lines from Martin substation.
22	**Tri-Valley Voltage Control:** This is a proposal to install two 48 MVAR shunt reactors at Vineyard substation and one 48 MVAR shunt reactor at Dublin substation. Substation terminal equipment may need to be upgraded as well.	PG&E	Greater Bay Area	PG&E proposed: Tri-Valley Voltage Control	Nov-10	10-15	This project mitigates higher voltages at Cayetano, North Dublin and Vineyard 230 kV substations and satisfies ISO reliability standard for voltage limits

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
1	**Humboldt 115/60 kV Transformer Replacements:** This is a project proposal to to replace Humboldt 115/60 kV Banks #1 and #2 banks with higher ratings transformers (200/220 MVA)	PG&E	Humboldt	Overloads of Humboldt 115/60kV Banks #1 and #2 under various B and C contingencies	Dec-10	15	This proposed project is consistent with the CAISO identified solutions to mitigate the overloading problems on these transformers under various category B and C contingency conditions. They also provide operation flexbility in the area.
2	**Maple Creek Reactive Support:** Install approx 10 MVAR of dynamic reactive support (SVC) at this substation	PG&E	Humboldt	Ridge Cabin, Maple Creek, Russ Ranch, Willow Creek, and Hoopa 60 kV	May-11	10	This proposed project is consistent with the CAISO identified solutions to mitigate the low voltage problems at these substations. It also provide dynamic reactive support that increases overall reliability of this system.
3	**Garberville Reactive Support:** Install approx 20 MVAR of dynamic reactive support (SVC) at this substation	PG&E	Humboldt	Bridgeville, Fruitland, Fort Seward, Garberville, Kekawaka, Laytonville, Covelo 60 kV	May-11	10	This proposed project is consistent with the CAISO identified solutions to mitigate the low voltage problems on these substations. It also provide dynamic reactive support that increases overall reliability of this system.
No	**Project & Scope**	**Project Sponsor**	**Area**	**Needs**	**In-Service Date**	**Estimate Costs ($M)**	**CAISO Justifications**

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
27	**Del Monte - Fort Ord 60 kV Reinforcement Project:** This is a proposal to install two 60 kV CBs at Ford Ord and reconductor Del Monte-Ford Ord 60 kV #1 and #2	PG&E	Central Coast, Los Padres, Kern	Normal overloads of Del Monte 60 kV Line #1 and overload of Del Monte 60 kV Line #2 following the outage od Del Monte 60 kV Line #1	May 2010 and May 2012	5-10	Mitigates Cat A and B overloads due to load growth in Fort Ord area.
28	**Natividad Substation Interconnection:** This proposal is proposed to build New distribution sub at Natividad with a 115kV ring bus and Reconductor the Crazy Horse – Salinas sections	PG&E	Central Coast, Los Padres, Kern	Overloads of Moss Landing – Salinas – Soledad #1 and #2 following the outages of Moss Landing Salinas #1 and #2 115 kV Lines (Category C)	May-12	15-20	Mitigates Cat C overload and provides additional distribution capacity which cannot be handled by existing Galiban station in Central Coast.
29	**San Justo Substation Interconnection:** This is a proposal to build a new San Justo substation connected to Crazy Horse – Hollister No. 1 115kV line	PG&E	Central Coast, Los Padres, Kern	- Improved service reliability for the City of San Juan Bautista - Cater to increasing load (almost 4 MW block load by 2009). Increase in load cannot be served by Hollister - Several food processing plants require reliable service - PG&E distribution expe	May-11	5-10	San Jusato susbstation will off-load Hollister and take care of block load increase downstream of Hollister.

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
30	**Burns Reliability Project:** This is a proposal to Install a 60kV breaker at Burns and SCADA operated switches at Big Basin and Lone Star Jct	PG&E	Central Coast, Los Padres, Kern	- Improved reliability (reduction in customer outage minutes) - Quicker restoration and isolation - Operational flexibility	Dec-10	3-5	Facilitates quick isolation of faults on Monta Vista-Burns 60kV path. Reduces restoration time.
31	**Caruthers - Kingsburg 70kV:** This is a proposal to reconductor Camden-Camden Junction, Camden Junction-Caruthers, and Camden Junction-Lemoore Naval Air Station (NAS) 70 kV line sections (approximately 25 miles in length). In addition, the 2 mile Henrietta-Lemoore NAS 70 kV line section will be double circuited to provide increased reliability. The project scope would also involve upgrading station terminal equipment and obtaining any necessary environmental and land permits to complete the reconductoring work.	PG&E	Central Coast, Los Padres, Kern	- NERC Category A - Reduce outage exposure by allowing Camden and Caruthers to operate as Flip-Flop Stations - to support anticipated additional load for Agricultural Internal Combustion Engine Conversion		10-15	Allows for Camden and Caruthers to be served from multiple sources.
32	**Guernsey-Henrietta 70 kV Line Reconductor Project:** This is a proposal to reconductor a 3 miles section of the line	PG&E	PG&E-San Joaquin Valley	- NERC Category B (G-1) - Known current operational issue	May-11	1-5	Reduce the overload exposure for the loss of the GWF Hanford Cogen

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
33	**Herndon 115 kV Circuit Breaker Replacement Project:** This project proposal involves the replacement of CB 122 with a 2000 Amps circuit breaker	PG&E	PG&E-San Joaquin Valley	New-PG&E identified (increase system reliability)	May-11	1-5	This project would remove the need to drop load for the loss of the parrallel circuit
34	**Herndon 230/115 kV Transformer Project:** This is a proposal to add 3rd 230/115kV Bank at Herndon.	PG&E	PG&E-San Joaquin Valley	Overload of Herndon 230/115kV Bank #1 or #2 following the ouatge of the parallel transformer (Category B)	May-11	10-15	Reduce the overload exposure of the 230/115kV Banks at Herndon and thereby also reducing the area LCR requirement
35	**Sanger-Reedley 70 kV to 115 kV Conversion Project:** This is a proposal to convert Sanger – Reedley 70 kV for 115 kV operation and reconductor line to carry minimum of 900 Amps under emergency conditions	PG&E	PG&E-San Joaquin Valley	Overloads of Kingsriver-Sanger-Reedley 115kV and Sanger-Reedley 70kV Lines following various Category B contingencies	May-11	20-25	This project would convert the last remaining 70kV element between Sanger and Reedley, thereby increase the load serving capabilty to the Reedley area
36	**Sanger-California Ave 70 kV to 115 kV Voltage Conversion Project:** This is a proposal to convert Sanger – California 70 kV Line #2 for 115 kV operations	PG&E	PG&E-San Joaquin Valley	Overload of Cal Ave-McCall 115kV Line after the outage of McCall-West Fresno 115kV Line (Category B)	May-11	5-10	This project would add a third source into the West Fresno/California Ave area significantly improve area reliability

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
37	**Sheperd Substation**	PG&E	PG&E-San Joaquin Valley	Required for load interconection request	May-11	8-10	Tariff and Compliance (Obligation to Serve)
38	**Barre-Ellis 230kV Line Upgrade Project:** This project will upgrade terminal equipment as required at both Barre and Ellis substations. Additionally, it will also modify/upgrade the structures in the right of way as required to increase the respective emerg	SCE		Overload on BARRE-ELLIS 230 kV line #1 after various category B and C contingencies	Jan-10	1	The CAISO Staff recommends that this project be approved by ISO Management. This project is determined to be the least cost feasible transmission alternative and would mitigate identified NERC Category B and C contingency overloads.
39	**Redondo-La Fresa 230 kV Line Upgrades:** This is a proposal to upgrade the terminal equipment at the Redondo 230 kV substation (i.e. disconnects, CBs etc), to raise its emergency rating	SCE		Overloads of Redondo -La Fresa 230 kV #1 and #2 following various category C contingencies	Dec-09	2.7	The CAISO Staff recommends that this project be approved by ISO Management.This project is determined to be the least cost feasible transmission alternative and would mitigate identified NERC Category C contingencies.

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
40	**Rector Static VAR System (SVS) Project:** This project is to expand Rector Static VAR System (SVS) by adding two 79.2 MVAR Mechanically Switched Capacitor (MSC) at Rector 230 kV Bus and SVC control points to maintain minimum voltages of 229 kV as directed by SOB17, and optimize SVC VAR output to prrovide dynamic stability for system disturbance	SCE		Transient Voltage and Frequency Dip at RECTOR 66KV Bus following the outages of Big Creek 3-Rector 230KV N-1 and Big Creek 3-Rector 230KV N-2	Apr-10	9.5	The CAISO Staff recommends that this project be approved by ISO Management with the condition that: (a) SCE implements fast fault clearing (4-cycle) of 3-phase fault using the fast-fault clearing capability of the 230kV circuit breakers in the Big Creek and Rector areas; (b) SCE completes the previously CAISO-approved San Joaquin Cross Valley Project as scheduled by 2012; and (c) SCE investigates the feasiblity of modifying the time it takes to run back Big Creek generation under N-1 and N-2 contingencies from 12 cycles to 4 cycles (note: if 4 cycles are not feasible for generation run-back, then consider 8 cycles)
41	**Bailey 66 kV Circuit Breakers Upgrades:** This is a proposal to replace 2 CAISO controlled 66 kV CB at Bailey Substation to 40 kA	SCE		Two CBs at Bailey substation will exceed their interrupting current limits	Dec-09	0.4	The CAISO agrees with the need of this project

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Table 7-1: New Transmission Projects in this planning cycle for which ISO staff has recommended approval (cont)

No	Project & Scope	Project Sponsor	Area	Needs	In-Service Date	Estimate Costs ($M)	CAISO Justifications
42	**Devers 115 kV circuit Breakers Upgrades:** This is a proposal to replace 7 CAISO controlled 115 kV CB at Devers Substation to 40 kA	SCE		Seven CBs at Devers substation will exceed their interrupting current limits	Dec-09	2.5	The CAISO agrees with the need of this project
43	**Kramer 115 kV circuit Breakers Upgrades:** This is a proposal to replace 10 CAISO controlled 115 kV CB at Kramer Substation to 40 kA	SCE		Ten CBs at Kramer substation will exceed their interrupting current limits	Dec-09	3.5	The CAISO agrees with the need of this project
44	**Victor 115 kV Circuit Breakers Upgrades:** This is a proposal to replace 4 CAISO controlled 115 kV CB at Victor Substation to 40 kA	SCE		Four CBs at Kramer substation will exceed their interrupting current limits	Dec-09	1.4	The CAISO agrees with the need of this project
45	**Antelope 66 kV Circuit Breakers Upgrades:** This is a proposal to replace 38 CAISO controlled 66 kV CB at Antelope Substation to 40 kA	SCE		Thirty six CBs at Kramer substation will exceed their interrupting current limits	Dec-09	7	The CAISO agrees with the need of this project
46	**New 138 Tap: TL13835** The project will create a new 138kV tap from Talega substation to TL13835 serving Laguna Niguel and San Mateo areas.	SDG&E		Overload of Talega-San Mateo following the outage of Laguna Niguel and vice versa	Oct-09	<10	Proposed by SDG&E. Will help to avoid reconductoring of two 138 kV lines in preparation for the Orange County Transmission Upgrade Project

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In addition to the project that ISO management has approved, this section lists new projects that ISO management has rejected the proposal

Table 7-2: Transmission Projects that were not recommend for approval by ISO staff

No	Project & Scope	Project Sponsor
1	Cottonwood Interim Solution	Transmission Technology Solutions LLC (TTS)
2	Missouri Flat Expansion	PG&E
3	Rio Oso Reactive	PG&E
4	Installation of additional capacitors on 230 and138 kV buses:	SDG&E
5	Garberville Interim Solution	Transmission Technology Solutions LLC (TTS)
6	Maple Creek Interim Solution	Transmission Technology Solutions LLC (TTS)
7	West Fresno Interim Solution	Transmission Technology Solutions LLC (TTS)
8	Shepherd Interim Solution	Transmission Technology Solutions LLC (TTS)

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7.2 Projects Requiring ISO Board of Governors Approval

In compliance with the ISO Transmission Planning BPM, Table 7-3 documents the projects that need the ISO Board of Governor's approval. The table also provides tentative ISO board meeting dates that these projects may be presented for ISO Board of Governors approval once ISO management has concurred with these project proposals. Consequently, it is possible this list contains the projects that still being evaluated by the ISO and the exact ISO board presentation may be revised at the later time.

Table 7-3: Transmission Projects that require ISO board approval and tentative board presentation

No	Project & Scope	Project Sponsor	Needs	Espected In-Service Date	Estimate Costs ($M)	Tentative ISO Board presentation
1	**Drycreekwind Location Constrained Resource Interconnection Facility (LCRIF) Project:** This is a project proposal to build Drycreekwind 230kV Substation and 4-mile 230kV transmission line connecting Drycreekwind to Whirlwind 500/230kV Substation. The total capacity for the transmission line is 1,150 MW. At this time, there are two proposed generation projects totaling 550 MW, or consisting 47.8% of the proposed LCRI facility.	SCE	Connecting location-constrained resource interconnection generators (LCRIGs), of which all are renewable generation, in the Tehachapi Wind Resources Area	Feb-10	49.8	May-09
2	**Highwind Location Constrained Resoruce Interconnection Facility Interconnection Facility (LCRIF) Project:** This is a project proposal to build Highwind 230kV Substation and 9.6-mile 230kV transmission line connecting Highwind to Windhub 500/230kV Substation. The total capacity for the transmission line is 1,150 MW. At this time, there are three proposed generation projects totaling 759 MW, or consisting 66% of the proposed LCRI facility.	SCE	Connecting location-constrained resource interconnection generators (LCRIGs), of which all are renewable generation, in the Tehachapi Wind Resources Area	Dec-10	46.1	May-09

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7.3 Ongoing Projects

Tables 7-4 contains a list of ongoing projects which includes conceptual projects that detailed project scope are being developed by project sponsors or the projects that ISO has conceptually agreed with the scope of the projects but still require further evaluation or additional information. Once the full project scope and all information have been provided, these projects may be considered for approval at the later time.

Table 7-4: Ongoing Transmission Projects

No	Project	Project Sponsor
1	Arco-Twisselman Area Reinforcement	PG&E
2	Ashlan- Gregg and Ashlan - Herndon 230 kV Reconductor	PG&E
3	Atlantic - Placer Voltage Conversion	PG&E
4	Atlantic - Rio Oso - Gold Hill 230 kV Lines	PG&E
5	Bay Area Bulk Transmission	PG&E
6	Borden Coppermine 70 kV Upgrade	PG&E
7	Brighton - Davis 115 kV Reconductoring	PG&E
8	Canada - Pacific Northwest - Norhtern CA Transmission Project	PG&E
9	Cascade Area Reinforcement	PG&E
10	Contra Costa Substation Reliability Improvement Plan	PG&E
11	Corcoran - Guernsey Area Reinforcement	PG&E
12	Cressey - Gallo 115 kV Line Project	PG&E
13	Drum - Grass Valley - Weimer 60 kV line	PG&E
14	E1 Substation	PG&E
15	Eagle Rock and Mendocino 115 kV Capacity Increase	PG&E
16	East Bay - Potrero 230 kV Transmission	PG&E
17	Eight Mile Road - Tesla 230 kV Lines Reconductor	PG&E
18	Essex Jct - Arcata - Fairhaven 60 kV Line Reconductoring Reinforcement	PG&E
19	Exchequer - Yosemite 70 kV Reconductor	PG&E
20	Ignacio-Mare Island 115 kV System Reinforcement Project	PG&E
21	Kern - Lamont Area Reinforcement	PG&E
22	Alberhill 500 kV Method of Service	SCE
23	West of Devers 230 kV Lines Rebuild	SCE
24	Antelope - Bailey - Windhub System Reconfiguration	SCE
25	Eldorado - Ivanpah Transmission Project	SCE
26	New Eastgate Tap 69kV	SDG&E
27	New ECO 500/230/69kV Substation & New 69kV Transmission Line to Boulevard Substation	SDG&E

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Table 7-4: Ongoing Transmission Projects (cont)

No	Project	Project Sponsor
28	Addition 3rd 500/230 kV Transformer Bank (82) at Imperial Valley Substation	SDG&E
29	Orange County Transmission Expansion	SDG&E
30	Bayfront Transmission Substation	SDG&E
31	Lemoore Area Reinforcement	PG&E
32	Lockeford - Lodi Area 60 kV Reinforcement	PG&E
33	Los Banos - Oro Loma 70 kV Area Reinforcement	PG&E
34	Metcalf-Morgan Hill 115 kV Reinforcement Project	PG&E
35	Morro Bay-Midway 230 kV Line Nos 1. and 2 Reconductor	PG&E
36	Mosher Transmission Project	PG&E
37	Oakhurst 115 kV Tap Reinforcement	PG&E
38	Oakland Area Long Term Plan	PG&E
39	Paso Robles Area Reinforcement	PG&E
40	Renfro Area Reinforcement	PG&E
41	San Luis Obispo Solar Switching Station #3	PG&E
42	San Vincente 230/115 kV Substation	PG&E
43	South of Palermo 115 kV Reinforcement	PG&E
44	Table Mountain - Vaca Dixon 230 kV Reinforcement	PG&E
45	Vaca Dixon - Davis 115 kV Conversion	PG&E
46	Vaca Dixon - Sobrante - Moraga 230 kV Reinforcement	PG&E
47	Valley Springs - Martell 60 kV Nos. 1 and 2 Reinforcement	PG&E
48	Valley Springs No. 1 60 kV Line Reinforcement	PG&E
49	West Fresno 115 kV Bus Upgrade Project	PG&E
50	Wilson-Oro Loma 115 kV Reconductor Project	PG&E
51	Kern-Old River 70 kV reconductor project	PG&E
52	Santa Cruz 115 kV Reinforcement Project	PG&E
53	Watsonville 60 kV to 115 kV Conversion Project:	PG&E
54	Old River Interim	TTS
55	Watsonville Interim Solution	TTS
56	Camp Evers Interim Solution	TTS
57	Trinity Interim Solution	TTS
58	Cal Cement Interim Solution	TTS
59	Barrett Interim Solution	TTS
60	Embarcadero-Potrero 230 kV Transmission Project	PG&E

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Chapter 8: Other major initiatives and transmission plan drivers

This chapter discusses other technical studies or initiatives that were conducted by the ISO during 2008 and their results.

8.1 Reliability Requirements

Sections 8.1.1 and 8.1.2 provide a summary of two technical studies conducted by ISO under the scope of Reliability Requirements initiative. These two studies are Local Capacity Requirements (LCR) studies and Generation and Import Deliverability Assessments

8.1.1 Local Capacity Requirements

In 2008, the ISO conducted two types of LCR studies. A short-term LCR analysis was conducted for the 2009 system configuration to determine the local capacity requirements for the 2009 resource procurement process. This study was completed in March 2008 to ensure the study results were available for interested stakeholders before the deadline issued by CPUC. A long-term LCR analysis was also performed to identify local capacity needs in the 2011 and 2013 time frames. The long-term analysis was also performed to provide ISO Transmission Planning Process participants the trend of future LCR requirements up to five-years in the future. This section summarizes study results from both the next year and long-term LCR studies.

As appeared in the LCR Report and indicated in LCR Manual, there are 10 load pockets throughout ISO Controlled Grid as shown below:

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Table 8-1: List of LCR areas and the corresponding PTO service territories within the ISO BAA

No	LCR Area	PTO Service Territory
1	Humboldt	PG&E
2	North Coast and North Bay	
3	Sierra	
4	Greater Bay area	
5	Stockton	
6	Greater Fresno	
7	Kern	
8	Los Angeles (LA) basin	SCE
9	Big Creek/Ventura	
10	SDG&E area	SDG&E

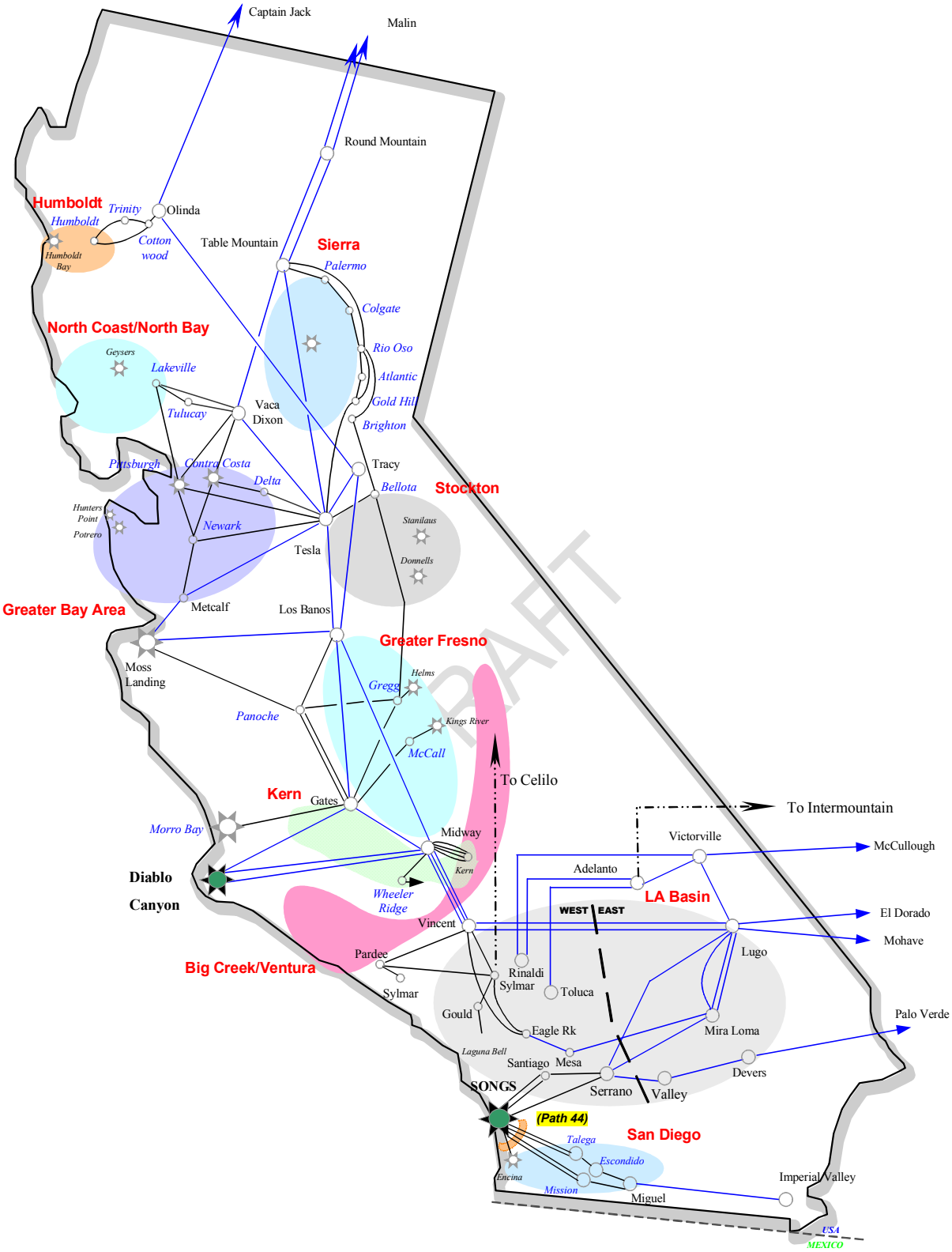

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Figure 8-1: Illustrates the approximate geographical locations of these LCR areas.

It is imperative to understand that each load pocket is unique and different in size of capacity

requirements due to different system configuration. For example, Humboldt is a small pocket with total capacity requirements approximately 200 MW while the requirements in LA-Basin is approximately 10,000 MW. Short-term and Long-term LCR study results from this year's studies are shown in table 8-2.

Table 8-2: Local capacity areas and requirements for 2009, 2011 and 2013

Local Area	Total LCR Need (MW) 2009	2011	2013
Humboldt	177	185	190
North Coast/North Bay	766	913	986
Sierra	2320	2099	2117
Stockton	726	685	714
Greater Bay Area	4791	5110	5344
Greater Fresno	2680	2715	2757
Kern	422	412	451
LA Basin	9728	10019	8585
Big Creek/Ventura	3178	4075	3402
San Diego	3093	2324*	2489*
Total	**27881**	**28537**	**27035**

* Potentially higher requirements combined with another area (please see more details in the LCR report)

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For more information of the short-term and long-term LCR studies, please refer to ISO website at http://caiso.com/1ca5/1ca5d8334b920.html.

8.2 ISO Short-Term Plan – Addressing Operational Needs

Integral to the ISO Transmission Planning Process, the Short Term California Transmission Plan focuses on providing transmission reliability and/or economic solutions for the short term: one to three years in the future. The Short Term Plan analyzes the system and recommends solutions to existing and/or anticipated reliability/congestion issues. It also tracks the cost/benefits of any projects as they are connected to the grid.

The ISO Short Term Plan is produced by Regional Transmission Engineering. It takes a proactive approach at identifying operational gaps where an operating limit developed to meet reliability standards may be exceeded in real-time. In analyzing the operational gaps, the plan focuses on overload and voltage issues, under both normal and N-1 conditions. All the operational gaps identified in this report fall into two categories: Congestion and Reliability. It is considered a Congestion issue when an operating limit violation can be mitigated without load curtailment. On the other hand, if an operating limit violation can not be mitigated without pre-contingency load curtailment, it is considered a Reliability issue. To identify and resolve Congestion and Reliability issues Regional Transmission Engineering works closely with ISO Operating Personnel (Grid Ops group) throughout the year. This interaction allows Regional Transmission Engineers to prepare a list of key congestion & reliability issues that need to be addressed in the Short Term Plan. Once the Congestion or Reliability issues are identified, short term solutions are developed by, working closely with PTOs, ISO Operation Personnel and stakeholders.

The short-term solutions proposed in the Short Term Plan are limited to projects with lead times less than three years. These types of projects include:

- Transmission Line Re-Rates
- Transformer Re-Rates
- New SPS/RAS
- Enhance Existing SPS/RAS
- SCADA/RTU installation
- System Re-Configuration
- Maintain or Expedite projects already scheduled.

Table 8-3 summarizes the study results from this year ISO short-term plan which include the identified concerns (reliability or congestion), ISO proposals (new and previously identified), and related information. The Status column indicates the current position that a given project is in. In general, column H of this table provides the updated status of each proposal which can be one of the following categories:

ISO-Proposed-Projects proposed by the ISO but have not been accepted by the PTOs.

PTO Planning – Projects that the PTO is currently engaged in the Planning work. These could include projects proposed by the ISO or PTO and have been approved by PTO and ISO.

PTO Implementing – Projects on track to being put into service. Given with project number and parallel date, reference found in Attachment #1 – "Transmission Project June 2009-June 2011".

In Service – Projects completed during 2008, listed with impacts to operating requirements (Procedures or SPS/RAS)

Withdrawn – Projects proposed by ISO from previous year(s) Short-Term Plans but turn out to not be ***economically*** or ***feasibly*** justifiable and noted as such.

Each project is provided with the cost and benefits received where appropriate. The Gap column is intended to indicate the number of summers expected for the issue to persist starting from the summer of 2008. The list is grouped by PTO and not arranged in any order.

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Table 8-3: Complete List of Proposed and Completed projects

#	Contingency/Condition	Project/Solution	Concern	Region	Cost (M)	Status	Gap (Yrs)
1	Cont: None Cond: Low Voltage on Davis 115kV Bus	**Woodland Davis Voltage Support** **Long Term:** Consider new project to install a shunt capacitor at Woodland or Davis Substation. **Short Term:** Install UVLS relays at Woodland Substation	Reliability	PG&E – North East		PTO Implementing: May 2012 Implemented: July 2007	4
2	Cont: Loss of Rio Bravo (Rocklin) Gen Cond: Normal Overload	**Atlantic 230/60kV Bank** **Long Term:** Convert the 60kV to 115kV. Maintain the In-Service date; slipped 1 year since last year's plan. **Short Term:** Complete necessary bus work to operate with both N.O. Bank 1 and Bank 2 in-service. They can be in parallel or split on the 60kV bus	Reliability	PG&E – North East		PTO Implementing: T759C (May 2009) Implemented: Piggy-Back Banks 1 & 2 (May 2007)	1
3	Cont: Loss of Table Mt – Vaca Dixon 500kV Line Cond: Emergency Overload	**Table Mt-Rio Oso 230kV Upgrade and Tower Raise** **Long Term:** Reconductor the line, current schedule is May 2010. **Short Term:** Complete any interim upgrades available. (Modify 500kV RAS)	Reliability	PG&E – North East		PTO Implementing: T1030 (Slipped to: May 2010 From May 2009) Implemented into T-165 May 2008	2

#	Contingency/Condition	Project/Solution	Concern	Region	Cost (M)	Status	Gap (Yrs)
4	Cont: None and Loss of Gates-Gregg 230kV Cond: Normal and Emergency Overload during Peak and Off-Peak (Helms Pumping)	Panoche-Kearney 230kV line Upgrade **Long Term:** Consider new project to reconductor the Panoche-Kearney 230kV line or build another source into Gregg. **Short Term:** Apply Short Term Emergency Rating across peak and Temperature Adjust when pumping at Helms.	Reliability	PG&E – South	$22-$33	ISO-Proposed: 2008/2009 Implemented: July 2007	
5	Cont: None and Loss of parallel path into McCall 230kV bus Cond: Normal and Emergency Overload during Peak and Off-Peak (Helms Pumping)	Gates-McCall (1), Panoche-Helm (2), and Helm-McCall (3)230kV lines **Long Term:** Consider the following: Promote new generation projects tied into some critical 230kV sources. Reconductor the Panoche-Helm (2), Helm-McCall (3), and Gates-McCall (1) 230kV lines or build another source into Gregg or McCall. Make system upgrades at Helm to allow Helm-McCall and Panoche-Helm 230kV lines to the HTT RAS. **Short Term:** Apply Short Term Emergency Rating to the Panoche-Helm, Helm-McCall, and Gates-McCall 230kV lines across peak and Temperature Adjust when pumping at Helms.	Reliability	PG&E – South	1: $18.8-28.8 2: $12.4-18.6 3. $14.8-22.2	ISO-Proposed: 2008/2009	
6	Cont: Loss of Palermo-Colgate	Palermo 230/115kV Bank #2	Congestion	PG&E – North		ISO-Proposed: 2009	

#	Contingency/Condition	Project/Solution	Concern	Region	Cost (M)	Status	Gap (Yrs)
	230kV or Table Mtn-Rio Oso 230kV Line Cond: Emergency overload of the Palermo 230/115 kV Bank #2	Short Term: Replace 115kV conductor and breaker Develop contract with area QF generators to remain online during summer weekends		East			
6	Cont: Loss of Colgate 230/60 kV Bank #3 Cond: Normal and Emergency Overload of Colgate-Palermo 60kV Line	New Pease-Marysville 60kV line Palermo-Rio Oso 115kV Reconductor **Long Term:** Maintain current schedule or expedite. Do not let the current schedules slip. Pease-Marysville 60kV line slipped since last year's plan. Both projects are required to allow the Colgate-Palermo 60kV system to operate in a radial fashion	Reliability	PG&E – North East		PTO Implementing: T815, T686A (Slipped to Dec 2009 From 2007)	1.5
7	Cont: Loss of Rio Oso 230/115kV Bank 1 or 2 Cond: Emergency Overload of remaining Bank	Rio Oso 230/115kV Banks 1 & 2 Upgrade **Long Term:** Maintain current schedule of May 2009. **Short Term:** Apply Short Term Emergency rating on the Rio Oso Banks	Congestion	PG&E – North East		PTO Implementing: T985B (Slipped to May 2011 From May 2011) Implemented: July 2007	3

#	Contingency/Condition	Project/Solution	Concern	Region	Cost (M)	Status	Gap (Yrs)
8	Cont: Loss of Moraga 230/115kV Bnk Cond: Overload of Moraga 230/115kV Bnk #1 or #2	Moraga 230/115kV Banks 1 and 2 Upgrade **Long Term:** Maintain current schedule of May 2010 and complete in parallel with the B-X #2 cable.	Congestion	PG&E – Bay Area		PTO Implementing: T990 (May 2010)	2
9	Cont: Loss of CX or DL 115kV Lines Cond: Overload of remaining 115kV Line	Third Oakland 115kV Cable **Long Term:** Maintain May 2010 date for new Oakland B-X #2 cable.	Congestion	PG&E – Bay Area		PTO Implementing: T983 (May 2010)	2
10	Cont: None Cond: Normal Overload on AHW#2 115kV Line	Larkin Breaker Upgrade\ Potrero Unit #3 Short Term: 1. Determine upgrades required at Larkin to permanently close CB 192. 2. Ensure Potrero Unit #3 available in 2009 or develop RAS to drop load post-contingency	Congestion	PG&E – Bay Area	$1-2 ?	1. PTO Implementing: Project T-1078 (December 2008) 2. ISO- Proposed: 2009	.5
11	Cont: Loss of Ravenswood – San Mateo #1 and #2 230kV Lines Cond: Emergency Overload of Ravenswood – San	South of San Mateo Capacity Increase **Long Term:** Maintain May 2011 schedule to reconductor the Ravenswood-San Mateo 115kV line	Congestion	PG&E – Bay Area		PTO Implementing: T920A (Slipped to May 2011 From 2009)	3

#	Contingency/Condition	Project/Solution	Concern	Region	Cost (M)	Status	Gap (Yrs)
	Mateo 115kV Line						
12	Cont: Loss of Placer-Gold Hill #1 or #2 Cond: Emerg. Overload of remaining line	Placer-Gold Hill #1 & #2 115kV lines **Long Term:** Maintain May 2008 schedule to reconductor the two lines.	Reliability	PG&E – North East		PTO Implementing: T444 (Slipped to May 2009 From 2008)	1
13	Cont: Loss of Brighton 230/115kV Bank #10 Cond: 1HR Emerg rating exceeded	Brighton 230/115kV Bank 9 **Long Term:** Maintain current schedule to replace Bank 9.	Reliability	PG&E – North East		PTO Implementing: T758A (Slipped to Nov 2009 from 5/2009)	1.5
14	Cont: Brighton-Davis 115kV Line Cond: Emerg Overload	West Sacramento-Brighton 115kV line **Long Term:** Maintain May 2009 schedule to reconductor the line. **Short Term:** Undo the 4fps re-rate back to the standard emergency rating.	Reliability	PG&E – North East		PTO Implementing: T177B (May 2009)	1
15	Cont: Loss of Bell – Placer or Drum – Bell 115kV Line Cond: Emerg Overload of Drum-Rio Oso #1 or #2 115kV Lines	Drum-Rio Oso #1 and #2 115kV line Reconductor or Drum Generation SPS. **Long Term:** Consider new project to reconductor the Drum-Rio Oso #1 and #2 115kV lines **Short Term:** 1. Install an SPS that drops Drum Area generation post-contingency. 2. Apply Short-Term Rating	Congestion	PG&E – North East		ISO-Proposed: 2008	

#	Contingency/Condition	Project/Solution	Concern	Region	Cost (M)	Status	Gap (Yrs)
16	Cont: None Cond: Normal Overload	Bellota-Gregg 230kV Reconductor **Long Term:** Consider new project to reconductor the Warnerville-Wilson (1), Wilson-Gregg (2), Gregg-Borden (3), and Wilson-Borden (4) 230kV lines. **Short Term:** Temperature adjust the lines only when pumping at Helms	Congestion	PG&E – South	1: $17.6-26.4 2: $18.8-28.2 3: $4.8-7.2 4: $16.4-24.6	ISO-Proposed: 2008 Implemented into T-129	
17	Cont: None Cond: No Emerg Limit due relay setup During Winter	Dairlyand-Le Grand and Le Grand-Chowchilla 115kV Protection Upgrade **Long Term:** Replace the over-current relays with impedance relays. **Short Term:** De-rate the line in the winter season	Congestion	PG&E – South	$0.6-$1.0	Withdrawn – Not economically feasible Implemented into T-129 Feb 2007	
18	NA	Long Term Planning Observations Long Term: Propose projects that protect against drought or low hydro conditions. Consider hydro generation sensitivities under peak load conditions. Re-analyze all re-rates implemented on the system for 10am to 7pm violations.	Reliability	PG&E		ISO-Proposed: 2008/2009	
19	NA	Fresno 70kV system plan	Reliability	PG&E –		ISO-Proposed:	

#	Contingency/Condition	Project/Solution	Concern	Region	Cost (M)	Status	Gap (Yrs)
		Long Term: Add more banks to account for Helm and Mendota on radial or make 70kV upgrades to allow for looped operation. **Short Term:** Radial the Helm and Mendota 70kV systems		South		2008 Implemented into T-129 June 2007	
20	Cont: Lost of McCall – West Fresno 115kV Cond: Low voltage on California/West Fresno Loop	West Fresno Shunt Capacitor **Long Term:** Reconductor and convert the idle Sanger – California Ave 70kV Line.	Reliability	PG&E – South		PTO Implementing Project #? (Maintained: May 2010)	2
21	Cont: None Cond: Low voltage on the McCall 230kV Bus	McCall 230kV Reactive Support **Long Term:** Consider new projects, Transmission and Generation that tie into the McCall substation	Reliability	PG&E – South		ISO-Proposed: 2009	
22	Cont: None Cond: Early retirement of Potrero Unit #3		Reliability	PG&E – Bay Area		ISO-Proposed: 2009	
23		Victorville-Lugo 500kV Terminal Equipment Upgrade **Short Term:** Upgrade the terminal equipment to at least 3,300 Amps on the LADWP side.	Congestion	SCE		ISO-Proposed	

#	Contingency/Condition	Project/Solution	Concern	Region	Cost (M)	Status	Gap (Yrs)
24		Barre Lewis 220kV Upgrade **Short Term:** Upgrade terminal equipment at Barre and Lewis to allow for a higher rating.	Congestion	SCE		ISO-Proposed	
25		Magunden-Vestal #1 and #2 220kV line upgrade **Long Term:** Consider a new project to reconductor the 220kV lines to cover the N-1. **Short Term:** Resolve Clearance issue to allow for higher Short Term Emergency rating.	Congestion	SCE		ISO-Proposed	
26		New Antelope-Pardee 220 kV line to relieve overloads on the Antelope-Vincent 220 kV line **Long Term:** Advance the new Antelope-Pardee 220 kV line to 6/2008 instead of 12/2008	Congestion	SCE		PTO-Planning Last Parcels are being worked out with U.S. Forest Service 6/1/2009	
27		AA Bank Double Breaker Position Upgrades **Long Term:** Upgrade 9 500 kV AA Banks at Eldorado, Lugo, Mira Loma, Valley and Vincent to a double-breaker or breaker-and-a-half configuration.	Reliability	SCE		PTO-Planning Vincent 2/1/2009 Lugo 12/31/2010 ISO-Proposed (all other locations)	
28		Julian Hinds-Mirage 220 kV Line Upgrades **Short Term:** Resolve ground clearance issues to	Congestion	SCE		ISO-Proposed	

#	Contingency/Condition	Project/Solution	Concern	Region	Cost (M)	Status	Gap (Yrs)
		get a higher rating for Julian Hinds-Mirage line					
29		Upgrade CB's on South of Lugo 500 kV Lines	Reliability	SCE		ISO-Proposed	
30		Imperial Valley Banks 80 & 81 **Long Term:** Add a third bank at IV		SDG&E		ISO-Proposed	
31		Miguel Banks 80 & 81 **Short Term:** Reconfigure SPS for loss of one Miguel Bank				ISO-Proposed	
32		New Division-Naval Station Metering 69kV #2 line **Short Term:** Expedite project to build a second Division-Naval Station 69kV #2 line to June 2008		SDG&E		ISO-Proposed	
33		Reconductor TL 13812 Talega-San Mateo **Short Term:** Expedite the Reconductor project depending on load forecast		SDG&E		ISO-Proposed	
34		Upgrade Miguel 69kV feeders to be double breaker double bus configuration **Short Term:** Consider upgrading the feeders at Miguel 69kV bus to be double breaker double bus arrangement.		SDG&E		ISO-Proposed	
35		Escondido 230kV Breaker **Short Term:** Replace Bank 70 & 71 230kV disconnects with Circuit Breakers.		SDG&E		ISO-Proposed	
36		New Escondido-Ash 69kV line **Short Term:** Consider providing operation		SDG&E		ISO-Proposed	

#	Contingency/Condition	Project/Solution	Concern	Region	Cost (M)	Status	Gap (Yrs)
		instructions in operating procedures to avoid load shedding for N-1-1 contingencies					
37		Add a third source to big load centers (>100 MW) **Long Term:** Consider building a third source to Margarita, Granite Hills, Laguna Miguel, and Mesa Rim.		SDG&E		ISO-Proposed	

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8.3 Generation Interconnection

The foundation for the generation interconnection process had been established by FERC in Order No. 2003 and its progeny. The ISO's Large Generator Interconnection Procedures (LGIP) tariff has assured open transmission access for new generation interconnections. Over the past few years, several factors, largely unanticipated at the time of Order No. 2003's adoption, including the very large number of Interconnection Requests for renewable generation, imposed significant challenges to the efficiency of processing the Interconnection Requests (IRs) using the serial interconnection study approach that the ISO had been utilizing. One year ago (February 12, 2008), the ISO Queue consisted of 188 active IRs totaling 62,608 MW (42,526 MW renewable generation) for a system with a historic peak load of 50,270 MW. By July 27, 2008, there were 361 active IRs totaling 105,342 MW (68,556 MW renewable generation). The large number of requests and high level of MW capacity in the ISO's Queue had overwhelmed available resources, led to delays and frustration with the study process, and exposed, or reinforced, fundamental deficiencies in the interconnection study process. FERC had also acknowledged the existence of challenges to the generation interconnection process and encouraged the ISO to engage in a stakeholder process to evaluate possible LGIP reforms for a spring 2008 filing with FERC.

The ISO and its stakeholders recommended possible actions the Commission could take to assist in streamlining reform to the interconnection process. Through a collaborative effort, soliciting input through a series of stakeholder meetings and conference calls, the Generation Interconnection Process Reform (GIPR) LGIP was developed and presented to the ISO's Board of Governors and filed with FERC.

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Objectives identified for the GIPR stakeholder process included:

- Clearing the backlog of Interconnection Requests existing in the ISO Queue by reducing the number of projects in the Queue through increased financial commitments on the part of Interconnection Customers and project viability tests.
- Clustering projects when performing interconnection studies.
- Developing procedures and requirements that lead to more accurate study outcomes that ensure a more efficient interconnection of resources which more closely match system needs.
- Providing Interconnection Customers with reasonable cost and timing certainty.
- Reducing or eliminating the need for re-studies.
- Creating greater certainty in the timing of study outcomes.
- Better integrating transmission planning with the generation interconnection process.
- Allowing for the integration of state efforts to identify transmission needs for Energy Resource Areas (ERAs).
- Ensuring that only viable projects enter the Phase II Studies in coordination with the annual ISO Transmission Planning Process (TPP).

Information regarding the Generation Interconnection Process Reform (GIPR) is accessible from the ISO's website at: http://www.caiso.com/1f42/1f42c00d28c30.html

The GIPR LGIP was approved by FERC on September 26, 2008, subject to certain modifications. The ISO submitted those modifications to FERC on November 25, 2008.

Today, there are 224 active projects in the ISO Queue, totaling 67,821 MW (as of February 5, 2009). At a minimum, System Impact Studies are complete for the 76 projects in the Serial Group, totaling 21,713 MW. Interconnection Studies are complete for an additional 31 projects, totaling 7,080 MW.

Under the reformed process, the Transition Cluster Phase I Study is currently underway and consists of a 108 proposed generation projects, totaling 38,863 MW. The Transition Cluster Phase I Study is to be completed by July 28, 2009.

8.4 Long-Term Congestion Revenue Rights

In conformance with the BPM for the Transmission Planning Process, the 2008 Long Term Planning Congestion Revenue Right (LT-CRR) study involved the creation of a process for evaluating the continued feasibility of Long Term LT-CRRs under Peak and Off-Peak conditions. The goal of the study was to determine whether the fixed LT-CRR's allocated as part of the CRR Annual Allocation and Auction Process would remain feasible for at least ten years into the future as new transmission infrastructure is added across the same time horizon

8.4.1 Data Preparation and Assumptions

The 2008 LT-CRR study was performed using the base case network topology used for the CRR 2008 Annual Allocation and Auction Process. RTE incorporated all ISO approved transmission projects in the study base case and performed a full AC power flow analysis to validate acceptable system performance across the ten year planning horizon. This modified base case was then used to perform a CRR market run (Simultaneous Feasibility Test-SFT) to check for feasibility. In the CRR market run setup, the network was limited to 60% full capacity, with the fixed CRR for Transmission Ownership Right set to 60%, and LT CRR set to 100% respectively. At this point, the CRR team has selected to set up and run the market in the CRR Test System. This provides a reliable and convenient user interface in data setup and results displays. Results can also be dumped as complete save cases for further review and record-keeping. Altogether, six markets were run, reflecting Season 2, 3, 4, and two time-of-uses On-peak and Off-peak conditions. Season 1 had no fixed LT CRR's, so it was not applicable.2.7.2 Results Analysis and Observations

The following criteria were used to verify that the long term planning study maintains the feasibility of Long Term Fixed CRRs:

- SFT is completed successfully with no limit expansion needed.
- The worst case base loading in each market run does not exceed 100% of enforced branch rating.
- No new binding constraints are introduced.

In reviewing the results, the worst base loading flows ranged from 81.8 % to 93.8 % of enforced branch rating. The worst flow of 93.8 % occurred in Season 3 Off-peak. No limit expansion was necessary, and no new binding constraints were introduced. A marginal improvement to the worst base loading flows (slightly lower percentage flows) was also observed throughout all the cases.

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8.4.2 Data and Results Maintenance Process

After a comprehensive review of the current process of performing Long Term Planning CRR Feasibility study, both RTE and the CRR Team believed that the current process in place is adequate and acceptable, given the tools available, and completion time frame requirement.

A recap of the current process is:

- Base Case FNM data preparation by RTE i.e. applies new projects to CRR FNM base case PTI PSSE raw data file.
- Set up and perform market runs in the CRR Test System.
- Review results using user interfaces and displays.

Dump and save complete data and results as save cases to a secured location.

The current process, however, has a small shortfall. The CRR Test platform, where the runs were executed, is not an ultimate repository for saving data and results. Both groups agreed that we should at least dump the complete save cases to a secured location for re-use and audit purpose, if necessary.

8.4.3 Future Approaches

Going forward, the dumped saves cases can be restored to the CRR Off-line Hedge system. This system has the same engine as what was used in the CRR Test System. The Off-line Hedge is not a GUI based system, but it is an excellent analytical tool based on powerful macros, command type executions, and CSV data files. Through the Off-line Hedge, the save case data files and results are recoverable, and can be further used for expansion studies. In the long term, migration to the Off-line Hedge system will be considered. Both RTE and the CRR Team also proposed that the timing for performing a Long Term Planning CRR Feasibility study should be based on the timing and availability of the following constituents:

- The next updated FNM data.
- The next LT CRR Market run data.
- New long term projects data.

At this point, it is anticipated that one to two long term planning CRR feasibility studies would be performed annually.

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Chapter 9: 20% Renewable Integration Supplemental Studies

California has one of the most aggressive Renewables Portfolio Standards (RPS) in the U.S., requiring that 20% of retail load be served from renewable resources by 2010. The state's energy regulators and Governor have also advocated a longer-term goal whereby 33% of all retail load should be served by renewable energy by 2020. Two main transmission projects "The Sunrise Powerlink Transmission Project " and the "Tehachapi Transmission Project " were approved by the ISO Board of Governors in August, 2006 and January, 2007 respectively to provide access to renewable resources in the SCE and SDG&E service areas in an effort to meet the states 20% RPS.

To achieve these goals, the ISO must ensure a successful integration of renewable resources into its markets, transmission planning and operating systems. This chapter only covers the reevaluation of reactive devices (size and location) for the Tehachapi Transmission Project to meet 20% RPS.

9.1 20% RPS – Reevaluation of the Reactive Support for Tehachapi Transmission Plan

In 2007, the ISO and General Electric Energy (GE) Staff embarked on a study to reassess the Tehachapi Transmission Project to determine the feasibility of maintaining reliable and high-quality electric service under the 20 % RPS. The ISO issued a detailed report of the study titled "Integration of Renewable Resources, November, 2007" In that report, the ISO concluded that:

- 4,200 MW of wind resources in the Tehachapi area could be integrated into the system without causing any transient stability concerns,
- Under light load conditions in the Western Interconnection (100 GW), frequency response was adequate following the loss of major generating units,
- Dynamic reactive capability at the wind plants is necessary to meet the WECC transient dip performance criteria and ensure system stability, and
- Post-transient analysis indicated that the grid performance met applicable WECC planning standards,

The study also identified the need to:

- Reevaluate the reactive support that was originally proposed for the Tehachapi Transmission Project to determine the optimal location and size for the dynamic/static reactive support (i.e. SVC), and
- Determine, through additional studies, solutions for improving the nose point for critical 500 kV busses under critical contingency conditions.

9.1.1 Initial Tehachapi Transmission Plan

The initial Tehachapi Transmission Plan approved by the ISO Board of Governors in January 2007, identified the need for several transmission upgrades to successfully integrate 4,200 MW of generation. In 2006, only transient stability studies were evaluated for the preliminary analyses for the dynamic voltage support requirement. The total project included the need for the following:

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- Eleven new 500 kV line segments (three of which will initially be operated at 230 kV pending justification to convert to 500 kV operation),
- Four new substations
- Dynamic MVAR Requirement
    - 600 MVAR SVC at Vincent Substation, and
    - 200 MVAR SVC at Antelope Substation.
- Static MVAR Requirement
    - 1,300 MVARS of shunt capacitor installation.

The supplemental studies done in 2008 to reevaluate the reactive devices included voltage stability (QV) and modal analyses primarily focusing on the proposed 600 MVARS SVC installation at Vincent substation and the proposed 200 MVARS SVC for the Antelope substation.

9.1.2 Summary of Findings

Modal analysis: The Antelope–Bailey 66 kV area is the weakest area in terms of voltage stability. Modal analysis identified the 66 kV buses in this area as having high participation factors.

Q-V analysis: The buses with high participation factors also had low reactive margin. Also, the original estimate of installing 1,300 MVARS shunt capacitors was reduced to 500 MVARS.

SVC Location: The best location for the dynamic reactive support were determined to be at the Windhub 500 kV Substation (300 MVAR of SVC), and at Antelope Substation (250 MVAR of SVC). This reflects a reduction of 250 MVAR of dynamic reactive support when compared to the original proposed 800 MVAR of SVCs.

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9.2 Planning Criteria

The study was conducted by applying the ISO/WECC/NERC planning standards outlined in Chapter 3. The main criteria applicable to the following studies are shown in Table 9-1.

Table 9-1: WECC Disturbance-Performance of Allowable Effects on Other Systems

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (Outage/Year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post-Transient Voltage Deviation Standard
A	Not Applicable	Nothing in Addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6 Hz** for 6 cycles or more at a load bus	Not to exceed **5%** at any bus
C	0.033 – 0.33	Not to exceed 30% at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0 Hz** for 6 cycles or more at a load bus	Not to exceed **10%** at any bus
D	< 0.033	Nothing in Addition to NERC		

9.3 Power Flow Cases and Dynamic Data

The 2013 heavy summer basecase for the ISO reliability assessment of the SCE Transmission System was used to build the base case for the following study. Loads used within the SCE system reflected a coincident peak load for a 1-in-10 year heat wave condition. The load forecast data was obtained from the California Energy Commission (CEC) and the basecase was modified to show approximately 3,500 MW of new wind generation and 700 MW of existing wind generation in the Tehachapi area. A description of the case assumptions is summarized in Table 9-2. The model used for all new wind projects was the WECC Type 3 wind turbine generator (doubly-fed induction generator). Existing wind plants in the Tehachapi area were all modeled as the WECC Type 1 wind turbine generator (induction generators).

Table 9-2: Base Case Assumptions (MW)

Load and Resource

Path Name	Path Flow (MW)
Generation	21,400
Load	26,759
Pump Load	723
Losses	662
Import	6,744

Import Path

Path Name	Path Flow (MW)
SCIT (Southern California Import Transmission)	15,988
Path 46 (WOR)	8,047
Path 49 (EOR)	5,798
Path 65 (PDCI)	3,000
Path 26 (Midway-Vincent)	2,198
S/O Lugo	5,086
Vincent-Mira Loma	1,013

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9.3.1 Contingency List

Seventeen line faults, generation trips and the Pacific DC Intertie outages shown in Table 9-3 were studied.

Table 9-3: Contingency Descriptions

No	Outage	Description
1	Diablo-g2	Loss of 2 Diablo Canyon generators.
2	IPP-bipolar	Loss of IPP bipole with north-to-south flow.
3	Lugo-Vincent-dlo	3-phase, 4 cycle Fault at Lugo 500 kV. Loss of 2 Lugo-Vincent 500 kV lines.
4	Midway-Vincent-dlo-SPS	3-phase, 4 cycle Fault at Midway 500 kV. Loss of Midway-Vincent 500 kV lines; SPS generation trip.
5	Palo Verde-g2	Loss of 2 Palo Verde generators.
6	PDCI-NS-bipolar	Loss of PDCI Bipole with north to south flows.
7	Palo Verde-Devers-slo	3-phase, 4-cycle fault at Palo Verde 500 kV. Loss of Palo Verde-Devers 500 kV line.
8	SONGS-g1-svc	Loss of 1 SONGS generator.
9	Sub.1-Antelope-slo	3-phase, 4-cycle fault at Tehachapi Sub. 1 500 kV. Loss of Tehachapi Sub.1-Antelope 500 kV line.
10	Sub.1-Sub.5-slo	3-phase, 4-cycle fault at Tehachapi Sub. 1 500 kV. Loss of Tehachapi Sub. 1-Sub. 5 500 kV line.
11	Sub.5-Midway-slo	3-phase, 4-cycle fault at Tehachapi Sub. 5 500 kV. Loss of Tehachapi Sub. 5-Midway 500 kV line.
12	Sub.5-South-dlo	3-phase, 4-cycle fault at Tehachapi Sub. 5 500 kV. Loss of Sub. 5-Antelope and Sub. 5-Vincent 500 kV lines.
13	Vincent-Antelope-dlo	3-phase, 4-cycle fault at Vincent 500 kV. Loss of 2 Vincent-Antelope 500 kV lines.
14	Vincent-Antelope-slo	3-phase, 4-cycle fault at Vincent 500 kV. Loss of 1 Vincent-Antelope 500 kV line.
15	Vincent-Mesa 230-dlo	3-phase, 4-cycle fault at Vincent 230 kV. Loss of 2 Vincent-Mesa Cal 230 kV lines.
16	Vincent-Mesa 230-slo	3-phase, 4-cycle fault at Vincent 230 kV. Loss of 1 Vincent-Mesa Cal 230 kV lines.
17	Vincent-Miraloma-slo	3-phase, 4-cycle fault at Mira Loma 500 kV. Loss of Vincent-Mira Loma 500 kV line.

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9.4 Study Results

9.4.1 Modal Analysis Results

The VSAT tool was used to perform modal analysis and identify voltage stability weak regions of the system. The modal analysis approach gives voltage stability-related information from a system-wide perspective and identifies areas that have potential problems.

As shown in Table 9-4, modal analysis identified the Antelope 66 kV system is a weak area in the SCE system in terms of voltage stability. The majority of the exiting Tehachapi wind generation is interconnected to the Antelope 66 kV system. The turbines are conventional induction generators (Type 1) and always consume reactive power during operation. The results of modal analysis were verified using the Q-V analysis. The buses having large participation factors also have small reactive margin. Figures 9-1, 9-2 and 9-3 show the QV curves at selected buses in the Antelope 66 kV system.

In order to increase voltage stability in the Antelope 66 kV system, two existing shunt capacitors (30.6 MVAR total) at the Monolith 66 kV bus were switched on. Adding more shunt capacitors in the Antelope 66 kV system is constrained by the over-voltage problem under normal operating condition. Figures 9-4 shows that reactive margin was increased by switching on the shunt capacitors at the Monolith 66 kV bus.

Table 9-4: Modal Analysis Result before Switching on Monolith Shunt Capacitors

VSAT 8.0
Modal Analysis Report

Base point (1)
==========

Mode No. 7: EigenValue = 0.069506 0.000000

Bus Participations

No.	Bus No., Name	Gen.	Area No., Name	Zone	Part.Fac.
1	24456 BOREL 66.0		24 SOCALIF	244	1.00000
2	24417 HAVILAH 66.0		24 SOCALIF	244	0.98013
3	24453 TAP 84 66.0		24 SOCALIF	244	0.97988
4	24416 WALKERBN66.0		24 SOCALIF	244	0.93520
5	24454 TAP 83 66.0		24 SOCALIF	244	0.93515
6	28503 NORTHWND12.0	QL	24 SOCALIF	244	0.88086
7	28505 ZONDWND212.0	QL	24 SOCALIF	244	0.81551
8	24415 LORAINE 66.0		24 SOCALIF	244	0.81305
9	24455 TAP 82 66.0		24 SOCALIF	244	0.81302
10	28504 ZONDWND112.0	QL	24 SOCALIF	244	0.76587
11	28502 SOUTHWND12.0	QL	24 SOCALIF	244	0.72555
12	28501 MIDWIND 12.0	QL	24 SOCALIF	244	0.70765
13	28507 BREEZE2 12.0	QL	24 SOCALIF	244	0.70378
14	28506 BREEZE1 12.0	QL	24 SOCALIF	244	0.68302
15	24463 ZONDWIND66.0		24 SOCALIF	244	0.62621
16	24462 NORTHWND66.0		24 SOCALIF	244	0.62613
17	24474 TAP 77 66.0		24 SOCALIF	244	0.62594
18	24408 BREEZE 66.0		24 SOCALIF	244	0.62552
19	24414 MONOLITH66.0		24 SOCALIF	244	0.62364
20	24461 SOUTHWND66.0		24 SOCALIF	244	0.60153
21	24491 OAKWIND 66.0	QL	24 SOCALIF	244	0.60076
22	24490 TAP 90 66.0		24 SOCALIF	244	0.60062
23	24410 CUMMINGS66.0		24 SOCALIF	244	0.59434
24	24457 ARBWIND 66.0	QL	24 SOCALIF	244	0.59321
25	24469 TAP 78 66.0		24 SOCALIF	244	0.59309
26	24472 TAP 76 66.0		24 SOCALIF	244	0.59010
27	24476 CORRECT 66.0		24 SOCALIF	244	0.57249
28	24478 TAP 51 66.0		24 SOCALIF	244	0.57245
29	24458 ENCANWND66.0	QL	24 SOCALIF	244	0.55226
30	24405 VARWIND 66.0		24 SOCALIF	244	0.55086

Figures 9-1, 9-2 and 9-3 shows the the 66 kV voltages at Borel, Havilah and Monolith before and after the existing 30.6 MVARS of capacitors at Monolith were switched on.

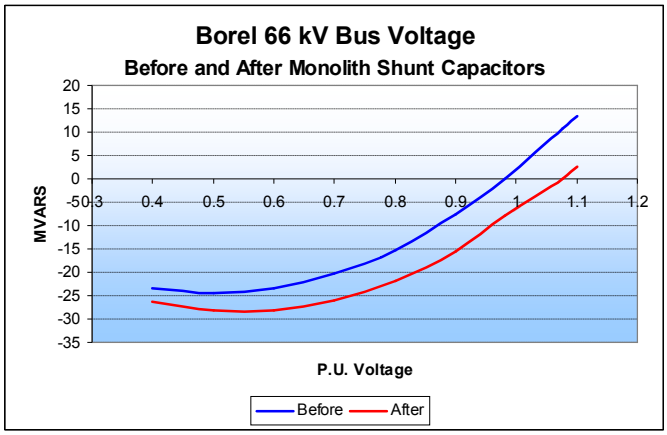

Figure 9-1: QV Curve at Borel 66 kV Bus Before and After Switching on Monolith Shunt Capacitors

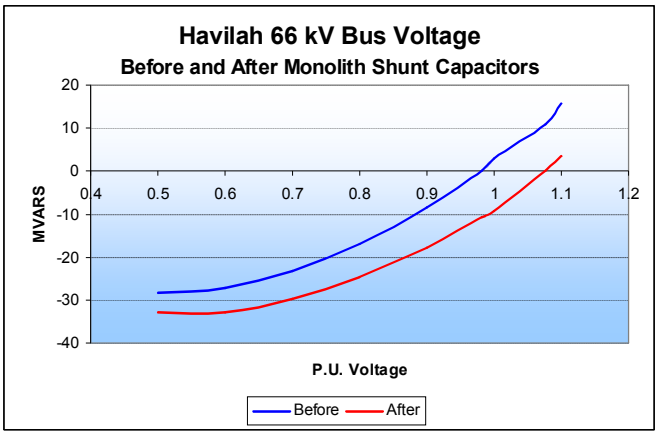

Figure 9-2: QV Curve at Havilah 66 kV Bus Before and After Switching on Monolith Shunt Capacitors

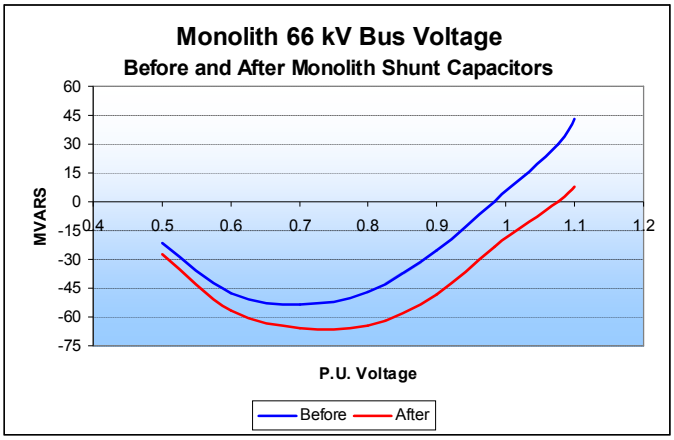

Figure 9-3: QV Curve at Monolith 66 kV Bus Before and After Switching on Monolith Shunt Capacitors

9.4.2 Transient Stability Analysis Results

Transient stability with 10-second run time was performed for the following 4 scenarios:

- Case 1: No SVC,
- Case 2 (Original Case): 600 MVAR SVC at Vincent 500 kV and 200 MVAR SVC at Antelope 500 kV,
- Case 3: 300 MVAR SVC at Sub.5 500 kV and 250 MVAR SVC at Antelope 500 kV,
- Case 4: 300 MVAR SVC at Sub.1 500 kV and 250 MVAR SVC at Antelope 500 kV,
- Case 5: 300 MVAR SVC at Sub.1 500 kV and 200 MVAR SVC at Antelope 500 kV.

Table 9-5 summarizes the transient stability study results. Transient voltage dip violations at Antelope 66 kV load buses for Cases 1, 3 and 5 were observed. There were no transient voltage dip violation at load buses for Cases 2 and 4. It should be noted that the SVC requirement for Case 4 is less than that for Case 2. Thus, the best locations for the SVCs are SUB1 and Antelope 500 kV stations. New dynamic reactive requirements are 250 MVAR less than the original proposal of 800 MVAR.

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Table 9-5: Transient Stability Study Results

No	Contingency	WECC TRANSIENT STABILITY CRITERIA VIOLATIONS?				
		Case 1	Case 2	Case 3	Case 4	Case 5
1	Diablo G-2					
2	IPPDC Bipole					
3	Lugo-Vincent 500kV DLO	Old Tehachapi wind gen area, Vdip=46.5-47.3% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=40.9-41.6% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=42.9-43.6% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=43.0-43.7% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=43.3-44.0% (>30% for N-2).
4	Midway-Vincent 500kV DLO	Old Tehachapi wind gen area, Vdip=32.7-33.1% (>30% for N-2).				
5	Palo Verde G-2					
6	PDCI N-S Bipole					
7	Palo Verde-Devers 500kV SLO					
8	SONGS G-1					
9	Sub.1-Antelope 500kV SLO					
10	Sub.1-Sub.5 500kV SLO					
11	Sub.5-Midway 500kV SLO					
12	Sub.5-South 500kV DLO					
13	Vincent-Antelope 500kV DLO	Old Tehachapi wind gen area, Vdip=31.8-59.9% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=30.4-58.7% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=30.9-59.2% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=30.9-59.2% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=31.0-59.2% (>30% for N-2).

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Table 9-5: Transient Stability Study Results (cont)

No	Contingency	WECC TRANSIENT STABILITY CRITERIA VIOLATIONS?				
		Case 1	Case 2	Case 3	Case 4	Case 5
14	Vincent-Antelope 500kV SLO	Antelope 66kV load buses, Vdip=25.4-26.7% (>25% for N-1). Old Tehachapi wind gen area, Vdip=31.1-59.3% (>30% for N-1).	Old Tehachapi wind gen area, Vdip=31.7-58.1% (>30% for N-1).	Antelope 66kV load buses, Vdip=25.1% (>25% for N-1). Old Tehachapi wind gen area, Vdip=30.1-58.5% (>30% for N-1).	Old Tehachapi wind gen area, Vdip=30.1-58.5% (>30% for N-1).	Antelope 66kV load buses, Vdip=25.1% (>25% for N-1). Old Tehachapi wind gen area, Vdip=30.2-58.5% (>30% for N-1).
15	Vincent-Mesa 230kV DLO	Old Tehachapi wind gen area, Vdip=30.1-60.8% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=32.6-60.2% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=32.8-60.4% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=32.8-60.4% (>30% for N-2).	Old Tehachapi wind gen area, Vdip=32.9-60.5% (>30% for N-2).
16	Vincent-Mesa 230kV SLO	Old Tehachapi wind gen area, Vdip=30.2-60.8% (>30% for N-1).	Old Tehachapi wind gen area, Vdip=30.5-60.3% (>30% for N-1).	Old Tehachapi wind gen area, Vdip=32.7-60.5% (>30% for N-1).	Old Tehachapi wind gen area, Vdip=32.7-60.5% (>30% for N-1).	Old Tehachapi wind gen area, Vdip=32.7-60.5% (>30% for N-1).
17	Vincent-Mira Loma 500kV SLO					

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9.4.3 Post-Transient Analysis Results

In order to support the new wind generation in the Tehachapi area, a significant amount of reactive devices would be required. In the original Tehachapi Transmission Project there were 1,300 MVARs of 500 kV static shunt capacitors located at:

Vincent 500 kV (400 MVAR shunt),

Antelope 500 kV (300 MVAR shunt),

Sub.5 500 kV (2*150 MVAR shunt),

Sub.1 500 kV (2*150 MVAR shunt).

The following capacitors were used to maintain acceptable normal voltages and to achieve better voltage performance (i.e., nose point) under Q-V analysis:

Antelope 500kV (300 MVAR shunt),

Sub.5 500kV (150 MVAR shunt),

Sub.1 500kV (150 MVAR shunt).

Therefore 700 MVAR of 500kV shunt capacitors were removed in the base cases for both the transient and post-transient stability analyses.

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Post-transient governor power flow analyses were performed for the contingencies listed in Table 9-3. QV curves were plotted at key monitored buses following contingencies to determine whether the Tehachapi Transmission Project with the proposed dynamic/static reactive support met applicable WECC planning standards by having adequate positive reactive margin at the monitored buses. To determine the available reactive margin at a specific bus, a fictitious synchronous condenser with a reactive range of ±3,000 MVAR was modeled. Scheduled voltages were reduced automatically, in small increment, until voltage collapse was imminent. A station voltage was deemed unstable when the bus voltage magnitude decreased as the reactive power injection was increased.

The post-transient analysis study results for Case 4 indicated that the grid performance met applicable WECC planning standards on voltage stability. Adequate reactive margins at critical 500 and 230 kV buses were observed for critical contingencies. On the 500 kV system, reactive margin varied between 420 MVAR and more than 3,000 MVAR while on the 230 kV system, reactive margin varied between 989 MVAR and 1,597 MVAR. Figure 9-4 shows the QV curves for selected 500 kV and 230 kV stations for an outage of the Midway-Vincent 500 kV #1 & #2 lines.

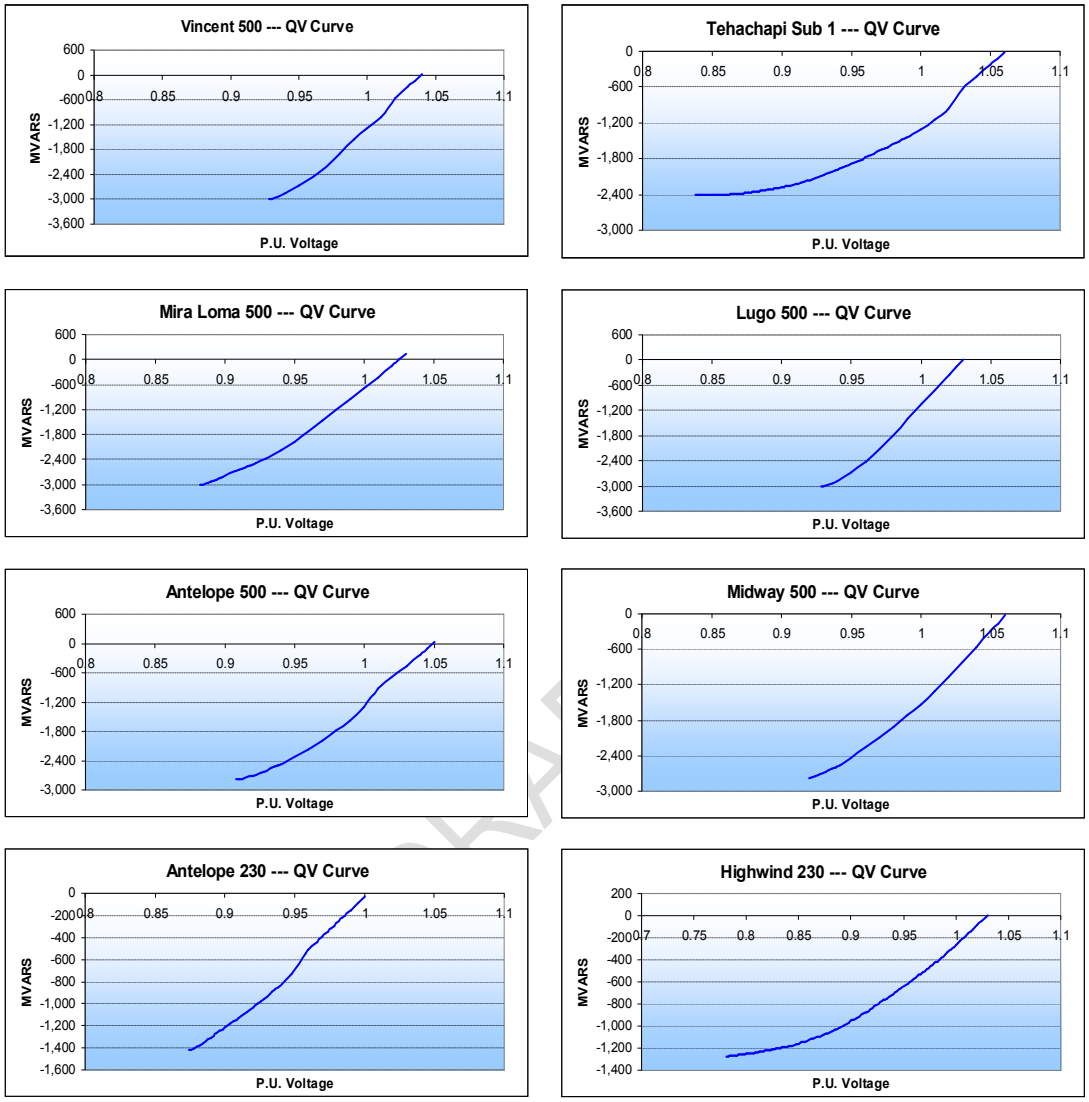

Figure 9-4: Post-Transient Voltage Stability Analysis

Appendix A: Detailed study assumptions

This appendix provides more details of the assumptions that were used in the reliability assessment as shown in table A-1 through A-4 below.

Transmission projects

Table A-1 lists all the ISO-approved transmission projects that were modeled in the power flow study base cases (base cases) for the assessment.

Table A-1 transmission projects modeled in the reliability assessment

No	Project Title	PTO	Targeted In-Service
1	Herndon-Bullard 115 kV Reconductoring	PG&E	2008
2	Kasson-Lammers 115 kV Reconductoring	PG&E	2008
3	Lone Tree Substation	PG&E	2008
4	McCall 230/115 kV Transformer Replacement	PG&E	2008
5	Metcalf - El Patio 115 kV Reconductoring	PG&E	2008
6	Monta Vista 115/60 kV Transformer	PG&E	2008
7	Newark - Fremont 115 kV Reconductoring	PG&E	2008
8	Palermo 230/115 kV Transformer	PG&E	2008
9	Stagg 230/60 kV Transformers	PG&E	2008
10	Templeton – Atascadero 70 kV Reconductoring	PG&E	2008
11	Weber #1 60 kV Line	PG&E	2008
12	Humboldt - Harris 60 kV Reconductoring	PG&E	2008
13	Martin 115/60 kV Transformer Replacement	PG&E	2008
14	Metcalf-Moss Landing 230 kV Reconductoring	PG&E	2008
15	Martin-Hunters Point 115 kV Cable	PG&E	2009
16	DCPP (Mesa) 230 kV Shunt Capacitors	PG&E	2009
17	Glass – Madera 70 kV Reconfiguration (Scope change)	PG&E	2009
18	Gold Hill - Clarksville 115 kV Line Reconductoring	PG&E	2009
19	Hollister 115 kV Reconductoring	PG&E	2009
20	Lakeville – Ignacio #2 230 kV Line Project	PG&E	2009
21	Lakeville 230/60 kV Transformer Capacity Increase	PG&E	2009
22	North Coast Switch and Breaker Upgrade	PG&E	2009
23	Pease-Marysville 60 kV Line	PG&E	2009
24	Rio Oso 230/115 kV Transformer Upgrades	PG&E	2009
25	West Point – Valley Springs 60 kV Line	PG&E	2009
26	Gregg 230 kV Reactor	PG&E	2009
27	Bay Meadows 115 kV Reconductoring	PG&E	2010
28	Contra Costa – Moraga 230 kV Line Reconductoring	PG&E	2010
29	Half Moon Bay Reactive Support	PG&E	2010
30	Mendocino Coast Reactive Support	PG&E	2010

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Table A-1 transmission projects modeled in the reliability assessment (cont)

No	Project Title	PTO	Targeted In-Service
31	Moraga Transformer Capacity Increase	PG&E	2010
32	Oakland Underground Cable	PG&E	2010
33	Pittsburg – Tesla 230 kV Reconductoring	PG&E	2010
34	Cortina 60 kV Reliability	PG&E	2011
35	Monta Vista - Los Altos 60 kV Reconductoring	PG&E	2011
36	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	2011
37	Soledad 115/60 kV Transformer Capacity	PG&E	2011
38	South of San Mateo Capacity Increase	PG&E	2011
39	Tesla-Newark 230 kV Path Upgrade	PG&E	2011
40	Metcalf-Evergreen	PG&E	2012
41	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	2012
42	Ignacio-San Rafael	PG&E	2015
43	San Leandro - Oakland J 115 kV Line Reconductoring	PG&E	2015
44	San Mateo and Moraga Synchronous Condenser Replacement	PG&E	2015
45	Woodward 115 kV Reinforcement	PG&E	2016
46	Menlo 60 kV Switch Upgrade	PG&E	2008
47	Merced 115 kV Bus Reconductoring	PG&E	2008
48	Stone Substation Capacity Increase (D)	PG&E	2008
49	Plainfield Substation Capacity Increase (D)	PG&E	2008
50	Live Oak Substation Capacity Increase (D)	PG&E	2008
51	Plumas Substation Capacity Increase (D)	PG&E	2008
52	Davis 115 kV Circuit Breaker	PG&E	2008
53	Potrero Bus Parallel Circuit Breaker Project	PG&E	2009
54	7th Standard Substation Capacity Increase (D)	PG&E	2009
55	Battery Storage Project	PG&E	2009
56	Humboldt Reactive Support (Scope Change)	PG&E	2009
57	Newark – Ravenswood 230 kV Line (Scope Change)	PG&E	2009
58	West Sacramento-Brighton 115 kV Reconductoring	PG&E	2009
59	Brighton 230/115 kV Transformer Replacement	PG&E	2009
60	Contra Costa – Las Positas 230 kV Line (Scope Change)	PG&E	2010
61	Cooley Landing 115/60 kV Transformer Capacity Upgrade	PG&E	2010
62	Table Mountain – Rio Oso 230 kV Line	PG&E	2010
63	Tesla 115 kV Capacity Increase	PG&E	2010
64	West Fresno Reactive Support	PG&E	2010
65	Wheeler Ridge 230/70 kV Transformer	PG&E	2010

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Table A-1 transmission projects modeled in the reliability assessment (cont)

No	Project Title	PTO	Targeted In-Service
66	East Nicolaus 115 kV Area Reinforcement	PG&E	2011
67	Missouri Flat - Gold Hill 115 kV Line	PG&E	2011
68	Placer - Horseshoe 115 kV Reinforcement Project	PG&E	2009
69	Vaca Dixon - Birds Landing 230 kV Reconductoring	PG&E	2009
70	Antelope SPS	SCE	2008
71	HDPP SPS	SCE	2008
72	Antelope 280 MVA 230/66 kV #3 transformer bank Replacement	SCE	2008
73	Antelope-Oasis-Palmdale-Quartz Hill and Antelope-Shuttle 66 kV Line Reconductor Project	SCE	2008
74	Method of Service for 56 MVA Ritter Ranch 66/12 kV Sub	SCE	2009
75	San Joaquin Cross Valley Loop	SCE	2010
76	Antelope 66 kV Capacitor	SCE	2009
77	BC3-BC8 SPS	SCE	2009
78	Devers-Coachella Valley 230 kV Line Loop	SCE	2010
79	Devers-Mirage 115 kV System Split	SCE	2010
80	Mira Loma 500 kV Shunt Capacitors	SCE	2009
81	New Antelope-Quartz Hill 66 kV line #2	SCE	2009
82	Rancho Vista 500/230 kV Substation	SCE	2009
83	Jurupa 230/66 kV Sub	SCE	2009
84	Devers-Palo Verde 500 kV T/L #2 (DPV2)	SCE	2011
85	Method of Service to El Casco 230/115 kV Sub	SCE	2010
86	Two-Line Service to Acton 66/12 kV Sub	SCE	2011
87	Victor #3 280 MVA 230/115 kV Transformer Bank	SCE	2009
88	Del Sur 66 kV Terminal Upgrades	SCE	2014
89	Central Coast Switching Station (Crazy Horse)	SCE	2009
90	Mira Loma Substation Install new 500kV CBs for AA Banks	SCE	2009
91	Vincent Substation Install new 500kV CBs for AA Banks	SCE	2008
92	Lugo Substation Install new 500kV CBs for AA Banks	SCE	2011
93	Helijet Shunt Capacitor Bank	SCE	2009
94	Frazier Park Dynamic Voltage Support	SCE	2010
95	Transmission for Otay Mesa Power Generation Project	SDG&E	2008
96	Reconductor TL13836, Talega – Pico	SDG&E	2009
97	New 230/69 kV Substation: Silvergate	SDG&E	2008
98	2nd 69 kV line: Division-Naval Station Metering	SDG&E	2009
99	New 500 kV line: Sunrise Powerlink	SDG&E	2010
100	Lake Hodges Pump Storage Project (Generator Interconnection)	SDG&E	2008

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Table A-1 transmission projects modeled in the reliability assessment (cont)

No	Project Title	PTO	Targeted In-Service
101	Reconductor TL689, Escondido-Felicita Tap	SDG&E	2009
102	Loop-in TL651: Silvergate 69 kV Switchyard	SDG&E	2009
103	Rearrange 230 kV Switchyard: San Luis Rey	SDG&E	2008
104	Reconfigure TL13821 & 13822, Carlton Hills Area	SDG&E	2010
105	Reconductor TL13837, Capistrano-Laguna Niguel	SDG&E	2010
106	Reconductor TL678, Los Coches-Alpine	SDG&E	2009
107	Reconductor TL13812, Talega-San Mateo	SDG&E	2009
108	Reconductor TL6915, TL6924: Pomerado-Sycamore	SDG&E	2009
109	New 230/138 kV transformer: Miguel Substation	SDG&E	2010
110	Loop-in TL13825: Shadowridge 138 kV Switchyard	SDG&E	2009

Protection System

Table A-2 lists the protection systems modeled in the ISO reliability assessment

Table A-2 protection system modeled in the reliability assessment

RAS / SPS Name
Middletown UVLS
Humboldt SPS
Alameda Overload SPS
Bay Area UVLS
Bay Meadows OL SPS
Eastshore 230/115 kV TB #1 and #2 Overload SPS
Evergreen - San Jose B OL
Gilroy Energy Center SPS
Grant - Eastshore OL SPS
Metcalf - El Patio OL SPS
Metcalf SPS
Monta Vista L-2 OL SPS
Moraga - Oakland J OL SPS
Newark Dumbarton OL SPS
San Francisco RAS
South of San Mateo SPS
Mirage Overpower /Undervoltage Relays
MWD Eagle Mountain Thermal Relay
West of Devers Overload Protection Scheme (“WOD SPS”)
Blythe SPS
Low Voltage Load Shedding (LVLS) Scheme.
South of Lugo (SOL) N-2 SPS
Helm RAS
Helms Transfer Trip (HTT-RAS)
Coppermine RAS
Mariposa UVLS
Henrietta RAS

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Appendix B: NERC Compliance reference table

In this appendix, compliance to NERC TPL 001 through 004 planning standards is provided in Table B-1 through Table B-4. [The locations are being reviewed]

Table B-1: NERC TPL 001 Reference Table

Requirement	Control Activity	Note	Location
R1	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner Assessments shall		
R1.1	Be made annually	Reliability assessment which includes power flow and stability study is part of the annual ISO Transmission Planning Process. This activity is conducted of the annual of an open stakeholder process that starts in January of the first year and ends in March of the following year.	
R1.2	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons	The ISO's planning horizon is a minimum of ten years. The assessment that is conducted part of the transmission plan include the study for the short-term (up to 5 years) and long-term (10 years or longer)	

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Table B-1: NERC TPL 001 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.3	Be supported by a current or past study and/or system simulation testing that address each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).	As stated in R1.1, the ISO conducts this assessment annually and the transmission plan is presented to ISO Board of Governors in February or March of each year. The scope of the covers evaluation of system conditions under normal (Category A) and emergency (Categories B, C, D) conditions	
R1.3.1	Cover critical system conditions and study years as deemed appropriate by the entity performing the study	The study models different system conditions e.g. load models, import MW flow that represent stress conditions in each area being studied.	
R1.3.2	Be conducted annually unless changes to system conditions do not warrant such analyses	As stated in R1.1, the ISO conducts this assessment annually	
R1.3.3	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions	The ISO studies were conducted on both 2013 and 2018 scenarios for Normal and category B and C outages. Category D contingencies were evaluated for the long-term (2018) scenarios. The PTOs also conducts similar studies covering the interim years	
R1.3.4	Have established normal (pre-contingency) operating procedures in place	Pre-contingency operating procedures were modeled in the study	
R1.3.5	Have all projected firm transfers modeled	Path flows to/from each study area were modeled representing stress conditions. Future improvement on path capability also (if exist) were modeled as well	

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Table B-1: NERC TPL 001 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.3.6	Be performed for selected demand levels over the range of forecast system demands	Different demand levels were modeled in the study depending on the area being studied. In general, summer peak loads were studied in all areas since it most areas under ISO footprints are summer peaking. However, winter and summer off-peaks were also studied in several areas (e.g. winter peaking area) where these conditions also result in stressed system conditions.	
R1.3.7	Demonstrate that system performance meets Table 1 for Category A (no contingencies)	The study results in each area show system performance and criteria violations under normal (Category A) conditions	
R1.3.8	Include existing and planned facilities	Existing and future generation plants, transmission projects, load, reactive resources, protection system were modeled according to their scheduled in-service dates.	
R1.3.9	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance	Existing and new reactive resources were modeled in all the base cases	

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Table B-1: NERC TPL 001 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.4	Address any planned upgrades needed to meet the performance requirements of Category A.	For each identified criteria violation, the upgrades were discussed as part of the study results	
R2	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:		
R2.1	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon	A short of summary of each upgrades to mitigate category A violations	
R2.1.1	Including a schedule for implementation	For each identified criteria violation, the upgrades were discussed as part of the study results	

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Table B-1: NERC TPL 001 Reference Table (cont)

Requirement	Control Activity	Note	Location
R2.1.2	Including a discussion of expected required in-service dates of facilities		
R2.1.3	Consider lead times necessary to implement plans		
R2.2	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed		
R3	The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization	Following the presentation of the 2009 ISO Transmission Plan to ISO Board of Governors during the March 2009 Board meeting, the ISO has submitted this Transmission Plan to WECC. This report is also posted on ISO website for public access.	A copy of submission letter

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Table B-2: NERC TPL 002 Reference Table

Requirement	Control Activity	Note	Location
R1	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:		
R1.1	Be made annually	Reliability assessment which includes power flow and stability study is part of the annual ISO Transmission Planning Process. This activity is conducted of the annual of an open stakeholder process that starts in January of the first year and ends in March of the following year.	
R1.2	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons	The scope of ISO Transmission Planning Process covers both the operational and planning time frame. It includes technical study	
R1.3	Be supported by a current or past study and/or system simulation testing that address each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	As stated in R1.1, the ISO conducts this assessment annually and the transmission plan is presented to ISO Board of Governors in February or March of each year. The scope of the covers evaluation of system conditions under normal (Category A) and emergency (Categories B, C, D) conditions	

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Table B-2: NERC TPL 002 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.3.1	Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	The ISO studies evaluated the impact from all Category B contingencies that were supplied to ISO by its PTOs. This includes a comprehensive list of Category B outages (G-1, L-1, T-1,G-1/L-1) throughout ISO footprint	
R1.3.2	Cover critical system conditions and study years as deemed appropriate by the responsible entity	The study models different system conditions e.g. load models, import MW flow that represent stress conditions in each area being studied.	
R1.3.3	Be conducted annually unless changes to system conditions do not warrant such analyses	As stated in R1.1, the ISO conducts this assessment annually	
R1.3.4	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions	The ISO studies were conducted on both 2013 and 2018 scenarios for Normal and category B and C outages. Category D contingencies were evaluated for the long-term (2018) scenarios. The PTOs also conducts similar studies covering the interim years	Section 2.1.1.3
R1.3.5	Have all projected firm transfers modeled	Path flows to/from each study area were modeled representing stress conditions. Future improvement on path capability also (if exist) were modeled as well	
R1.3.6	Be performed and evaluated for selected demand levels over the range of forecast system Demands	Different demand levels were modeled in the study depending on the area being studied. In general, summer peak loads were studied in all areas since it most areas under ISO footprints are wsummer peaking. However, winter and summer off-peaks were also studied in several areas (e.g. winter peaking area) where these conditions also result in stressed system conditions.	

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Table B-2: NERC TPL 002 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.3.7	Demonstrate that system performance meets Category B contingencies	The study results in each area show system performance and criteria violations under Category B contingencies conditions	
R1.3.8	Include existing and planned facilities	Existing and future generation plants, transmission projects, load, reactive resources, protection system were modeled according to their scheduled in-service dates.	
R1.3.9	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance	Existing and new reactive resources were modeled in all the base cases	
R1.3.10	Include the effects of existing and planned protection systems, including any backup or redundant systems	Existing and planned protection system such as SPS or RAS were included in the study	
R1.3.11	Include the effects of existing and planned control devices	Existing and planned protection system such as HVDC, RAS were included in the study	
R1.3.12	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.	Planned outages were modeled in the base cases that representing planned outages situations are likely to occur	

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Table B-2: NERC TPL 002 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.4	Address any planned upgrades needed to meet the performance requirements of Category B of Table I	For each identified criteria violation, the upgrades were discussed as part of the study results	
R2	When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each		
R2.1	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon	A short of summary of each upgrades to mitigate category A violations	
R2.1.1	Including a schedule for implementation		
R2.1.2	Including a discussion of expected required in-service dates of facilities		
R2.1.3	Consider lead times necessary to implement plans		

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Table B-2: NERC TPL 002 Reference Table (cont)

Requirement	Control Activity	Note	Location
R2.2	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.		
R3	The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization	Following the presentation of the 2009 ISO Transmission Plan to ISO Board of Governors during the March 2009 Board meeting, the ISO has submitted this Transmission Plan to WECC. This report is also posted on ISO website for public access.	A copy of submission letter

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Table B-3: NERC TPL 003 Reference Table

Requirement	Control Activity	Note	Location
R1	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall		
R1.1	Be made annually	Reliability assessment which includes power flow and stability study is part of the annual ISO Transmission Planning Process. This activity is conducted of the annual of an open stakeholder process that starts in January of the first year and ends in March of the following year.	
R1.2	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons	The scope of ISO Transmission Planning Process covers both the operational and planning time frame. It includes technical study	
R1.3	Be supported by a current or past study and/or system simulation testing that address each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	As stated in R1.1, the ISO conducts this assessment annually and the transmission plan is presented to ISO Board of Governors in February or March of each year. The scope of the covers evaluation of system conditions under normal (Category A) and emergency (Categories B, C, D) conditions	

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Table B-3: NERC TPL 003 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.3.1	Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information	All C contingencies were considered in the ISO studies but only the C contingencies that would produce more severe impact such as loss of two EHV transmission lines on the same corridor or loss of two nuclear units were evaluated	
R1.3.2	Cover critical system conditions and study years as deemed appropriate by the responsible entity	The study models different system conditions e.g. load models, import MW flow that represent stress conditions in each area being studied.	
R1.3.3	Be conducted annually unless changes to system conditions do not warrant such analyses	As stated in R1.1, the ISO conducts this assessment annually	
R1.3.4	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions	The ISO studies were conducted on both 2013 and 2018 scenarios for Normal and category B and C outages. Category D contingencies were evaluated for the long-term (2018) scenarios. The PTOs also conducts similar studies covering the interim years	
R1.3.5	Have all projected firm transfers modeled	Path flows to/from each study area were modeled representing stress conditions. Future improvement on path capability also (if exist) were modeled as well	
R1.3.6	Be performed and evaluated for selected demand levels over the range of forecast system demands	Different demand levels were modeled in the study depending on the area being studied. In general, summer peak loads were studied in all areas since it most areas under ISO footprints are wsummer peaking. However, winter and summer off-peaks were also studied in several areas (e.g. winter peaking area) where these conditions also result in stressed system conditions.	

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Table B-3: NERC TPL 003 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.3.7	Demonstrate that System performance meets Table 1 for Category C contingencies.	The study results in each area show system performance and criteria violations under Category B contingencies conditions	
R1.3.8	Include existing and planned facilities	Existing and future generation plants, transmission projects, load, reactive resources, protection system were modeled according to their scheduled in-service dates.	
R1.3.9	Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance	Existing and new reactive resources were modeled in all the base cases	
R1.3.10	Include the effects of existing and planned protection systems, including any backup or redundant systems	Existing and planned protection system such as SPS or RAS were included in the study	
R1.3.11	Include the effects of existing and planned control devices	Existing and planned protection system such as HVDC, RAS were included in the study	
R1.3.12	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed	Planned outages were modeled in the base cases that representing planned outages situations are likely to occur	

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Table B-3: NERC TPL 003 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.4	Address any planned upgrades needed to meet the performance requirements of Category C	For each identified criteria violation, the upgrades were discussed as part of the study results	
R1.5	Consider all contingencies applicable to Category C	All C contingencies were considered in the ISO studies but only the C contingencies that would produce more severe impact such as double circuit tower line outages or loss of lines on the common corridor were studied	
R2	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each		
R2.1	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon	A short of summary of each upgrades to mitigate category A violations	

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Table B-3: NERC TPL 003 Reference Table (cont)

Requirement	Control Activity	Note	Location
R2.1.1	Including a schedule for implementation		
R2.1.2	Including a discussion of expected required in-service dates of facilities		
R2.1.3	Consider lead times necessary to implement plans		
R2.2	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.		
R3	The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization	Following the presentation of the 2009 ISO Transmission Plan to ISO Board of Governors during the March 2009 Board meeting, the ISO has submitted this Transmission Plan to WECC. This report is also posted on ISO website for public access.	A copy of submission letter

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Table B-4: NERC TPL 004 Reference Table

Requirement	Control Activity	Note	Location
R1	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall		
R1.1	Be made annually	Reliability assessment which includes power flow and stability study is part of the annual ISO Transmission Planning Process. This activity is conducted of the annual of an open stakeholder process that starts in January of the first year and ends in March of the following year.	
R1.2	Be conducted for near-term (years one through five).	The scope of ISO Transmission Planning Process covers both the operational and planning time frame. It includes technical study	
R1.3	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	As stated in R1.1, the ISO conducts this assessment annually and the transmission plan is presented to ISO Board of Governors in February or March of each year. The scope of the covers evaluation of system conditions under normal (Category A) and emergency (Categories B, C, D) conditions	

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Table B-4: NERC TPL 004 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.3.1	Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information	All D contingencies were considered in the ISO studies but only the D contingencies that would produce more severe impact such as loss of entire 500 kV substation or entire major import path were evaluated	
R1.3.2	Cover critical system conditions and study years as deemed appropriate by the responsible entity	The study models different system conditions e.g. load models, import MW flow that represent stress conditions in each area being studied.	
R1.3.3	Be conducted annually unless changes to system conditions do not warrant such analyses.	As stated in R1.1, the ISO conducts this assessment annually	
R1.3.4	Have all projected firm transfers modeled	Path flows to/from each study area were modeled representing stress conditions. Future improvement on path capability also (if exist) were modeled as well	
R1.3.5	Include existing and planned facilities	Existing and future generation plants, transmission projects, load, reactive resources, protection system were modeled according to their scheduled in-service dates.	
R1.3.6	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance	Existing and new reactive resources were modeled in all the base cases	
R1.3.7	Include the effects of existing and planned protection systems, including any backup or redundant systems	Existing and planned protection system such as SPS or RAS were included in the study	
R1.3.8	Include the effects of existing and planned control devices	Existing and planned protection system such as HVDC, RAS were included in the study	
R1.3.9	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed	Planned outages were modeled in the base cases that representing planned outages situations are likely to occur	

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Table B-4: NERC TPL 004 Reference Table (cont)

Requirement	Control Activity	Note	Location
R1.4	Consider all contingencies applicable to Category D	All D contingencies were considered in the ISO studies but only the D contingencies that would produce more severe impact such as loss of entire 500 kV substation or entire major import path were evaluated	
R2	The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization	Following the presentation of the 2009 ISO Transmission Plan to ISO Board of Governors during the March 2009 Board meeting, the ISO has submitted this Transmission Plan to WECC. This report is also posted on ISO website for public access.	A copy of submission letter

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WECC 2009 PATH RATING CATALOG

January 2009

Prepared By:
TECHNICAL STUDIES SUBCOMMITTEE

WECC PATH RATING CATALOG

Disclaimer

This catalog contains descriptions of path components and describes path ratings as provided by individual WECC members. The path ratings in this catalog are "Maximum Path Transfer Capabilities" and not "First Contingency Incremental Transfer Capabilities" (the method used by other NERC councils). Most of the ratings reflect capabilities based on technical limits determined from system studies. They do not represent Available Transmission Capacity because they do not indicate the degree to which the path transfer capability has been committed with existing transactions.

This document is not intended to be used for the purposes of validating the applicability of a path or to determine if WECC procedures were followed to determine its rating. Publication of a path rating in this document does not imply WECC approval of that rating. The appropriate WECC procedures must be followed to achieve formal WECC approval of a path rating. Per WECC procedure, any path rating can be challenged if the reliability criteria are violated. This document is only intended to compile currently available information into a single document.

Introduction

This *WECC Path Rating Catalog* contains a collection of discussions on individual path ratings within the WECC system. A path rating can be related to an individual transmission line or a combination of parallel transmission lines. The transfer path may be composed of transmission lines between control areas or internal to a control area, or a combination of both.

All information in this Path Rating Catalog was provided, and should continue to be provided on a voluntary basis. From this information, transfer limitations can be identified for regional planning analysis. Identification of path ratings, with supporting information, will assure that any relation between existing ratings and proposed new projects can be identified during a project review process according to the *WECC Procedures for Regional Planning Project Review and Rating Transmission Facilities.*

Purpose

The Path Rating Catalog compilation of transfer path rating information is intended to:

- Be a reference document for planning purposes,
- Serve as a primary source of currently available information on maximum, non-simultaneous path ratings to WECC Members,
- Provide a resource for discussion of simultaneous interactions between major transmission paths.

Among other things, this Path Rating Catalog is not intended to:

- Ascertain if WECC Procedures were followed to determine a path rating,
- Support regulatory proceedings against a WECC member because of erroneous information,
- Imply WECC approval of the rating, although a path can receive an "Accepted Rating" via the Three Phase Rating Process,

- Provide OASIS information or Available Transfer Capability (ATC) or the most current operating limits,
- Serve as a complete list of all path information, or
- Enforce, support or implement any WECC Policy.

Contents

This Path Rating Catalog should include:
- All significant paths (i.e., Loop Flow Qualified paths, OTC Policy Group paths and constrained paths),
- A compilation of best available path rating information consisting of accepted ratings, Phases 2 and 3 ratings, existing ratings and other ratings,
- The names of contact persons of the appropriate WECC members (single point of contact),
- "Maximum Path Transfer Capabilities," not "First Contingency Incremental Transfer Capabilities" and reflects technical transfer capabilities based on technical limits from system planning studies.

Path Descriptions

The minimum specific content of each path description should include:
- A specific identification of the facilities that make up the transmission path,
- A discussion of the non-simultaneous path rating and the conditions used to achieve the path rating,
- Any necessary Remedial Action Schemes to achieve the path rating,
- An identification of interactions or relationships with other paths including applicable nomograms (Information should be provided on where a "current" nomogram can be located),
- Ownership and allocation or rights on the path,
- Date of submittal or update and contact person.

Additional explanatory information supporting transfer path ratings is welcome such as identification of internal paths that are considered to have no significant regional impact.

Document Update Policy

Changes to an "accepted" or "existing" path rating must follow the *WECC Procedures for Regional Planning Project Review and Rating Transmission Facilities (WECC Procedures).* Minor changes to a path rating (such as moving a metering location) should be submitted as part of the 60-day Expedited Process defined in Part 2B, Section 3.0 of the WECC Procedures (assuming no comments require reissuing a study report). Changes to a path with an "other" path rating do not need to follow the WECC Procedures; however, the path will retain the "other" status. Changes to an "accepted" or "existing" path rating that do not follow the WECC procedures will be reclassified to "other" status. Although updated entries to the *WECC Path Rating Catalog* may be submitted to the WECC staff at any time, the catalog will be published once annually. Each path rating narrative shall indicate the date it was added to the catalog. When a path rating narrative is revised, the word "Revised" will be added followed by the revision date. Paths can be deleted if superseded by another path with newly defined accepted rating or with notification and explanation to TSS.

Prior to a member system submitting additions or changes to the *WECC Path Rating Catalog* to WECC, it shall notify and coordinate these additions and/or changes with other WECC members Holding rights on the path. Additions or changes to the *WECC Path Rating Catalog* will be solicited, compiled, and distributed by the WECC staff prior to January 1st for review and comment by the Technical Studies Subcommittee. Members having any concerns with the content of a proposed submittal shall seek resolution with the member making the submittal. If resolution is not reached prior to the publication of the document, the member's concerns should be outlined in the appropriate narrative section submitted by the submitting member.

WECC Procedures

Prior to August 1991, project ratings for new facilities were defined using the *Annual Progress Reporting Procedure*. In August 1991, the *Notification Procedure for Changes in Facility Ratings and/or Operating Procedures* was adopted for documenting up-rates in existing facilities. This augmented the *Annual Progress Reporting Procedure*. In November of 1992, the *Policies and Procedures for Rating Transmission Facilities* was adopted which added a formal review process for checking the proposed non-simultaneous rating and simultaneous operating problems of the new or existing path being rated. In November of 1993, the *Interim Procedures for Regional Planning Project Review and Rating Transmission Facilities* were adopted to address issues related to Regional Transmission Planning. This new procedure incorporated into it the *Policies and Procedures for Rating Transmission Facilities* of November 1992. The final version, called *Procedures for Regional Planning Project Review and Rating Transmission Facilities,* was approved in March 1995.

In March of 1996, the procedures were further enhanced and are included in the *WECC Procedures for Regional Planning Project Review and Rating Transmission Facilities*. In March of 2000 the TSS revised the introduction for clarity. This change included improved procedures for adding (removing) paths to (from) the Catalog. In August 2004 the TSS revised the Path Rating Catalog document update policy to include procedures for making minor changes to path ratings.

Explanation of Rating Categories as Used in this Catalog

- Accepted Rating — A project rating that has been reviewed and accepted by WECC members. This rating is granted by WECC at the conclusion of reviewed planning studies and will be the rating of the project when it is put in service, if it is built per specification. This is a comprehensive rating including both the simultaneous and non-simultaneous transfer capabilities. (Reference: *Procedures for Regional Planning Project Review and Rating Transmission Facilities.*)

- Existing Rating — Transmission path ratings that were known and used in operation as of January 1, 1994. (Reference: *Procedures for Regional Planning Project Review and Rating Transmission Facilities.*)

- Other — A transmission path rating, either proposed or planned, that is not an accepted or existing rating.

EXPLANATION OF TERMS

Path Name

Accepted Rating ☐
Existing Rating ☐
Other ☐

Location:	Where the path is located, physically and geographically
Definition:	A description of the path in terms of the transmission lines comprising the path, the area interconnected by the path, and any project or operations name given to the path.
Transfer Limit:	The rating of the path. This can be a single maximum rating or a range of operation dependent on system conditions. If the path is rated bidirectional, then information for each direction is given.
Critical Disturbance that limits the transfer capability:	What was the critical disturbance(s) that limits the path rating? What was the limitation (steady-state thermal, transient or dynamic stability, post-transient voltage or thermal)?
When:	The date the path rating was defined and in which forum.
System Conditions:	Under what system conditions were the path rating determined (transmission system, area load level, generation pattern, transfer direction, time of year, etc.). Describe any fictitious transmission devices, generation, or power scheduling that was utilized to achieve transfer levels, voltage levels, or generation resources.
Study Criteria:	The planning and operating reliability criteria that was met in defining this path rating (WECC, internal company).
Remedial Actions Required:	A description of any remedial actions (both external and internal) required to achieve the path rating.
Formal Operating Procedure:	The formal operating procedures utilized to achieve the path rating and meet applicable reliability criteria.
Allocation:	Allocation of the path rating among the owners and major users of the path (be specific by participant and percent allocation).
Interaction w/Other Transfer Paths:	Under what conditions and operating procedures would the path rating be reduced?
Contact Person:	Person(s) who can be contacted for additional information on this path rating (include address).

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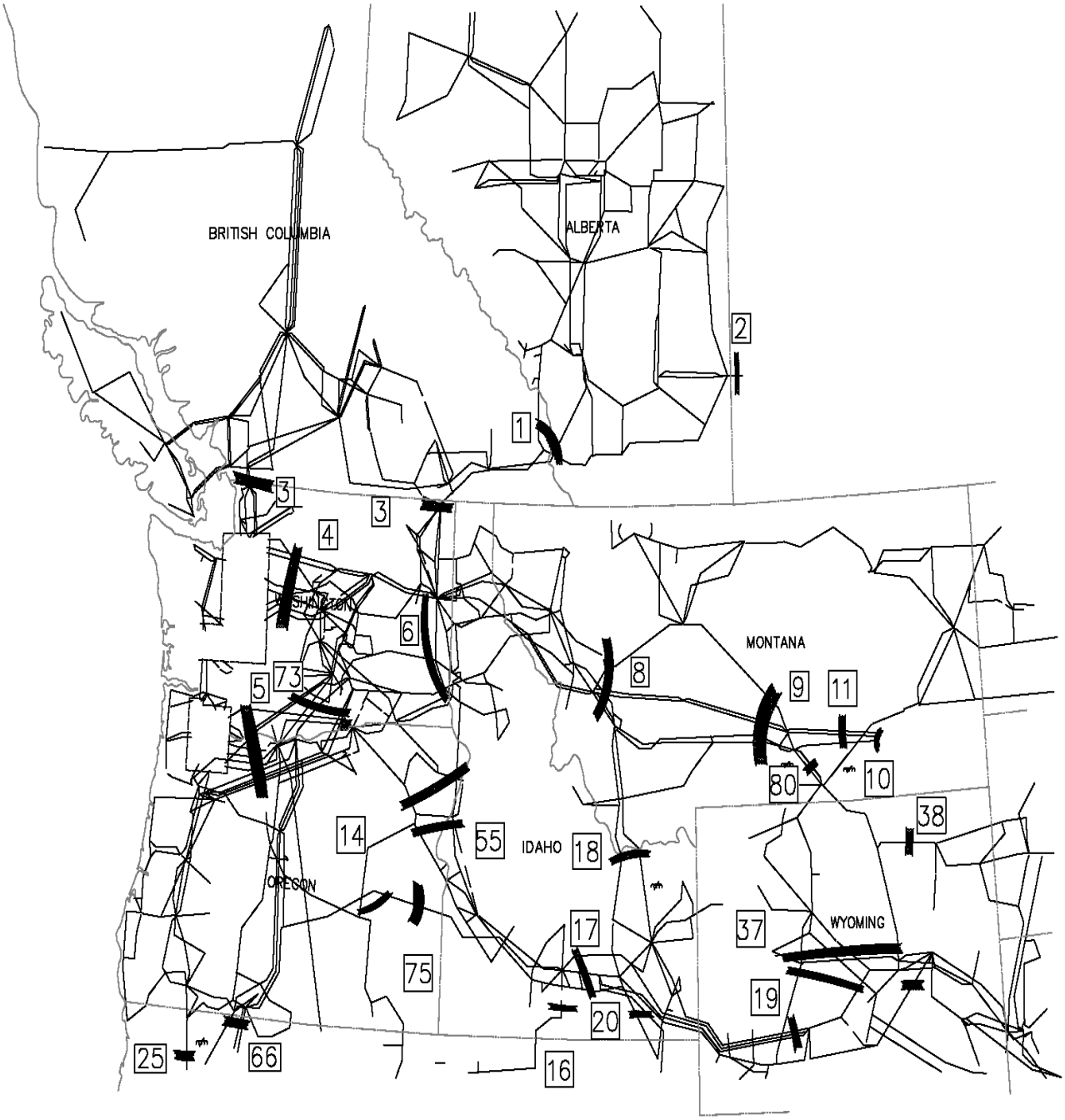
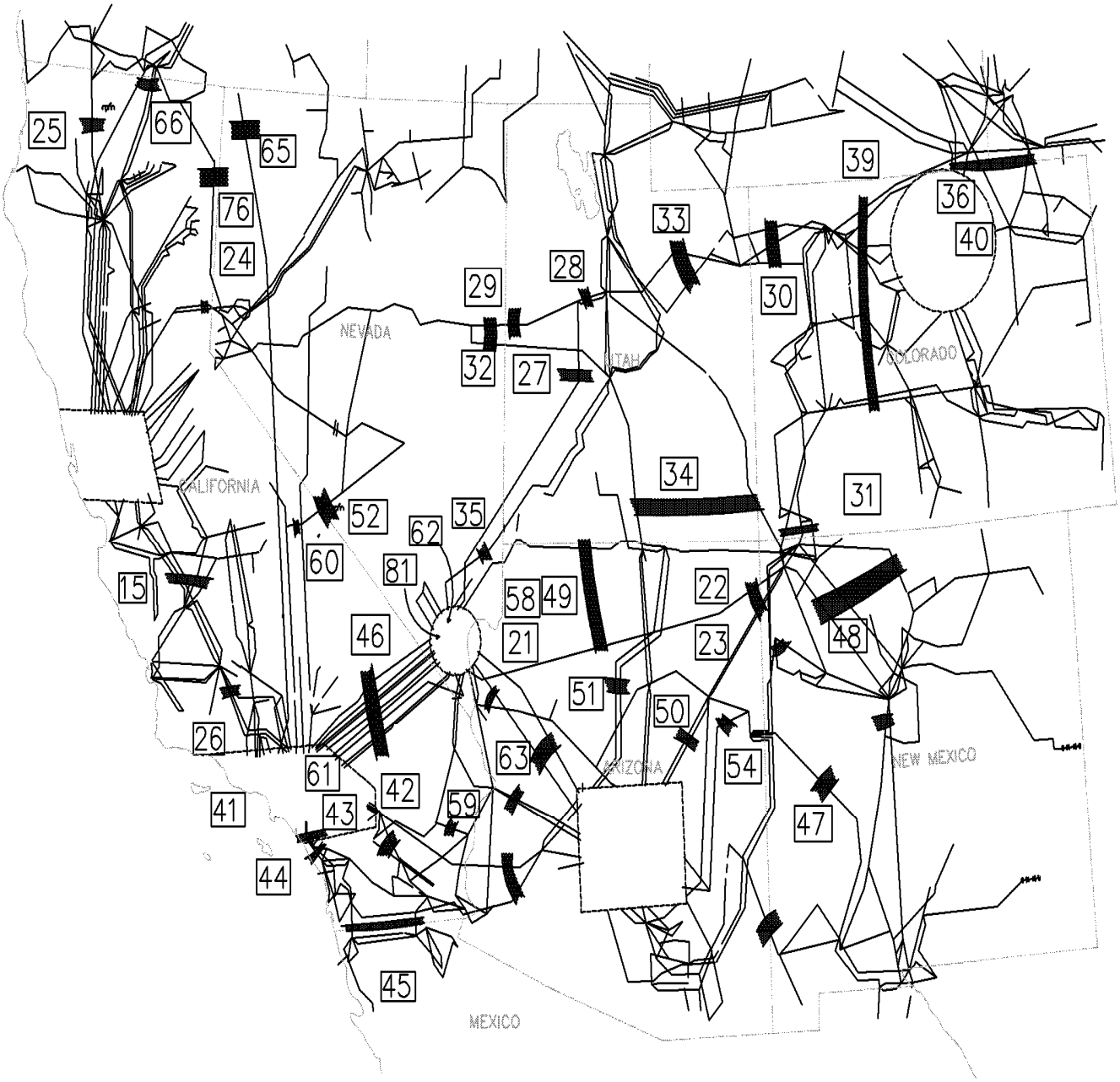
EXISTING PATHS

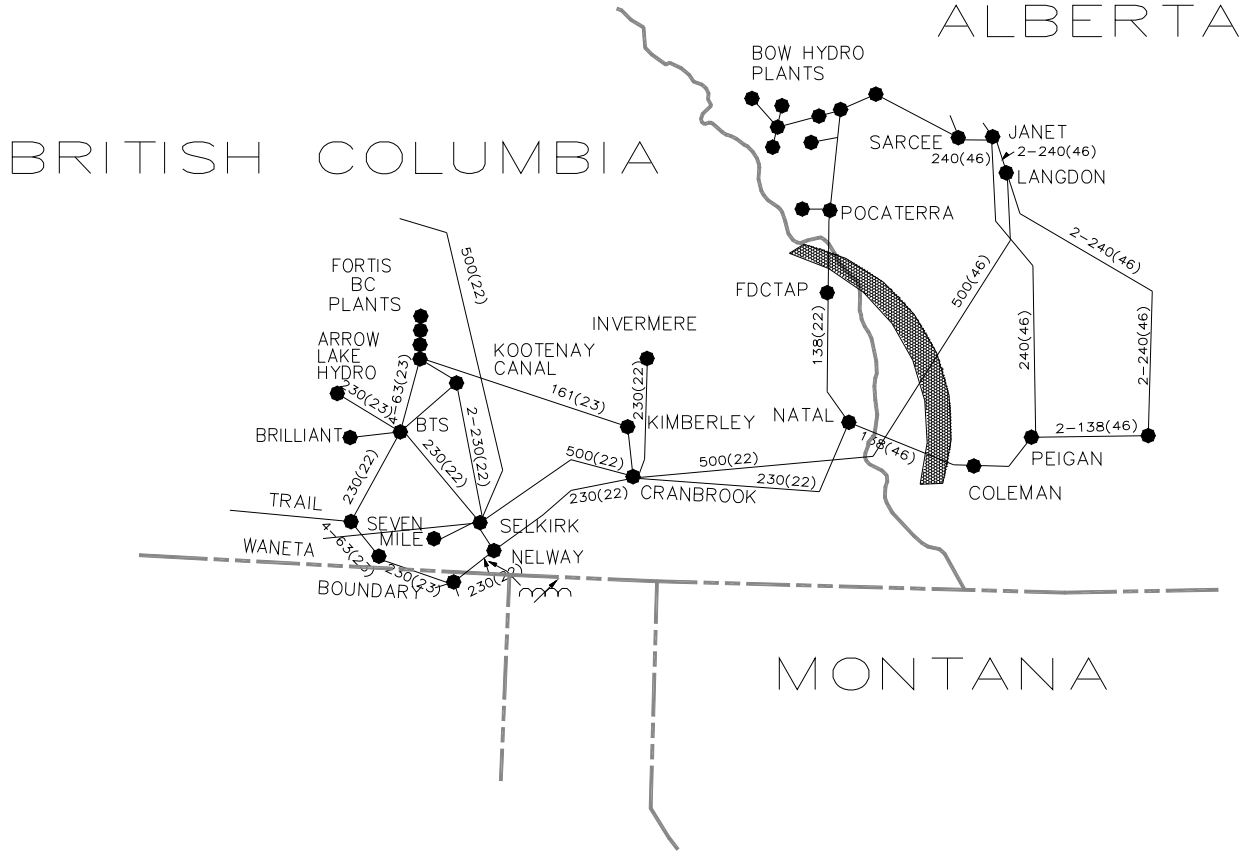
WECC Transfer Paths



WECC Transfer Paths



1. Alberta - British Columbia



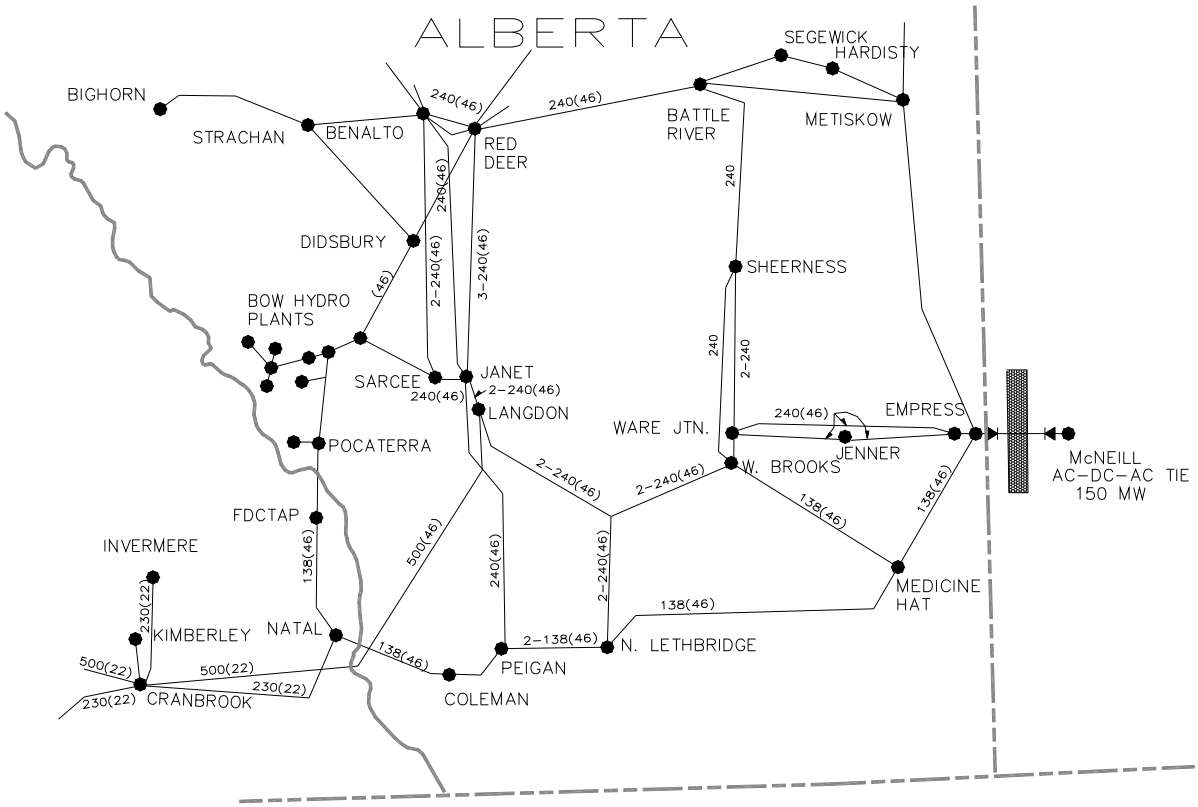
1. Alberta - British Columbia

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Southern Alberta and Southern British Columbia
Definition:	Sum of the flows on the following lines: Line — Metered End Langdon-Cranbrook 500 kV — Langdon (Alta Link) Pocaterra-Fording Coal Tap 138 kV — Pocaterra (Alta Link) Coleman-Natal 138 kV — Natal (BCTC)
Transfer Limit:	East to West: 1000 MW West to East: 1200 MW
Critical Disturbance That limits the transfer capability:	West to East: Loss of the Langdon-Cranbrook 500 kV line.
When:	The 1000 MW bidirectional path rating was established in Progress Reports during the period from 1978 to 1985. Studies were conducted jointly by B.C. Hydro and Power Authority (BCH) and TransAlta Utilities Corp. (TAUC). East to West: Studies conducted since that time, show that loss of the PDCI dipole at high transfers could cause separation between Alberta and BC during high Alberta to BC transfer. Subsequent studies done by BPA in 1994 show that separation still occurs with the COTP in service. Alberta accepts separation for loss of PDCI or for any N-1 outage. West to East: Internal studies conducted since the 1985 Progress Report indicates the transfer capability is 1200 MW.
System Conditions:	East to West: Typical flows are 0 to 400 MW and usually occur during light load hours. West to East: Typical flows are 0 to 400 MW although they can be as high as 800 MW and usually occur during peak load hours.
Study Criteria:	All facilities loaded within normal ratings under normal system conditions. All facilities loaded within emergency ratings under outage conditions. The maximum acceptable transient voltage is 0.85 p.u. for 0.5 seconds on the 500 kV system.
Remedial Actions Required:	Remedial actions are required to achieve the rated transfer capability. Most involve tripping the tie line for outages in the B.C. Hydro system. East to West: For high transfers, one of the units at Keephills may be tripped (up to 370 MW). West to East: For transfer 400 MW or greater, interruptible load is armed based on system load.
Formal Operating Procedure:	BC Transmission Corporation System Operating Order 7T-17. Alberta Electric System Operator (AESO) OPP 303, 304 and 312.

Allocation:	BC Hydro owns but BC Transmission Corporation plans, operates, and manages the lines and associated facilities in British Columbia. Alta Link owns the lines and associated facilities in Alberta. The Alberta Electric System Operator (AESO) plans and administers operation of the lines and associated facilities in Alberta.
Interaction w/Other Transfer Paths:	A nomogram showing the relationship between the transfers on the BC-Alberta Intertie and the PDCI were developed prior to the completion of COTP. Since Alberta now accepts separation of their intertie with B.C. Hydro for loss of PDCI or any N-1 outage, no nomogram is required.
Contact Person:	Guihua Wang British Columbia Transmission Corporation Suite 1100, Four Bentall Centre 1055 Dunsmuir Street P.O. Box 49260 Vancouver, British Columbia Canada V7X 1V5 (604) 699-7367 (604) 699-7538 - fax guihua.wang@bctc.com Neil J. Brausen Alberta Electric System Operator 2500, 330 – 5th Ave. S.W. Calgary, Alberta, CANADA T2P 0L4 (403) 539-2533 (403) 539-2612 - fax neil.brausen@aeso.ca

2. Alberta - Saskatchewan

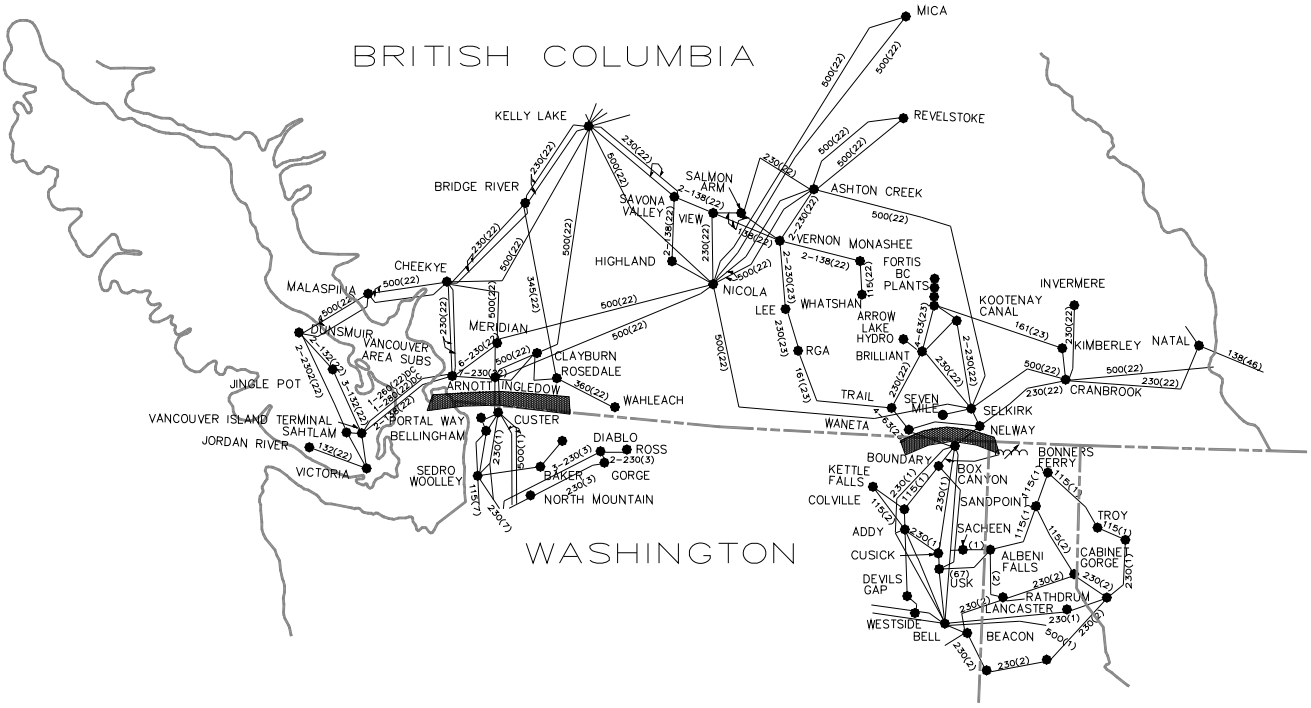


2. Alberta - Saskatchewan

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Southern Alberta and Southern Saskatchewan
Definition:	This interconnection consists of the McNeill AC-DC-AC tie. This back-to-back DC converter station is operated at 42.2 kV.
Transfer Limit:	East to West: 150 MW West to East: 150 MW
Critical Disturbance that limits the transfer capability:	The capacity of this path is currently limited by the DC converter rating.
When:	
System Conditions:	This rating is independent of transfer levels between major areas of WECC. The transfer limit is impacted by local conditions.
Study Criteria:	
Remedial Actions Required:	None
Formal Operating Procedure:	Transmission Administrator of Alberta Ltd. TAOP 324 (draft) operating procedure under development.
Allocation:	ATCO Electric owns the converter facilities in Alberta, and SaskPower Ltd. owns and operates the converter facilities in Saskatchewan. The Transmission Administrator of Alberta Ltd. plans and administers operation of the facilities in Alberta.
Interaction w/Other Transfer Paths:	None
Contact Person:	Neil J. Brausen, P. Eng. Director, System Planning Alberta Electric System Operator 2500, 330 - 5th. Ave. S. W. Calgary, Alberta, CANADA T2P OL4 (403) 539-2533 (403) 539-2612 - fax neil.brausen@aeso.ca

3. Northwest – British Columbia



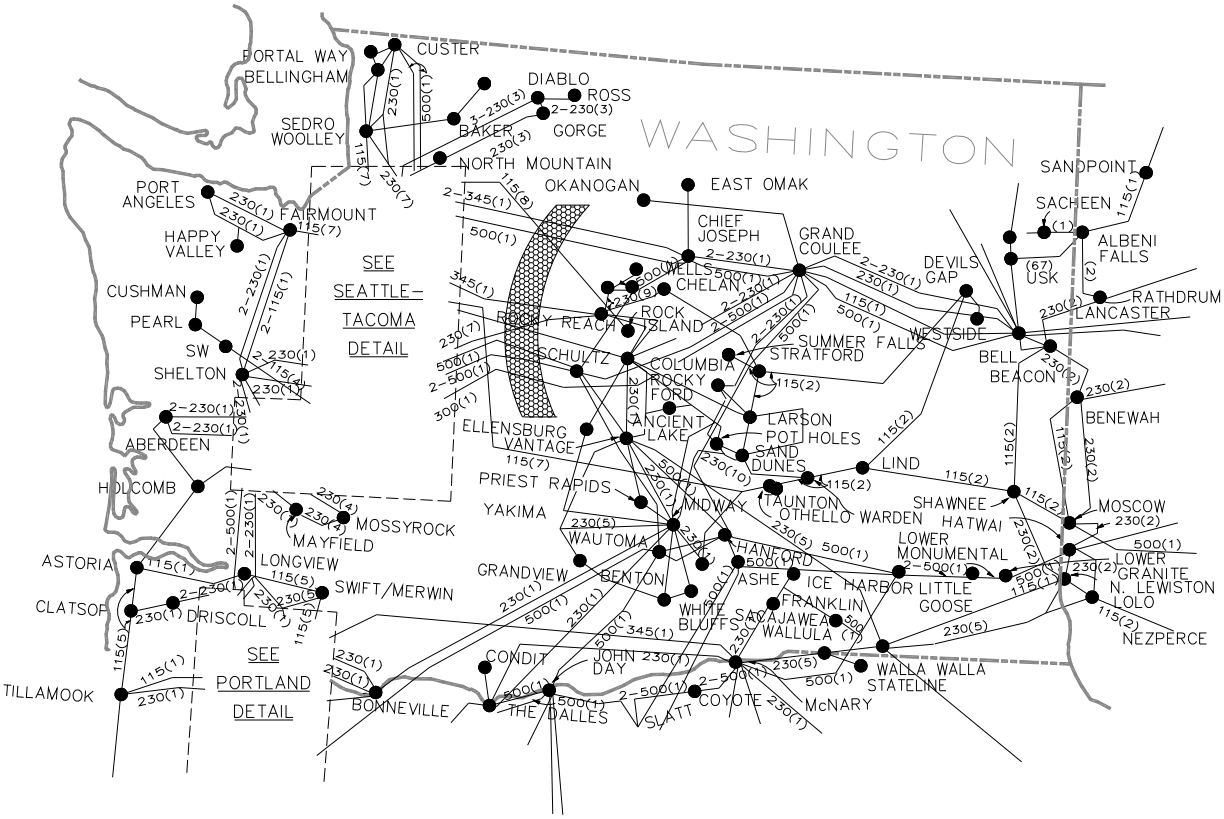
3. Northwest – British Columbia

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Washington and southern British Columbia
Definition:	BC Transmission Corporation plans, operates, and manages all transmission equipment owned by BC Hydro in British Columbia. Line — Owner — Metered End Custer (BPA)-Ingledow (BCTC) 500 kV lines 1&2 (Westside Intertie) — Joint — Ingledow (North end) Boundary (BPA)-Waneta (Fortis BC) 230 kV (Eastside Intertie, Normally Open) — Joint — Boundary (South end) Boundary (BPA)-Nelway (BCTC) 230 kV (Eastside Intertie, Normally Close) — Joint — Boundary (South end)
Transfer Limit:	North to South: Up to 3150 MW (all ties). Flow cannot exceed 2850 MW on both Custer-Ingledow lines 1&2 (Westside Intertie) or 400 MW on the Boundary-Nelway line (one of the two Eastside Interties). South to North: Up to 2000 MW (all ties). Flow cannot exceed 2000 MW on both Custer-Ingledow lines 1&2 (Westside Intertie) or 400 MW on the Boundary-Nelway line (one of the two Eastside Interties).
Critical Disturbance that limits the transfer capability:	Depending on the season, load level, direction of transfer and the pattern of generation in the local area, different outages will limit the transfer capability. Typically the most severe outages are on the 500, 345 and 230 kV grid in the Puget Sound area. Typically the limiting facilities are on the 230 and 115 kV system. Recent study work addressing the N-2 common mode outages (breaker failures, common ROW, etc.) has identified the limiting contingencies. Addition of new sectionalizing breakers, reconfiguration of the 230 kV system and uprating of existing lines has improved the operating capability of the Northern Intertie. Work is continuing on further system improvements.
When:	North to South: The 2300 MW path rating was established in January 1989 with the publication of "Facility Rating Studies for Joint BPA-BCH 2300 MW Intertie Uprate Report." The 3150 MW path rating was established with the completion of the 2850 MW Westside BCH-BPA Intertie Project. The Westside BCH-BPA 2850 MW Intertie Uprate WECC Ad Hoc Review Group issued a final report titled "Report On the Accepted Rating Study of the Westside BCH-BPA 2850 MW Intertie Uprate" in May 1994.

System Conditions:	North to South: The two Custer-Ingledow tielines can transmit 2850 MW from Canada to the Northwest when B.C. Transmission Corporation's load (Canada) is between approximately 40% and 70% of its annual peak load. South to North: Restrictions occur during winter peak demand periods due to voltage stability concerns in the Northwest and B.C. Transmission Corporation. However, predominant transfers occur during spring months when voltage stability limitations are not a concern in northwest Washington.
Study Criteria:	All applicable B. C. Transmission Corporation, Bonneville Power Administration, and NERC/WECC Standards.
Remedial Actions Required:	North to South: The maximum amount of generator tripping in Canada (B.C. Transmission Corporation) is about 110% of the scheduled export from Canada to the Northwest. Reactive power equipment switching scheme is used in B.C. Transmission Corporation (Canada) to control voltages when the transfer on the Ingledow-Custer tielines is between 2300 and 2850 MW. South to North: The 230 kV tielines are directly tripped after outages of both 500 kV Ingledow-Custer ties when the South to North total transfer exceeds 400 MW, thus separating the Northwest from Canada.
Formal Operating Procedure:	B.C. Transmission Corporation's System Operating Order #7T-18 "Custer-Ingledow 500 kV Interconnection," BPA Dispatcher Standing Order #320 "Operation of the Northern Intertie" and Standing Order #323 "Bellingham Area-Intalco Load Tripping."
Allocation:	North to South: All of the capacity is allocated to B. C. Transmission Corporation, BPA, and PSE. South to North: All of the capacity is allocated to B.C. Transmission Corporation, BPA, and PSE.
Interaction w/Other Transfer Paths:	North to South: For the Ingledow-Custer intertie 2850 MW accepted rating, there is a potential interaction with the Raver-Paul loading.
Contact Person:	Guihua Wang British Columbia Transmission Corporation Suite 1100, Four Bentall Centre 1055 Dunsmuir Street P.O. Box 49260 Vancouver, British Columbia Canada V7X 1V5 (604) 699-7367 (604) 699-7538 - fax guihua.wang@bctc.com Kyle Kohne (TPP-OPP-3) Bonneville Power Administration 7500 NE 41st Street, Suite 130 P.O. Box 61409 Vancouver, WA 98666-1409 (360) 619-6839 (360) 619-6589 - fax krkohne@bpa.gov

4. West of Cascades - North



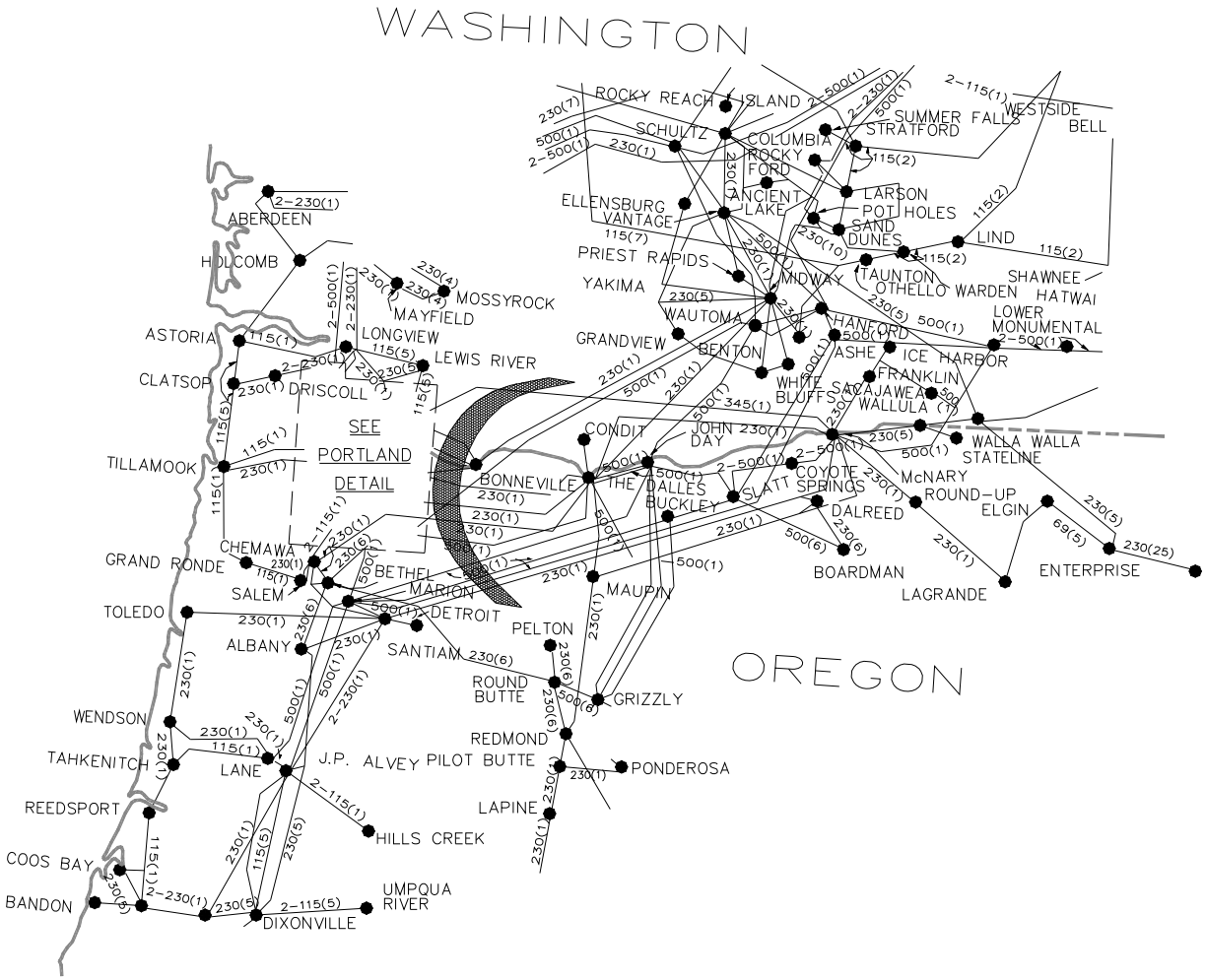
4. West of Cascades - North

Accepted Rating ☐
Existing Rating ☐
Other ☒

Location:	Central Washington
Definition:	Sum of the flows on the following lines: Line / Owner / Metered End Chief Joseph-Monroe 500 kV / BPA / Chief Joseph Schultz-Raver 1, 3, 4 500 kV / BPA / Schultz Chief Joe-Snohomish 345 kV lines 3&4 / BPA / Chief Joseph Rocky Reach-Maple Valley 345 kV / BPA / Rocky Reach Coulee-Olympia 300 kV / BPA / Coulee Rocky Reach-White River 230 kV / PSE / Rocky Reach Columbia-Covington 230 kV / BPA / Columbia Schultz-Echo Lake 500 kV / BPA / Schultz
Transfer Limit:	The transfer limit is approximately 10,200 MW and is voltage stability limited.
Critical Disturbance that limits the transfer capability:	The two critical outages include the single line outage of the Chief Joseph-Monroe 500 kV line under "extra heavy" winter peak load levels and the double outage of the Raver-Schultz 500 kV lines 1&2 under normal winter peak load levels.
When:	The most recent studies were coordinated with the Northwest Power Pool in November 2007.
System Conditions:	Generally, to achieve high west of Cascades north flows, the Northwest region must experience an "extra heavy" winter load condition. These unusual "Arctic storm" conditions have occurred on several occasions in the past. High flows can also occur during Spring when many Westside thermal units are off-line and the power is coming from East of the Cascades
Study Criteria:	All applicable BPA and NERC/WECC Standards.
Remedial Actions Required:	None. Automatic under-voltage load tripping is in place to trip up to 15% of load in the Puget Sound Area for multiple contingencies.
Formal Operating Procedure:	BPA Dispatch Standing Order 322, "Voltage Collapse Mitigation Procedures for the Puget Sound Area."
Allocation:	All of the capacity is allocated to BPA and PSE.
Interaction w/Other Transfer Paths:	None

Contact Person:	Kyle Kohne (TPP-OPP-3) Bonneville Power Administration 7500 NE 41st Street, Suite 130 P.O. Box 61409 Vancouver, WA 98666-1409 (360) 619-6839 (360) 619-6589 - fax krkohne@bpa.gov	Joe Seabrook Puget Sound Energy M/S EST-06E 355 110th Avenue NE (98004) P.O. Box 97034 Bellevue, WA 98009-9734 (425) 462-3577 (425) 462-3049 - fax joe.seabrook@pse.com

5. West of Cascades - South



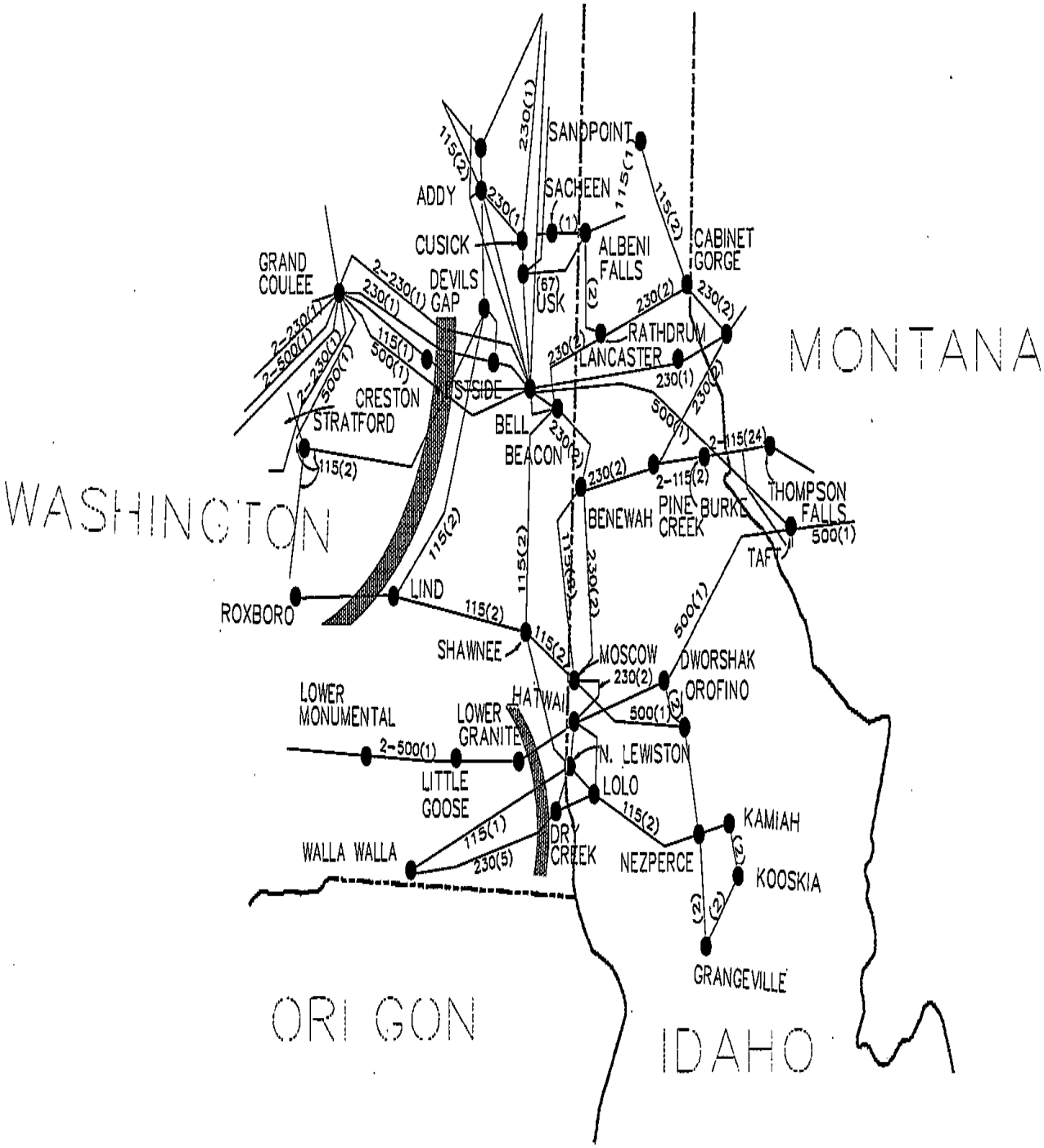
5. West of Cascades - South

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Northwestern Oregon and Southwestern Washington
Definition:	Sum of the flows on the following lines: Line / Owner / Metered End Big Eddy-Ostrander 500 kV / BPA / Big Eddy Ashe-Marion 500 kV / BPA / Ashe Buckley-Marion 500 kV / BPA / Buckley Wautoma-Ostrander 500 kV / BPA / Wautoma John Day-Marion 500 kV / BPA / John Day McNary-Ross 345 kV / BPA / McNary Big Eddy-McLoughlin 230 kV / BPA / Big Eddy Big Eddy-Chemawa 230 kV / BPA / Big Eddy Midway-N. Bonneville 230 kV / BPA / N. Bonneville Jones Canyon-Santiam 230 kV / BPA / Jones Canyon Big Eddy-Troutdale 230 kV / BPA / Big Eddy Round Butte-Bethel 230 kV / PGE / Bethel
Transfer Limit:	The transfer limit is 7000 MW and is voltage stability limited.
Critical Disturbance that limits the transfer capability:	Big Eddy-Ostrander 500 kV
When:	The most recent studies were coordinated with the Northwest Power Pool in November 2007.
System Conditions:	Generally, to achieve high west of Cascades south flows, the Northwest region must experience an "extra heavy" winter load condition. These unusual "Arctic storm" conditions have occurred on several occasions in the past. High flows can also occur during Spring when many Westside thermal units are off-line and the power is coming from East of the Cascades.
Study Criteria:	All applicable BPA and NERC/WECC Standards.
Remedial Actions Required:	None. Automatic under-voltage load tripping is in place to trip up to 15% of load in the Willamette Valley/Southwest Washington area for multiple contingencies.
Formal Operating Procedure:	BPA Dispatch Standing Order 324 "Voltage collapse mitigation procedures for the Willamette Valley/Southwest Washington area."
Allocation:	All of the capacity is allocated to BPA and PGE
Interaction w/Other Transfer Paths:	None.

Contact Person:	Kyle Kohne (TPP-OPP-3) Bonneville Power Administration 7500 NE 41st Street, Suite 130 P.O. Box 61409 Vancouver, WA 98666-1409 (360) 619-6839 (360) 619-6589 - fax krkohne@bpa.gov

6. West of Hatwai



6. West of Hatwai

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Eastern Washington
Definition:	Sum of the flows on the following line sections: Line — Metered End Hatwai (BPA)-Lower Granite (BPA) 500 kV — Hatwai Bell (BPA)-Coulee (USBR) 230 kV lines 3&5 — Bell Westside (AVA)- GrandCoulee (BPA) 230 kV — Westside Dry Creek (AVA) 230 kV – Talbot (PAC) — Dry Creek Bell (BPA)-Creston (BPA) 115 kV — Bell N. Lewiston (AVA)-Tucannon River (BPA) 115 kV — North Lewiston Harrington (AVA)-Odessa (AVA) 115 kV — Harrington Lind (AVA)-Roxboro (AVA) 115 kV — Lind Dry Gulch (AVA) 115/69 kV (PAC) transformer — 115 kV Bell (BPA) – Grand Coulee (USBR) 500kV — Bell
Transfer Limit:	East to West: 4277 MW West to East: Not defined Current SOL Transfer Limits: 4250 MW Year Round Achieving the full-accepted rating of 4277 MW is dependent on Avista completing their remaining West of Hatwai improvements. Until then, seasonal OTC limits will be used. The limits will change as remaining facilities are placed in service.
Critical Disturbance that limits the transfer capability:	Double line outage of the Bell-Coulee 500 kV and Westside-Coulee 230 kV, and breaker failure at Taft 500 kV tend to be the most limiting contingencies.
When:	The Accepted Rating was approved on March 31, 2005 following issuance of the West of Hatwai System Upgrade Projects Phase 2 Report by the West of Hatwai Review Group.
System Conditions:	The system conditions which result in high West of Hatwai flows include high Western Montana hydro generation, high Colstrip generation, high Boundary generation, and light loads. These conditions occur in late spring or early summer during off-peak hours.
Study Criteria:	All applicable AVA, BPA, and WECC criteria.
Remedial Actions Required:	Generator dropping (Libby, Colstrip (via ATR), Dworshak and Lancaster) Reactor tripping (Garrison) Tripping of Miles City DC link

Formal Operating Procedure:	WECC Operating Procedure BPA-16 BPA dispatcher standing order 325
Allocation:	BPA: 3677 MW AVA: 600 MW
Interaction w/Other Transfer Paths:	There is an interaction with the Idaho to Northwest path (Path 14) with low or west-to east flow on Path 14. Under these conditions, the critical outage becomes the Hatwai-Lower Granite 500 kV line, and the limiting line is the parallel Dry Creek-Walla Walla 230 kV line. Steady state loading on Path 18 (Amps) also becomes limiting with the W-E flow on the Idaho-NW path.
Contact Person:	Tracy Rolstad Avista Corp. 1411 East Mission P. O. Box 3727 Spokane, WA 99220-3727 (509) 495-4538 (509) 495-8542 - fax tracy.rolstad@avistacorp.com Kyle Kohne (TPP-DITT-2) Bonneville Power Administration 5411 NE HWY 99 P.O. Box 491 Vancouver, WA 98666-0491 (360) 418-8429 (360) 418-2258 - fax krkohne@bpa.gov

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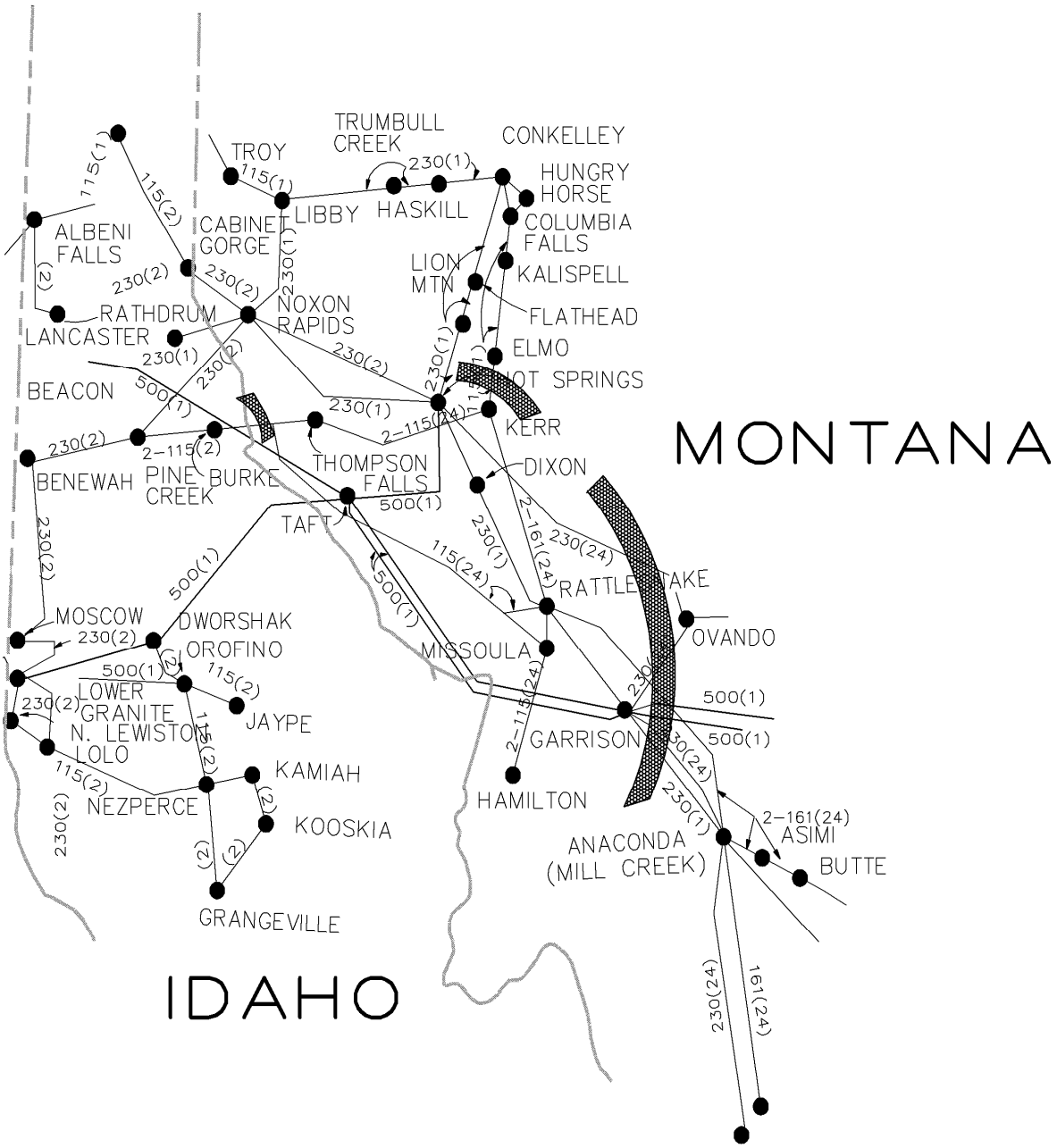
8. Montana to Northwest



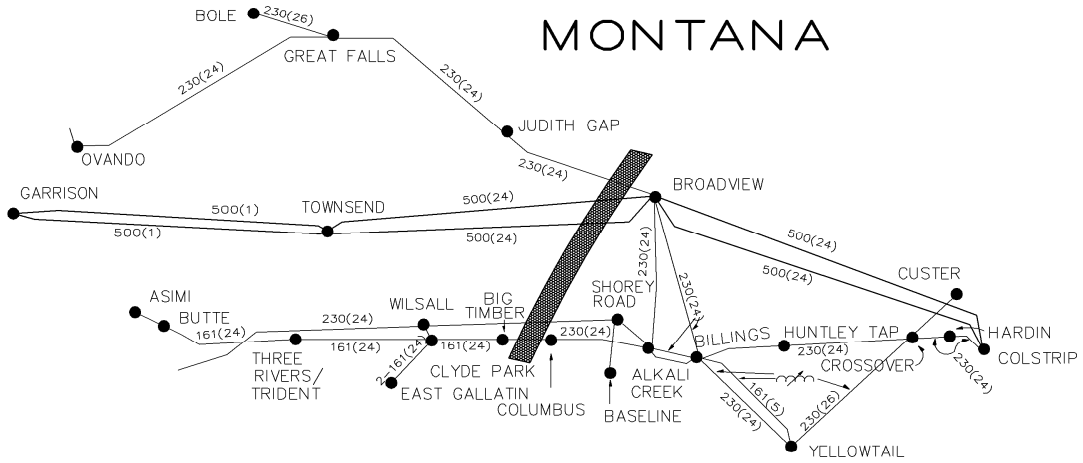
8. Montana to Northwest

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	The lines between western Montana and the Northwest US
Definition:	The lines involved in this path are the metered tie lines between NorthWestern Energy (NWMT) and Bonneville Power Administration (BPA), plus the metered tie lines between NWMT and Avista Corp. (AVA). Broadview-Garrison #1 & #2 500 kV lines — Metered End: Garrison Mill Creek-Garrison 230 kV line — Garrison Anaconda (BPA)-Garrison 230 kV line — Anaconda Ovando-Garrison 230 kV — Garrison Placid Lake-Hot Springs 230 kV — Hot Springs Rattlesnake 230/161 kV transformer — 230 kV Kerr-Kalispell 115 kV — Kerr Thompson Falls-Burke 115 kV — Burke Crow Creek-Burke 115 kV — Burke
Transfer Limit:	East to West: 2200 MW West to East: 1350 MW
Critical Disturbance that limits the transfer capability:	The constraint that sets the East-to-West rating is pre-outage steady-state voltage performance. The West-to-East rating is set by post-transient voltage performance for the loss of both Garrison-Taft 500 kV lines. The ratings of the series capacitor bank lines between Garrison and Taft were increased to 2000 A in 2004.
When:	This rating is based on studies conducted by the Montana Power Company (now NWMT) and the Bonneville Power Administration in 1993. This study was reviewed by an Ad Hoc Review Group under the auspices of the WECC. The West to East rating of 1350 MW was studied and approved by the three-phase rating process.
System Conditions:	
Study Criteria:	
Remedial Actions Required:	This limit has been enhanced by the application of remedial action schemes. Without the remedial action schemes stability performance would be the limiting constraint for this path. The remedial actions which are used to enhance stability performance are as follows: 1. Switching shunt reactors at the Garrison 500 kV bus for the loss of critical 500 kV lines. 2. Tripping the back-to-back DC tie at Miles City. 3. Tripping Colstrip generation.(via ATR) 4. Tripping Libby generation.
Formal Operating Procedure:	None

Allocation:	East-West NWMT/AVA 250 MW — Ovando-Hot Springs 230 kV NWMT/AVA 132 MW — Thompson Falls-Burke 115 kV NWMT/BPA 1818 MW — Kerr-Kalispell 115 kV, Garrison-Taft 500 kV, Garrison-Hot Springs 230 kV West-East NWMT/AVA 382 MW — Ovando-Hot Springs 230 kV, Thompson Falls-Burke 115kV NWMT/BPA 968 MW — Kerr-Kalispell 115 kV, Garrison-Taft 500 kV, Garrison-Hot Springs 230 kV
Interaction w/Other Transfer Paths:	None
Contact Person:	Charles A. Stigers NorthWestern Energy 40 East Broadway Butte, MT 59701 (406) 497-4538 (406) 497-3393 - fax Chuck.Stigers@northwestern.com Scott Waples Avista Corp. 1411 East Mission P. O. Box 3727 Spokane, WA 99220-3727 (509) 495-4462 (509) 495-8542 - fax scott.waples@avistacorp.com Kyle Kohne (TPP-DITT-2) Bonneville Power Administration 5411 NE HWY 99 P.O. Box 491 Vancouver, WA 98666-0491 (360) 418-8429 (360) 418-2258 - fax krkohne@bpa.gov

9. West of Broadview

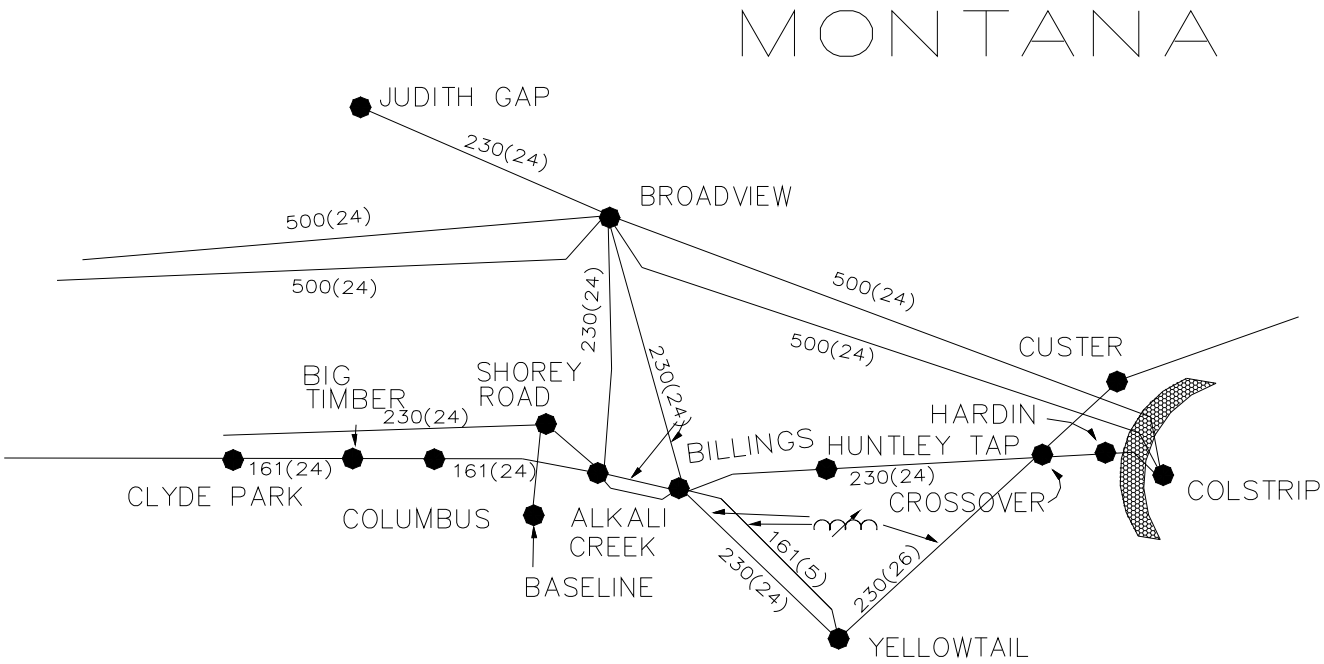


9. West of Broadview

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Central Montana
Definition:	The West of Broadview path consists of the following transmission lines: Line — Metered End Broadview-Garrison 500 kV #1 & #2 — Broadview Broadview-Judith Gap South 230 kV — Broadview Shorey Road-Wilsall 230 kV — Shorey Road Columbus/Rapleje-Big Timber 161 kV — Columbus/Rapelje Broadview 2-230/100 kV auto transformers — Broadview This path includes all lines which proceed west from the Billings area.
Transfer Limit:	East to West: 2573 MW Since the flow on this path is almost always east to west, and is never large when it is west to east, no effort has been made to determine the west to east capacity.
Critical Disturbance that limits the transfer capability:	The capacity rating is based on the maximum flow for which a two-phase-ground fault at the Broadview end of a Broadview-Garrison line when cleared normally will result in a worst case voltage dip after the fault has cleared no more than 20% of the starting voltage on any load bus with no generator tripping at Colstrip.
When:	This capacity rating is based on studies done in 1980 for the Colstrip participants.
System Conditions:	
Study Criteria:	
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	
Interaction w/Other Transfer Paths:	
Contact Person:	Charles A. Stigers NorthWestern Energy 40 East Broadway Butte MT 59701 (406) 497-4538 (406) 497-3393 - fax Chuck.Stigers@northwestern.com

10. West of Colstrip



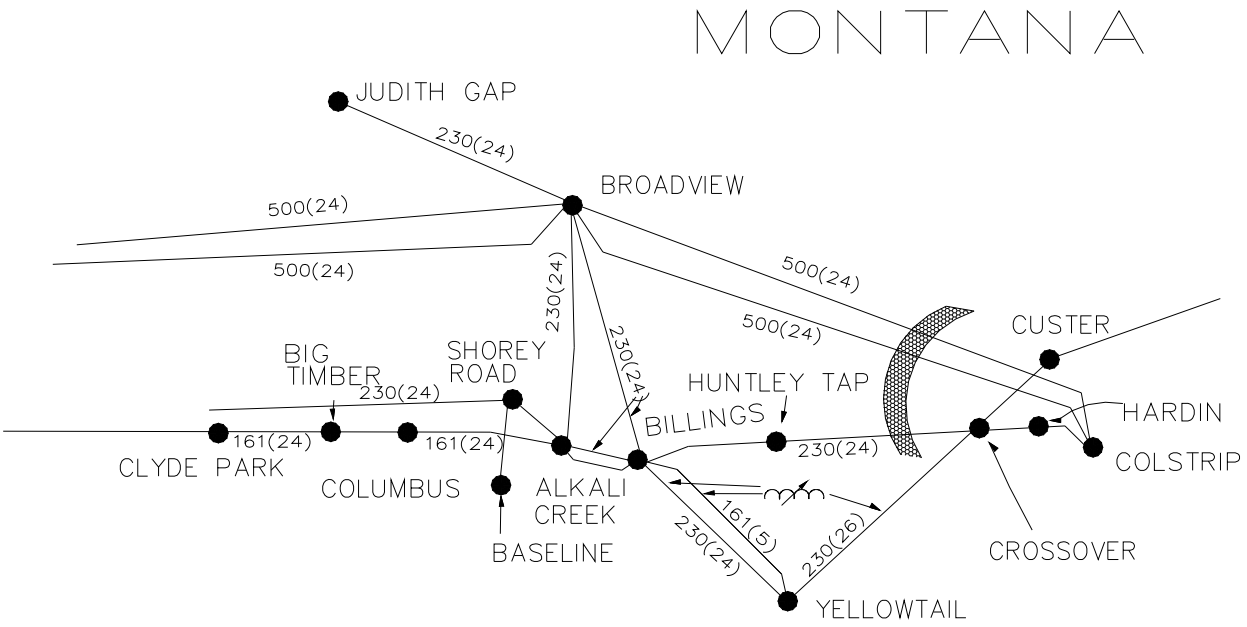
10. West of Colstrip

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Southeastern Montana
Definition:	The West of Colstrip path consists of the following transmission lines: Line — Metered End Colstrip-Broadview 500 kV lines #1 & #2 — Colstrip Colstrip-Hardin 230 kV — Colstrip Colstrip-Hardin 115 kV — Colstrip
Transfer Limit:	East to West: 2598 MW Since this path was constructed to integrate the Colstrip generation project into the Montana system, no effort has been made to determine the west to east capacity.
Critical Disturbance that limits the transfer capability:	
When:	The path capacity is based on studies done in 1980 for the Colstrip participants. This study result must be regarded as only approximate, since the transmission system model used in the study did not include significant changes which have occurred since 1980. These include: 1. The insertion of the Crossover bus in the Colstrip-Billings 230 kV line connecting this NWMT line to the Miles City-Yellowtail 230 kV Western Area Power Administration (WAPA) line at the location where the two lines intersect. 2. The addition of the Miles City back-to-back DC tie. 3. The insertion of the Hardin bus in the Colstrip-Crossover 230 kV line. 4. The addition of the Montana 1 power station on the 115 kV line between Colstrip and the Nichols pumping station. 5. The 230/115 kV transformer at Hardin. 6. Closing through the 115 kV line between Colstrip and Hardin. 7. A load tap has been placed between Crossover and Billings to serve the Huntley area. It is not likely that any of these changes has a significant impact on the capacity of this path.
System Conditions:	
Study Criteria:	
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	

Interaction w/Other Transfer Paths:	
Contact Person:	Charles A. Stigers NorthWestern Energy 40 East Broadway Butte, MT 59701 (406) 497-4538 (406) 497-3393 - fax Chuck.Stigers@northwestern.com

11. West of Crossover



11. West of Crossover

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Southeastern Montana
Definition:	The branches included in this path are: Line — Metered End Colstrip-Broadview #1 & #2 500 kV lines — Colstrip Crossover-Huntley 230 kV line — Crossover
Transfer Limit:	East to West: 2598 MW Since this path integrates the Colstrip generation and the Miles City DC tie into the system, no effort has been made to determine the west to east capacity.
Critical Disturbance that limits the transfer capability:	
When:	The path capacity is based on studies done in 1980 for the Colstrip participants. The original purpose of the study was to determine the transfer capacity west of Colstrip. This study result must be regarded as only approximate, since the transmission system model used in the study did not include significant changes which have occurred since 1980. These include: 1. The insertion of the Crossover bus in the Colstrip-Billings 230 kV line connecting this line to the Miles City-Yellowtail 230 kV Western Area Power Administration (WAPA) line at the location where the two lines intersect. 2. The addition of the Miles City back-to-back DC tie. 3. The insertion of the Hardin bus in the Colstrip-Crossover 230 kV line. 4. The addition of the Montana 1 power station on the 115 kV line between Colstrip and the Nichols pumping station. 5. The 230/115 kV transformer at Hardin. 6. Closing through the 115 kV line between Colstrip and Hardin. 7. A load tap has been placed between Crossover and Billings to serve the Huntley area. 8. The addition of the Hardin Generator interconnected at Hardin Auto. It is not likely that any of these changes has a significant impact on the capacity of this path.
System Conditions:	
Study Criteria:	
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	

Interaction w/Other Transfer Paths:	
Contact Person:	Charles A. Stigers NorthWestern Energy 40 East Broadway Butte, MT 59701 (406) 497-4538 (406) 497-3393 - fax chuck.stigers@northwestern.com

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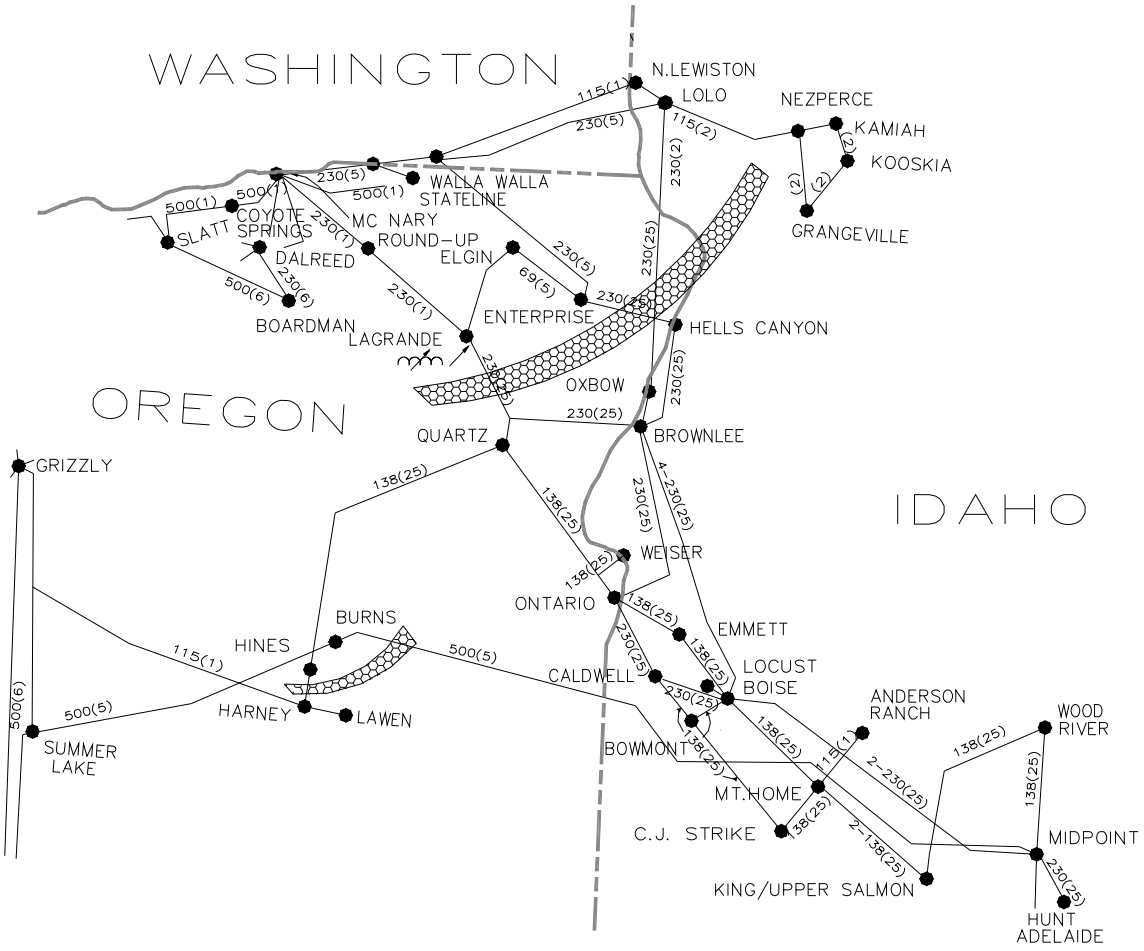
14. Idaho to Northwest



14. Idaho to Northwest

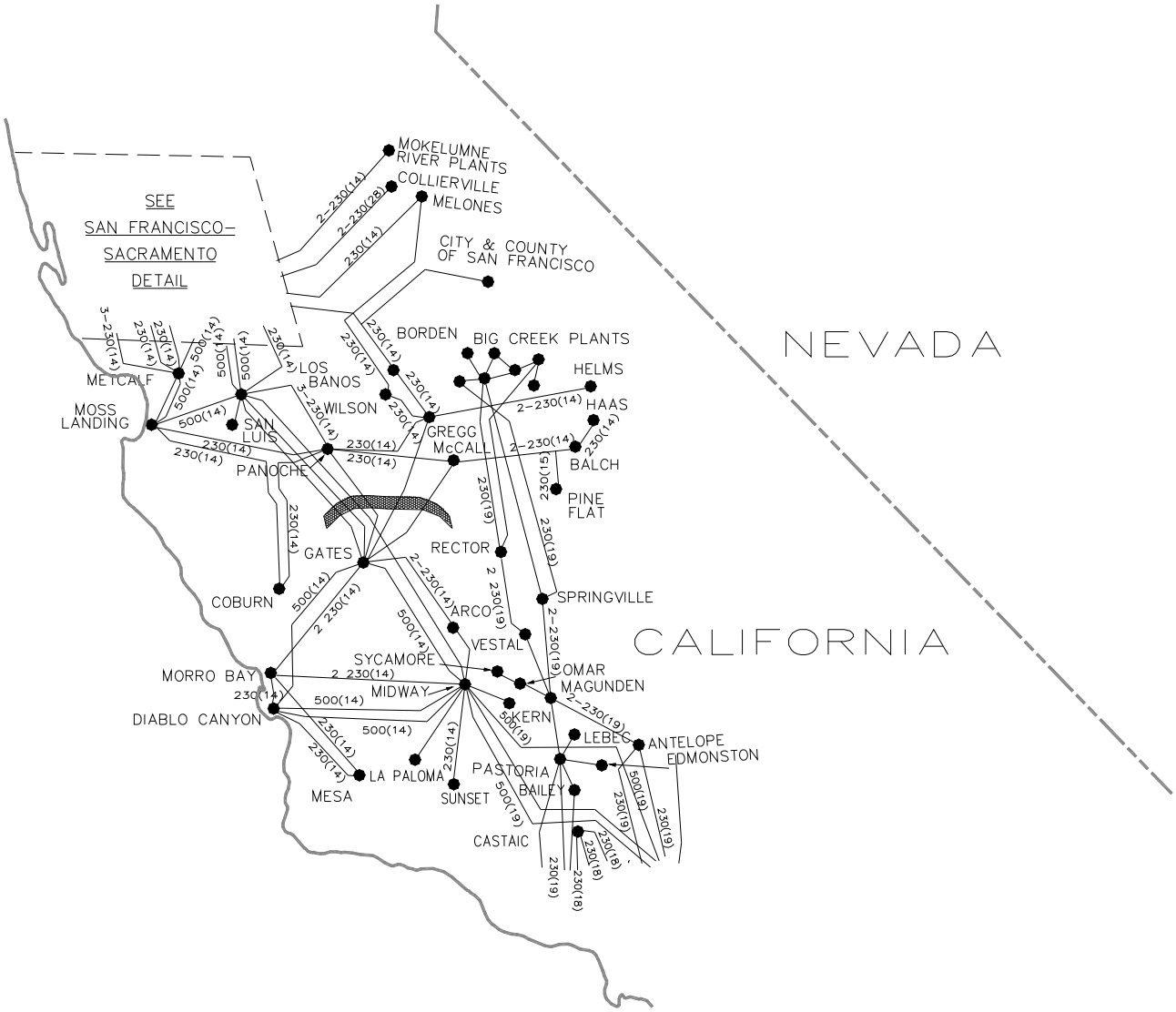
Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Southwest Idaho and Eastern Oregon/Washington and Northern Idaho
Definition:	Sum of the flows on the following lines: 500 kV system: — Metered End Midpoint-Summer Lake 500 kV — Midpoint 230 kV and 115 kV system: Imnaha-Lolo 230 kV — Imnaha Hells Canyon-Enterprise 230 kV — Enterprise Quartz Tap-LaGrande 230 kV — LaGrande Hines-Harney 115 kV — Harney
Transfer Limit:	Combined Ratings East to West: 2400 MW West to East: 1200 MW Individual Systems Ratings: 500 kV system — East to West: 1500 MW; West to East: unallocated 230 kV and 115 kV system — East to West: 1200 MW; West to East: 1200 MW Current OTC Seasonal Transfer Limits: East to West: 2304 NW* West to East: 1200 MW Winter 1150 MW Spring/Fall** 1090 MW Summer** * The East to West OTC transfer capability is limited due to network changes, which consisted of the removal of the Copperfield series capacitor and thermal limitations on the Imnaha-Lolo 230 kV line section. ** The West to East OTC transfer capability is limited in the spring, summer, and fall seasons due to thermal limitations on the Imnaha-Lolo 230 kV line section.
Critical Disturbance that limits the transfer capability:	East to West: Transient voltage dip at LaGrande, post-transient voltages at LaGrande, Hines, and West John Day, and the thermal overload on the Walla Walla series capacitor following the loss of the Midpoint-Summer Lake 500 kV line. West to East: The transfer capacity on the three 230 kV and one 115 kV tie lines is based on steady state thermal limits. The 1200 MW transfer capacity assumes no allocation on the Midpoint-Summer Lake line during normal system conditions.

When:	The 2400 MW east to west rating was established in August, 1989 with the publication of Idaho Power Company to Pacific Northwest Intertie Capacity Study. The WECC Notification Procedures for Changes in Facility Ratings and/or Operating Procedures was followed. The 1200 MW west to east rating was established in 1981 and reconfirmed in 1986. The 2400 MW east to west rating was conducted jointly by: Bonneville Power Administration (BPA) Idaho Power Company (IPCO) PacifiCorp (PAC) Avista Corp. (AVA) The 500 kV system east to west capability was demonstrated at the time of 2400 MW east to west study in 1989. The 230 kV and 115 kV system east to west capability was established in 1976 and re-demonstrated with the 1989 study. The 1200 MW west to east rating was established in 1981 and reconfirmed in 1986 without allocation of capacity to the Midpoint-Summer Lake 500 kV line. The studies were conducted by Idaho Power Company.
System Conditions:	The 2400 MW east to west transfer rating was studied with light load conditions in Idaho with heavy eastern thermal resources, and moderate generation on the remaining hydro plants in Idaho. Studies were performed with both north to south and south to north on the PACI and near maximum transfers on parallel paths; i.e. transfers to Northwest and Arizona to California. The 1200 MW west to east transfer rating was studied with high hydro conditions in the Northwest with low to moderate eastern thermal resources. In addition, the 1200 MW west to east rating cannot be fully utilized simultaneous with heavy Hells Canyon complex generation because of steady state thermal overloads and/or post disturbance voltage change in Idaho Power's internal transmission system.
Study Criteria:	NERC/WECC Reliability Criteria For Transmission System Planning
Remedial Actions Required:	A remedial action scheme is required to achieve the 2400 MW east to west transfer capability. Outage of the Midpoint-Summer Lake 500k kV line requires Jim Bridger unit(s) tripping (IPC-6 Jim Bridger Generator Transfer Trip Scheme for loss of the Midpoint-Summer Lake 500 kV line). A remedial action scheme is required to achieve the 1200MW west to east transfer capability simultaneous with high Hells Canyon generation (IPC-2 Automatic Reduction of Hells Canyon Generation).
Formal Operating Procedure:	Under certain generation and load conditions, 2400 MW Idaho to Northwest transfer simultaneous with heavy Northwest to California transfers may cause overloading of the Midpoint-Summer Lake line. During these conditions, one-half of the Burns series capacitor can be bypassed to reduce Midpoint-Summer Lake loading but it results in reduced Bridger West capacity.

Allocation:	The transfer capability of the path is allocated among the interconnections as follows: • 2400 MW East to West: 1587 MW IPC - PacifiCorp interconnection 413 MW IPC - BPA interconnection 400 MW IPC - AVA interconnection • 1200 MW West to East: 350 MW BPA - IPC interconnection 400 MW PacifiCorp - IPC interconnection 450 MW AVA - IPC interconnection
Interaction w/Other Transfer Paths:	
Contact Person:	Mark D. Hanson Idaho Power Company P. O. Box 70 Boise, ID 83707 (208) 388-2253 (208) 388-6647 - fax mhanson@idahopower.com Scott Waples Avista Corp. 1411 East Mission P. O. Box 3727, MSC-16 Spokane, WA. 99220-3727 (509) 495-4462 (509)-495-8542 - fax scott.waples@avistacorp.com Gil Coulam PacifiCorp, 1407 West North Temple Suite 275 Salt Lake City, UT 84116 (801) 220-2954 (801) 220-2842 - fax Gilbert.coulam@pacificorp.com Kyle Kohne (TOP-PPOC2-2) Bonneville Power Administration 5411 NE Hwy 99 P.O. Box 491 Vancouver, WA 98666-0491 (360) 418-8429 (360) 418-2258 - fax krkohne@bpa.gov

15. Midway - Los Banos



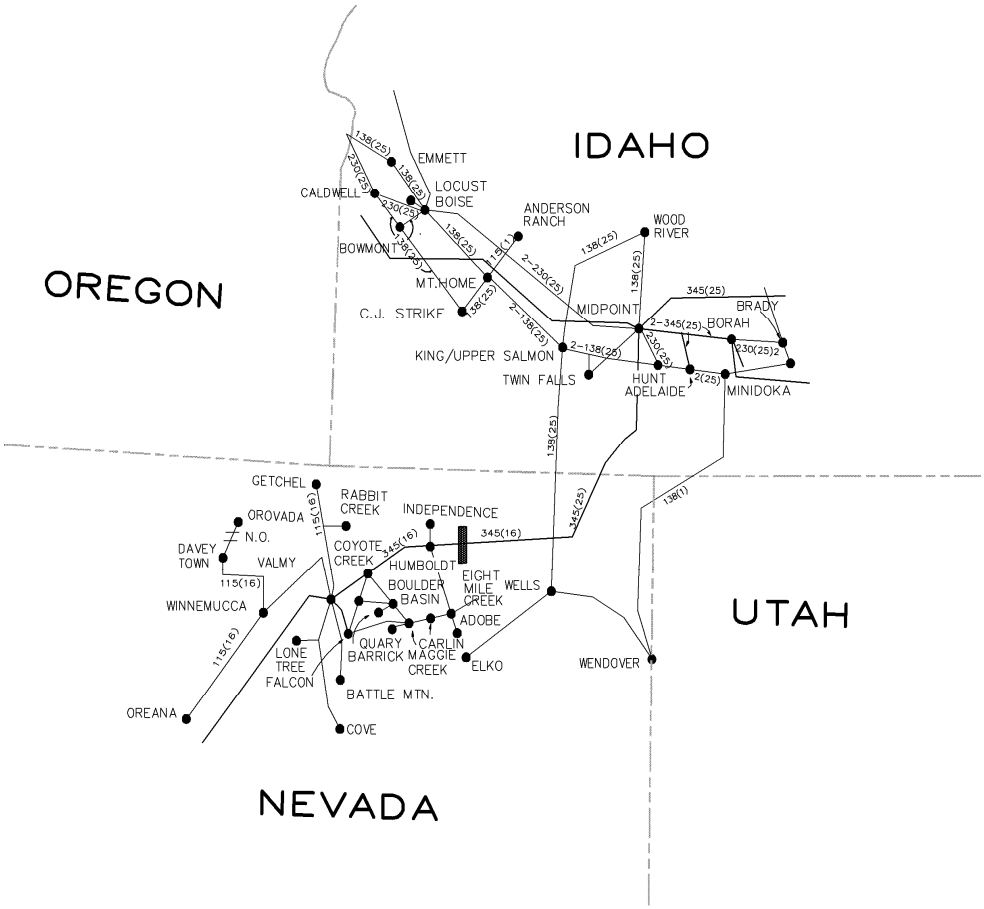
15. Midway - Los Banos

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Between central and southern California within the PG&E system and south of Los Banos substation (PG&E internal Path 15).
Definition:	Measured at Los Banos for all 500 kV lines and at Gates for all 230 kV lines for both north-to-south and south-to-north flows: Midway-Los Banos 500 kV line (at Los Banos) Los Banos-Gates # 1 and #3 500 kV lines (at Los Banos) Gates-Panoche #1 & #2 230 kV lines (at Gates) Gates-Gregg 230 kV line (at Gates) Gates-McCall 230 kV line (at Gates)
Transfer Limit:	The transfer limit ranges from 2000-3265 MW from north to south. The transfer limit ranges from 4800-5400 MW from south to north.
Critical Disturbance that limits the transfer capability:	From north to south: Midway-Gates and Midway-Los Banos 500 kV double line outage. Double Palo Verde unit outage. Los Banos-Tesla and Los Banos-Tracy 500 kV double line outage. From south to north: Double line 500 kV outages between Tesla and Midway.
When:	The 3265 MW north-to-south rating was established in the August 5, 2002 Path 15 Upgrade north-to-south Project Comprehensive Progress Report. Phase III Status granted on October 23, 2003. The 5400 MW south-to-north rating was established in the September 18, 2001 Path 15 Upgrade Project Comprehensive Progress Report. A letter from the PCC chair indicating the Phase II report was accepted and granting Phase III status was distributed on February 5, 2003.
System Conditions:	The north-to-south path rating was based on north-to-south transfers under heavy summer (high temperature) operating conditions. The south-to-north path rating was based on south-to-north transfers under light winter operating conditions.
Study Criteria:	NERC/WECC Planning Standards.
Remedial Actions Required:	Remedial actions are employed on an as needed basis for double line outages between Tesla and Midway.
Formal Operating Procedure:	CISO T-122 and PG&E O-51 operating procedures which are periodically updated.
Allocation:	PG&E, SCE, SDGE, CDWR, and various new owners.
Interaction w/Other Transfer Paths:	For high north-to-south flows on Path 15 and high north-to-south flows on COI and/or PDCI it is necessary to operate based on a nomogram. Path 15 north-to-south transfer limit can be significantly less with high generation levels in the Midway area because of Path 26 limitations. For high south-to-north flows on Path 15 and high east-to-west flows on West of Borah it is necessary to operate based on a nomogram.

Contact Person:	Kang-Ling Ching Pacific Gas and Electric Company Mail Code B15A P.O. Box 770000 San Francisco, CA 94177-0001 (415) 973-7637 (415) 973-8804 – fax kxc5@pge.com Larry Tobias Western Area Power Administration – Sierra Nevada Region 114 Parkshore Drive Folsom, CA 95630 (916) 353-4766 (916) 985-1935 – fax Tobias@wapa.gov

16. Idaho - Sierra



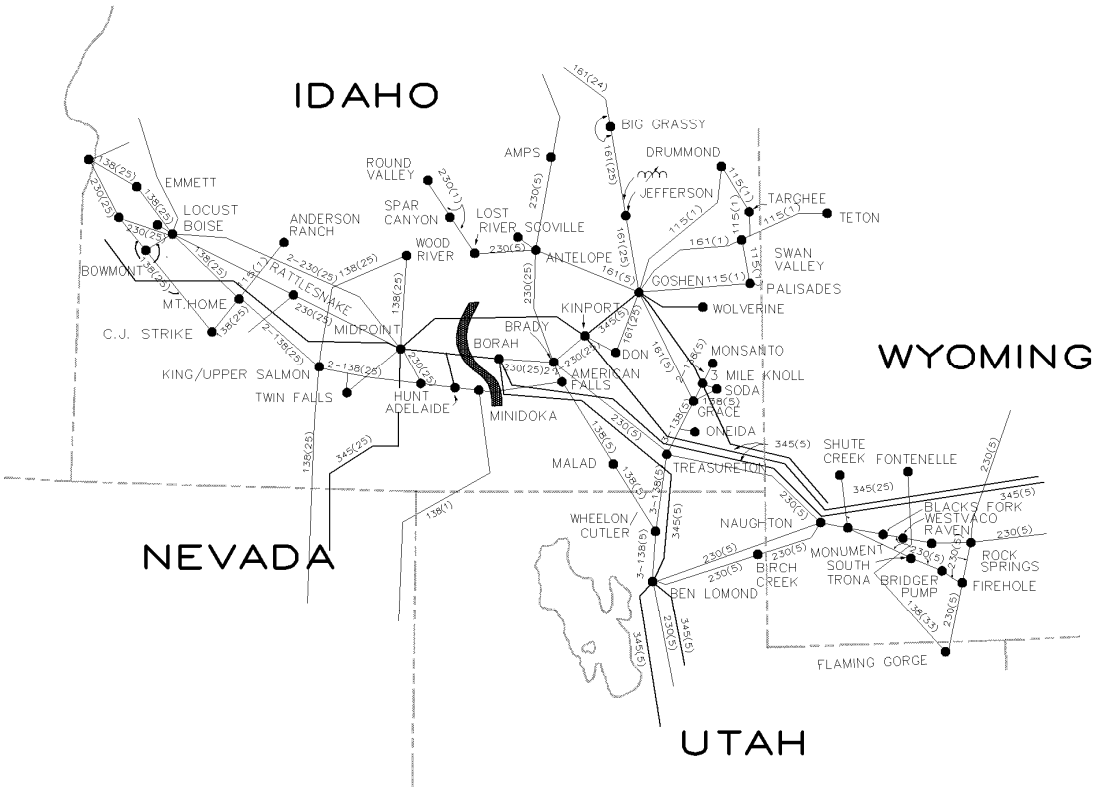
16. Idaho - Sierra

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Border between southern Idaho and northern Nevada
Definition:	Midpoint (Idaho Power Co.) – Humboldt (SPPC) 345 kV line. The metering point is at the Humboldt end of the line.
Transfer Limit:	North to South: 500 MW South to North: 360 MW The capacities listed above are non-simultaneous ratings of the line. Simultaneous ratings are dependent on Sierra's net control area operations. Seasonal OTC limits may be more restrictive for operating South to North.
Critical Disturbance that limits the transfer capability:	Outage of the Humboldt-Coyote Creek 345 kV line which overloads the Humboldt 345/120 kV transformer, is a critical disturbance which determines the North to South rating. The South to North rating is determined by both outages of the Coyote Creek-Valmy and/or Coyote Creek-Humboldt 345 kV lines and following thermal overloads of the 345/120 transformers and underlying 120 kV system..
When:	Initial non-simultaneous transfer studies were performed jointly by Sierra Pacific Power Company and Idaho Power Company in 1980. Periodically, Sierra updates their net system import limit studies to quantify simultaneous limits.
System Conditions:	Studies of the Sierra net system import limit have been conducted for all seasons and at various load levels.
Study Criteria:	Criteria used in determining Sierra's net import and export limits: • The post disturbance steady state voltages on the Ft. Churchill-Pavant 230 kV load buses must recover to 90% of pre-disturbance voltage and no less than 0.90 p.u. Automatic reactor switching allowed. • The post disturbance net flow on the Sierra-PG&E 120 kV and 60 kV interties must not exceed the limitations on that intertie (nominally 180 MW).
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	The transfer capability of the path is allocated as follows: Ownership — Allocation 50% Idaho — 100% North-bound capacity 50% Sierra — 100% South-bound capacity
Interaction w/Other Transfer Paths:	Sierra's system import and export limits and the flows on their other tie lines affect the scheduling capability of this intertie.

Contact Person:	Edi Von Engeln Sr. ENGR. Regional Planning 6100 Neil Road M/S S3B40 Reno, NV 89511 (775) 834-4456 (775) 834-3047 - fax evonengeln@sppc.com

17. Borah West



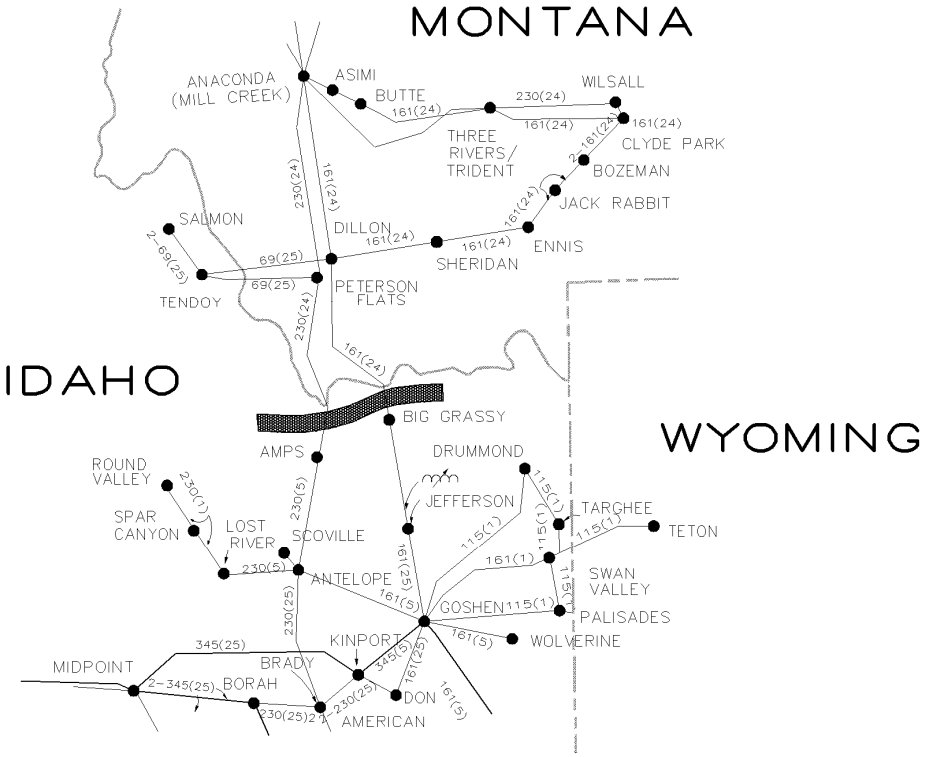
17. Borah West

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Southeast Idaho
Definition:	Sum of the flows on the following lines: Line — Metered End Kinport-Midpoint 345 kV — Kinport Borah-Adelaide-Midpoint #1 345 kV — Borah Borah-Adelaide-Midpoint #2 345 kV — Borah Borah-Hunt 230 kV — Borah AmFalls-Raft River-Minidoka 138 kV — American Falls
Transfer Limit:	East to West: 2557 MW West to East: Not defined The transfer capacity listed above is the accepted rating following the completion of the Borah West 250 MW uprate project.
Critical Disturbance that limits the transfer capability:	The double line loss of the Kinport-Midpoint 345 kV line and one of the Borah-Adelaide-Midpoint 345 kV lines. Prior to the Borah West 250 MW uprate project, the Borah West transfer capacity was an existing rating of 2307 MW.
When:	The 2557 MW Borah West rating was established in the Phase II comprehensive progress report, which was issued September 10, 2002. The Borah West Uprate project was granted Phase III status on March 24, 2003. The projected Borah West Uprate project was placed in-service in June 2007.
System Conditions:	The Borah West transfer rating was determined with simultaneous heavy transfers on series path (Path C south to north, and Bridger West) consistent with the transfer of eastern thermal resources to the west.
Study Criteria:	WECC/NERC Reliability Criteria for Transmission System Planning
Remedial Actions Required:	The loss of two of the 345 kV lines simultaneously or one line initially out-of-service and loss of another line will initiate a trip of one Jim Bridger unit if the flow from the east on the three 345 kV lines into Midpoint exceeds 1050 MW. For the special contingency of the loss of the Kinport-Midpoint 345 kV line with one of the Borah-Adelaide-Midpoint 345 kV lines under high flow conditions, a trip of two Jim Bridger units may be required.
Formal Operating Procedure:	For PDCI south to north operation, a nomogram exists for flows on the PDCI, COI, Borah West and available load dropping in the Northwest. California ISO T-122 (West of Borah versus Path 15 nomogram).
Allocation:	Idaho Power Company (IPC) owns the Borah West transfer path and capacity. IPC has long-term agreements to provide transmission services on this path to PacifiCorp for up to 1600 MW.

Interaction w/Other Transfer Paths:	There is a known interaction for south to north transfers on PDCI and COI and Borah West. Also, there is a known interaction for high south to north transfer on Path 15 and Path 26 (under outage conditions) and high east-to-west transfers on Borah West that requires operation based on a nomogram.
Contact Person:	Mark D. Hanson Idaho Power Company P. O. Box 70 Boise, ID 83707 (208) 288-2253 (208) 388-6647 - fax mhanson@idahopower.com

18. Montana - Idaho



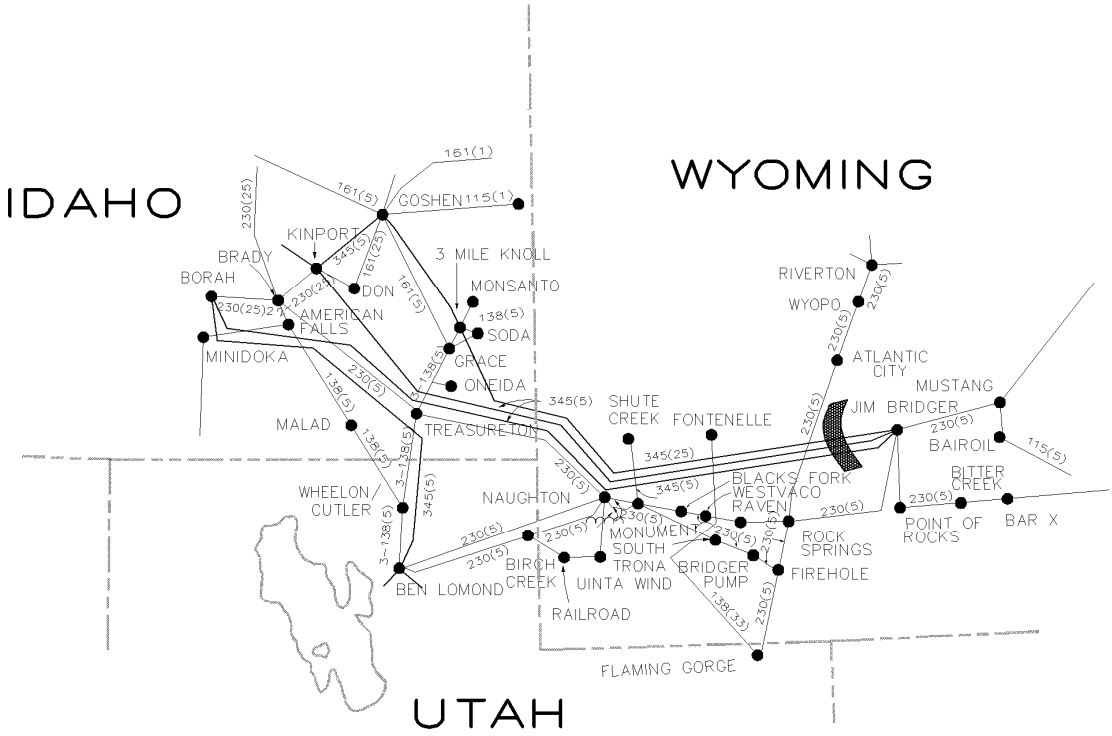
18. Montana - Idaho

Accepted Rating ☒
Existing Rating ☒
Other ☐

Location:	Eastern Idaho and Western Montana
Definition:	Sum of the flows on the following lines: Meter Location Dillon Salmon-Big Grassy 161 kV Big Grassy Peterson Flats-AMPS 230 kV Amps
Transfer Limit:	North to South: 337 MW South to North: 337 MW
Critical Disturbance that limits the transfer capability:	External: Outage of the Bridger-Goshen and Bridger-Kinport 345 kV lines with RAS tripping two Bridger units. Internal: Outage of the Anaconda-Antelope 230 kV line. Outage of the Big Grassy-Dillon Salmon 161 kV Line.
When:	The 356/351 MW capability was established by the transmission path owners (PacifiCorp, NorthWestern Energy, and Idaho Power) April 19, 2005 and was approved by WECC on June 29, 2005.
System Conditions:	North to south flows achieved with high Montana hydro and thermal generation and low Idaho generation patterns, and heavy loads in Eastern Idaho.
Study Criteria:	The 356 MW North-to-South rating of this path (with the Bridger West flow < 1650 MW) is based on meeting the 2.5 percent margin for voltage stability for the post-transient condition after the critical contingency. The critical contingency is the Bridger – Kinport, Bridger – Goshsen double contingency. The 351 MW North-to-South rating of this path (with the Bridger West flow > 1650 MW) is based on the post-contingency relative voltage performance for service to loads served by both lines. The basis for the rating is somewhat less conservative than the present WECC criterion for post-transient voltage performance. However, with the relaxed criteria the stated capacity is within the 2.5 percent margin prescribed by the WECC voltage stability criterion for this contingency. The north-to-south ratings are Accepted Ratings. This path rating study was performed in June 2005. The owners of this path have agreed to limit the total scheduled North-to-South flow on the path to 337 MW. The difference between the stated North-to-South ratings of 356/351 MW and schedule limit of 337 MW is used as Transmission Reserve Margin (TRM). This TRM is for explicit reliability margin. Refer to the OTC operating procedure, available through WECC for details. The South-to-North rating of this path is 337 MW. This rating is based on study work performed in 1999. No official path rating study has been performed for South-to-North flows to update this rating. It is rare for this path to be heavily loaded South-to-North. This rating is an "Existing Rating". However, more recent operational evaluations of the path have shown that flows on the path should be limited to 256 MW (or less). The critical

	contingency is the loss of the Brady – Antelope 230 kV line. This leads to overloading of the Goshen – Antelope 161 kV line. An Overload Mitigation Scheme has been installed to mitigate this overload. See to operating procedures for additional details.
Remedial Actions Required:	None
Formal Operating Procedure:	The owners of this path have agreed to limit the total scheduled flow on the path to 337 MW. The difference between the stated southbound ratings of 356/351 MW and 337 MW is Transmission Reserve Margin (TRM) for explicit reliability margin. The owners have agreed not to use the TRM for commercial transactions. Refer to the OTC operating procedure, available through WECC for details.
Allocation:	Based upon Hot Springs to Brady: Ownership approx. (varies year to year) / Allocation 230 kV IPC 31.9% 31.9% (80 MW)* NWMT 31.9% 31.9% (80 MW)* PAC 36.2% 36.2% (90 MW)* 161 kV Goshen-Stateline IPC 100.0% 100.0% (87 MW)* Stateline-Dillon NWMT 100.0% 100.0% (87 MW)* *Based on the Schedule limit of 337 MW
Interaction w/Other Transfer Paths:	None
Contact Person:	Mark D. Hanson Idaho Power Company P. O. Box 70 Boise, ID 83707 (208) 388-2253 (208) 388-6647 - fax mhanson@idahopower.com Charles A. Stigers Northwestern Energy 40 East Broadway Butte, MT 59701 (406) 497-4538 (406) 497-3393 - fax chuck.stigers@northwestern.com Gil Coulam PacifiCorp, 1407 West North Temple Suite 275 Salt Lake City, UT 84116 (801) 220-2954 (801) 220-2842 - fax gilbert.coulam@pacificorp.com

19. Bridger West



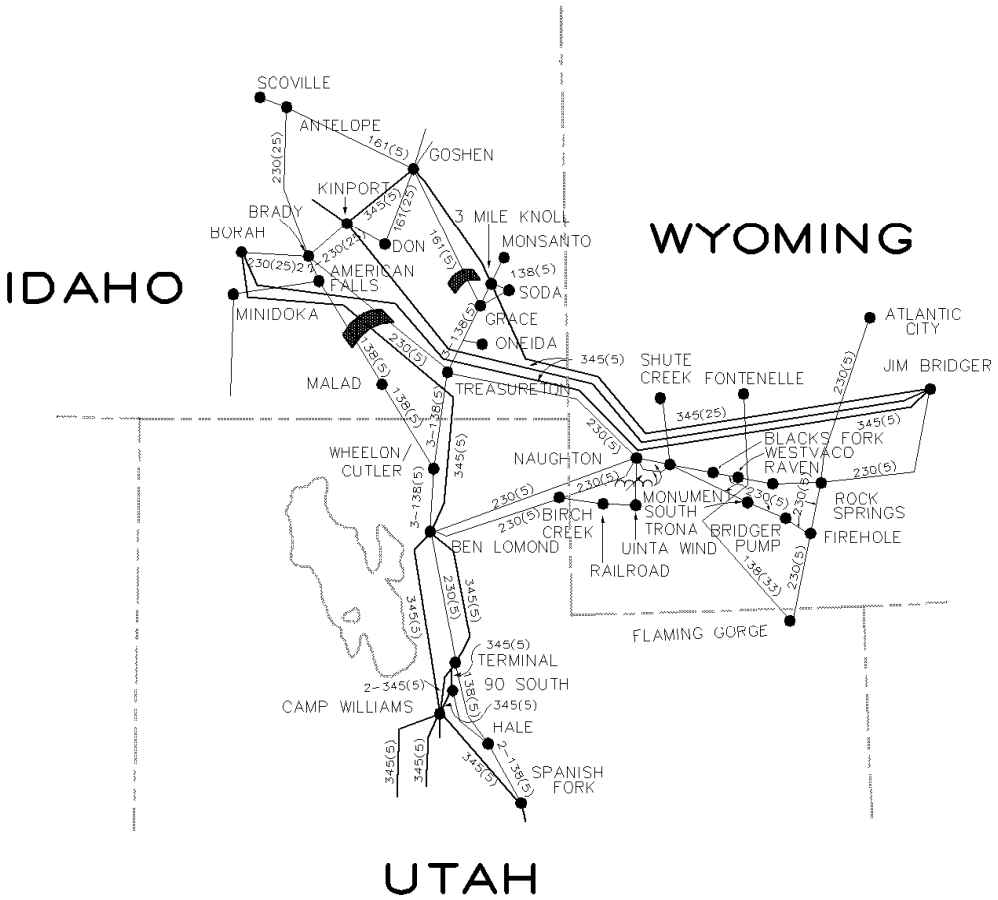
19. Bridger West

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Border between Southeast Idaho and Southwest Wyoming
Definition:	Sum of the flows on the following lines: Line — Metered End Jim Bridger-Borah 345 kV — Jim Bridger Jim Bridger-Three Mile Knoll 345 kV — Jim Bridger Jim Bridger-Kinport 345 kV — Jim Bridger
Transfer Limit:	East to West: 2200 MW West to East: Not defined
Critical Disturbance that limits the transfer capability:	The 30 minute thermal rating of the 345 kV series capacitors in the remaining lines limits transfers for the single most critical outage which is loss of the Jim Bridger-Three Mile Knoll 345 kV line. Transient voltage dips and post transient voltage stability are the limiting conditions for N-2 outages of the Jim Bridger 345 kV system.
When:	The 2200 MW rating was established in 1982 and reconfirmed in 1990 and 1992. The studies were conducted jointly by Idaho Power Company (IPCO) and PacifiCorp. Since the transfer capability did not increase, the WECC "Notification Procedure for Changes in Facility Ratings and/or Operating Procedures" were not implemented.
System Conditions:	The Bridger West transfer rating was determined with simultaneous heavy transfers on series and parallel paths consistent with heavy transfers of eastern thermal resources to the west. The original transfer studies were performed with simultaneous flows on Montana-Northwest at 1800-1900 MW, TOT 4A at 600 MW, Path C (Utah North) at 700 MW, and high West of Borah and Idaho-Northwest flows (actual flow dependent on load conditions assumed in Idaho). Subsequently, transfer studies have been performed with simultaneous flows on Path C at 850 MW-950 MW depending on seasonal conditions.
Study Criteria:	Initial Conditions: • Per unit bus voltages within PacifiCorp and IPCO systems between 0.95 p.u. and 1.05 p.u. • All line and transformer loadings maintained within allowable continuous ratings. • Synchronous condensers at Kinport, Goshen, and American Falls operating in the middle of their boost-buck range. The Jim Bridger 200 MVAR shunt capacitor bank in service. • The Treasureton 2 x 50 MVAR 138 kV shunt capacitor banks will be switched in service when the flows exceed either 1750 MW on Bridger West or 700 MW on Path C. Transient: WECC/NERC Reliability Criteria for Transmission System Planning. Post Transient: For single contingencies (N-1), a 250 MVAR reactive margin will be maintained from the point of voltage instability (nose of the QV curve) at the critical bus for an outage of the critical line with successful operation of remedial action scheme. For double contingencies (N-2), a 200 MVAR

	reactive margin will be maintained at the critical bus.
Remedial Actions Required:	A remedial action scheme is required to achieve the 2200 MW east to west rating. Multi-phase faults, SLG faults with delayed clearing, and multi-line outages on the Jim Bridger 345 kV lines require Jim Bridger unit(s) tripping. The addition of the Jim Bridger 200 MVAR 345 kV, Kinport 175 MVAR 345 kV, and Goshen 100 MVAR 161 kV shunt capacitor banks, along with the bypassing of Burns 500 kV series capacitor bank, has eliminated Jim Bridger unit tripping for SLG faults. The Jim Bridger shunt capacitor is normally on to reduce the reactive output of the Jim Bridger units so more reactive support can be provided during a disturbance. The Kinport and Goshen shunt capacitors are normally off and held in reserve to be switched at the time of a disturbance for additional reactive support.
Formal Operating Procedure:	Bridger West vs Path C South – North seasonal nomograms (Operating Procedure: PCC-005 Path C, South to North)
Allocation:	The transfer capability of the path is allocated as follows: 2200 MW East to West: Ownership Allocation 733 MW (1/3) IPC 707 MW (1/3 Max Jim Bridger Generation) 1467 MW (2/3) PacifiCorp 1493 MW (Remainder)
Interaction w/Other Transfer Paths:	The Bridger West Path has a nomogram identifying simultaneous operating constraints between this path and Path C in the south to north direction during light load conditions. The intersection exists for Bridger West flows in excess of 2100 MW.
Contact Person:	Mark D. Hanson Idaho Power Company P. O. Box 70 Boise, ID 83707 (208) 388-2253 (208) 388-6647 - fax mhanson@idahopower.com Craig Quist Pacificorp 1407 West North Temple Suite 275 Salt Lake City, UT 84116 (801) 220-4264 (801) 220-2842- fax craig.quist@pacificorp.com

20. Path C


SCOVILLE
ANTELOPE
GOSHEN
KINPORT
BRADY
BORAH
DON
3 MILE KNOLL
MONSANTO
SODA
GRACE
ONEIDA
AMERICAN FALLS
MINIDOKA
MALAD
TREASURETON
WYOMING
IDAHO
ATLANTIC CITY
JIM BRIDGER
SHUTE CREEK
FONTENELLE
BLACKS FORK
WESTVACO
RAVEN
ROCK SPRINGS
FIREHOLE
NAUGHTON
WHEELON/ CUTLER
BIRCH CREEK
MONUMENT SOUTH
TRONA
BRIDGER PUMP
UINTA WIND
RAILROAD
BEN LOMOND
FLAMING GORGE
TERMINAL
90 SOUTH
CAMP WILLIAMS
HALE
SPANISH FORK
UTAH

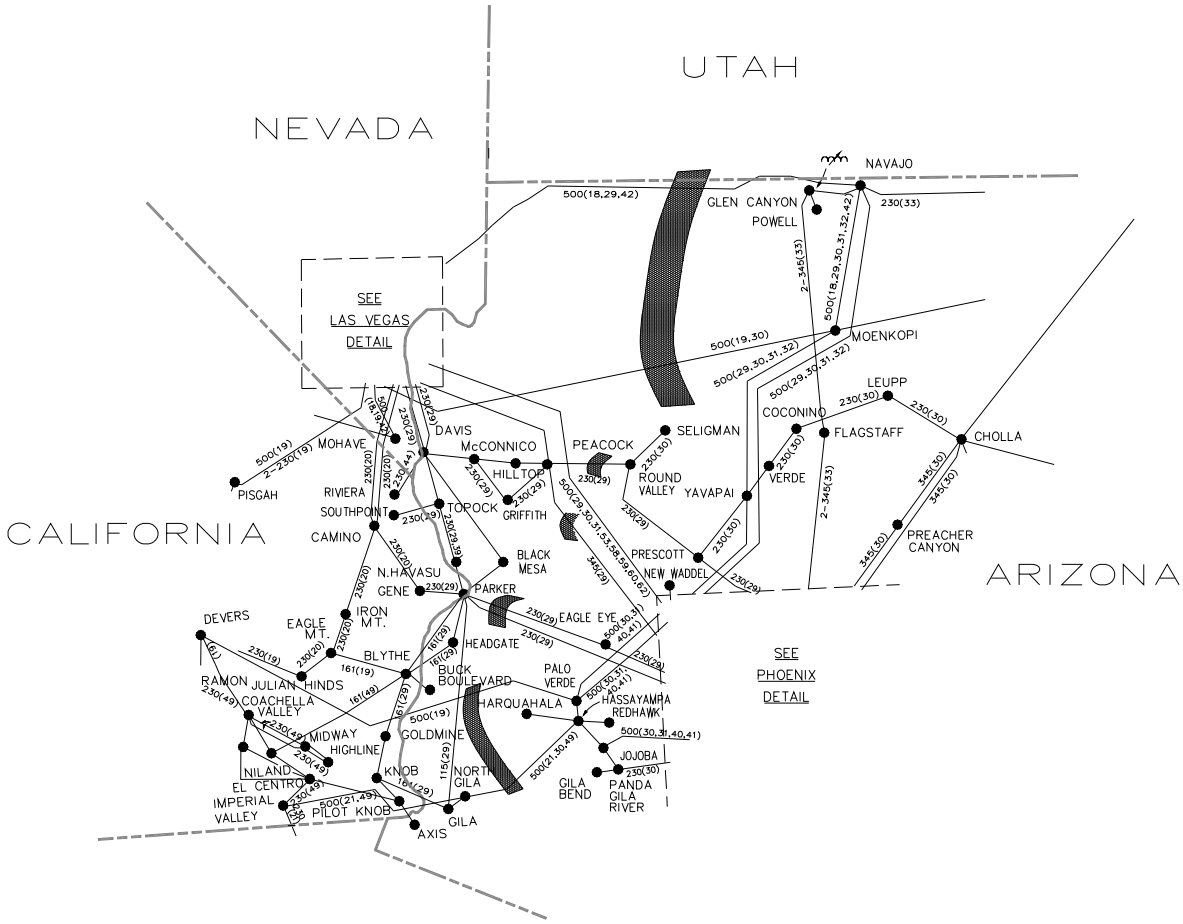
20. Path C

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Northern Utah/Southern Idaho
Definition:	Sum of the flows on the following transmission lines: Line Ben Lomond-Borah 345 kV Three mile knoll 345/138 transformer Treasureton-Brady 230 kV Grace-Goshen 161 kV Malad-American Falls 138 kV
Transfer Limit:	North to South: 1000 MW (nominal) South to North: 1000 MW (nominal) Operating limits are based on OTC studies.
Critical Disturbance that limits the transfer capability:	South bound: N-2 outage of Borah-Ben Lomond 345 kV and Brady-Treasureton 230 kV lines. North bound: N-2 outage of Borah-Ben Lomond 345 kV line and one Ben Lomond-Wheelon 138 kV line
When:	Studies conducted by PacifiCorp in 1982 established the 1000 MW rating. The most current south to north studies were conducted in 1992. These studies developed the relationship between rating, ambient temperature, and load levels.
System Conditions:	The stated ratings are a function of load and generation in the northern Utah and southeastern Idaho area. As ratings are limited by thermal line ratings, they also depend on ambient temperatures.
Study Criteria:	• Steady state pre disturbance voltages between .95 p.u. and 1.05 p.u. • Post-disturbance voltages between .90 p.u. and 1.10 p.u. • Post-disturbance line loadings less than "emergency ratings." • First-swing transient voltage dips not to exceed .80 p.u.
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	PacifiCorp

Interaction w/Other Transfer Paths:	
Contact Person:	Craig Quist PacifiCorp 1407 W. North Temple - Suite 275 Salt Lake City, UT 84116 (801) 220-2620 (801) 220-2842 - fax craig.quist@pacificorp.com

21. Arizona to California



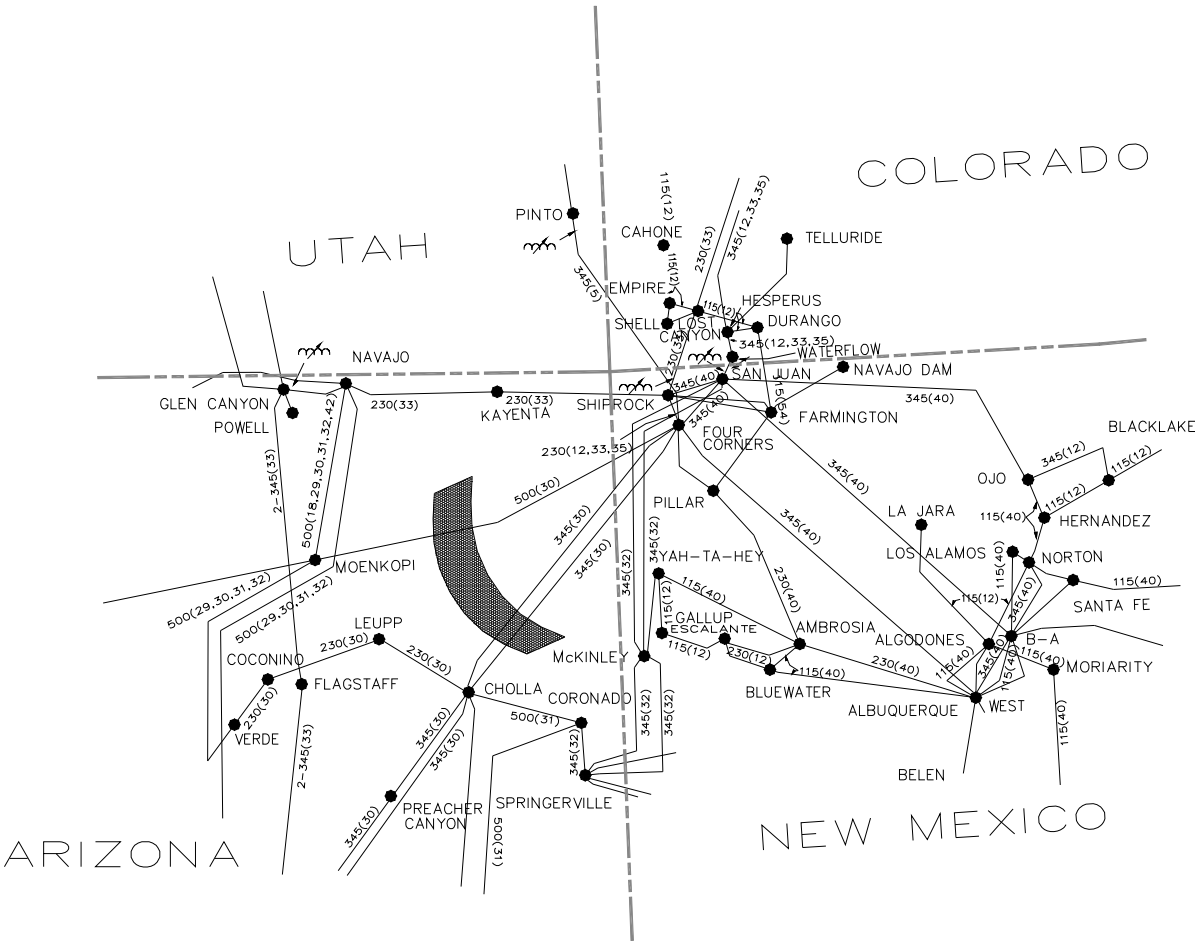
21. Arizona to California

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Western Arizona
Definition:	The sum of the flows on the following transmission lines: Line — Metered End Navajo-Crystal-McCullough 500 kV — Navajo Moenkopi-Eldorado 500 kV — Eldorado Liberty-Peacock-Mead — Liberty Palo Verde-Devers 500 kV — Palo Verde Hassayampa-North Gila 500 kV — Hassayampa Round Valley-Peacock 230 kV — Peacock Liberty-Parker #1 230 kV — Parker Liberty-Parker #2 230 kV — Parker
Transfer Limit:	East to West: 5700 MW (Non-simultaneous) West to East: Not rated The present east to west, non-simultaneous path rating is 5700 MW and assumes a "normal" operating system with all lines in service and full series compensation levels in the Navajo, Palo Verde and Liberty-Mead transmission systems. Path 21 was initially qualified in the late 1980's. Since the study determining the rating of 5700 MW was performed, system upgrades and a parallel 500 kV transmission line have been added. No re-rating studies have been performed since the unscheduled flow curtailment procedure was installed in 1994.
Critical Disturbance that limits the transfer capability:	The 5700 MW non-simultaneous limit is due to the continuous rating of the series capacitors at the Palo Verde end of the Palo Verde-Devers 500 kV line. The transfer capability is limited under normal (all-lines-in-service) conditions. However, various East of the Colorado River (EOR) line outages may result in 97-99% loading of emergency ratings on various EOR lines.
When:	The non-simultaneous transfer rating was established in 1987 by the Western Arizona Transmission Systems (WATS) Task Force. The Task Force was comprised of members from the following companies: Arizona Public Service Company El Paso Electric Company DOE-Western Area Power Administration Imperial Irrigation District Los Angeles Department of Water & Power Nevada Power Company Public Service Company of New Mexico Salt River Project San Diego Gas & Electric Company Southern California Edison Company Southern California Public Power Authority Tucson Electric Power Company

System Conditions:	Flows on the transfer path have historically been east to west due to the large amount of joint participation plants located in Arizona and New Mexico which are partly owned by southern California and Nevada entities.
Study Criteria:	WECC Reliability Criteria for Transmission System Planning
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	The 5700 MW transfer capability is divided among the following entities: Southern California Edison Company 2232 MW Los Angeles Department of Water & Power 1229 MW Western Area Power Administration 527 MW Nevada Power Company 353 MW San Diego Gas & Electric Company 914 MW Salt River Project 160 MW Imperial Irrigation District 153 MW Arizona Public Service Company 132 MW 5700 MW
Interaction w/Other Transfer Paths:	The simultaneous transfer limit into southern California is governed by the Southern California Import Transmission (SCIT) Nomogram and is a function of the EOR (Path 49) flow of which this path is a subset.
Contact Person:	Peter Krzykos Arizona Public Service Company P. O. Box 53999, Station 2260 Phoenix AZ 85072-3999 (602) 250-1649 (602) 250-1674 - fax peter.krzykos@aps.com

22. Southwest of Four Corners
(Unscheduled Flow Qualified Path)



22. Southwest of Four Corners
(Unscheduled Flow Qualified Path)

Accepted Rating ☐
Existing Rating ☒
Other ☐

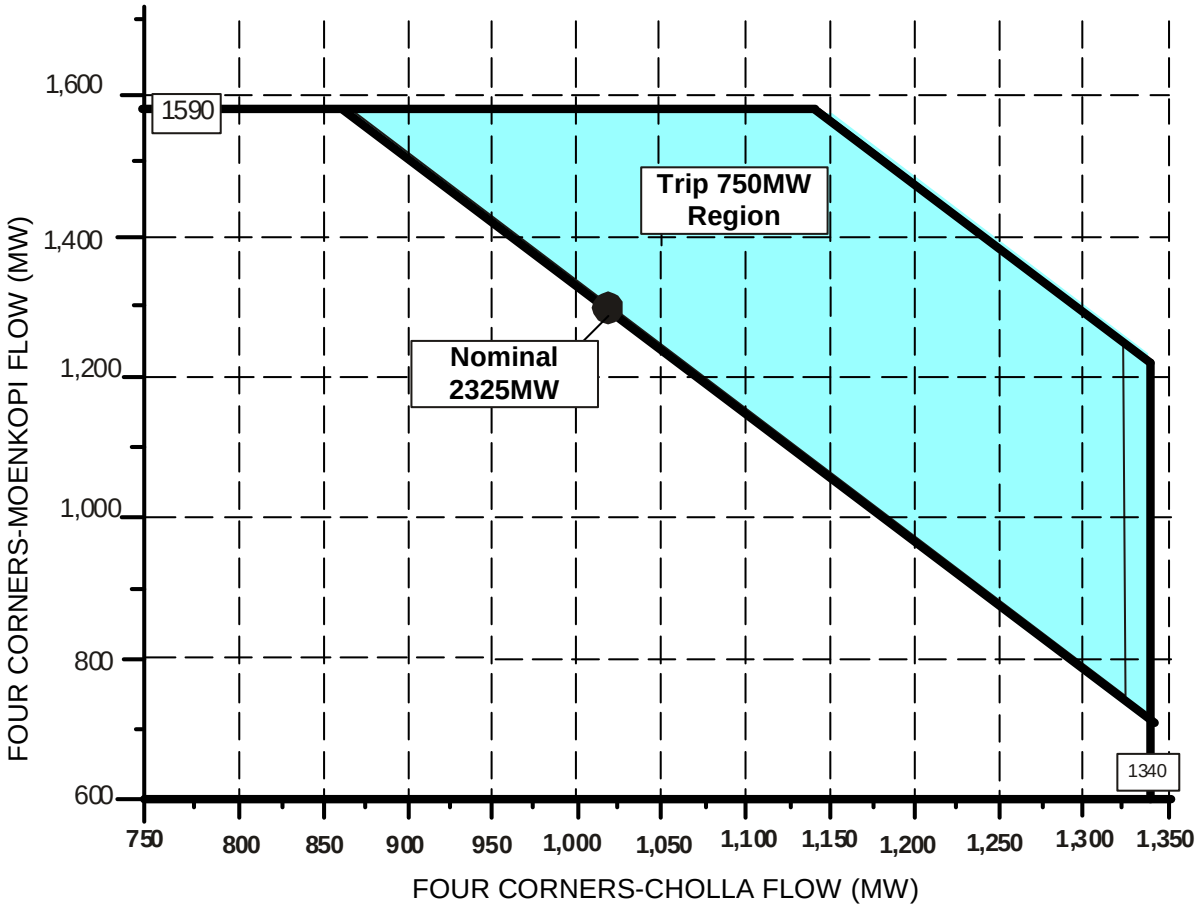
Location:	Northeastern Arizona
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Four Corners-Moenkopi 500 kV — Four Corners Four Corners-Cholla 345 kV #1 — Four Corners Four Corners-Cholla 345 kV #2 — Four Corners
Transfer Limit:	East-West: 2325 MW nominal West-East: Not rated The 2325 MW nominal operating limit is limited by the thermal rating of the Four Corners-Cholla 345 kV lines and voltage deviation at Pinnacle Peak following the critical disturbance. The actual rating is defined by the diagonal on the attached nomogram.
Critical Disturbance that limits the transfer capability:	The Critical Disturbance is dependent on the location along the nomogram. Two critical contingencies for defining the nomorgram are loss of the Four Corners-Moenkopi line and loss of the Four Corners-Cholla #2 345 kV line.
When:	The transfer rating was established in the mid 1980's by the Four Corners Technical Studies Task Force. The task force is comprised of members from the following companies: • Arizona Public Service Company • El Paso Electric Company • Public Service Company of New Mexico • Salt River Project • Southern California Edison Company • Tucson Electric Power Company Verified by 2004 OTC studies.
System Conditions:	Flows on this transfer path have historically been east to west due to the large amount of generation located in northwestern New Mexico. This generation is partly owned by entities west of the Arizona - New Mexico border. The 2325 MW nominal limit was determined due to voltage deviation, and thermal constraints.
Study Criteria:	Same as WECC Reliability Criteria for Transmission System Planning.
Remedial Actions Required:	None
Formal Operating Procedure:	None

Allocation:	The transfer rating was established in the mind 1980's by the Four Corners Technical Studies Task Force. The task force is comprised of members from the following companies: • Arizona Public Service Company owns all rights on the Four Corners-Cholla 345 kV lines. • Southern California Edison Company owns all the rights on the Four Corners-Moenkopi 500 kV line.
Interaction w/Other Transfer Paths:	None
Contact Person:	Barrie Kokanos Arizona Public Service Company P. O. Box 53999, Station 2260 Phoenix AZ 85072-3999 (602) 250-1370 (602) 250-1654 - fax barrie.kokanos@aps.com

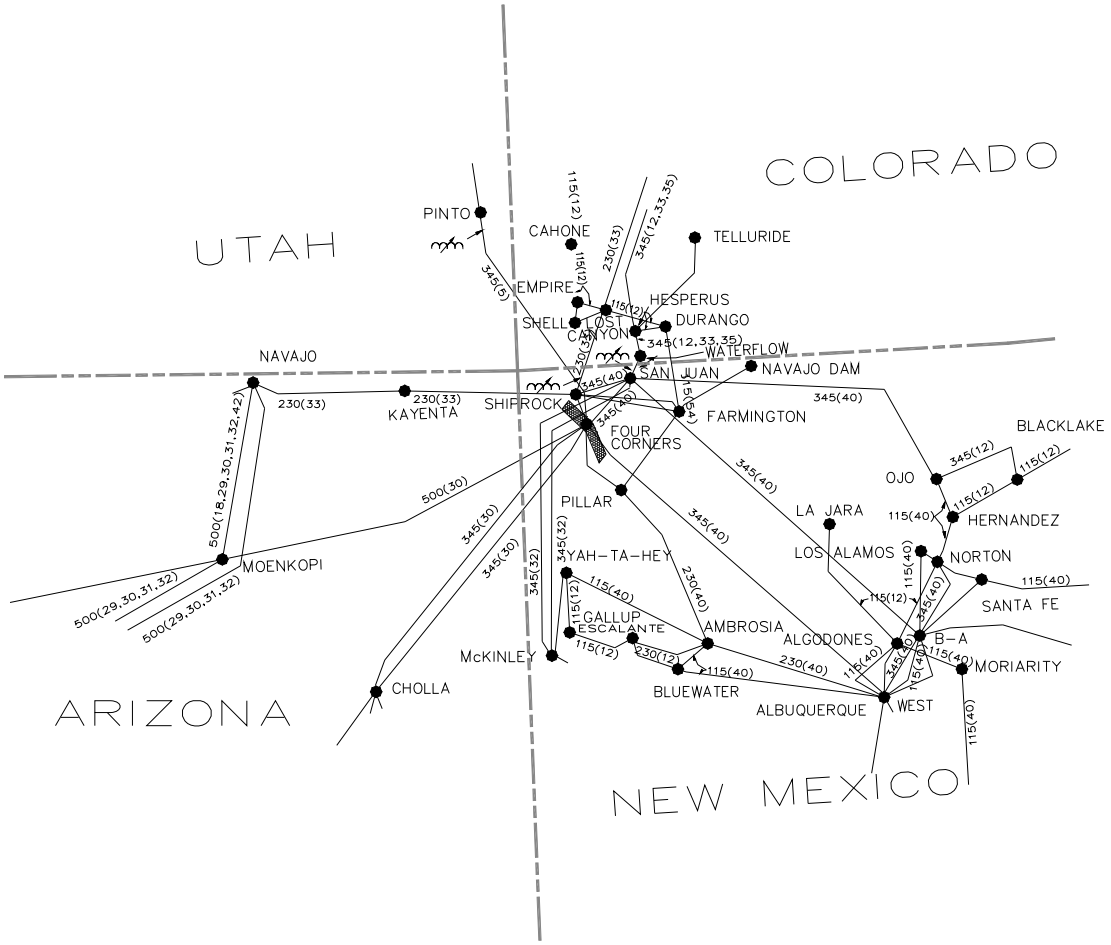
2004 PATH 22 OPERATING NOMOGRAM

FOUR CORNERS SYSTEM LIMITS

FOUR CORNERS-CHOLLA SERIES COMPENSATION - 25%
FOUR CORNERS-MOENKOPI SERIES COMPENSATION 0 - 24%



23. Four Corners 345/500 Qualified Path

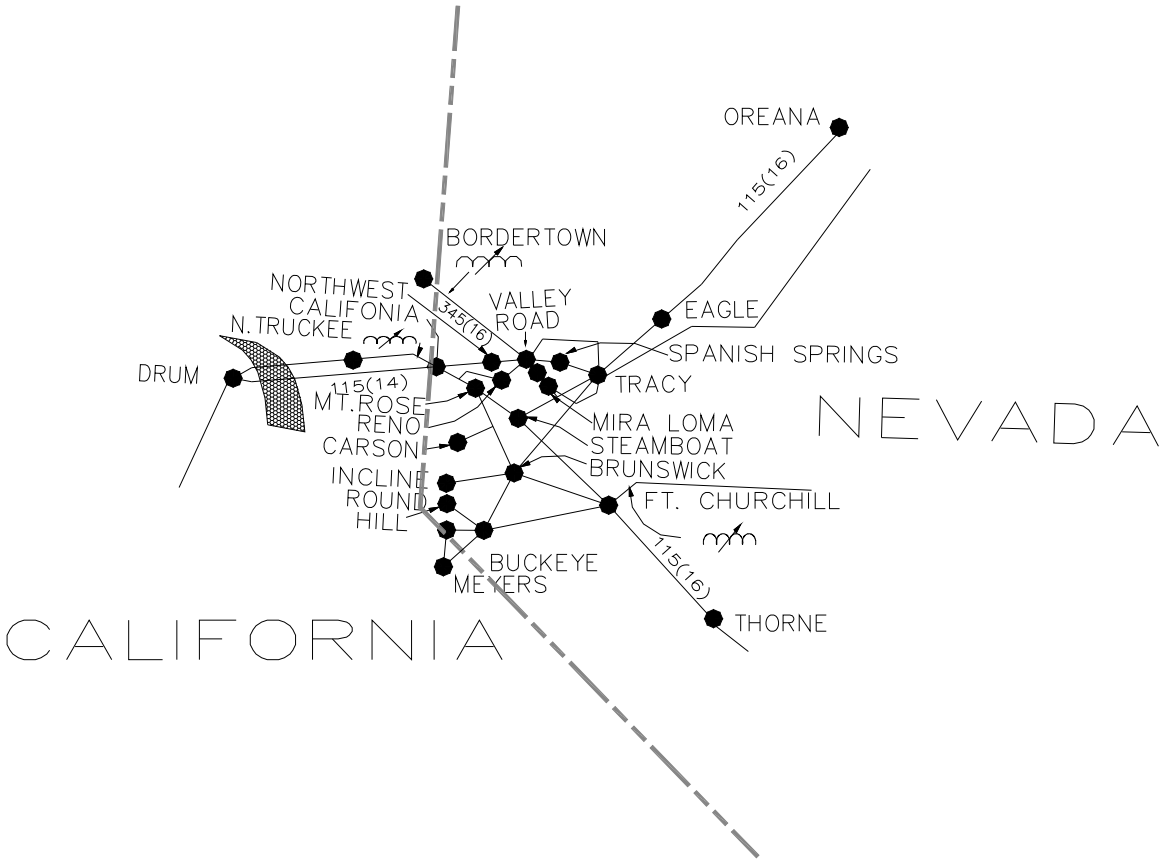


23. Four Corners 345/500 Qualified Path

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Northeastern Arizona
Definition:	Flow on 345/500 kV transformer
Transfer Limit:	345 to 500 kV: 840 MVA (top FOA) 500 to 345 kV: 840 MVA (top FOA)
Critical Disturbance that limits the transfer capability:	Loss of Four Corners #5 (750 MVA) with high transfers on Four Corners-Moenkopi 500 kV.
When:	Certified as a qualified path in mid 1980s.
System Conditions:	Flows in this area are from east to west due to the large amount of generation in the area. The 345/500 kV transformer is in series with the 500 kV line and is the limiting element when Four Corners #5 is off line.
Study Criteria:	Base case loading not to exceed 100% of continuous rating.
Remedial Actions Required:	None.
Formal Operating Procedure:	None
Allocation:	Owners of the transformer are: Southern California Edison Company 48% Arizona Public Service Company 15% Public Service Company of New Mexico 13% Salt River Project 10% El Paso Electric Company 7% Tucson Electric Power Company 7% 100%
Interaction w/Other Transfer Paths:	None
Contact Person:	Barrie Kokanos Arizona Public Service Company P. O. Box 53999, Station 2260 Phoenix AZ 85072-3999 (602) 250-1370 (602) 250-1674 - fax barrie.kokanos@aps.com

24. PG&E - Sierra



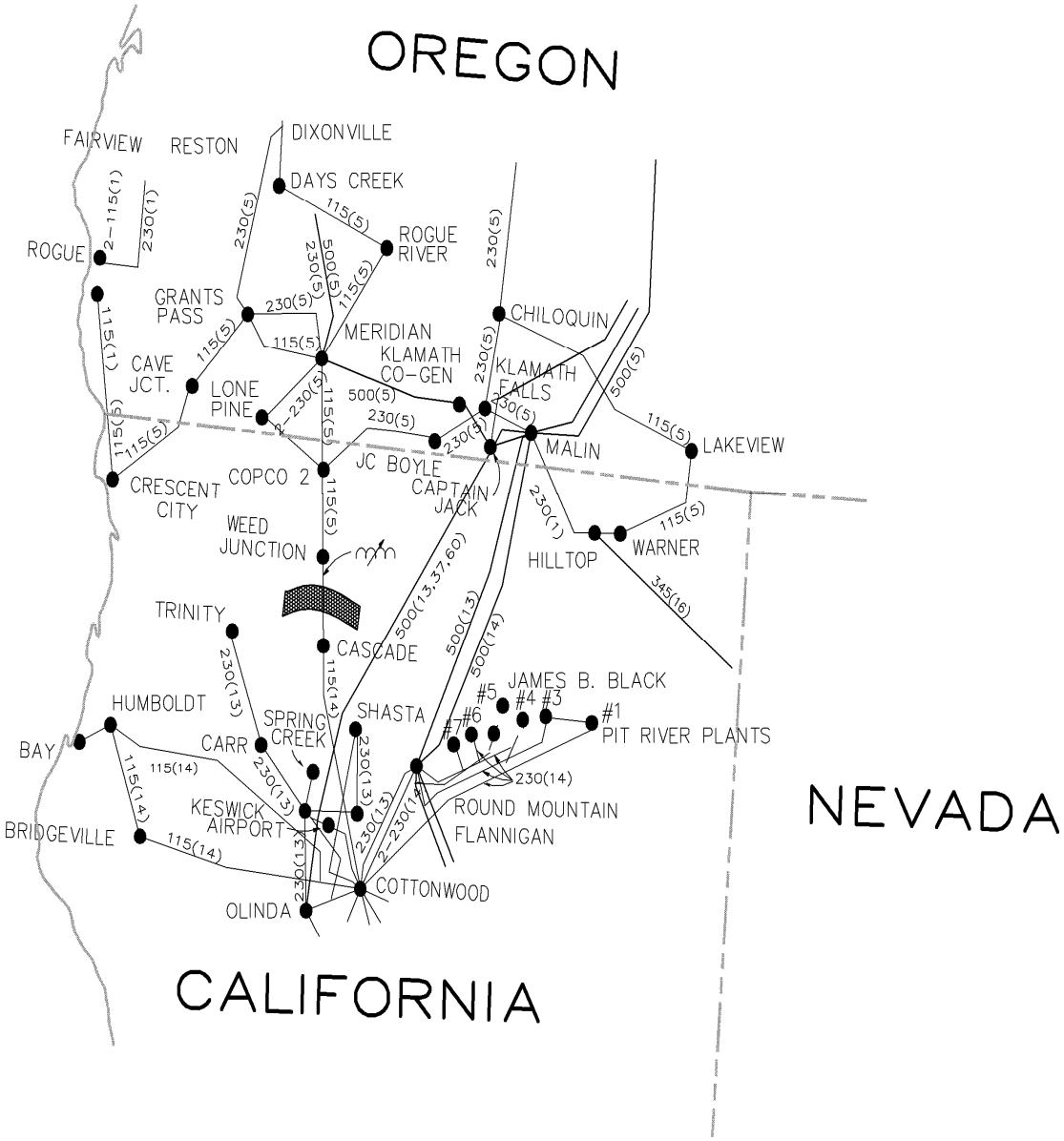
24. PG&E - Sierra

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Between Northern California and Nevada
Definition:	Drum-Summit (2-115 kV lines) Spaulding-Summit (1-60 kV line) Sum of the flows on the following transmission lines: Line — Metered Point Drum-Summit 1 115 kV — Summit 1 115 kV bus Drum-Summit 2 115 kV — Summit 2 115 kV bus Drum-Summit 60 kV — Summit 60 kV bus
Transfer Limit:	160 MW West to East 150 MW East to West Transfer limit may vary from 0-160 MW depending on generation and load in the Drum-Rio Oso-Goldhill area. East to west limit based on N. Tahoe loads and Cal Sub phase shifter.
Critical Disturbance that limits the transfer capability:	Loss of the Drum Powerhouse Loss of Drum-Rio Oso #1 (115 kV) Loss of Drum-Summit 1&2 Goldhill-Placer #2 (115 kV) Halsey Jct-Newark #1 & #2 (between Drum and Placer)
When:	
System Conditions:	Heavy Summer Heavy Winter
Study Criteria:	All facilities loaded within normal ratings under normal system conditions. All facilities loaded within emergency ratings under outage conditions. Fully meets WECC Reliability Criteria in effect at time rating was established.
Remedial Actions Required:	Open Drum-Summit lines. For NE/SE separation, opening of the PG&E-Sierra tie lines is required. Open Drum-Atlantic 60 kV line at Weimer.
Formal Operating Procedure:	
Allocation:	Sierra, PG&E
Interaction w/Other Transfer Paths:	Affected by flow at California-Oregon border. The flow on the Midpoint-Humboldt line affects the scheduling capability of this path.

Contact Person:	Ronnie Lau Pacific Gas and Electric Company Mail Code B15A PO Box 770000 San Francisco, CA 941077-0001 (415) 973-7092 (415) 973-8804 - fax prl6@pge.com	Edi Von Engeln Sr. ENGR. Regional Planning 6100 Neil Road M/S S3B40 Reno, NV 89511 (775) 834-4456 (775) 834-3047 - fax evonengeln@sppc.com

25. PacifiCorp/PG&E 115 kV Interconnection



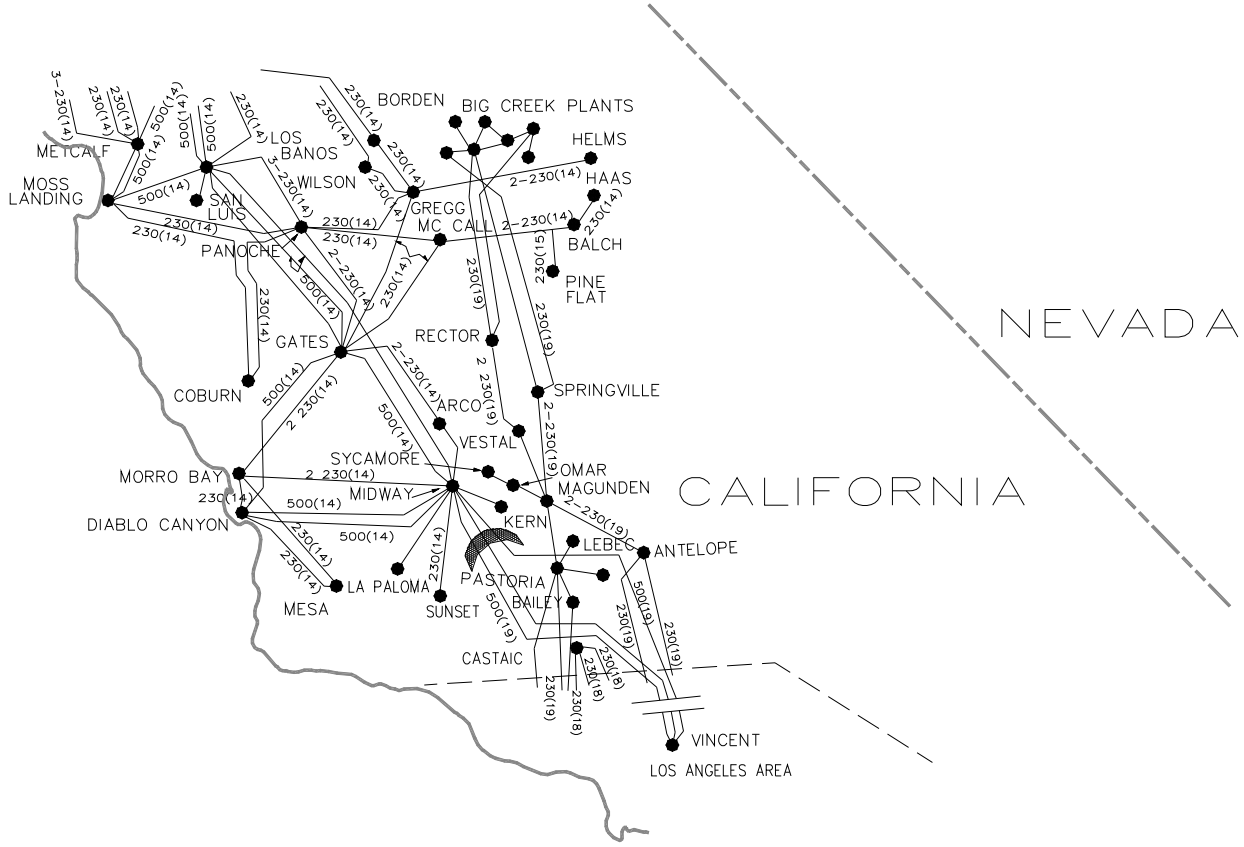
25. PacifiCorp/PG&E 115 kV Interconnection

Accepted Rating ☐
Existing Rating ☐
Other ☒

Location:	Southern Oregon/Northern California (Line 14)
Definition:	Sum of flow on Line 14, measured at Cascade.
Transfer Limit:	Winter / Summer North to South: 100 MW * / 80 MW South to North: 45 MW ** / 45 MW ** The thermal rating of this 115 kV line is 100/149 MVA Summer/Winter (397.5 ACSR conductor). * Due to load growth in the area, there are periods when the winter transfer limit may be reduced below 100 MW, sometimes as low as 80 MW. ** The south to north non-simultaneous rating listed in the WECC Transfer Capability Diagram is 45 MW. This capability is rated under tie-line open south of phase shifter and is equivalent to the magnitude of PacifiCorp's local area load.
Critical Disturbance that limits the transfer capability:	
When:	Path rating was established on April 19, 1984 with the publishing of the WECC progress report, by project owners. The powerflow and stability studies deriving the path rating, above, were conducted by PacifiCorp and PG&E.
System Conditions:	This interconnection operates in parallel with the California-Oregon Intertie (COI). In order to direct flow of the 100 MW south on Line 14, a 75/100/125 MVA, 118 kV 0-60 degrees compensated phase shifter is installed at PacifiCorp's Weed Junction substation, Weed Junction, California. This phase-shifting transformer regulates the flow of power, preventing power scheduled over it from flowing on the COI.
Study Criteria	The following stability simulations were made: A. Islanding Without the Line 14, 115 kV Tie This simulation assumes 3200 MW on the COI as well as 4163 MW on the Arizona to southern California path and indicates that minimum standards for stable operation can be achieved, complying with WECC criteria. Stability plot of the Devers 500 kV bus shows oscillations of increasing amplitude through the first 7-8 seconds, with decreasing amplitude thereafter. The minimum transient swing voltage was at the Devers 230 kV bus with 81.7%. Use of the SDG&E's Damping Coefficient Method demonstrates a 7.6% damping on this bus. Frequencies drop to 58.84 Hz minimum in California causing some under-frequency load shedding.

Study Criteria (*continued*)	B. Islanding With the PAC-PG&E 115 kV Tie This simulation assumes the addition of 100 MW on the existing Line 14, 115 kV Tie. This increase indicates that the minimum transient swing voltage at Devers would drop from 81.7% to 79.5% or a 2.2% reduction.
Remedial Actions Required:	In addition to standard protection, a thermal relay is installed at Cascade and out-of-step indication is installed at Weed Junction. In the event of islanding, Line 14 is tied into the relaying and communication of the WECC "islanding" scheme. It is to be tripped approximately six cycles after the 3-line loss of the COI.
Formal Operating Procedure:	PacifiCorp is the operating agent and uses real-time flows to monitor this path.
Allocation:	The entire path transfer capability is owned by PacifiCorp.
Interaction w/Other Transfer Paths:	No interaction with other WECC paths. However, transfer capability could be limited at times due to local loads.
Contact Person:	Tom Tjoelker PacifiCorp Lloyd Center Room 1800 Transmission Planning 825 NE Multnomah Portland, OR 97232 (503) 813-6887 (503) 813-6508 - fax tom.tjoelker@pacificorp.com Kang-Ling Ching Pacific Gas and Electric Company Mail Code B15A PO Box 770000 San Francisco, CA 94177-0001 (415) 973-7637 (415) 973-8804 – fax Email: kxc5@pge.com

26. Northern - Southern California



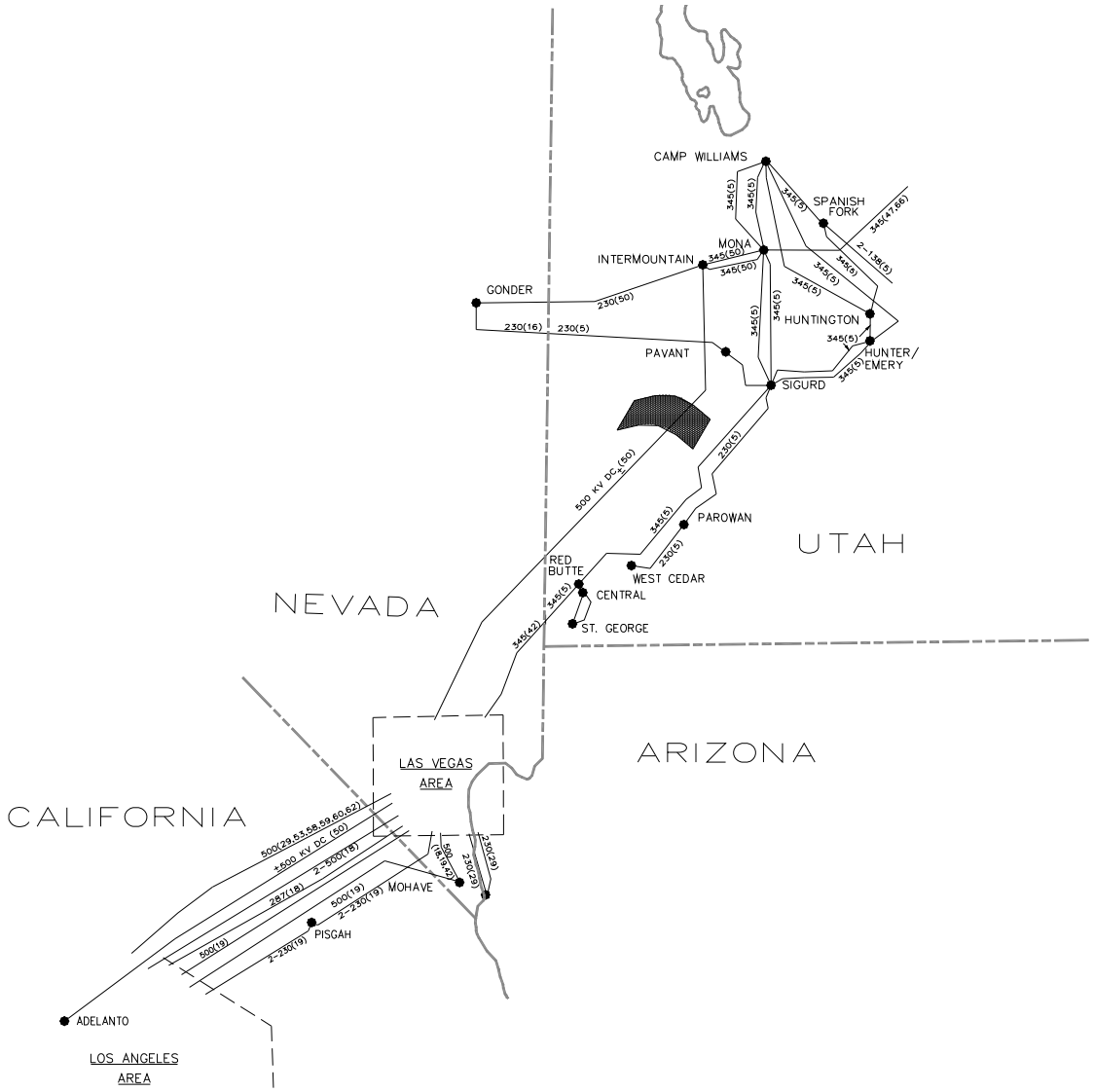
26. Northern - Southern California

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Between PG&E and Southern California Edison (Midway-Vincent)
Definition:	Midway-Vincent (3-500 kV lines) metered at Midway
Transfer Limit:	North to South: 4000MW (Accepted Rating) South to North: 3000 MW (Existing Rating) Transfer limits are affected by generation and load levels between Path 15 and Midway. North to south seasonal limits can vary from 900 to 4000 MW and south to north from 1400 to 2400 MW.
Critical Disturbance that limits the transfer capability:	Midway-Vincent #1 and #2 500 kV double-line outage can overload the Midway-Vincent #3 500 kV line and/or cause voltage criteria violation.
When:	North to south rating of 4000 MW was approved by WECC on May 5, 2006. The existing Path 26 RAS was upgraded and released for operation on June 19, 2006 to support the north to south rating.
System Conditions:	North to south transfer was based on heavy summer and light spring conditions. South to north transfer was based on light winter conditions.
Study Criteria:	All facilities loaded within normal ratings under normal system conditions. All facilities loaded within emergency ratings under outage conditions. The system meets the post transient voltage criteria. Fully meets NERC/WECC Planning Standards.
Remedial Actions Required:	Based on the nomogram curve designed for north to south flow between 3000 and 3700 MW, the Path 26 RAS would trip up to 1400 MW of Midway area generation for loss of any two of the Midway-Vincent #1, #2, and #3 500 kV lines. For north to south flow between 3700 and 4000 MW, the Path 26 RAS would trip 1400 MW of Midway generation and up to 500 MW load at SCE's Rio Honda and/or Walnut Substations for the same 500 kV double-line outage.
Formal Operating Procedure:	California ISO T-103, T-118A, T-120 and T-122.
Allocation:	PG&E, SCE, SDGE, CDWR
Interaction w/Other Transfer Paths:	South to north flows on Path 26 are typically limited by Path 15 capability. North to south flows on Path 26, during peak load and heavy transfer conditions, may be limited by the Southern California Import Transmission (SCIT) nomogram. (See entry to "Formal Operating Procedure" above.) Under light load and heavy transfer conditions in Northern California, the north to south flows may be limited by Midway area reactive margin.

Contact Person:	Kang-Ling Ching Pacific Gas and Electric Company Mail Code B15A P.O. Box 770000 San Francisco, CA 94177-0001 (415) 973-7637 (415) 973-8804 – fax Kxc5@pge.com	Patricia L. Arons Southern California Edison P. O. Box 800 2131 Walnut Grove Avenue Rosemead, CA 91770 Phone:(626) 302-9644 (626) 302-9647 - fax patricia.arons@sce.com

27. Intermountain Power Project DC Line



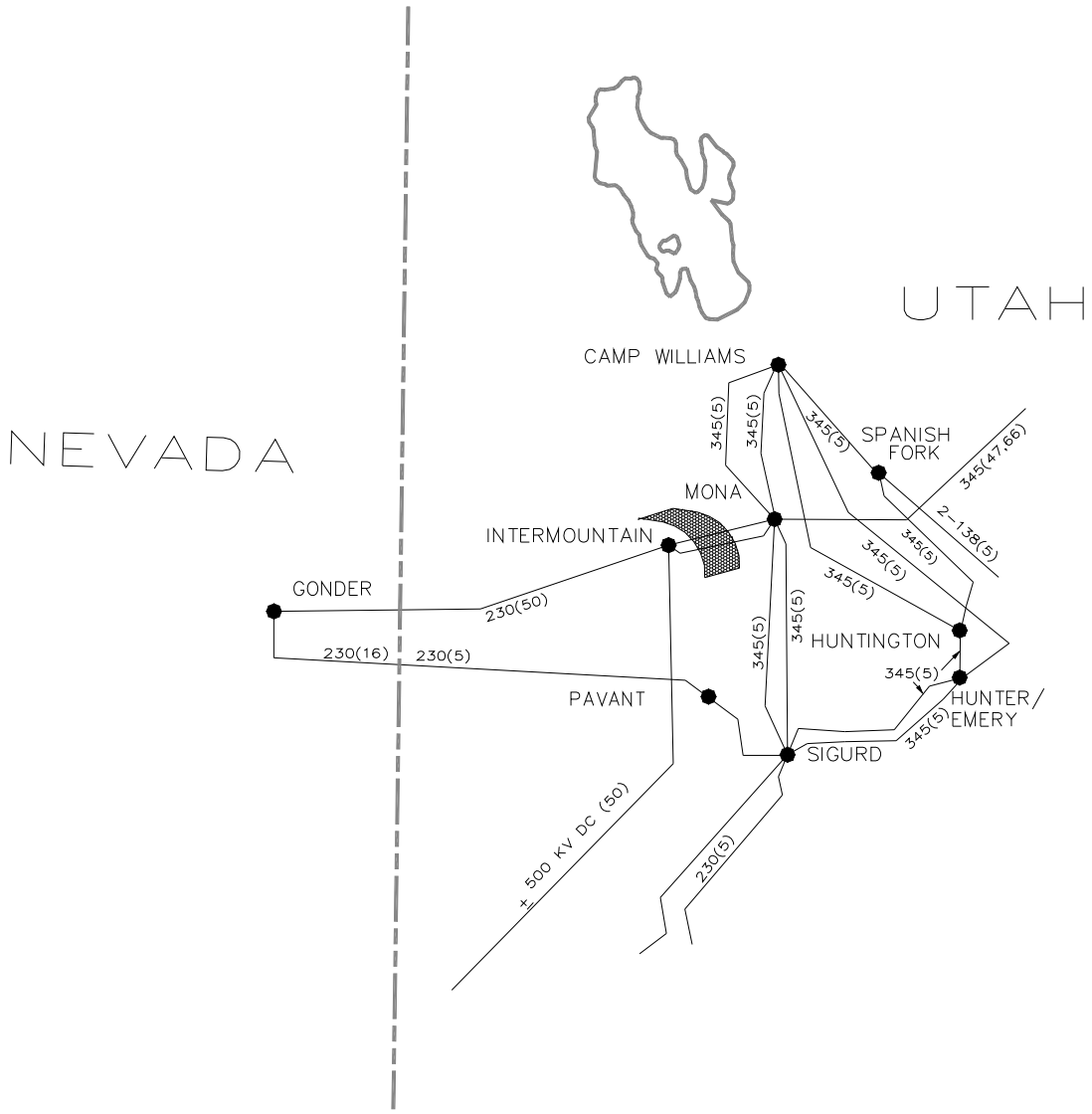
27. Intermountain Power Project DC Line

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Line from Intermountain station in central Utah to Adelanto station in southern California (IPPDC)
Definition:	The IPPDC line is a ±500 kV DC bipole system. Power flow on the DC line is measured at the Intermountain end.
Transfer Limit:	Intermountain to Adelanto (NE-SW): 1920 MW Adelanto to Intermountain (SW-NE): 1400 MW
Critical Disturbance that limits the transfer capability:	Loss of the IPPDC bipole line.
When:	The NE-SW rating was established in May 1987 with the publication of the "Intermountain Power Project WECC Progress Report No. 9." The SW-NE rating established in conjunction with the DOE Form IE-411 reporting in 1989. The NE-SW rating was established by the Los Angeles Department of Water and Power (LADWP), operating agent of the IPPDC. The SW-NE rating was established jointly by LADWP and PacifiCorp-Utah Power.
System Conditions:	IPPDC line NE-SW rating, when established, was dependent on the power flows on the NE/SE and the PACI paths. IPPDC line was most sensitive to the Pinto-Four Corners 345 kV and the Sigurd-Glen Canyon 230 kV line flows. Flows on the Sigurd-Red Butte-Harry Allen 345 kV line, which was built subsequent to the IPPDC line, has similar impact as the other two lines. The NE-SW rating studies assumed established maximum non-simultaneous flow capability of the NE/SE lines. IPPDC line SW-NE rating is dependent on the AC ties to the Utah system. The Intermountain-Mona 345 kV line transfer limitation is 1400 MW line thermal rating based on N-1 contingency, i.e., one of the Intermountain-Mona 345 kV lines being out.
Study Criteria:	(Summary) <u>System intact</u>: • Pre-disturbance voltage between 0.98 p.u. and 1.05 p.u. in Utah <u>Single contingency outage conditions</u>: • Transient voltage swing minimum of 0.85 p.u. in Utah • Post-disturbance voltage minimum of 0.95 p.u. in Utah <u>Double contingency outage conditions</u>: • Transient voltage swing minimum of 0.80 p.u. in Utah • Post-disturbance voltage minimum of 0.90 p.u. in Utah

Remedial Actions Required:	The Intermountain Power Project (IPP) Contingency Arming System (CAS) has been implemented to mitigate IPPDC disturbances by tripping one or two IPP generating units. The IPP CAS has been in operation since 1986. The design and operations of this RAS has been reported to WECC on April 1986 with a report entitled "Intermountain Power Project Contingency Arming System: One Unit Operation" and on August 1992, with a report entitled "Intermountain Power Project Contingency Arming System: Non-Credibility of Remedial Action Scheme Failure."
Formal Operating Procedure:	The IPP CAS consists of arming charts where real-time power output of the IPP generating units and the IPPDC line flows are used to select the no-unit, one-unit or two-unit arming of remedial actions. The IPP CAS and associated operating procedures are included with the LDWP's Energy Control Center Energy Management System (ECC-EMS) computers.
Allocation:	LADWP 59.5% Anaheim 17.7% Riverside 10.2% Pasadena 5.9% Burbank 4.5% Glendale 2.3%
Interaction w/Other Transfer Paths:	Originally, there were simultaneous transfers for the IPPDC vs. PACI which were developed under Pacific and Southwest Transfer (PAST) studies. The need for IPPDC/PACI nomogram operation was determined to be unnecessary in 1991.
Contact Person:	Ly Le Los Angeles Department of Water and Power P. O. Box 111, Room 1246 111 North Hope Street Los Angeles, CA 90051 (213) 367-0302 (213) 367-3829 – fax ly.le@ladwp.com

28. Intermountain - Mona 345 kV



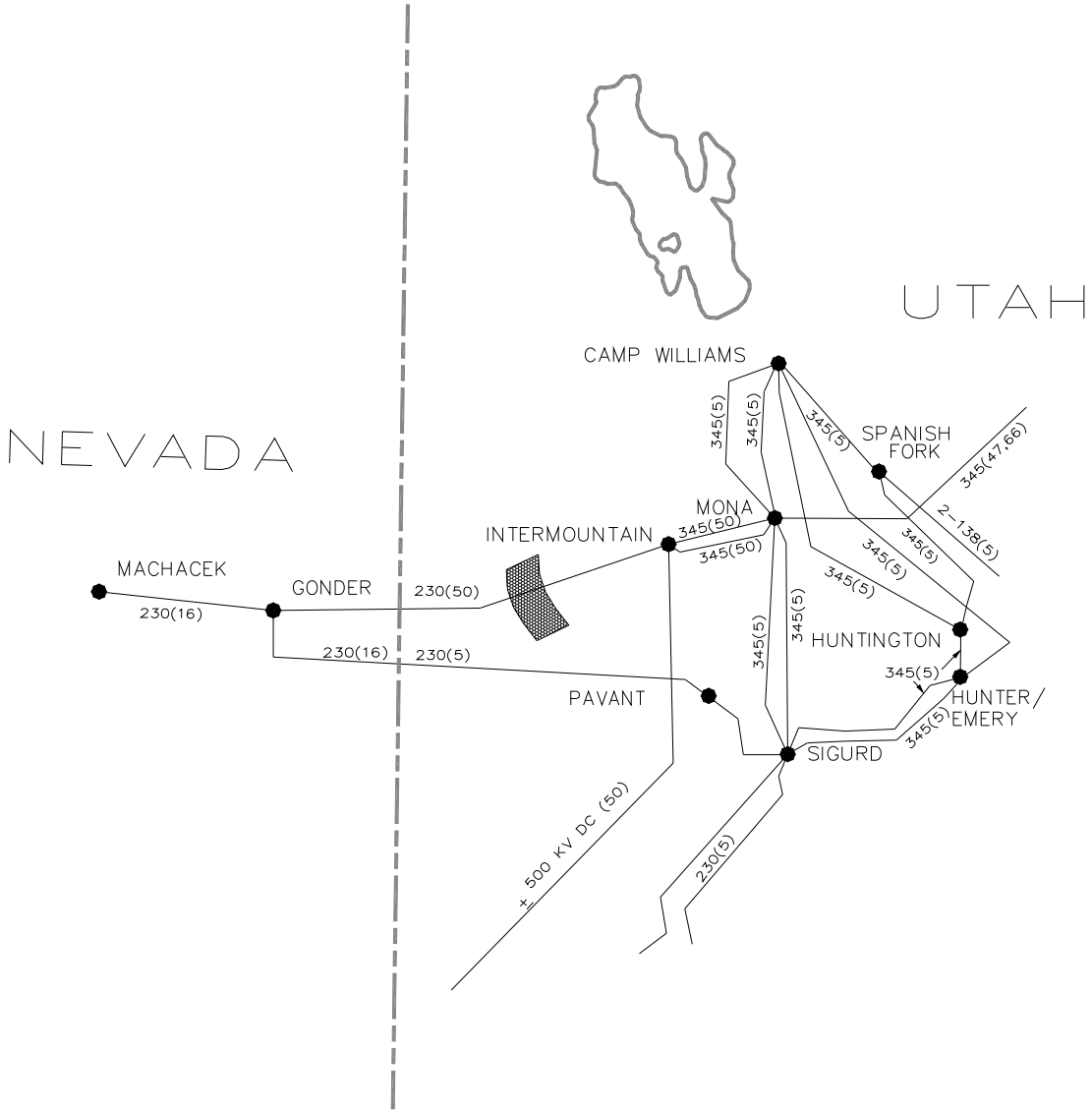
28. Intermountain - Mona 345 kV

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Transmission line from Intermountain Power Facility (IPF) at Delta, Utah to Mona station in central Utah
Definition:	Two 50-mile 345 kV transmission lines from the 345 kV IPF station to the 345 kV Mona station. The IPF 345 kV station is in the Los Angeles Department of Water and Power (LDWP) control area, while the Mona 345 kV station is in the PacifiCorp control area.
Transfer Limit:	East to West: 1200 MW West to East: 1400 MW
Critical Disturbance that limits transfer capability:	N-1 load flow studies
When:	These ratings were established in 1987, when the IPF was first put into service. These ratings have been documented in the WECC Operations Committee's Non-Simultaneous Transfer Capability Diagram as well as in the NERC Form OE-411, Item 5A reportings.
System Conditions:	East to West: Sum of a) 200 MW: Intermountain-Gonder line non-simultaneous capability, and b) 1000 MW: IPPDC capability with the two IPF units at minimum generation output (1920 - (2*460 MW)). This is N-1 rating since each line's thermal capability is above 1400 MW. West to East: Based on N-1 load flow with two IPF generating units on line. The thermal capability of the IPF-Mona 345 kV lines is above 1400 MW.
Study Criteria:	WECC Reliability Criteria for System Design. (The applicable WECC reliability criteria at that time.)
Remedial Actions Required:	A back-up protection to the IPF unit tripping RAS (the IPP Contingency Arming System) trips the IPF-Mona 345 kV line for failure of the IPF RAS. The relay protection, which is based on power surge measurement on the lines, trips the lines if the power surge exceeds a pre-selected power level. The power surge on these lines is expected to exceed the relay tripping level only when there are IPF bipole outages or two unit IPF tripping, and failure of the IPF RAS.
Formal Operating Procedure:	There are automatic and operating procedures to fast-reclose the Mona lines whenever the lines are tripped due to the power-surge relay protection or other causes.
Allocation:	The following utilities have entitlements on these lines: LDWP, Anaheim, Riverside, Pasadena, Burbank, Glendale, and PacifiCorp.
Interaction w/Other Transfer Paths:	

Contact Person:	Ly Le Los Angeles Department of Water and Power P. O. Box 111, Room 1246 111 North Hope Street Los Angeles, CA 90051 (213) 367-0302 (213) 367-3829 - fax ly.le@ladwp.com Gil Coulam PacifiCorp 1407 West North Temple Suite 275 Salt Lake City, UT 84116 (801) 220-2954 (801) 220-2842 - fax gilbert.coulam@pacificorp.com

29. Intermountain - Gonder 230 kV



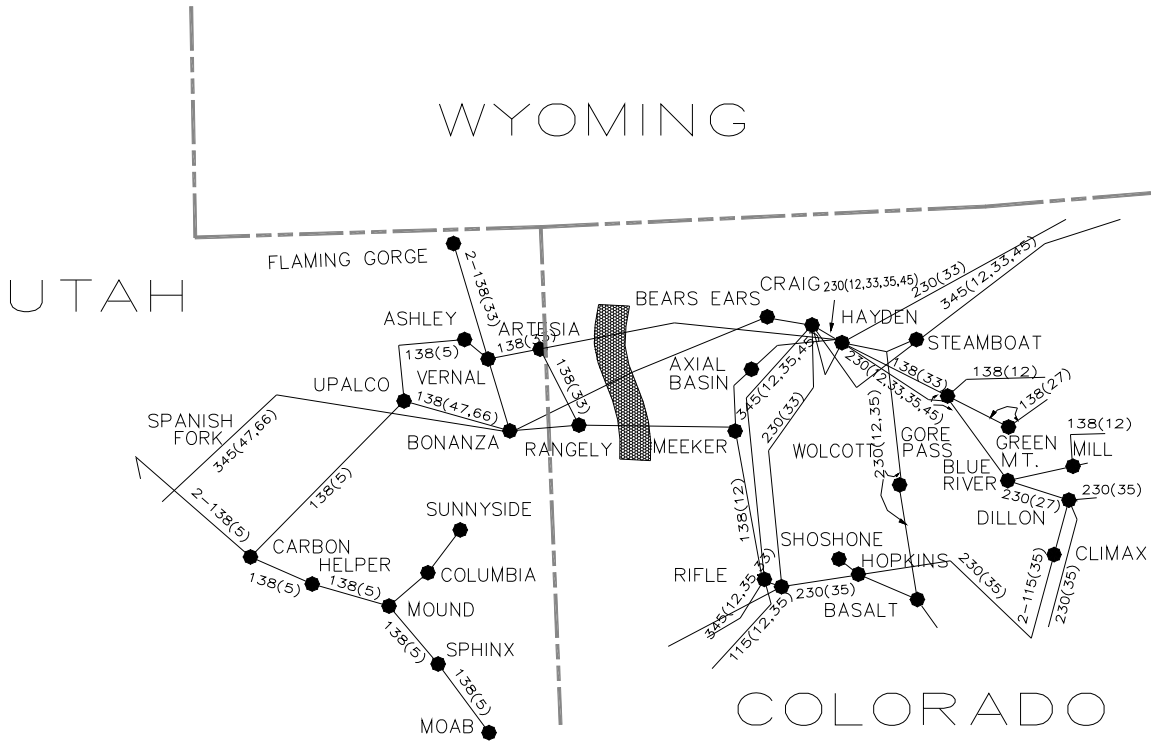
29. Intermountain - Gonder 230 kV

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Transmission line from Intermountain Power Facility (IPF) at Delta, Utah to Gonder station in eastern central Nevada
Definition:	A 144-mile 230 kV transmission line from the 230 kV IPF station to the Mt. Wheeler Power Cooperative's Gonder 230 kV station. The IPF 230 kV station is connected to the IPF 345 kV station through a 300 MVA regulating transformer. The IPF 345 and 230 kV stations are in the Los Angeles Department of Water and Power (LADWP) control area, while the Gonder 230 kV station is in the Sierra Pacific Power Company's control area.
Transfer Limit:	East to West: 200 MW (non-simultaneous) Studies to determine the simultaneous rating of this line with the Pavant-Gonder 230 kV line are presently on-going.
Critical Disturbance that limits the transfer capability:	The non-simultaneous rating is based on the rule-of-thumb criterion of 30 degree power angle difference between the sending and the receiving end, and on N-0 load flow studies.
When:	The 200 MW bidirectional non-simultaneous rating was established in 1987, when the IPF was first put into service. This rating has been documented in the WECC Operations Committee's Non-Simultaneous Transfer Capability Diagram as well as in the NERC Form OE-411, Item 5A reportings.
System Conditions:	The non-simultaneous rating is based on the rule-of-thumb criterion of 30 degree power angle difference between the sending and the receiving end, and on N-0 load flow studies.
Study Criteria:	WECC Reliability Criteria for System Design. (The applicable WECC reliability criteria at that time.)
Remedial Actions Required:	For disturbances where both of the IPF-Mona 345 kV lines are tripped, a transfer trip protection trips the IPF-Gonder 230 kV line.
Formal Operating Procedure:	There is an established energization/synchronization procedure for the line to control overvoltage conditions on the line. The IPF 230/345 kV regulating transformer (ULTC) is under the LADWP SCADA system.
Allocation:	The following utilities have entitlements on this line: LDWP, Anaheim, Riverside, Pasadena, Burbank and Glendale.
Interaction w/Other Transfer Paths:	At the maximum flow conditions, the transfer capability of the line is sensitive to the flows on the Pavant-Gonder 230 kV line. Simultaneous flow capability of these two lines at the Gonder station cut-plane is presently under going a study.

Contact Person:	Ly M Le Los Angeles Department of Water and Power P. O. Box 111, Room 1246 111 North Hope Street Los Angeles, CA 90051 (213) 367-0302 (213) 367-5136 - fax ly.le@ladwp.com

30. TOT 1A


WYOMING
UTAH
COLORADO
FLAMING GORGE
2-138(33)
ASHLEY
138(5)
ARTESIA
138(5)
VERNAL
UPALCO
138(47,66)
SPANISH FORK
345(47,66)
2-138(5)
138(5)
BONANZA
RANGELY
138(33)
BEARS EARS
CRAIG
230(12,33,35,45)
230(33)
345(12,33,45)
HAYDEN
STEAMBOAT
AXIAL BASIN
345(12,35,45)
230(33)
230(12,33,35,45)
138(33)
138(12)
138(27)
GREEN MT.
138(12)
MILL
MEEKER
WOLCOTT
230(12,35)
GORE PASS
BLUE RIVER
230(27)
230(35)
DILLON
138(12)
SHOSHONE
HOPKINS
230(35)
CLIMAX
2-115(35)
230(35)
RIFLE
345(12,35,45)
115(12,35)
230(35)
BASALT
SUNNYSIDE
CARBON
HELPER
138(5)
138(5)
COLUMBIA
MOUND
138(5)
SPHINX
138(5)
MOAB

30. TOT 1A

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Extreme Northwest Colorado
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Bears Ears-Bonanza 345 kV — Bears Ears Hayden-Artesia 138 kV — Hayden Meeker-Rangely 138 kV — Rangely
Transfer Limit:	East to West: 650 MW (maximum) West to East: Not defined Depending on local generation levels and the flows on underlying 115 kV and 138 kV facilities, the real-time rating can range between a minimum of 230 MW and a maximum of 650 MW (see attachment). Typically, the real-time rating centers around 550 MW.
Critical Disturbance that limits the transfer capability:	Outage of the Bears Ears-Bonanza 345 kV line. The limiting element can be the emergency overload on the Upalco-Carbon 138 kV line, the Flaming Gorge 230/138 kV transformer, the Hayden-Artesia 138 kV line, or the Meeker-Rangely 138 kV line (see attachment).
When:	Rating established in March 1990 with the publication of "Bears Ears-Bonanza 345 kV Line Operating Study Report." The operating study was conducted jointly by: Western Area Power Administration - Salt Lake, Golden, Montrose Tri-State Generation & Transmission Association, Inc. (TSGT) Utah Associated Municipal Power System Platte River Power Authority Deseret Generation and Transmission Co-operative Salt River Project Utah Power & Light Co. (now PacifiCorp) Colorado-Ute Electric Association (now TSGT and Public Service Company of Colorado)
System Conditions:	This rating is independent of transfer levels between major areas of WECC, although the actual flow is heavily impacted by east to west inadvertent. The transfer limit is impacted by local area generation and load levels. Historically, the flows have all been east to west across the path.

Study Criteria:	(Summary) System intact: • Per unit voltages between 0.95 p.u. and 1.05 p.u. • All lines and transformers loaded to less than continuous rating. Single contingency outage conditions: • Per unit voltages between 0.90 p.u. and 1.10 p.u. • All lines loaded to less than 15-minute emergency ratings. • All transformers loaded to less than 30-minute emergency ratings. • Transient voltage swings down to 0.7 p.u. permitted, except PacifiCorp which is limited to 0.85 p.u. and DG&T Rangely bus which is limited to 0.75 p.u.
Remedial Actions Required:	Remedial action schemes are required to achieve the rated transfer capability. Following an outage, all overloaded lines and transformers must have their loadings reduced to continuous ratings within 15 minutes. This is accomplished by reducing schedules or lowering local generation. Unit trip schemes are implemented for Bonanza and Flaming Gorge generation for outages of the Bonanza-Mona 345 kV line. Remedial action schemes are required to achieve the rated transfer capability.
Formal Operating Procedure:	There is a formal operating procedure dated July 26, 1990. WAPA-Montrose is the operating agent and uses real-time flows to monitor the path.
Allocation:	The transfer capability of the path is divided between WAPA, PRPA, TSGT and UAMP.
Interaction w/Other Transfer Paths:	None
Contact Person:	M. Jared Griffiths Western Area Power Administration Rocky Mountain Region P.O. Box 3700 Loveland, CO 80539-3003 (970) 461-7603 (970) 461-7423 - fax jgriffit@wapa.gov

TRANSFER CAPABILITY ALGEBRAIC EXPRESSIONS

TOT 1A transfer (schedule) limit is equal to

The lesser of

1 - TOT 1A limit based on Upalco-Carbon limit due to Bonanza-Mona outage

TOT 1A = UPC>CBNlf + 5.4(145 - UPC>CBNlf) + .886(BNZg)
+ .52(FGg) + NET INTERCHANGE + VNL>FGlf

2 - TOT 1A limit based on Flaming Gorge 138/230 Transformer limit due to Bonanza-Mona outage

TOT 1A = UPC>CBNlf + 4.5(200 - FGxf) + 1.13(BNZg)
+ 2.74(FGg) + NET INTERCHANGE + VNL>FGlf

3 - TOT 1A limit based on Hayden-Artesia or Meeker-Rangely limit due to a Bears Ears-Bonanza outage

Hayden-Artesia

TOT 1A = MKR>SWRlf + HDN>ARTlf + 7.0(140 - HDN>ARTlf)

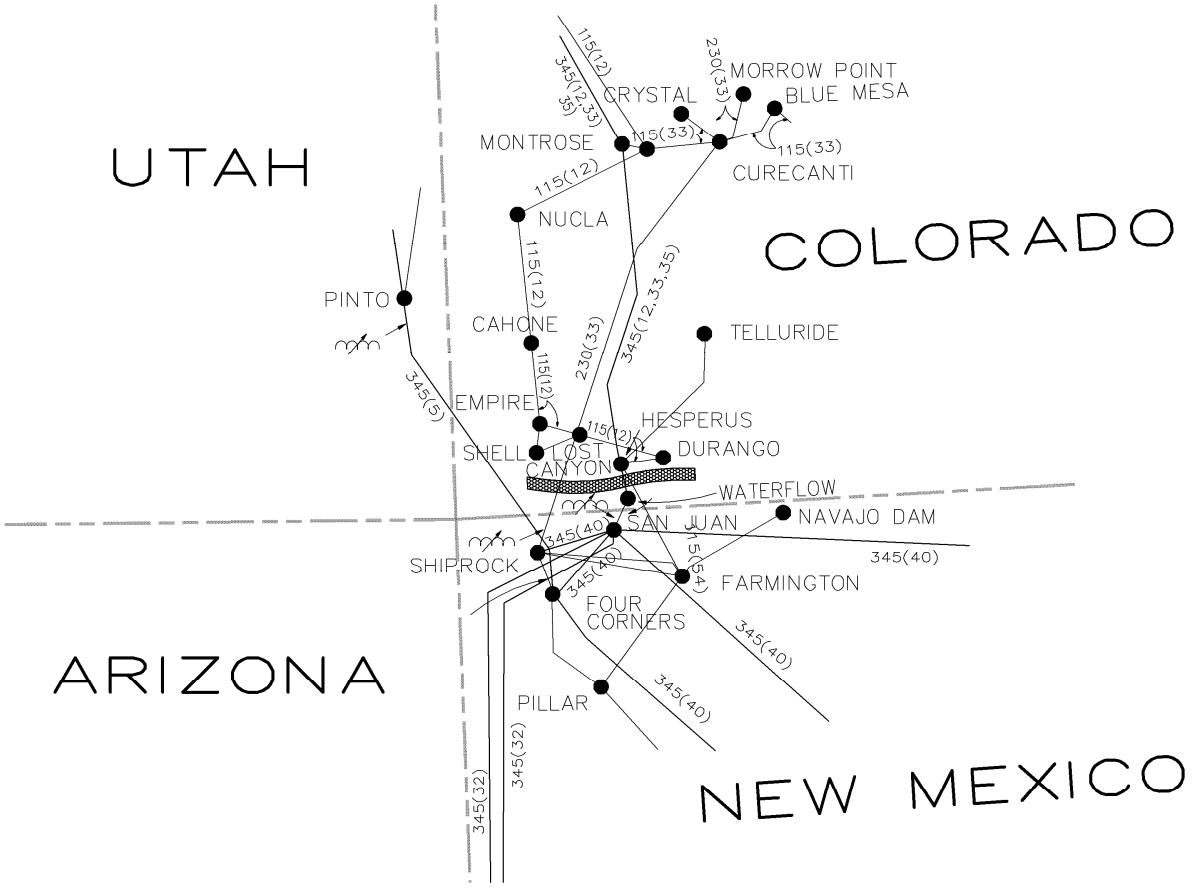
Meeker-Rangely

TOT 1A = MKR>SWRlf + HDN>ARTlf + 4.9(160 - MRK>SWRlf)

Where

BNZg	= Droppable Bonanza generation
FGg	= Droppable Flaming Gorge generation
MRK>SWRlf	= Meeker-Southwest Rangely line flow
HDN>ARTlf	= Hayden-Artesia line flow
VNL>FGlf	= Vernal-Flaming Gorge 1 & 2 line flows
UPC>CBNlf	= Upalco-Carbon line flow
FGxf	= Flaming Gorge 138/230 1 & 2 transformer flows
140	= Hayden-Artesia emergency rating
160	= Meeker-Rangely emergency rating
250	= Flaming Gorge transformers emergency rating
145	= Upalco-Carbon emergency rating

31. TOT 2A


UTAH
COLORADO
ARIZONA
NEW MEXICO
MORROW POINT
BLUE MESA
CRYSTAL
MONTROSE
CURECANTI
NUCLA
PINTO
CAHONE
TELLURIDE
EMPIRE
HESPERUS
SHELL
LOST CANYON
DURANGO
WATERFLOW
NAVAJO DAM
SAN JUAN
SHIPROCK
FARMINGTON
FOUR CORNERS
PILLAR
115(12)
345(12,33,35)
230(33)
115(33)
345(5)
345(40)
345(32)

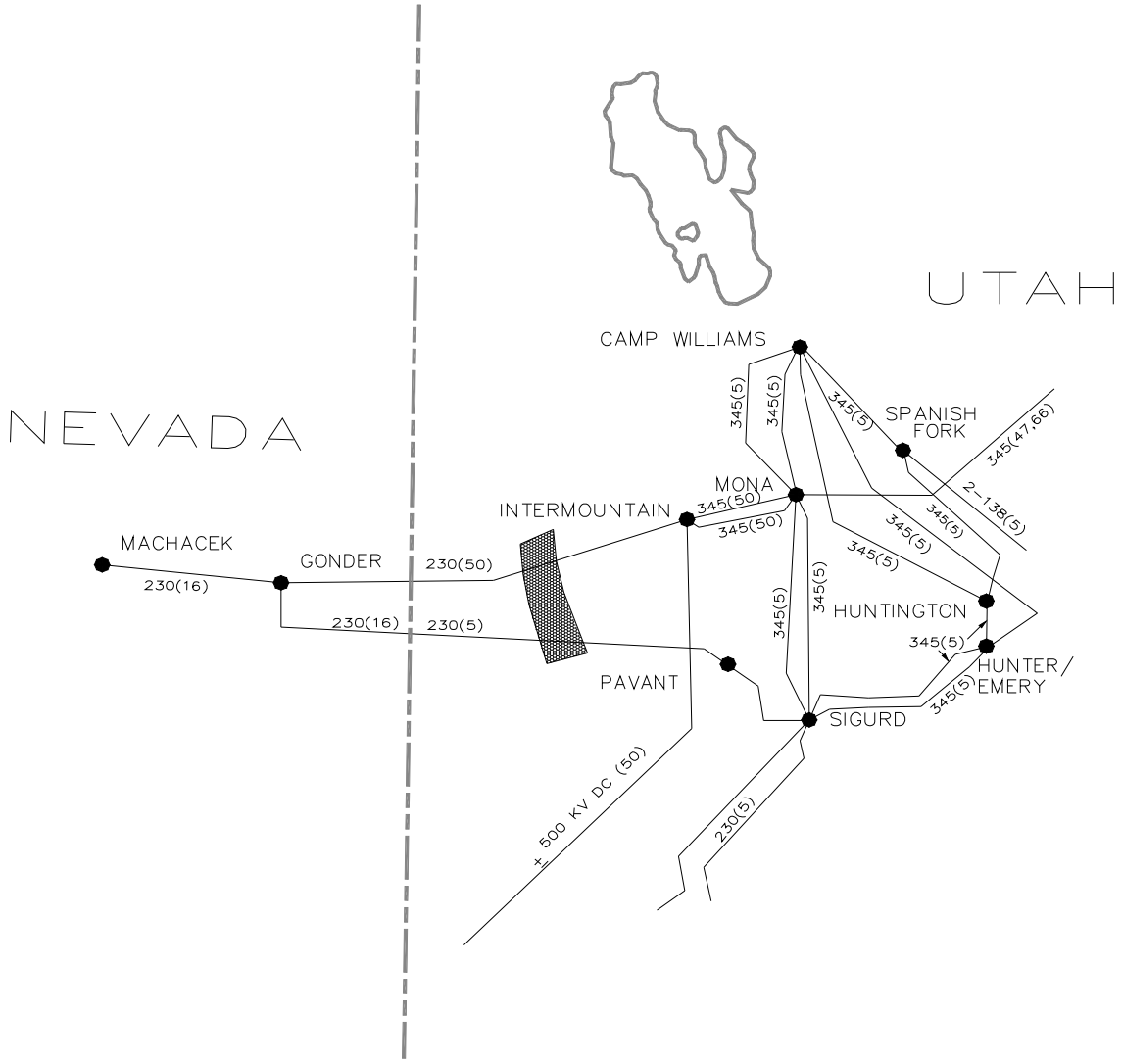
31. TOT 2A

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Extreme Southwest Colorado
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Hesperus-San Juan 345 kV — San Juan Hesperus-Glade Tap 115 kV — Glade Tap Lost Canyon-Shiprock 230 kV — Shiprock
Transfer Limit:	North to South: 690 MW minus net load in the Montrose-Curecanti-San Juan-Shiprock area of southwest Colorado. The load itself ranges 110-220 MW, and internal thermal generation can be 100 MW and hydro generation can be 15 MW. However, the maximum rating is 690 MW. South to North: Not defined Depending on local load and generation levels, the real-time rating ranges between a maximum of 690 MW and a minimum of 550 MW. Typically, the real-time rating centers around 650 MW.
Critical Disturbance that limits the transfer capability:	The critical disturbance is the outage of the 345 kV system between Montrose and San Juan. The limiting elements are low voltages or emergency overloads on the local 115 kV system, or emergency overloads on local 230/115 kV or 345/115 kV transformers. The specific outage and limiting element depend on load levels and generation patterns.
When:	The rating was established jointly by Colorado-Ute Electric Association (CUEA) and Western Area Power Administration (WAPA)-Montrose, in 1989.
System Conditions:	This rating is independent of transfer levels between major areas of WECC although the actual flow is heavily impacted by inadvertent. The transfer limit is impacted by local area generation and load levels. Historically, the flows have been predominately north to south across the path, although flows south to north have been recently experienced.
Study Criteria:	(Summary) System intact: • Per unit voltages between 0.95 p.u. and 1.05 p.u. • All lines and transformers loaded to less than continuous rating. Single contingency outage conditions: • Per unit voltages between 0.90 p.u. and 1.10 p.u. • All lines loaded to less than 15-minute emergency ratings. • All transformers loaded to less than 30-minute emergency ratings. • Transient voltage swings down to 0.7 p.u. permitted.

Remedial Actions Required:	Remedial action schemes are required to achieve the rated transfer capability. Following an outage, all overloaded lines and transformers must have their loadings reduced to continuous ratings within 15 minutes. This is accomplished by reducing schedules, lowering local generation or manually tripping a lower voltage parallel path. For the Montrose-Hesperus 345 kV line outage with generation at Nucla above 60 MW, the parallel Montrose-Nucla 115 kV line can be automatically transfer tripped. This automatic transfer trip scheme is normally enabled. If it is disabled, then real-time transfer capability limits are calculated using local load and local generation as input variables.
Formal Operating Procedure:	There is a formal operating procedure, in the form of a letter agreement between CUEA and WAPA, dated June 1, 1989. WAPA-Montrose is the operating agent and uses real-time flows to monitor the path.
Allocation:	The transfer capability of the path is divided between WAPA, Public Service Company of Colorado and Tri-State G&T.
Interaction w/Other Transfer Paths:	None
Contact Person:	M. Jared Griffiths Western Area Power Administration Rocky Mountain Region P.O. Box 3700 Loveland, CO 80539-3003 (970) 461-7603 (970) 461-7423 - fax jgriffit@wapa.gov

32. Pavant - Gonder 230 kV
Intermountain - Gonder 230 kV

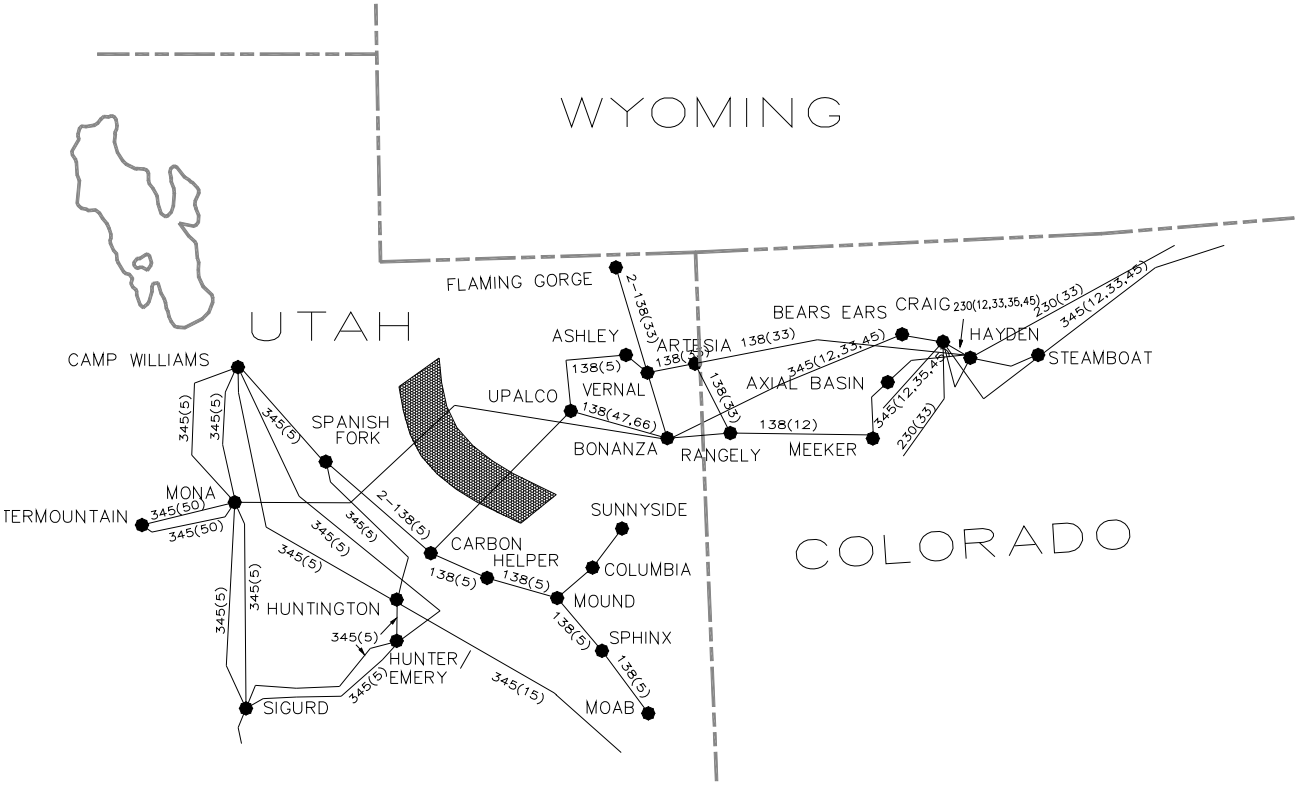


32. Pavant - Gonder 230 kV
Intermountain - Gonder 230 kV

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Central Eastern Nevada/Central Western Utah
Definition:	Sum of the flows on the following transmission lines: Line — Metered Point Gonder-Pavant 230 kV — NV-UT stateline Gonder-Intermountain 230 kV — Gonder
Transfer Limit:	East to West: 440 MW West to East: 235 MW
Critical Disturbance that limits the transfer capability:	East to West: Pavant 230 kV bus voltage for loss of the IPP-Gonder 230 kV line. West to East: Falcon 345/230 XFMR thermal overload for loss of the Valmy-Coyote Crk 345 kV line. Also, Ft. Churchill 230/120 kV XFMR thermal overload for loss of the Falcon-Gonder 345 kV line.
When:	A comprehensive progress report was accepted on August 27, 1999. A Phase II report was approved by the PCC chairman on 12/19/00.
System Conditions:	East to west transfers were studied on light winter and heavy summer conditions. West to east transfers were studied on heavy summer conditions.
Study Criteria:	Both WECC and Sierra Pacific reliability criteria were used in the comprehensive progress report and the Phase II report.
Remedial Actions Required:	None.
Formal Operating Procedure:	
Allocation:	Mt. Wheeler is allocated 40 MW during the summer and 22 MW during the winter on the Gonder-Pavant 230 kV line.
Interaction w/Other Transfer Paths:	None.
Contact Person:	Edi Von Engeln Sr. ENGR. Regional Planning 6100 Neil Road M/S S3B40 Reno, NV 89511 (775) 834-4456 (775) 834-3047 - fax evonengeln@sppc.com

33. Bonanza West



33. Bonanza West

Accepted Rating ☐
Existing Rating ☒
Other ☐

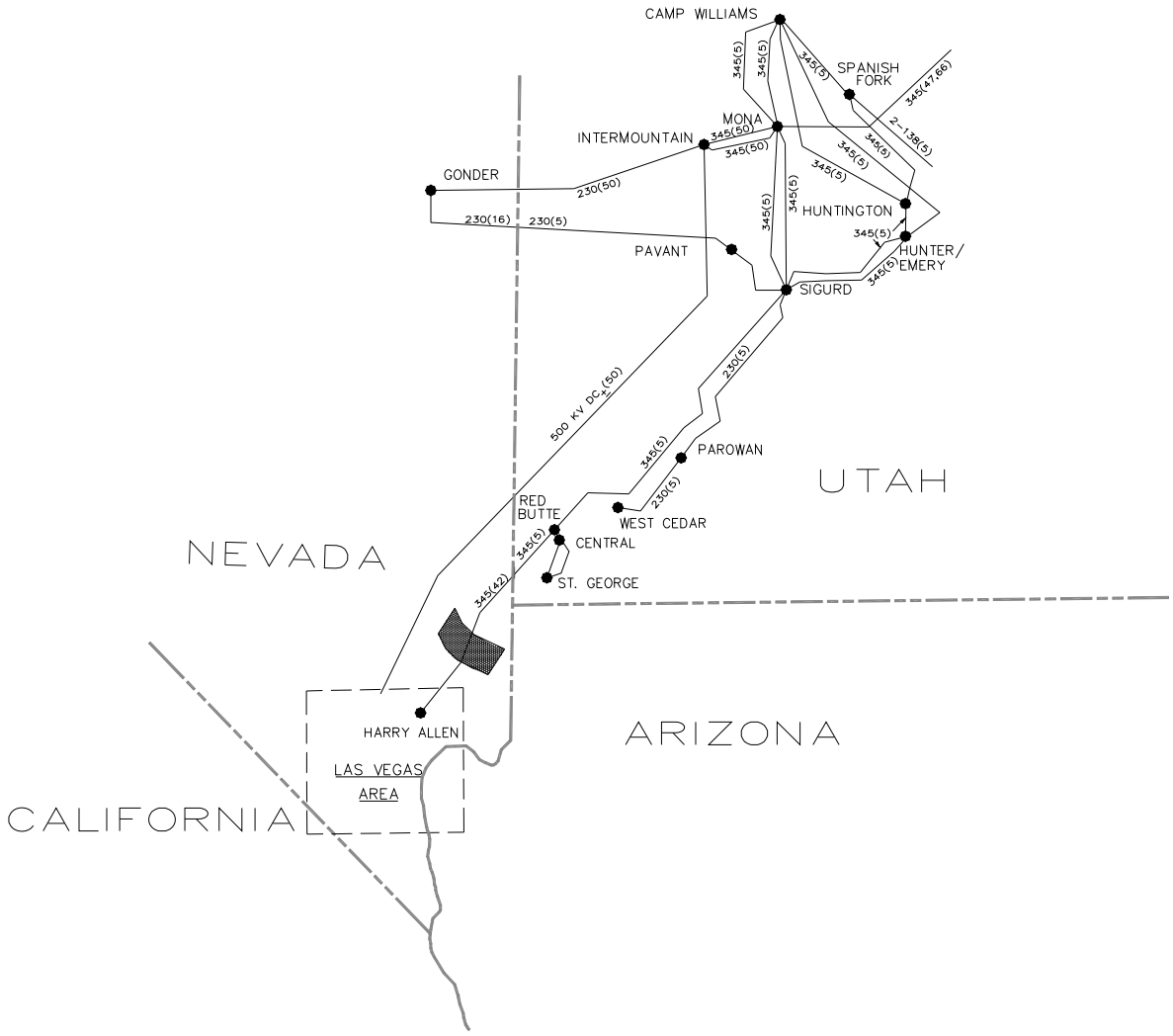
Location:	Northeast Utah to Central Utah
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Bonanza-Mona 345 kV — Mona Upalco-Carbon 138 kV — Carbon
Transfer Limit:	East to West: 785 MW West to East: Not defined Depending on local generation levels and the flows on underlying 138 kV facilities, the real-time rating can vary up to 785 MW. Typically the real-time rating is about 735 MW.
Critical Disturbance that limits the transfer capability:	Bonanza-Mona 345 kV outage. Based on modeled system conditions, outage results in post-transient overload on Upalco-Carbon 138 kV.
When:	December 1990. The rating was established with the publication of the "Bears Ears-Bonanza 345 kV Line Operating Study Report," March 1990, and with the upgrading of current transformers at Mona. The operating study was conducted jointly by the following entities: Western Area Power Administration - Salt Lake City, Golden, Montrose Tri-State Generation & Transmission Association, Inc. Utah Associated Municipal Power Systems Deseret Generation & Transmission Co-operative Platte River Power Authority Salt River Project PacifiCorp Colorado-Ute Electric Association
System Conditions:	The rating is independent of transfer levels between major areas of WECC, although the actual flow is heavily impacted by inadvertent flows. The transfer limit is impacted by local area generation and load levels. Historically, flows have been east to west across the path.
Study Criteria:	• Steady-state pre-disturbance voltages between 0.95 p.u. and 1.05 p.u. • All lines and transformers loaded to less than continuous rating. • Post-disturbance voltages between 0.90 p.u. and 1.10 p.u. • All lines loaded to less than 15-minute emergency ratings. • All transformers loaded to less than 110% of maximum continuous ratings. • Transient voltage swings down to 0.70 p.u. permitted, except for Utah Power facilities which were limited to 0.80 p.u. and Deseret G&T's Rangely bus which is limited to 0.75 p.u.

Remedial Actions Required:	Unit tripping schemes are implemented for Bonanza Unit 1 and for Flaming Gorge generation, as required, for an outage of the Bonanza-Mona 345 kV line in order to achieve the rated transfer capability.
Formal Operating Procedure:	None, although the operating procedures for TOT1A are based, in part, on the line loadings and implementation of the remedial action schemes for Bonanza West path. Western Area Power Administration and the control area operator, PacifiCorp East, monitor real-time power flows on the Bonanza West path.
Allocation:	The transfer capability of the path is divided among the following entities: Utah Associated Municipal Power Systems Utah Municipal Power Agency Deseret Generation & Transmission Co-operative PacifiCorp
Interaction w/Other Transfer Paths:	None, however, implementation of remedial action schemes and Bonanza West loading affect scheduling limits on TOT1A.
Contact Person:	Curt Winterfeld Deseret Generation & Transmission Co-operative 10714 South Jordan Gateway, Suite 300 South Jordan, Utah 84095 (801) 619-6511 (801) 619-6599 - fax ckwinter@desgt.com

34.

SEE PATHS 78 AND 79

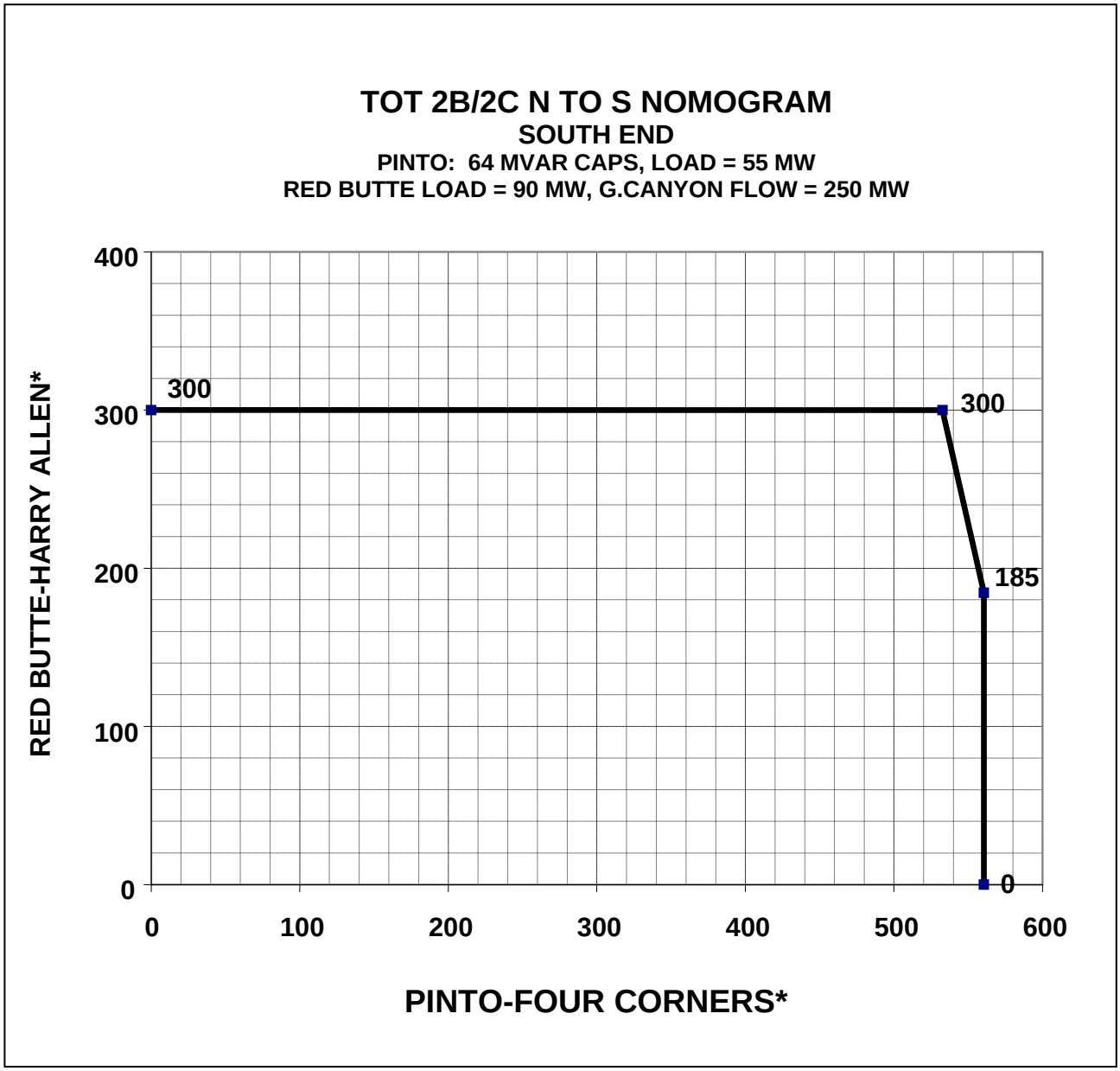
35. TOT 2C


CAMP WILLIAMS
SPANISH FORK
MONA
INTERMOUNTAIN
GONDER
HUNTINGTON
HUNTER/ EMERY
PAVANT
SIGURD
PAROWAN
WEST CEDAR
RED BUTTE
CENTRAL
ST. GEORGE
HARRY ALLEN
LAS VEGAS AREA
NEVADA
UTAH
ARIZONA
CALIFORNIA
345(5)
345(47,66)
2-138(5)
345(50)
230(50)
230(16)
230(5)
500 KV DC±(50)
345(42)

35. TOT 2C

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Southwestern Utah to South-East Nevada
Definition:	Red Butte-Harry Allen 345 kV Line Metering point is at Harry Allen 500 kV
Transfer Limit:	North to South: 300 MW South to North: 300 MW
Critical Disturbance that limits the transfer capability:	Non-simultaneous: Limited by pre-disturbance voltages in the Red Butte area and/or Harry Allen 345/230 transformer normal thermal rating. Simultaneous: Sigurd-Red Butte-Harry Allen 345 line outage, Huntington-Pinto-Four Corners 345 line outage.
When:	These ratings were established prior to January 1994.
System Conditions:	Non-simultaneous capability is a function of Red Butte load and/or Harry Allen 345/230 kV transformer thermal rating. Moderate flow levels on parallel lines.
Study Criteria:	WECC Reliability Criteria for System Design PacifiCorp Internal Reliability Criteria Nevada Power Internal Reliability Criteria
Remedial Actions Required:	None
Formal Operating Procedure:	TOT 2B/2C Nomogram (see attachment) TOT2 OTC limits
Allocation:	PacifiCorp/Nevada Power
Interaction w/Other Transfer Paths:	TOT 2B1, TOT 2B2, IPPDC, PDCI, COI
Contact Person:	William R. Hall PacifiCorp 1407 W. North Temple - Suite 275 Salt Lake City, UT 84116 (801) 220-4274 (801) 220-2842 - fax William.hall2@pacificorp.com Edi Von Engeln Sr. Engr. Regional Planning 6100 Neil Road M/S S3B40 Reno, Nevada 89511 (775) 834-4456 (775) 834-3047 - fax evonengeln@sppc.com

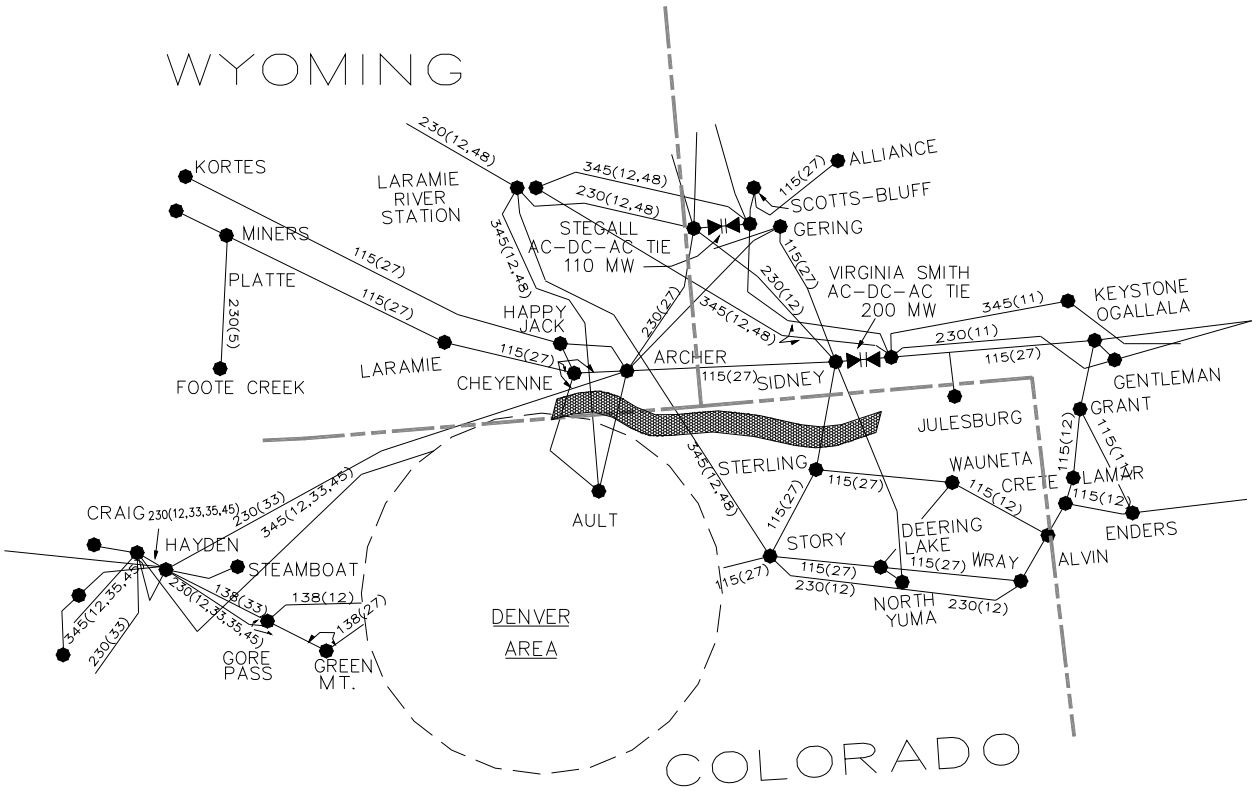


TOT 2B: Pinto-Four Corners* 345
Sigurd-Gcanyon* 230
TOT 2C: Red Butte-Harry Allen* 345

*metered end

Note: This is a representative nomogram. Red Butte load varies from 60 to 210 MW, affecting TOT 2C capability.

36. TOT 3


WYOMING
KORTES
MINERS
PLATTE
FOOTE CREEK
LARAMIE RIVER STATION
LARAMIE
CHEYENNE
HAPPY JACK
STEGALL AC-DC-AC TIE 110 MW
ARCHER
SIDNEY
ALLIANCE
SCOTTS-BLUFF
GERING
VIRGINIA SMITH AC-DC-AC TIE 200 MW
KEYSTONE OGALLALA
GENTLEMAN
GRANT
JULESBURG
STERLING
WAUNETA
CRETE
LAMAR
ENDERS
ALVIN
WRAY
DEERING LAKE
STORY
NORTH YUMA
AULT
CRAIG
HAYDEN
STEAMBOAT
GORE PASS
GREEN MT.
DENVER AREA
COLORADO
230(12,48)
345(12,48)
115(27)
230(12)
230(27)
345(11)
230(11)
115(12)
345(12,48)
230(12,33,35,45)
230(33)
345(12,33,45)
138(33)
138(12)
138(27)
345(12,35,45)
230(12,35,45)

36. TOT 3

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Border between Northeast Colorado and Southeast Wyoming
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Archer-Ault 230 kV — Archer Laramie River-Ault 345 kV — Laramie River Laramie River-Story 345 kV — Laramie River Cheyenne-Ault 115 kV — Cheyenne Sidney-Sterling 115 kV — Sidney Sidney-N. Yuma 230 kV — Sidney
Transfer Limit:	North to South: 1605 MW (Maximum) South to North: Not defined Depending on local generation levels, DC tie levels and direction, the real-time rating can range between a maximum of 1605 W and a minimum of 843 MW. Typically, the real-time rating is calculated dynamically and updated every minute based on Table 1B.
Critical Disturbance that limits the transfer capability:	The critical disturbances and limiting elements vary with the various scenarios. Reference Table 1B for further information.
When:	Rating was first established in 1981. The current rating was established in July 1999 with publication of the "Comprehensive Progress Report for the Revised Rating of the TOT 3 Transfer Path." The study was conducted by Western and the revised rating was jointly proposed by: Western Area Power Administration (WAPA) - Loveland Tri-State Generation & Transmission Association, Inc. (TSGT) Public Service Company of Colorado (PSCO) Basin Electric Power Cooperative (BEPC)
System Conditions:	This rating is independent of transfer levels between major areas of WECC. The transfer limit is impacted by local area generation and the direction and magnitude of DC tie flows. Historically, the flows have all been north to south across the path. Under certain operating conditions when TOT 3 is loaded to its limit, the TOT 5 capability cannot be used since additional schedule on TOT 5 will overload TOT 3.

Study Criteria:	(Summary) System intact: • Per unit voltages between 0.95 p.u. and 1.05 p.u. • All lines and transformers loaded to less than continuous rating. Single contingency outage conditions: • Per unit voltages between 0.90 p.u. and 1.10 p.u. • All lines loaded to less than 15-minute emergency ratings. • All transformers loaded to less than 30-minute emergency ratings. • Transient voltage swings down to 0.7 p.u. permitted.
Remedial Actions Required:	Remedial actions are required to achieve the rated transfer capability. Following an outage, all overloaded lines and transformers must have their loadings reduced to continuous ratings within 15 minutes. This is accomplished by reducing schedules and adjusting generation.
Formal Operating Procedure:	There is a formal operating procedure dated November 1999. WAPA-Loveland is the operating agent and uses real-time flows to monitor the path.
Allocation:	The transfer capability of the path is divided between WAPA, Missouri Basin Power Project (MBPP), Public Service Company of Colorado (PSCO), and Tri-State Generation & Transmission (TSGT). TSGT and BEPC are members of MBPP.
Interaction w/Other Transfer Paths:	None
Contact Person:	M. Jared Griffiths Western Area Power Administration Rocky Mountain Region P.O. Box 3700 Loveland, CO 80539-3003 (970) 461-7603 (970) 461-7423 - fax jgriffit@wapa.gov

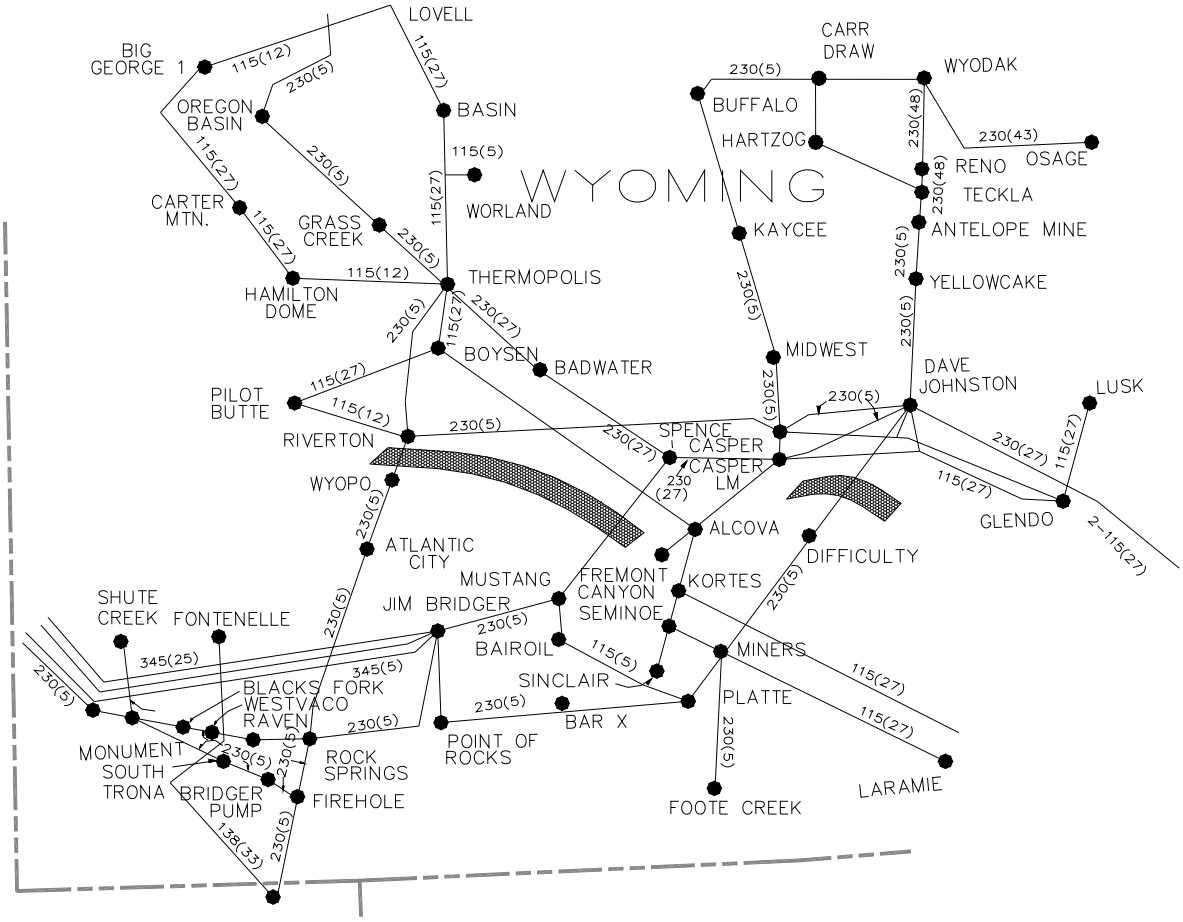
TABLE 1B
TOT3 PRIOR SYSTEM INTACT LIMITS
2001-2002 Heavy Winter
CPP: 68 MW

Gen Level	300 MW East to West	System Intact DC TIES 0 MW	300 MW West to East
LRS 1100 MW (Net) Pawnee 805 MW (Net)	**TOT3 = 1505 MW** (Outage LRS-Story 345-kV loaded LRS-Ault 345-kV to 100% of 956 MVA normal rating)	**TOT3 = 1321 MW** (Laramie bus at 0.90 p.u. for outage of LRS-Ault 345-kV line)	**TOT3 = 1245 MW** (Laramie bus at 0.90 p.u. for outage of LRS-Ault 345-kV line)
LRS 550 MW (Net) Pawnee 805 MW (Net)	**TOT3 = 1256 MW** (Laramie bus at 0.90 p.u. for outage of LRS-Ault 345-kV line)	**TOT3 = 1058 MW** (Laramie bus at 0.90 p.u. for outage of LRS-Ault 345-kV line)	**TOT3 = 901 MW** (Outage Stegall-DaveJohn 230-kV loaded DaveJohn-Lar.Rivr 230-kV to 100% of 442 MVA normal rating)
LRS 1100 MW (Net) Pawnee 300 MW (Net)	**TOT3 = 1605 MW** (Outage LRS-Story 345-kV loaded LRS-Ault 345-kV to 100% of 956 MVA normal rating)	**TOT3 = 1391 MW** (Laramie bus at 0.90 p.u. for outage of LRS-Ault 345-kV line)	**TOT3 = 1304 MW** (Outage LRS-Story 345-kV loaded Sidney-Stegall 230-kV to 100% of 319 MVA normal rating)
LRS 550 MW (Net) Pawnee 300 MW (Net)	**TOT3 = 1316 MW** (Outage Sidney-N.Yuma 230-kV loaded Sidney-Peetz 115-kV line to 100% of 109 MVA rating)	**TOT3 = 1134 MW** (May 115-kV voltage at .90 pu for outage LRS-DaveJohn 230-kV line)	**TOT3 = 927 MW** (Outage Stegall-DaveJohn 230-kV loaded DaveJohn-Lar.Rivr 230-kV to 104% of 442 MVA normal rating)

Case Summary Report
avossler@wapa.gov

WECC "Accepted Rating" is <= 1605 MW

37. TOT 4A


WYOMING
LOVELL
BIG GEORGE 1
OREGON BASIN
BASIN
WORLAND
CARTER MTN.
GRASS CREEK
HAMILTON DOME
THERMOPOLIS
BOYSEN
BADWATER
PILOT BUTTE
RIVERTON
WYOPO
ATLANTIC CITY
SHUTE CREEK
FONTENELLE
JIM BRIDGER
MUSTANG
FREMONT CANYON
SEMINOE
BAIROIL
SINCLAIR
BAR X
POINT OF ROCKS
BLACKS FORK
WESTVACO
RAVEN
MONUMENT
SOUTH TRONA
BRIDGER PUMP
ROCK SPRINGS
FIREHOLE
SPENCE
CASPER
CASPER LM
ALCOVA
KORTES
MINERS
PLATTE
FOOTE CREEK
LARAMIE
DIFFICULTY
GLENDO
LUSK
DAVE JOHNSTON
MIDWEST
KAYCEE
BUFFALO
HARTZOG
CARR DRAW
WYODAK
RENO
TECKLA
ANTELOPE MINE
YELLOWCAKE
OSAGE

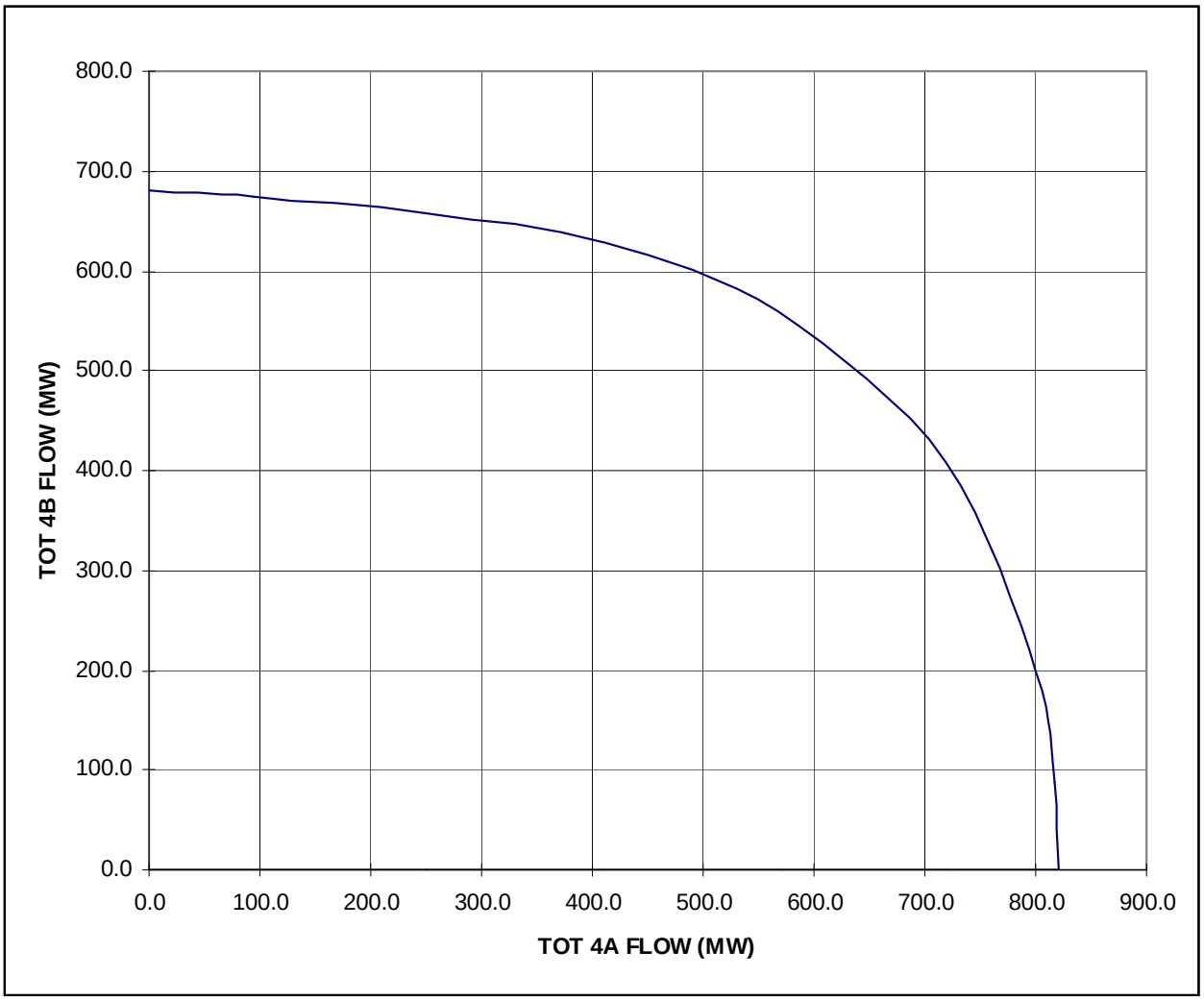
37. TOT 4A

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Southwest Wyoming
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Riverton-Wyopo 230 kV — Riverton Dave Johnston-Difficulty 230 kV — Dave Johnston Spence-Mustang 230 kV — Spence
Transfer Limit:	Northeast to Southwest: 810 MW (Non-simultaneous) Southwest to Northeast: Not defined Depending on flows on the adjacent TOT 4B path, the real-time rating can range between a minimum of 0 MW and a maximum of 810 MW (Reference attachment). Typically, the real-time rating centers around 650 MW.
Critical Disturbance that limits the transfer capability:	The critical disturbances and limiting elements vary with the various points on the nomogram. Reference attachment for further information.
When:	Rating was first established in March 1991 with the publication of "1990 Update of the TOT 4B vs. 4A Nomograms." The operating study was conducted jointly by: PacifiCorp (PAC) Western Area Power Administration (WAPA) - Loveland
System Conditions:	This rating is independent of transfer levels between major areas of WECC. Historically, the flows have all been northeast to southwest across the path.
Study Criteria:	(Summary) System intact: • Per unit voltages between 0.95 p.u. and 1.05 p.u. • All lines and transformers loaded to less than continuous rating. Single contingency outage conditions: • Per unit voltages between 0.90 p.u. and 1.10 p.u. • All facilities loaded to less than 100% of emergency ratings.
Remedial Actions Required:	Remedial actions are required to achieve the rated transfer capability. Following an outage, all overloaded lines and transformers must have their loading reduced to continuous ratings within 15 minutes. This is accomplished by reducing schedules and adjusting generation.
Formal Operating Procedure:	There is a formal operating procedure dated April 12, 1991. PAC is the operating agent and uses real-time flows to monitor the path.
Allocation:	PAC has the entire transfer capability of the path.
Interaction w/Other Transfer Paths:	See attachment

Contact Person:	Craig Quist PacifiCorp 1407 W. North Temple - Suite 275 Salt Lake City, UT 84140 (801) 220-4264 (801) 220-2842 - fax craig.quist@pacificorp.com

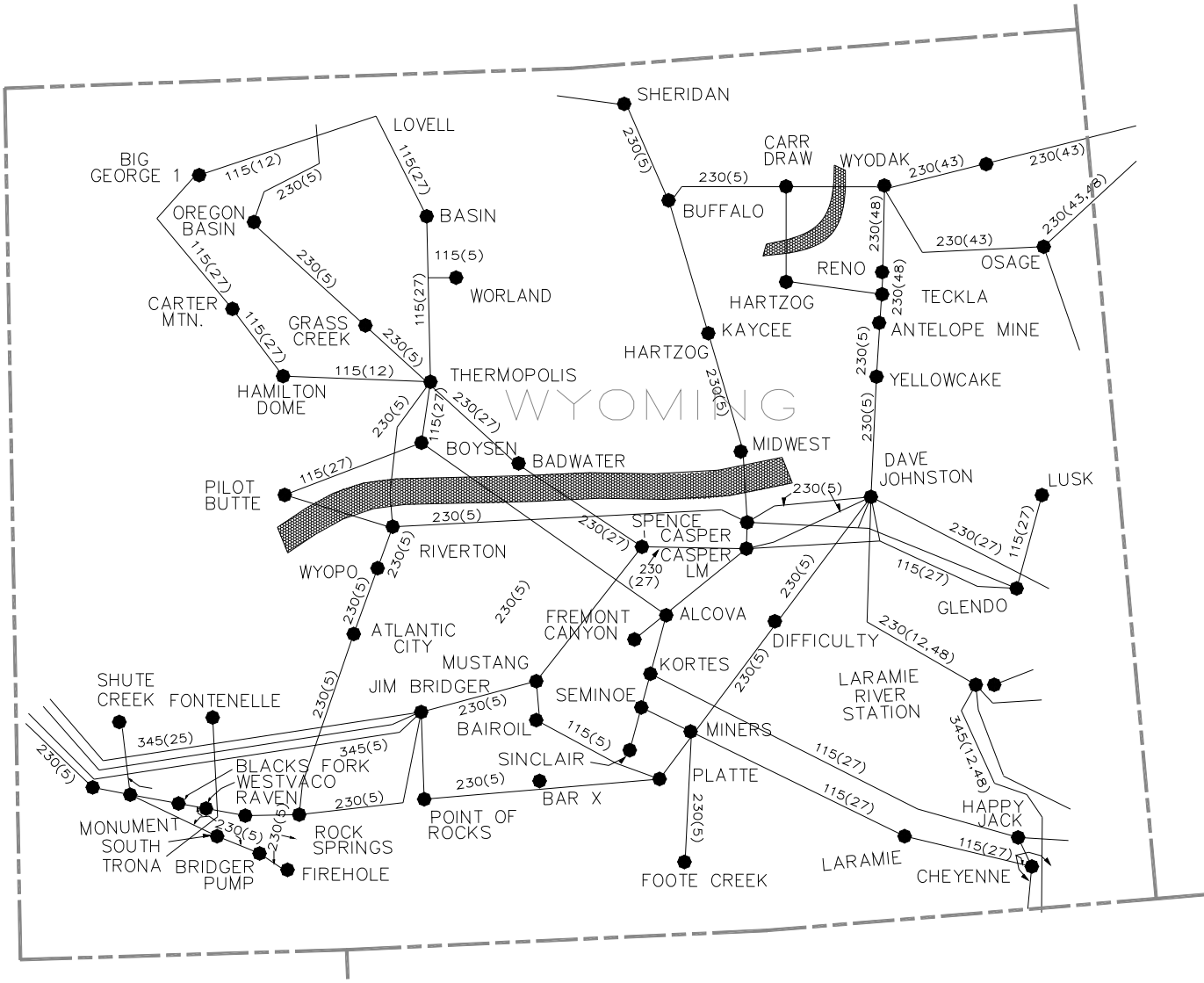
WYOMING SYSTEM OPERATING CURVE
SYSTEM NORMAL
(1990 STUDIES)



SYSTEM NORMAL

POWERFLOW CASE	TOT FLOWS (MW) 4A	4B	LIMITING OUTAGE LINE	KV	LIMITING CONDITION BUS/LINE KV	LIMIT
	0.0	680.0	ESTIMATED			
92LW206	94.1	675.0	NONE		BUF SHR 230	99.70%
92LW205	251.1	657.0	BUF - WYD	230	CSP DJ 230	99.90%
92LW204	411.1	628.2	BUF - SHR	230	CART MT 115	0.9005
92LW203	568.2	558.3	BUF - WYD	230	CSP DJ 230	99.60%
92LW202	719.1	407.8	DJ - DIF	230	SPENCE 230	0.9008
	800.0	200.0	ESTIMATED			
92LW201	817.0	87.2	DJ - DIF	230	SPENCE 230	0.9000
	820.0	0.0	ESTIMATED			

38. TOT 4B


SHERIDAN
LOVELL
BIG GEORGE 1
115(12)
230(5)
115(27)
OREGON BASIN
BASIN
115(5)
WORLAND
CARTER MTN.
GRASS CREEK
HAMILTON DOME
THERMOPOLIS
WYOMING
BOYSEN
BADWATER
PILOT BUTTE
RIVERTON
WYOPO
ATLANTIC CITY
SHUTE CREEK
FONTENELLE
JIM BRIDGER
MUSTANG
BLACKS FORK
WESTVACO
RAVEN
MONUMENT
SOUTH TRONA
BRIDGER PUMP
FIREHOLE
ROCK SPRINGS
POINT OF ROCKS
BAIROIL
SINCLAIR
BAR X
SEMINOE
FREMONT CANYON
SPENCE
CASPER
CASPER LM
ALCOVA
KORTES
MINERS
PLATTE
FOOTE CREEK
BUFFALO
CARR DRAW
WYODAK
RENO
HARTZOG
KAYCEE
MIDWEST
TECKLA
ANTELOPE MINE
YELLOWCAKE
DAVE JOHNSTON
OSAGE
LUSK
GLENDO
DIFFICULTY
LARAMIE RIVER STATION
HAPPY JACK
LARAMIE
CHEYENNE
345(25)
345(5)
345(12.48)
230(12.48)
230(43)
230(48)
230(27)
115(27)
115(5)

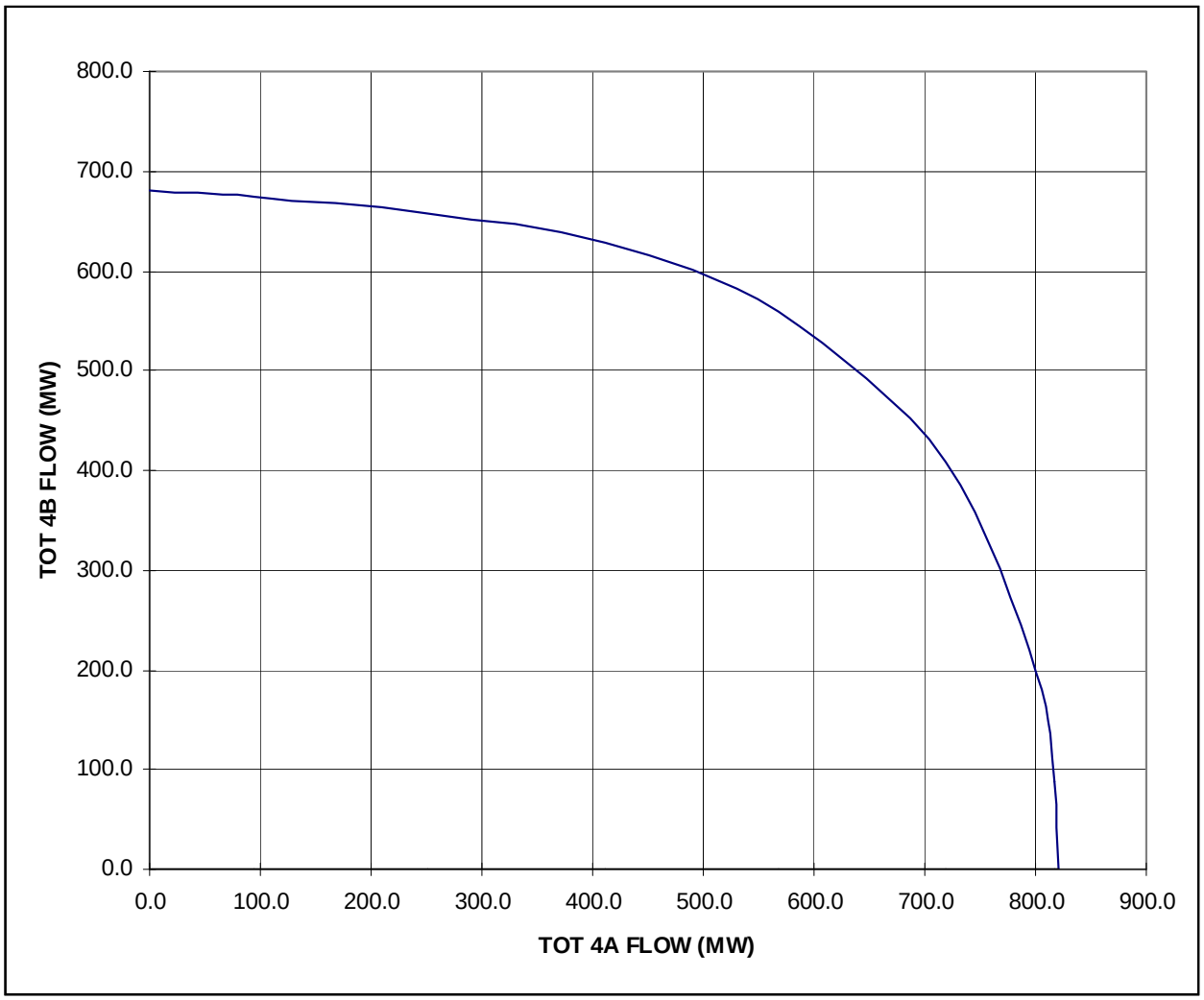
38. TOT 4B

Accepted Rating ☐
Existing Rating ☐
Other ☒

Location:	Northwest Wyoming
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Wyodak-CarrDraw 230 kV — Wyodak CarrDraw-230/12.5 kV transformers — CarrDraw 230 kV CarrDraw –Barber Creek 230 kV at CarrDraw Spence-Thermopolis 230 kV — Spence Alcova-Raderville 115 kV — Alcova Casper-Midwest 230 kV — Casper Riverton-Thermopolis 230 kV — Riverton Riverton-230/115 kV transformers — Riverton 230 kV
Transfer Limit:	Southeast to Northwest: 680 MW (Non-simultaneous) Northwest to Southeast: Not defined Depending on flows on the adjacent TOT 4A path, the real-time rating can range between a minimum of 0 MW and a maximum of 680 MW (Reference attachment). Typically, the real-time rating centers around 475 MW.
Critical Disturbance that limits the transfer capability:	The critical disturbances and limiting elements vary with the various points on the nomogram. Reference attachment for further information.
When:	Rating was established in March 1991 with the publication of "1990 Update of the TOT 4B vs. 4A Nomograms." The operating study was conducted jointly by: PacifiCorp (PAC) Western Area Power Administration (WAPA) – Loveland The study was updated in 2004 by Basin Electric to reflect the addition of Carr Draw – Teckla 230 kV Transmission Line. No changes to the Nomogram were recommended.
System Conditions:	This rating is independent of transfer levels between major areas of WECC. Historically, the flows have all been southeast to northwest across the path.
Study Criteria:	(Summary) System intact: • Per unit voltages between 0.95 p.u. and 1.05 p.u. • All lines and transformers loaded to less than continuous rating. Single contingency outage conditions: • Per unit voltages between 0.90 p.u. and 1.10 p.u. • All facilities loaded to less than 100% of emergency ratings.
Remedial Actions Required:	Remedial actions are required to achieve the rated transfer capability. Following an outage, all overloaded lines and transformers must have their loading reduced to continuous ratings within 15 minutes. This is accomplished by reducing schedules or lowering local generation.

Formal Operating Procedure:	There is a formal operating procedure dated April 12, 1991. PAC is the operating agent and uses real-time flows to monitor the path.
Allocation:	PAC and WAPA share the transfer capability of the path.
Interaction w/Other Transfer Paths:	See attachment
Contact Person:	Craig Quist PacifiCorp 1407 W. North Temple - Suite 275 Salt Lake City, UT 84140 (801) 220-4264 (801) 220-2842 - fax craig.quist@pacificorp.com

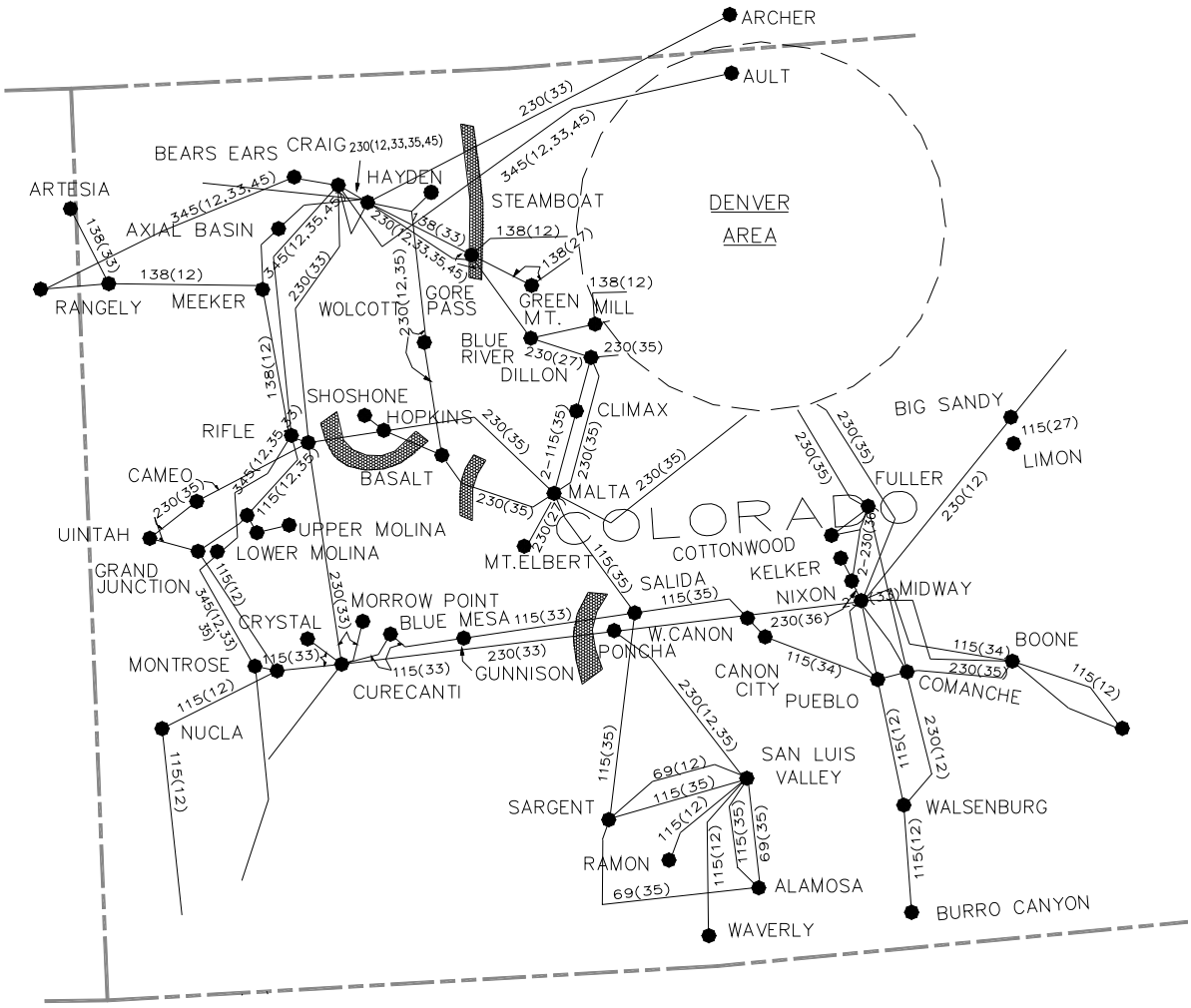
WYOMING SYSTEM OPERATING CURVE
SYSTEM NORMAL
(1990 STUDIES)



SYSTEM NORMAL

POWERFLOW	TOT FLOWS (MW)		LIMITING OUTAGE		LIMITING CONDITION	
CASE	4A	4B	LINE	KV	BUS/LINE KV	LIMIT
	0.0	680.0	ESTIMATED			
92LW206	94.1	675.0	NONE		BUF SHR 230	99.70%
92LW205	251.1	657.0	BUF - WYD	230	CSP DJ 230	99.90%
92LW204	411.1	628.2	BUF - SHR	230	CART MT 115	0.9005
92LW203	568.2	558.3	BUF - WYD	230	CSP DJ 230	99.60%
92LW202	719.1	407.8	DJ - DIF	230	SPENCE 230	0.9008
	800.0	200.0	ESTIMATED			
92LW201	817.0	87.2	DJ - DIF	230	SPENCE 230	0.9000
	820.0	0.0	ESTIMATED			

39. TOT 5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AULT
DENVER
AREA
BEARS EARS
CRAIG
HAYDEN
ARTESIA
AXIAL BASIN
STEAMBOAT
RANGELY
MEEKER
WOLCOTT
GORE
PASS
GREEN
MT.
MILL
BLUE
RIVER
DILLON
SHOSHONE
HOPKINS
CLIMAX
BIG SANDY
LIMON
RIFLE
BASALT
CAMEO
MALTA
FULLER
UINTAH
UPPER MOLINA
LOWER MOLINA
MT.ELBERT
COTTONWOOD
KELKER
GRAND
JUNCTION
SALIDA
NIXON
MIDWAY
MORROW POINT
CRYSTAL
BLUE MESA
W.CANON
BOONE
MONTROSE
GUNNISON
PONCHA
CANON
CITY
PUEBLO
COMANCHE
CURECANTI
NUCLA
SAN LUIS
VALLEY
SARGENT
WALSENBURG
RAMON
ALAMOSA
BURRO CANYON
WAVERLY

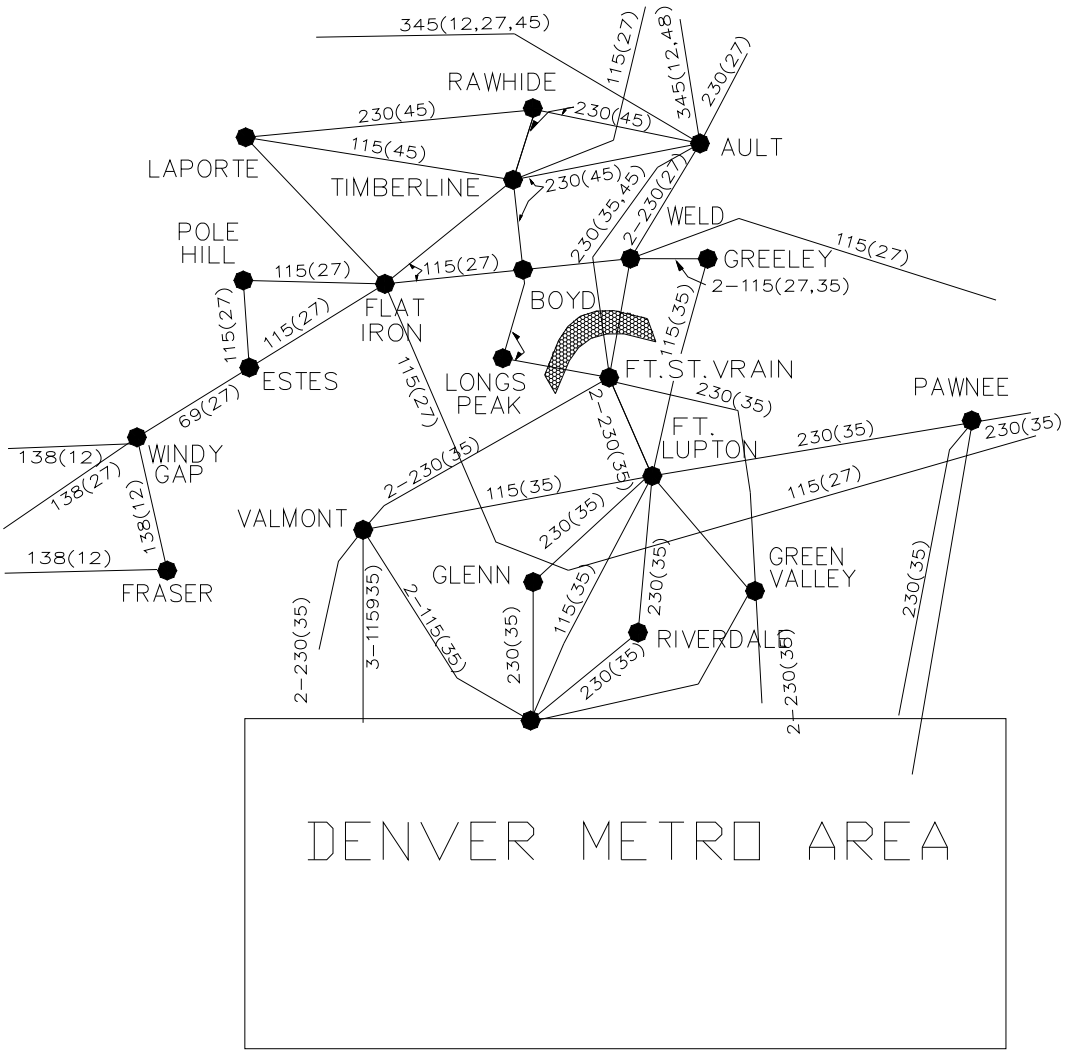
39. TOT 5

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	West-Central Colorado
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Hayden-Archer 230 kV — Archer Craig-Ault 345 kV — Craig Gore Pass-Blue River 230 kV — Blue River Hayden-Gore Pass 138 kV — Gore Pass Gore Pass 230/138 kV transformer — Gore Pass 230 Gunnison-Salida (Poncha Jct.) 115 kV — Poncha Curecanti-Poncha 230 kV — Curecanti Basalt-Malta 230 kV — Basalt Basalt-Hopkins 115 kV — Basalt Rifle-Hopkins 230 kV — Rifle
Transfer Limit:	West to East: 1675 MW East to West: Not defined
Critical Disturbance that limits the transfer capability:	The critical disturbance is the outage of the Hayden-Gore Pass 230 kV line and the remedial action of opening the parallel Hayden-Gore Pass 138 kV line. The limiting elements are the overload of the Craig-Ault 345 kV and Rifle-Malta 230 kV lines.
When:	Rating established in "Hayden-Blue River 230 kV Transmission Line Operating Study, Phase 1 Report - System Normal Operation" dated October 1987; and "Phase 2 Report - Line Outage Conditions" dated May 1988. The operating study was conducted jointly by: Colorado-Ute Electric Association (CUEA) (now PSCO and TSGT) Platte River Power Authority (PRPA) Public Service Company of Colorado (PSC) Tri-State Generation & Transmission Association, Inc. (TSGT) Western Area Power Administration (WAPA) - Salt Lake, Golden, Montrose, Loveland Salt River Project (SRP)
System Conditions:	This rating is independent of peak load/light load assumptions or transfer levels between major areas of WECC. This path is affected primarily by power exchanges within Colorado, and historically the flows have all been west to east across the path.

Remedial Actions Required:	Remedial actions are required to achieve the rated transfer capability. Following an outage, all overloaded lines and transformers must have their loadings reduced to continuous ratings within 15 minutes. This is accomplished by reducing schedules, lowering local generation or manually tripping a lower voltage parallel path for an outage of the Hayden-Gore Pass 230 kV line.
Formal Operating Procedure:	There is a formal operating procedure, the most current one dated April 10, 1997. WAPA-Rocky Mountain Region is the operating agent and uses real-time flows to monitor the path.
Formal Operating Procedure:	There is a formal operating procedure, the most current one dated April 10, 1997. WAPA-Rocky Mountain Region is the operating agent and uses real-time flows to monitor the path.
Allocation:	The transfer capability of the path is divided between WAPA, PRPA, TSGT and PSCO.
Interaction w/Other Transfer Paths:	None
Contact Person:	M. Jared Griffiths Western Area Power Administration Rocky Mountain Region P.O. Box 3700 Loveland, CO 80539-3003 (970) 461-7603 (970) 461-7423 - fax jgriffit@wapa.gov

40. TOT 7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115(27)
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230(27)
RAWHIDE
230(45)
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AULT
LAPORTE
115(45)
TIMBERLINE
230(45)
230(35,45)
2-230(27)
WELD
POLE HILL
115(27)
115(27)
GREELEY
115(27)
2-115(27,35)
BOYD
FLAT IRON
115(27)
115(27)
115(35)
ESTES
LONGS PEAK
FT.ST.VRAIN
115(27)
230(35)
PAWNEE
69(27)
2-230(35)
FT. LUPTON
230(35)
230(35)
138(12)
WINDY GAP
138(27)
2-230(35)
115(35)
115(27)
VALMONT
138(12)
138(12)
230(35)
GREEN VALLEY
FRASER
GLENN
2-230(35)
3-115935)
2-115(35)
230(35)
115(35)
230(35)
230(35)
RIVERDALE
230(35)
2-230(35)
DENVER METRO AREA

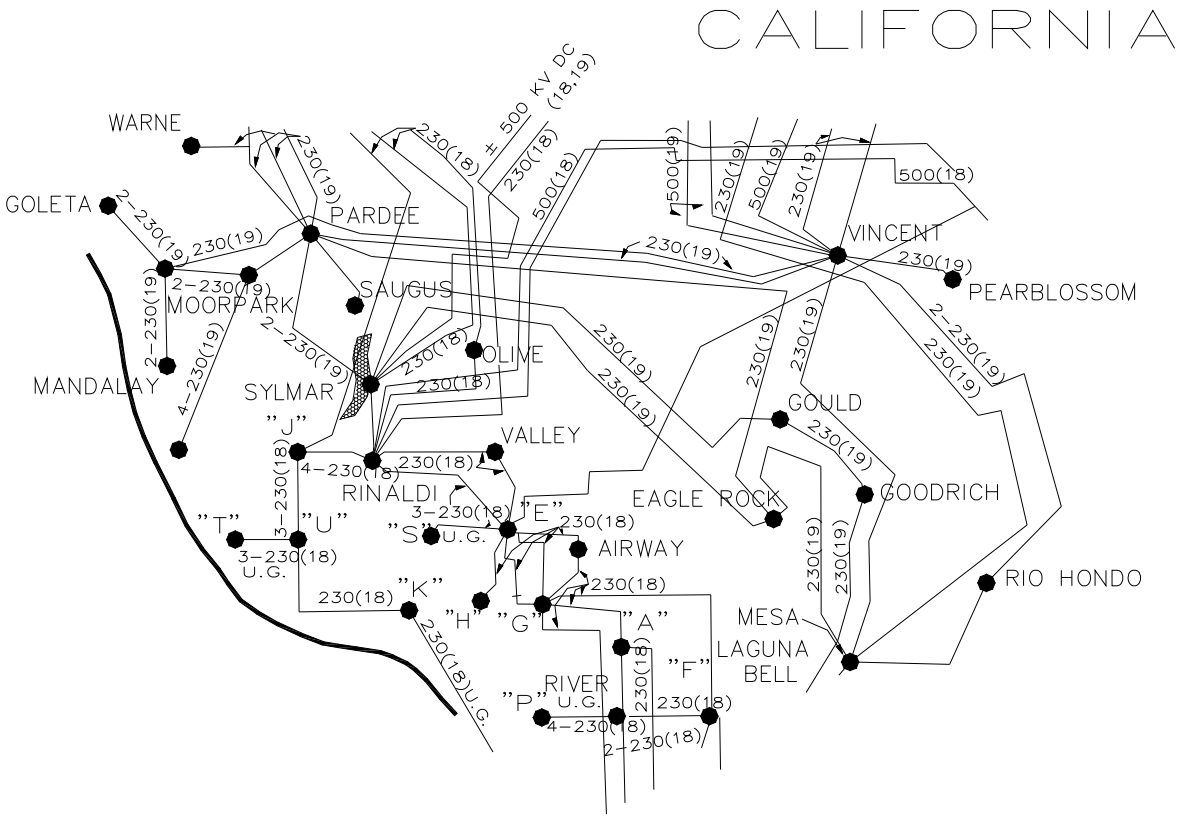
40. TOT 7

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	North Central Colorado
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Ault-Fort St. Vrain 230 kV — Ault Weld-Fort St. Vrain 230 kV — Weld Longs Peak-Fort St. Vrain 230 kV — Fort St. Vrain
Transfer Limit:	North to South: 890 MW (maximum) Depending on local generation and load levels, the real time limit can range between a maximum of 890 MW and a minimum of 562 MW (2005 summer study results). South to North: Not defined
Critical Disturbance that limits the transfer capability:	The critical disturbance is the outage of the Ault-Windsor-Fort St. Vrain 230 kV line. The limiting element is the emergency overload on the Weld-Fort St. Vrain 230 kV line or the Weld-Weld 230 kV bust tie meter CT, or the Timberline-Harmony 230 kV line.
When:	Rating established in December 1995 with publication of "Foothills Planning Group TOT 7 Operating Study Report." The operating study was conducted jointly by: Public Service Company of Colorado (PSCO) Western Area Power Administration (WAPA) - Loveland Tri-State Generation & Transmission Association, Inc. (TSGT) Platte River Power Authority (PRPA)
System Conditions:	This rating is independent of transfer levels between major areas of WECC. This path is affected primarily by Colorado/Wyoming power exchanges, and local load and generation historically the flows have all been north to south across the path.
Study Criteria:	(Summary) System intact: • Per unit voltages between 0.95 p.u. and 1.05 p.u. • All lines and transformers loaded to less than continuous rating. Single contingency outage conditions: • Per unit voltages between 0.92 p.u. and 1.10 p.u. • All lines loaded to less than 15-minute emergency ratings. • All transformers loaded to less than their continuous ratings.
Remedial Actions Required:	None required. Following an outage, re-dispatch of generation may be required to reduce loadings from acceptable short term emergency to levels within their continuous ratings.
Formal Operating Procedure:	There is a formal operating procedure; the most current one dated May 23, 2005. Public Service Company of Colorado is the operating agent and uses real-time flows to monitor the path and local load and generation update the real time operating limit.

Allocation:	The transfer capability of the path is divided between Public Service Company of Colorado and Platte River Power Authority.
Interaction w/Other Transfer Paths:	None
Contact Person:	Thomas W. Green Public Service Company of Colorado Technical Services Building 550 15th Street, Suite 700 Denver, CO 80202-4256 (303) 571-7223 (303) 571-7877 - fax thomas.green@xcelenergy.com

41. Sylmar to SCE

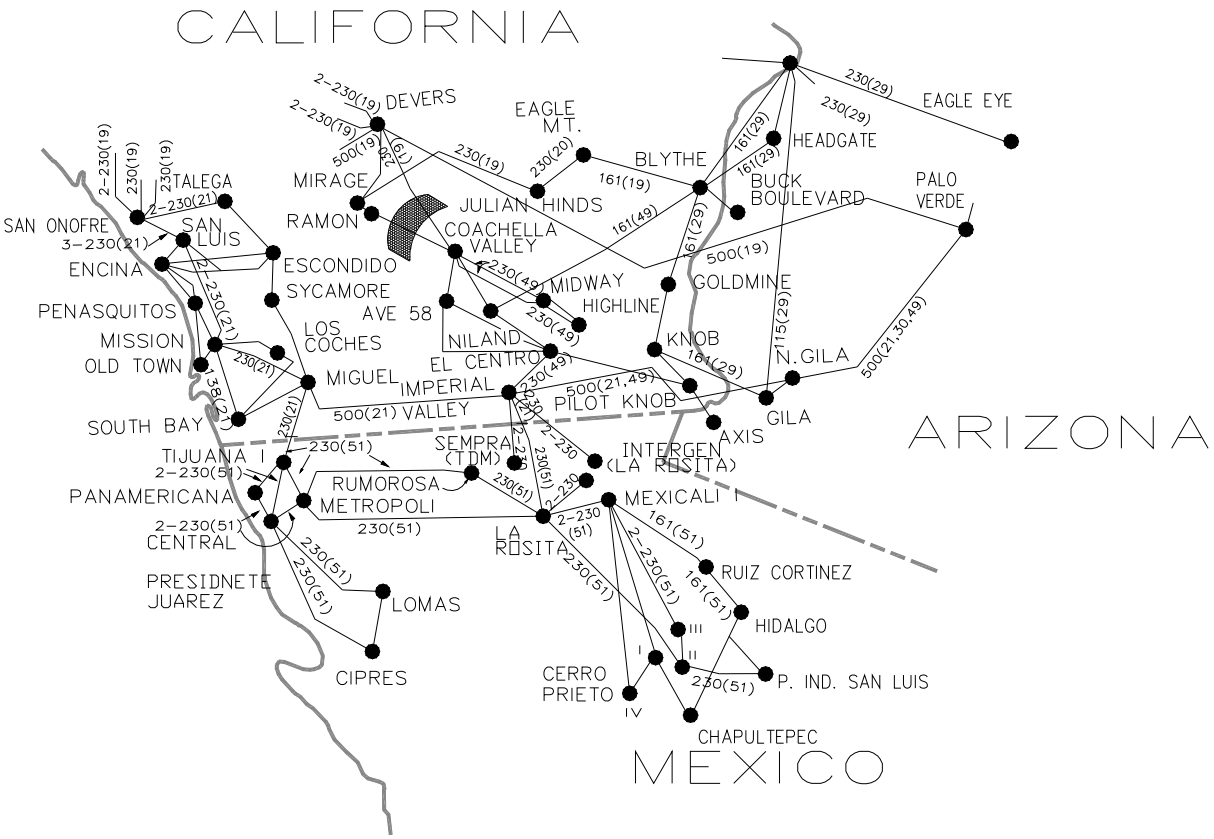


41. Sylmar to SCE

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Los Angeles County, California
Definition:	Flows on the three 220/230 kV transformer banks at Sylmar switching station. Metered at LDWP side of the banks.
Transfer Limit:	North to South: 1600 MW (non-simultaneous) South to North: 1600 MW (non-simultaneous)
Critical Disturbance that limits the transfer capability:	Transfer limit based on the emergency thermal rating of the two existing transformers (800 MW each) for the loss of the third transformer.
When:	The rating was approved by letter dated May 24, 2004 subsequent to WECC approval of the Comprehensive Progress Report titled Sylmar to SCE – Path 41 Upgrade Rating Report submitted on April 23, 2004.
System Conditions:	North to South flows (LDWP to SCE) are typical during heavy summer conditions with imports from the Northwest into southern California through the Pacific DC intertie. South to North flows (SCE to LDWP) occur during light winter, South to North PDCI flows.
Study Criteria:	WECC, LDWP, SCE
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	The transformer capability of the path is divided between: PG&E CDWR City of Anaheim SCE LDWP City of Riverside SDGE City of Pasadena
Interaction w/Other Transfer Paths:	None
Contact Person:	Patricia L. Arons Southern California Edison P. O. Box 800, Room 460 2131 Walnut Grove Avenue Rosemead, CA 91770 (626) 302-9644 (626) 302-9647 - fax patricia.arons@sce.com Ly Le Los Angeles Department of Water and Power P. O. Box 111, Room 1246 111 North Hope Street Los Angeles, CA 90051 (213) 367-0302 (213) 367-3829 - fax ly.le@ladwp.com

42. IID - SCE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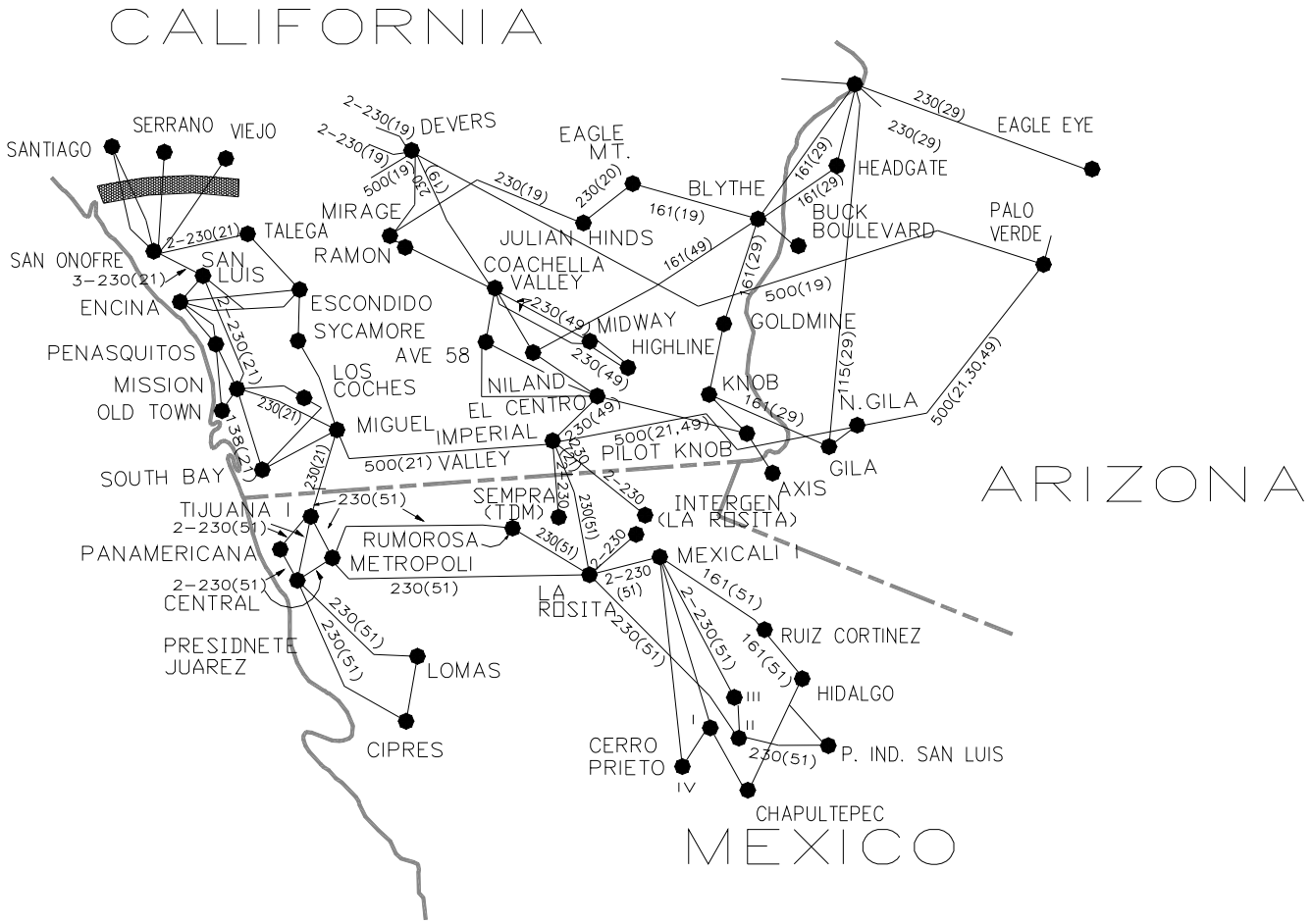
ARIZONA
MEXICO
DEVERS
EAGLE MT.
EAGLE EYE
HEADGATE
BLYTHE
BUCK BOULEVARD
PALO VERDE
TALEGA
MIRAGE
RAMON
JULIAN HINDS
COACHELLA VALLEY
SAN ONOFRE
SAN LUIS
ENCINA
ESCONDIDO
SYCAMORE
AVE 58
MIDWAY
HIGHLINE
GOLDMINE
PENASQUITOS
MISSION
OLD TOWN
LOS COCHES
NILAND
EL CENTRO
KNOB
N.GILA
MIGUEL
IMPERIAL
PILOT KNOB
GILA
SOUTH BAY
VALLEY
AXIS
TIJUANA I
SEMPRA (TDM)
INTERGEN (LA ROSITA)
PANAMERICANA
RUMOROSA
METROPOLI
MEXICALI I
CENTRAL
LA ROSITA
RUIZ CORTINEZ
PRESIDNETE JUAREZ
LOMAS
HIDALGO
CIPRES
CERRO PRIETO
P. IND. SAN LUIS
CHAPULTEPEC

42. IID - SCE

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Riverside County, California
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Ramon-Mirage 230kV — Mirage 230 kV Coachella-Devers 230 kV — Devers 230 kV
Transfer Limit:	East to West: 600 MW West to East: Not rated
Critical Disturbance that limits the transfer capability:	The limiting N-1 condition is an outage of Devers-Coachella line which results in power flow equaling the N-1 thermal rating of the Mirage-Coachella line.
When:	The 600 MW rating was established in 1990.
System Conditions:	The 600 MW rating is valid at all times. Flows on this transfer path have historically been east to west due to the presence of a number of QFs in the IID service territory delivering power to SCE.
Study Criteria:	WECC, SCE
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	SCE, IID
Interaction w/Other Transfer Paths:	None
Contact Person:	Patricia L. Arons Southern California Edison P. O. Box 800, Room 460 2131 Walnut Grove Avenue Rosemead, CA 91770 (626) 302-9644 (626) 302-9647 - fax patricia.arons@sce.com David L. Barajas Imperial Irrigation District P. O. Box 937 333 E. Barioni Blvd. Imperial, CA 92251-0937 (760) 339-9093 (760) 339-0525 - fax georgeb@thegrid.net

43. North of San Onofre

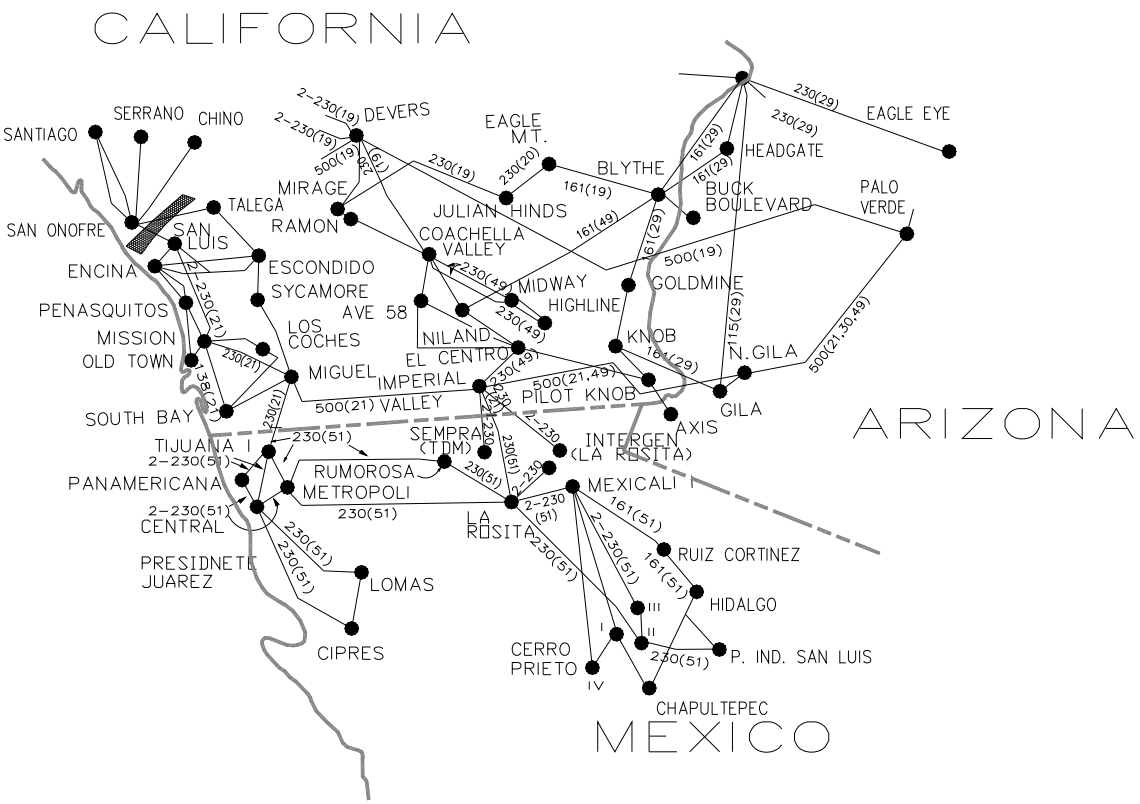


43. North of San Onofre

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	North of San Onofre Nuclear Generating Station (SONGS) San Onofre Interconnection San Diego County, California
Definition:	North of SONGS Lines — Metered End SONGS-Santiago #1 230 kV — SONGS SONGS-Santiago #2 230 kV — SONGS SONGS-Serrano 230 kV — SONGS SONGS-Viejo 230 kV — SONGS
Transfer Limit:	South to North: 2440 MW
Critical Disturbance that limits the transfer capability:	Transient instability can occur for N-2 loss of both SONGS-Santiago #1 and #2 230 kV lines.
When:	The stability limit was established in 1988. The north to south transfer limit designation was removed per PCC chair's May 19, 1999 letter addressing this issue.
System Conditions:	The ratings given above are used under all system conditions. The stability rating was established based on light load conditions.
Study Criteria:	WECC and SCE
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	Southern California Edison owns and operates the lines as defined above.
Interaction w/Other Transfer Paths:	
Contact Person:	Patricia L. Arons Southern California Edison P. O. Box 800, Room 460 2131 Walnut Grove Avenue Rosemead, CA 91770 (626) 302-9644 (626) 302-9647 - fax patricia.arons@sce.com

44. South of San Onofre

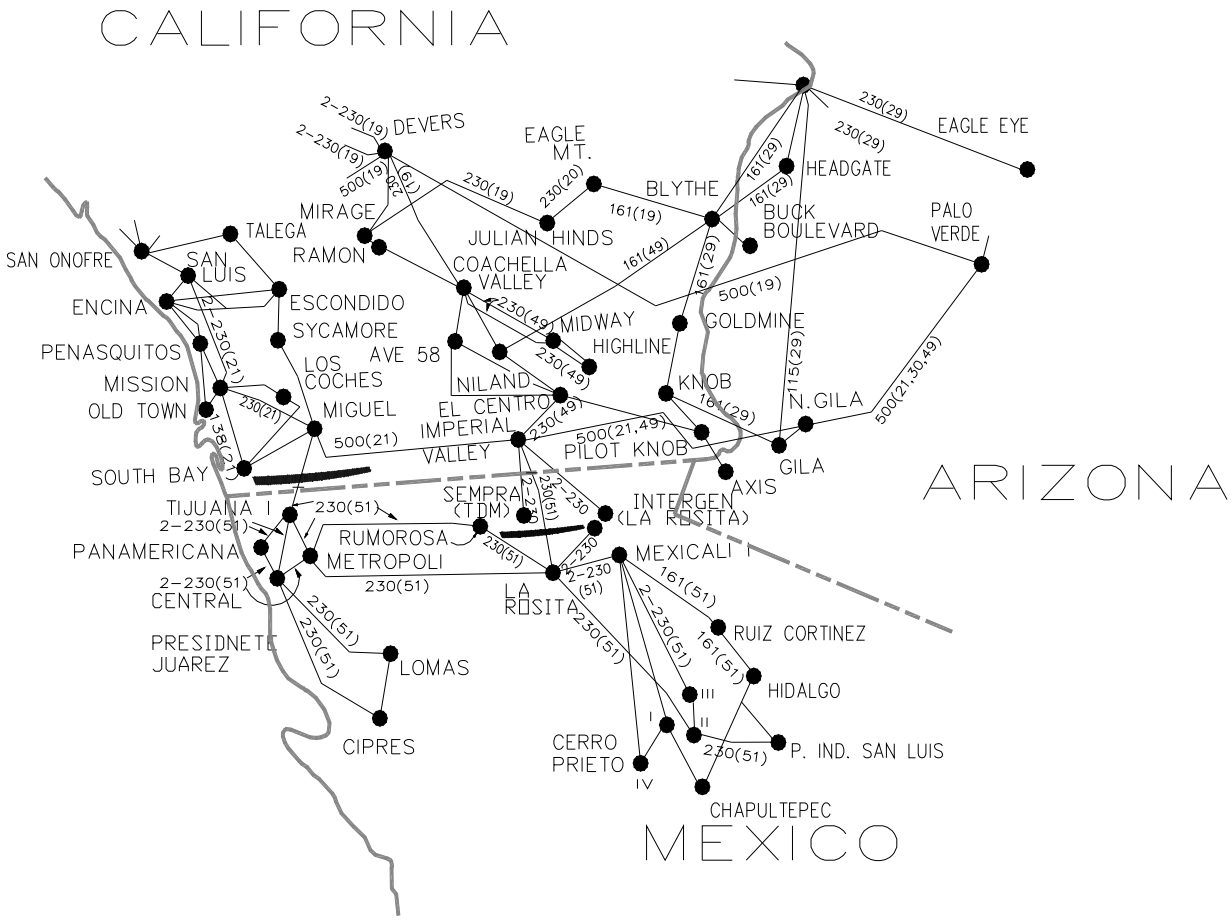


44. South of San Onofre

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	South of San Onofre Nuclear Generating Station (SONGS) San Onofre Interconnection, San Diego County, California
Definition:	South of SONGS Lines — Metered End SONGS-San Luis Rey — SONGS SONGS-San Luis Rey — SONGS SONGS- San Luis Rey — SONGS SONGS-Talega #1 — SONGS SONGS-Talega #2 — SONGS
Transfer Limit:	North to South: 2200/2500 MW (see System Conditions below) South to North: No longer required based on determination made in 1999 through WECC review. (See letter from PCC Chairman to PCC, OC, and TSS dated June 26, 2001)
Critical Disturbance that limits the transfer capability:	The 2200 MW north to south rating is based on flowability on the path under normal conditions. During critical contingency operating conditions with a 2500 MW north to south flow, outage of SCE's Del Amo-Ellis 230 kV line loads the Barre-Ellis 230 kV line to 99.8% of its N-1 contingency "A" rating of 2850 amps.
When:	Accepted dual ratings were approved by PCC on February 11, 2000.
System Conditions:	For north to south flow, the 2200 MW rating is applicable under normal conditions. The 2500 MW rating is applicable only for times when any segment of the Southwest PowerLink is out of service for any reason.
Study Criteria:	WECC, SDGE, and the California ISO.
Remedial Actions Required:	The need for arming RAS for local load shedding will be determined by the California ISO and SDGE during seasonal operating studies, however, no load shedding requirement has been identified at this time.
Formal Operating Procedure:	None
Allocation:	San Diego Gas & Electric owns lines as defined above. The California ISO exercises operational control of the lines and associated facilities.
Interaction w/Other Transfer Paths:	None
Contact Person:	Linda P. Brown San Diego Gas & Electric 8316 Century Park Court, CP52A San Diego, CA 92123-1582 (858) 654-6477 (858) 654-1692 - fax lpbrown@semprautilities.com

45. SDG&E - CFE


CALIFORNIA
ARIZONA
MEXICO
DEVERS
EAGLE MT.
EAGLE EYE
HEADGATE
BLYTHE
BUCK BOULEVARD
PALO VERDE
MIRAGE
TALEGA
SAN ONOFRE
SAN LUIS
RAMON
JULIAN HINDS
COACHELLA VALLEY
ENCINA
ESCONDIDO
SYCAMORE
PENASQUITOS
LOS COCHES
AVE 58
MIDWAY
HIGHLINE
GOLDMINE
MISSION
OLD TOWN
MIGUEL
NILAND
EL CENTRO
IMPERIAL VALLEY
KNOB
N.GILA
PILOT KNOB
GILA
AXIS
SOUTH BAY
TIJUANA I
SEMPRA (TDM)
INTERGEN (LA ROSITA)
PANAMERICANA
RUMOROSA
METROPOLI
CENTRAL
MEXICALI I
LA ROSITA
PRESIDNETE JUAREZ
LOMAS
RUIZ CORTINEZ
HIDALGO
CIPRES
CERRO PRIETO
P. IND. SAN LUIS
CHAPULTEPEC

45. SDG&E - CFE

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	San Diego County - Baja California Norte (Mexico)
Definition:	Tijuana Interconnection — Metered End Tijuana I-Miguel — Tijuana I La Rosita Interconnection — Metered End La Rosita-Imperial Valley — La Rosita
Transfer Limit:	North to South: 408 MW South to North: 800 MW per letters from PCC Chairman to PCC, OC, and TSS dated July 17, 2003, and from SDGE to PCC, OC, TSS, CMOPS and TOC dated June 11, 2003).
Critical Disturbance that limits the transfer capability:	The South to North path is collectively rated 800 MW to allow for loss of Imperial Valley-Miguel 500 kV line without overloading the Miguel-Tijuana 230kV line. Note that the North to South rating has not been changed and was established based on the old thermal rating of the La Rosita-Imperial Valley 230 kV line, which was 408 MW.
When:	
System Conditions:	The North to South ratings given above are used under all pre-contingency system conditions. The thermal ratings were established based on heavy load conditions. The South to North ratings given above were established based on winter and summer conditions, respectively, and maximum available generation in the CFE system.
Study Criteria:	WECC, SDGE and CFE
Remedial Actions Required:	None required at this time.
Formal Operating Procedure:	None
Allocation:	SDGE owns the lines and associated facilities in the United States, and CFE owns and operates the lines and associated facilities in Mexico. The California ISO exercises operational control of the lines and associated facilities in the United States.

Contact Person:	Ing. Jesús Moya Jefe del Area de Control BCN Comisión Federal de Electricidad PMB-42-023 120-A Rockwood Ave. Calexico, CA 92231 (USA address) 011-52(686)-558-1501 011-52(686)-558-1508 011 52(686)-558-1543 - fax 011-52(686)-558-1533 - fax jesus.moya@cfe.gob.mx	Linda P. Brown San Diego Gas & Electric 8316 Century Park Court, CP52A San Diego, CA 92123-1582 (858) 654-6477 (858) 654-1692 - fax lprown@semprautilities.com

46. West of Colorado River (WOR)

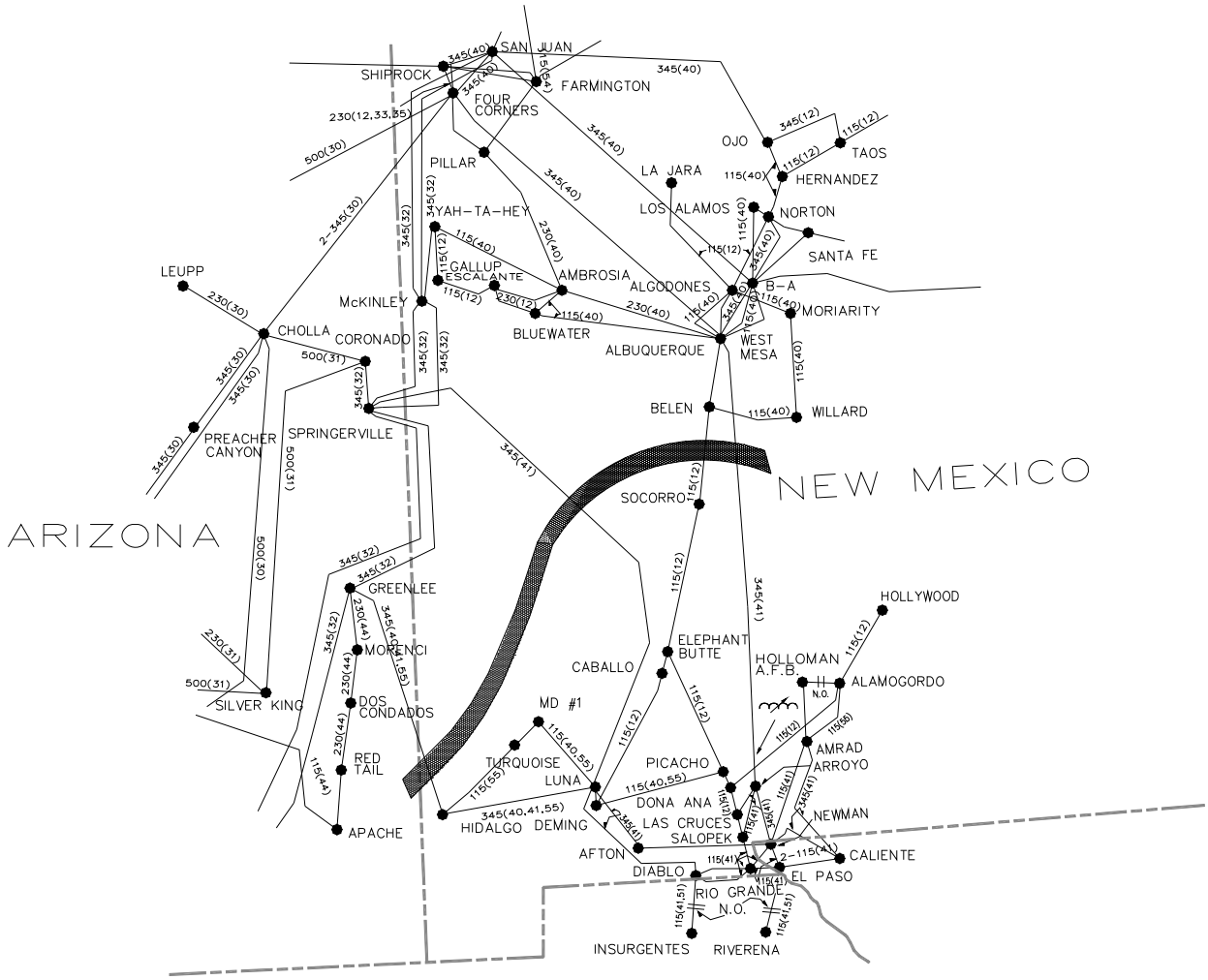
46. West of Colorado River (WOR)

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	The WOR lines interconnect southern Nevada and Arizona to southern California
Definition:	The sum of the flows on the following transmission lines: Line — Metered End (Northern System) Eldorado-Lugo 500 kV — Eldorado Eldorado-Lugo 230 kV lines 1 & 2 — Eldorado Mohave-Lugo 500 kV — Mohave Julian Hinds-Mirage 230 kV — Mirage McCullough-Victorville 500 kV lines 1 & 2 — McCullough Hoover-Victorville 287 kV — Hoover Marketplace-Adelanto 500 kV — Marketplace (Southern System) North Gila-Imperial Valley 500 kV — North Gila Palo Verde-Devers 500 kV — Devers (Underlying System) El Centro-Imperial Valley 230 kV — Imperial Valley Ramon-Mirage 230 kV — Mirage Coachella-Devers 230 kV — Devers
Transfer Limit:	10,623 MW
Critical Disturbance that limits the transfer capability:	Loss of the Palo Verde-North Gila or Palo Verde-Devers 500 kV lines.
When:	The rating increase from 10,118 MW to 10,623 MW was approved by letter dated October 13, 2006, from PCC chair granting WOR an accepted rating of 10,623 MW
System Conditions:	Rating valid under all system conditions.
Study Criteria:	WECC
Remedial Actions Required:	None
Formal Operating Procedure:	Operation is maintained within the boundaries of the Southern California Import Transmission (SCIT) nomogram.

Allocation:	**Northern System:** Net WOR Line Lines Allocation Entitlements McCullough-Victorville 500 1&2 +Hoover-Victorville 287 — 2592 MW — LDWP 2592 MW Marketplace-Adelanto 500 — 1291 MW — LDWP 313 MW; SCE 60 MW; Cities 918 MW Eldorado-Lugo 500 +Eldorado-Lugo 230 1&2 +Mohave-Lugo 500 +J. Hinds-Mirage 230 — 2754 MW — SCE 2509 MW; CDWR 235 MW; ANZA 10 MW Northern Subtotal 6637 MW **Southern System:** Net WOR Line Lines Allocation Entitlements Palo Verde-Devers 500 — 1802 MW — SCE 1334 MW; LDWP 468 MW Ramon-Mirage 230 +Coachella-Devers 230 — 600 MW — SCE 600 MW N. Gila-Imperial Valley 500 +El Centro-Imperial Valley 230 — 1584 MW — SDGE 1385 MW; IID 199 MW Southern Subtotal 3986 MW Total System: 10,623 MW Since IID's system is east of the WOR cut-plane, any schedules made by IID on the North Gila-Imperial Valley line are equal in magnitude and opposite in direction to IID's schedules on the El Centro-Imperial Valley line; thus, IID's schedules on the North Gila-Imperial Valley line and El Centro-Imperial Valley line are not added to the WOR flow total nor is IID required to curtail schedules for WOR or SCIT limitations.
Interaction w/Other Transfer Paths:	The maximum capability of the WOR path is influenced by the flows on the other paths bringing power into southern California. Real-time power flows are monitored for all of the paths defining the SCIT nomogram, including WOR, Midway-Vincent, PDCI, IPP DC and North of Lugo.
Contact Person:	Patricia L. Arons Southern California Edison Company P. O. Box 800, Room 460 2131 Walnut Grove Avenue Rosemead, CA 91770 (626) 302-9644 (626) 302-9647 - fax patricia.arons@sce.com

47. Southern New Mexico (NM1)



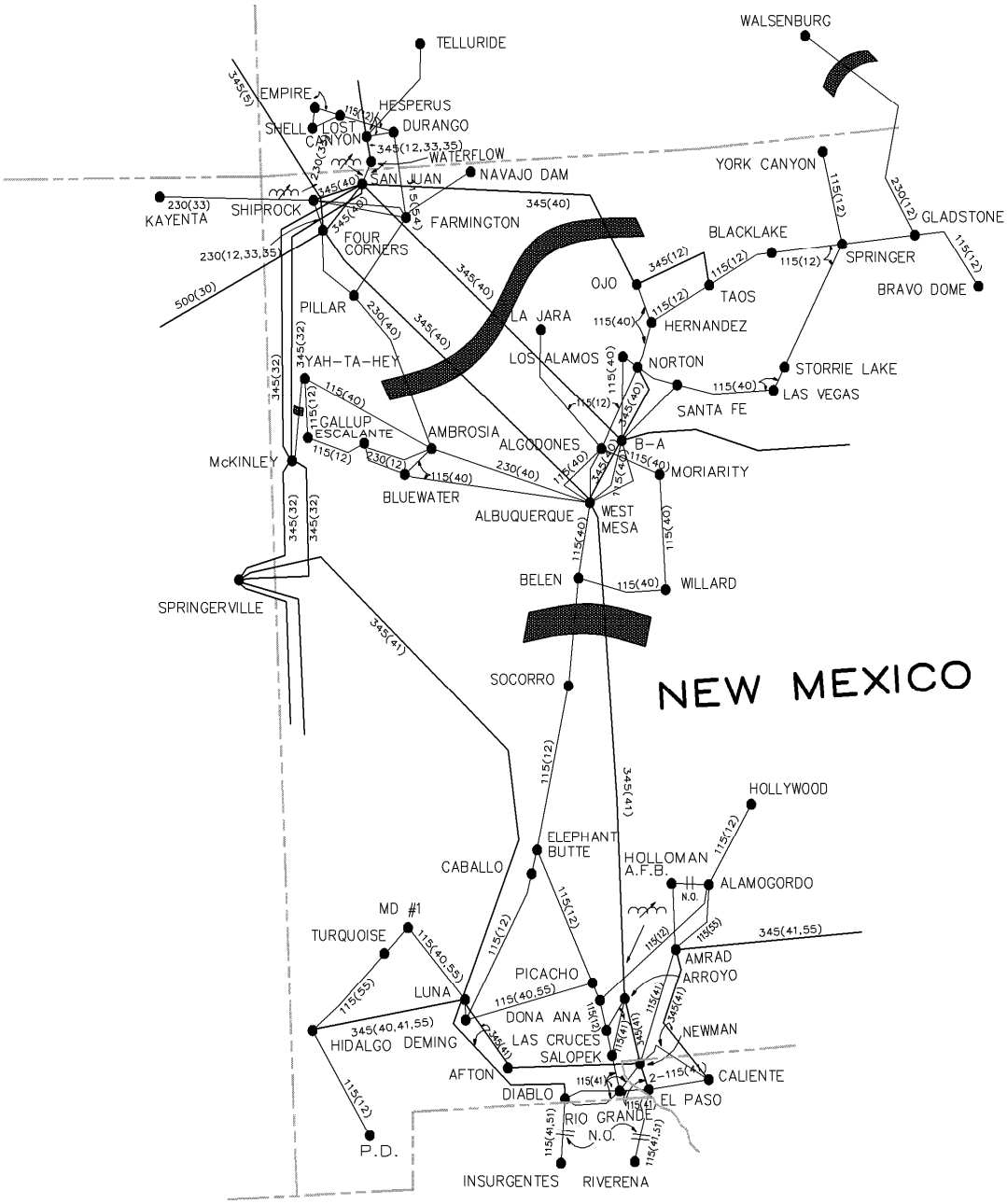
47. Southern New Mexico (NM1)

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Southern New Mexico
Definition:	Sum of the flows on the following transmission lines: Line — Metered End West Mesa-Arroyo 345 kV — West Mesa 345 kV Springerville-Luna 345 kV — Springerville 345 kV Greenlee-Hidalgo 345 kV — Greenlee 345 kV Belen-Bernardo 115 kV — Belen 115 kV The definition of Path 47 has been changed to replace the West Mesa-Belen 115 kV line with the Belen-Bernardo 115 kV line, metered at Belen. This does not result in a change in the path rating. In 2004, this change was put through the expedited process to preserve the accepted rating status.
Transfer Limit:	Simultaneous firm: 940 MW Non-simultaneous: 1048 MW
Critical Disturbance that limits the transfer capability:	Either the Springerville-Luna 345 kV or Greenlee-Hidalgo 345 kV lines.
When:	Simultaneous firm accepted rating established by New Mexico Transmission Operating Procedure 2005 and non-simultaneous accepted rating established by WECC Peer Review Group in 1995.
System Conditions:	Ratings are independent of transfer levels between major WECC areas. Ratings were established for a heavy summer system and are dependent upon Arroyo phase shifter schedules, generation levels, area power factors and reactor levels in southern New Mexico.
Study Criteria:	Local New Mexico pre-disturbance voltage levels between 0.95 p.u. and 1.05 p.u. Post-transient voltage deviation no greater than 7% from base case levels on southern New Mexico 345 kV buses and 6% on northern New Mexico 345 kV buses. WECC criteria applied for systems outside New Mexico area.
Remedial Actions Required:	For double contingencies on the 345 kV lines defined above, WECC Operating Procedure EPE-1 is implemented.
Formal Operating Procedure:	New Mexico Transmission Operating Procedure, effective 1/1/05.
Allocation:	EPE, Tri-State G&T, PNM
Interaction w/Other Transfer Paths:	Interaction with Northern New Mexico Transfer Path (NM2) is controlled with the Arroyo phase shifter.

Contact Person:	Dennis Malone El Paso Electric Company P. O. Box 982 El Paso, TX 79960 (915) 543-5757 (915) 521-4763 - fax dmalone@epelectric.com

48. Northern New Mexico (NM2)



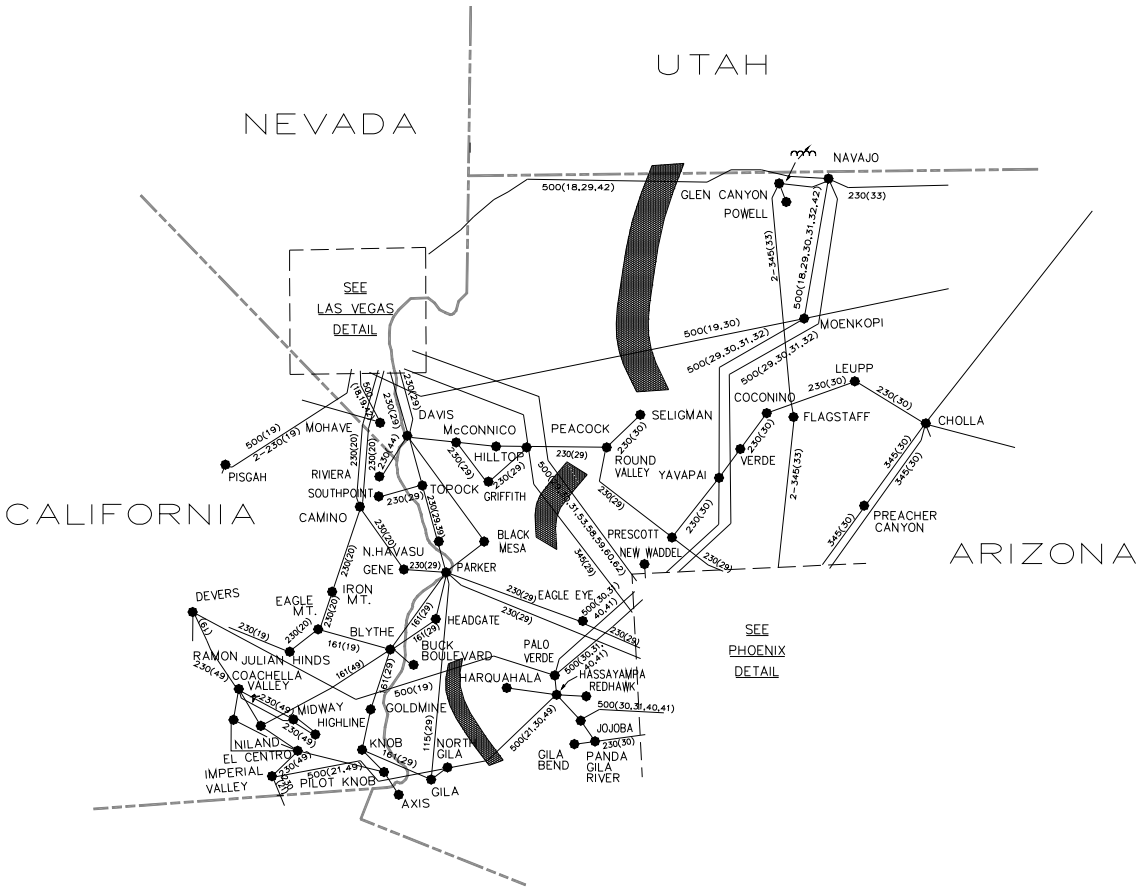
48. Northern New Mexico (NM2)

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Northern New Mexico
Definition:	Sum of flows on the following transmission elements: Element — Metered End Four Corners-West Mesa 345 kV line — Four Corners San Juan-BA 345 kV line — San Juan San Juan-Ojo 345 kV line — San Juan McKinley/Yah-Ta-Hey 345/115 kV trans — Yah-Ta-Hey Bisti-Ambrosia 230 kV line — Bisti Walsenburg -Gladstone 230kV line — Walsenburg Less the following flows: Belen-Bernardo 115 kV line — Belen West Mesa-Arroyo 345 kV line — West Mesa
Transfer Limit:	Simultaneous firm: 1849 MW Non-simultaneous: 1970 MW
Critical Disturbance that limits the transfer capability:	Four Corners-West Mesa or San Juan-BA 345 kV lines.
When:	The rating was approved by letter dated May 6, 2002, subsequent to WECC approval of the revised Comprehensive Progress Report titled Colorado-New Mexico Interconnection Project for Path 48 (NM2) Submitted March 1, 2006
System Conditions:	The operating transfer limit on Path 48 uses independent real-time nomogram equations that are incorporated in PNM's Energy Management System. These nomogram equations utilize metered real-time system conditions (e.g., real/reactive power flows, status of shunt capacitors/reactors, etc.) to determine the Path 48 limits on a one-minute basis. The nomogram equation variables included in the Path 48 calculations are therefore dependent upon system conditions and take into account seasonal and time-of-day variations.
Study Criteria:	Local New Mexico criteria include pre-disturbance voltage levels between 0.95 and 1.05 p.u., post transient voltage deviation no greater than 6% in northern New Mexico and 7% in southern New Mexico, or not less than a 5% voltage stability margin. PNM operates Path 48 based on the lower of the voltage or thermal limits.
Remedial Actions Required:	
Formal Operating Procedure:	Post-PST New Mexico Transmission Operating Procedure, effective June 18, 1999.

Allocation:	PNM owns and operates Path 48. Several entities have the rights to use the transfer capability on this path.
Interaction w/Other Transfer Paths:	Interacts with transfers over path NM1, but is controlled by the Arroyo phase-shifting transformer.
Contact Person:	Jeff Mechenbier Public Service Company of New Mexico Alvarado Square, MS 0604 Albuquerque, NM 87158 (505) 241-4570 (505) 241-4363 - fax jeff.mechenbier@pnm.com

49. East of the Colorado River (EOR)



49. East of the Colorado River (EOR)

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Western Arizona
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Navajo-Crystal-McCullough 500 kV — Navajo Moenkopi-Eldorado 500 kV — Eldorado Liberty-Peacock-Mead 345 kV — Liberty Palo Verde-Devers 500 kV — Palo Verde Hassayampa-North Gila 500 kV — Hassayampa Perkins-Mead 500 kV — Perkins
Transfer Limit:	East to West: 8055 MW (Non-simultaneous) West to East: Not rated The present east to west, non-simultaneous EOR rating is 8055 MW and assumes a 'normal' operating system with all lines in service and full series compensation levels in the Navajo, Palo Verde, and Mead-Phoenix Project (MPP) transmission systems.
Critical Disturbance that limits the transfer capability:	The critical disturbance is loss of the Palo Verde-Devers 500 kV line which causes the Perkins-Mead 500 kV line to reach the emergency ratings of both the line series capacitors and Perkins 500 kV phase Shifters.
When:	The non-simultaneous transfer rating was established in 1996 by the Western Arizona Transmission Systems (WATS) Task Force. The Task Force was comprised of members from the following companies: Arizona Public Service Company El Paso Electric Company DOE-Western Area Power Administration Imperial Irrigation District Los Angeles Department of Water and Power Nevada Power Company Public Service Company of New Mexico Salt River Project San Diego Gas and Electric Company Southern California Edison Company Southern California Public Power Authority Tucson Electric Power Company SDGE sponsored studies conducted within a WECC Review Group that led to approval of the Accepted Rating Report, and was granted Accepted Rating Status by the August 5, 1996 letter from the PCC Chairman.

System Conditions:	Flows on this transfer path have historically been east to west due to the large amount of joint participation plants located in Arizona and New Mexico which are partly owned by southern California and Nevada entities.
Study Criteria:	WECC Reliability Criteria for Transmission System Planning
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	The presently used allocation is as follows: Southern California Edison Co. 3105 MW Los Angeles Dept. of Water & Power 695 MW Western Area Power Administration 1218 MW Nevada Power Company 371 MW San Diego Gas & Electric Co. 1162 MW Imperial Irrigation Project 196 MW Arizona Public Service Co. 403 MW Southern California Public Power Authority 238 MW Salt River Project 236 MW Modesto-Santa Clara-Redding 150 MW Vernon 28 MW 8055 MW
Interaction w/Other Transfer Paths:	The simultaneous transfer limit into southern California is governed by the Southern California Import Transmission (SCIT) Nomogram, and is partly a function of the EOR flow. The SCIT Nomogram varies seasonally and is limited by post transient and transient conditions.
Contact Person:	Peter Krzykos Arizona Public Service Company P. O. Box 53999, Station 2260 Phoenix AZ 85072-3999 (602) 250-1649 (602) 250-1674 - fax peter.krzykos@aps.com

East-of-River/Southern California Import Transmission Nomogram

Based upon:
Three Palo Verde units
All transmission facilities in service

Reduction in SCIT Import Limit For Palo Verde Status:	
3 units on Line	0 MW
2 units on Line	200 MW
1 unit on Line	400 MW
0 unit on Line	700 MW

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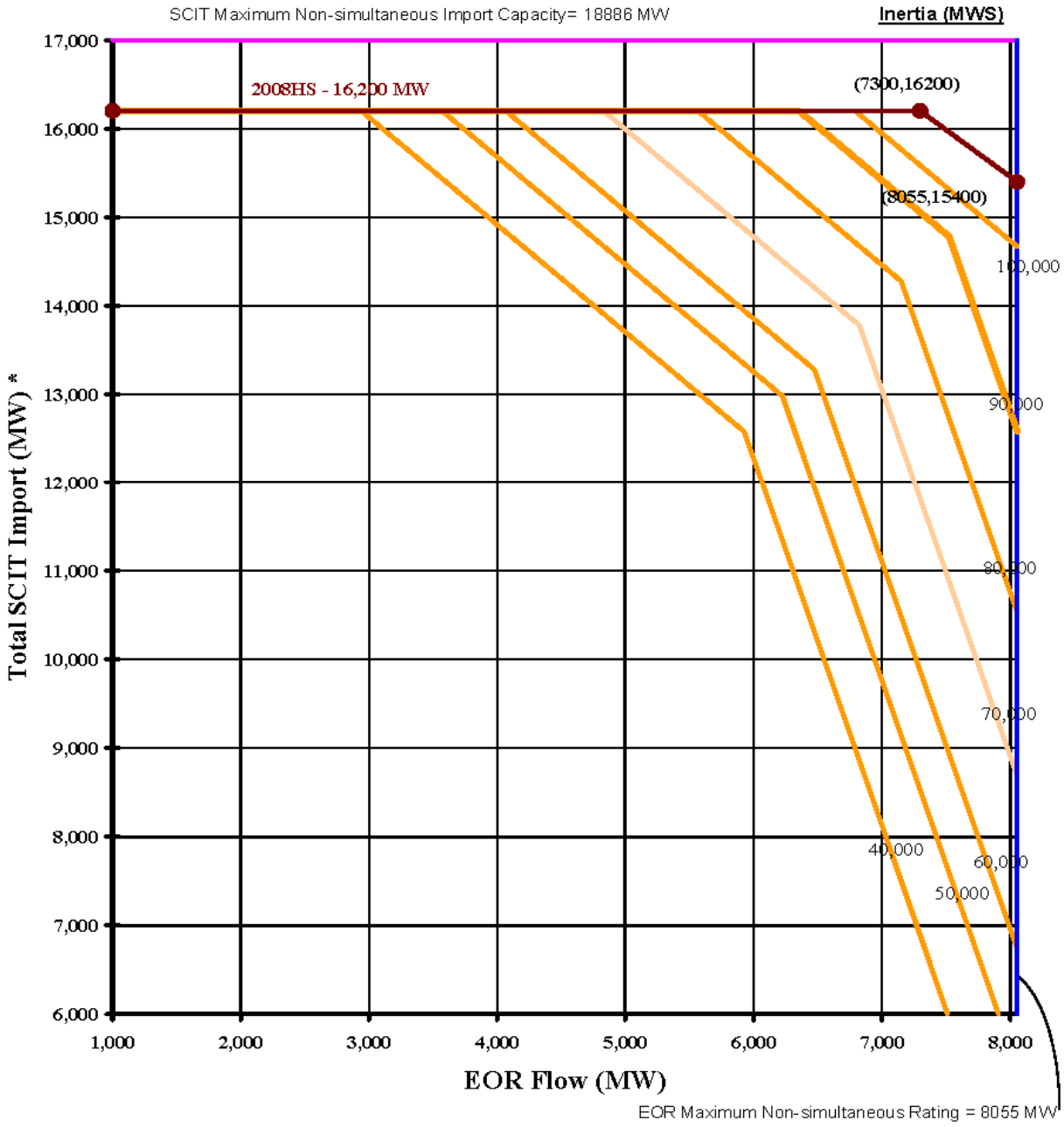
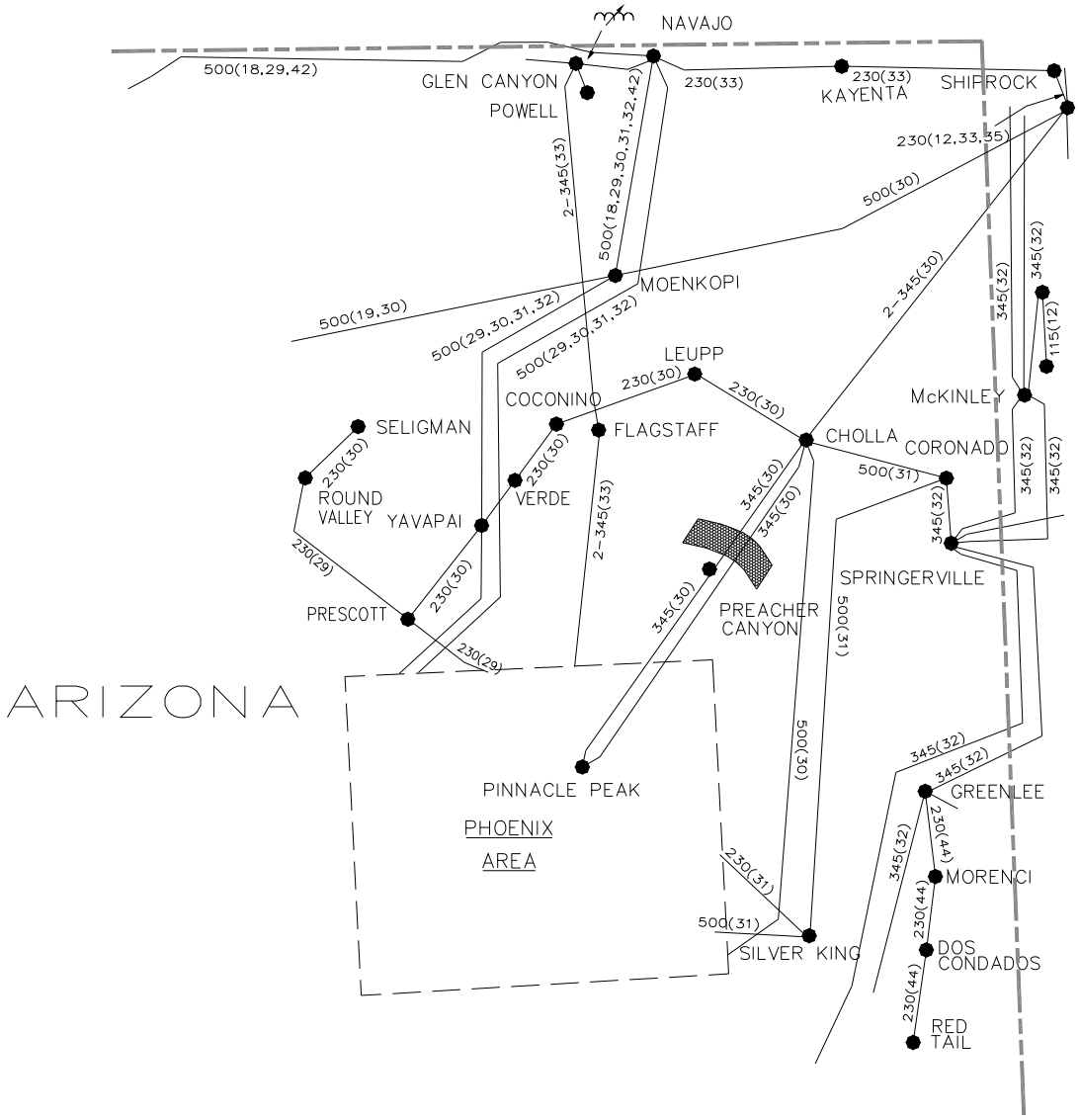


*Sum of flows on Midway-Vincent, PDCI, IPP, North of Lugo, and WOR.

50. Cholla - Pinnacle Peak

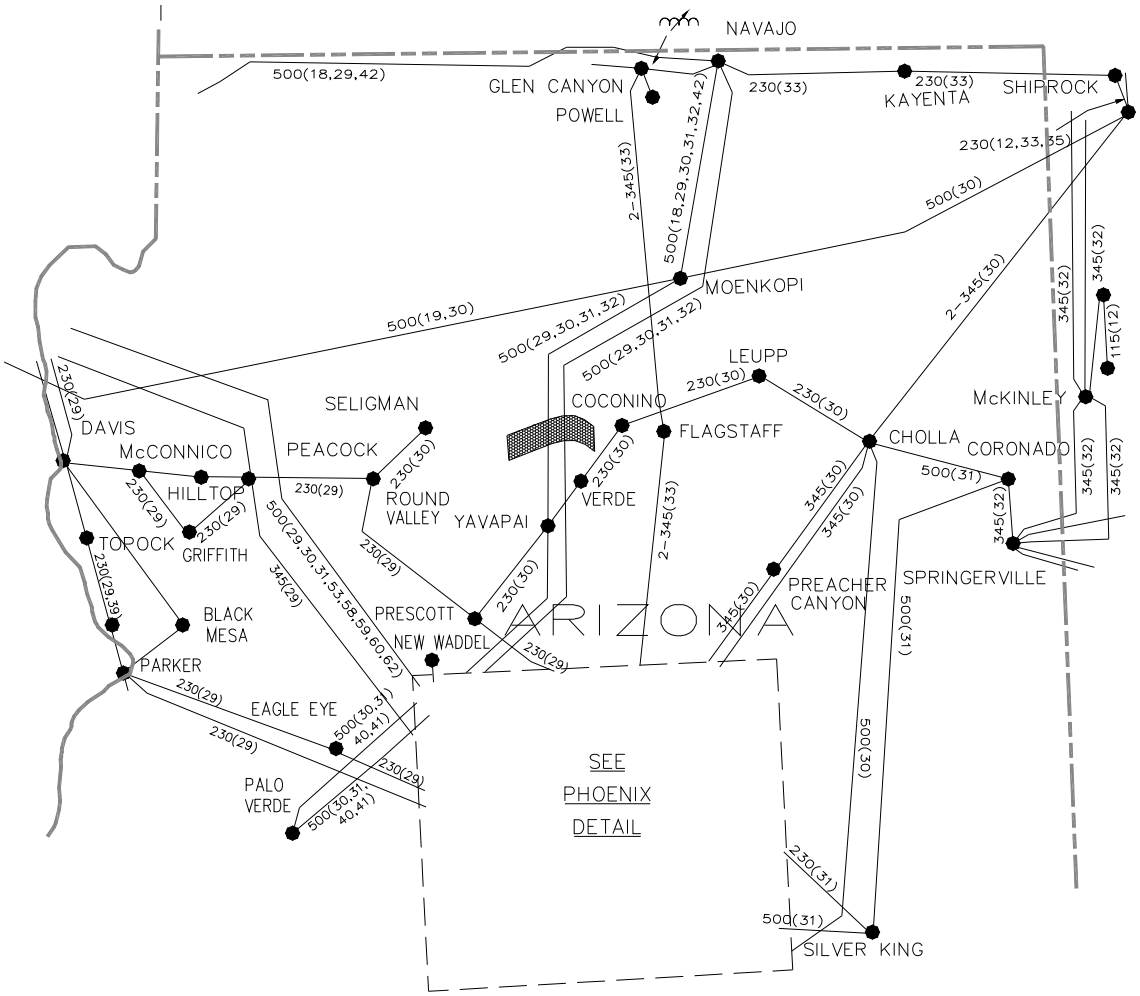


50. Cholla - Pinnacle Peak

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Northern Arizona
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Cholla-Pinnacle Peak 345 kV #1 — Cholla Cholla-Pinnacle Peak 345 kV #2 — Cholla
Transfer Limit:	East to West: 1200 MW West to East: Not rated
Critical Disturbance that limits the transfer capability:	The critical disturbance is loss of one of the Cholla-Pinnacle Peak 345 kV lines which causes the remaining Cholla-Pinnacle Peak 345 kV line to reach the emergency rating.
When:	The 1200 MW rating was established in the early 1980's by the Four Corners Technical Studies Task Force. The task force is comprised of members from the following companies: Arizona Public Service Company El Paso Electric Company Public Service Company of New Mexico Salt River Project Southern California Edison Company Tucson Electric Power Company Verified by 2004 OTC studies.
System Conditions:	Flows on this transfer path have historically been east to west due to the large amount of generation located in northwestern New Mexico and Cholla.
Study Criteria:	Same as the WECC Reliability Criteria for Transmission System Planning.
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	The transfer capability is wholly owned by AZPS.
Interaction w/Other Transfer Paths:	None
Contact Person:	Peter Krzykos Arizona Public Service Company P. O. Box 53999, Station 2260 Phoenix AZ 85072-3999 (602) 250-1649 (602) 250-1674 - fax peter.krzykos@aps.com

51. Southern Navajo

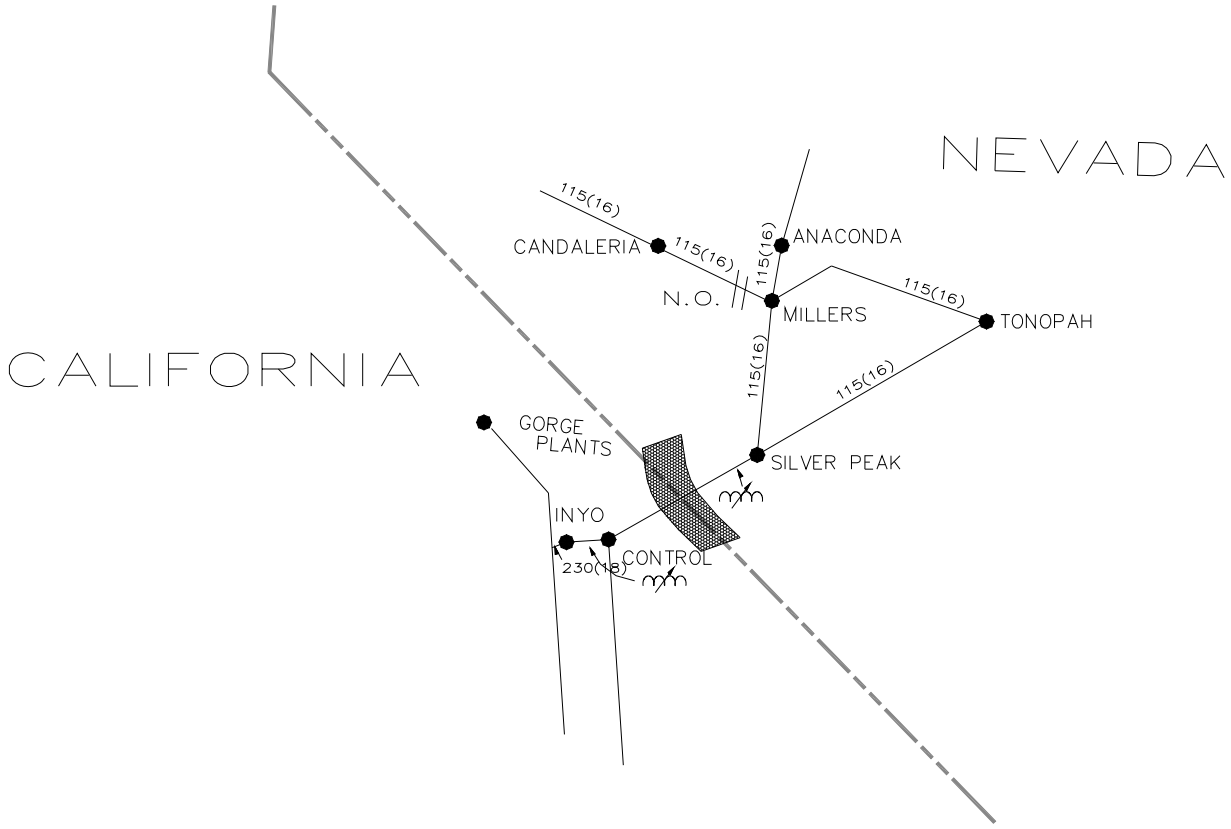


51. Southern Navajo Upgrade Project

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Northern Arizona
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Moenkopi-Yavapai 500 kV — Moenkopi Navajo-Westwing 500 kV — Navajo
Transfer Limit:	North to South: 2264 MW South to North: Not rated
Critical Disturbance that limits the transfer capability:	The 2264 MW Operating limit is limited by the continuous thermal rating of the series capacitors at the Moenkopi end of the Moenkopi-Yavapai line prior to any line changes.
When:	The transfer rating was established in 1994 in a study performed by AZPS Transmission Planning. Detailed report mailed August 5, 1994.
System Conditions:	Flows on this transfer path have historically been north to south due to the generation at the Navajo power plant and flows for the east and west of Path 51.
Study Criteria:	Same as the WECC Reliability Criteria for Transmission System Planning.
Remedial Actions Required:	None.
Formal Operating Procedure:	None.
Allocation:	The transfer capability is divided amount the following entities: • Salt River Project 38.3% • Arizona Public Service Company 24.7% • Department of Energy 23.7% • Tucson Electric Power Company 13.3% 100.00%
Interaction w/Other Transfer Paths:	None.
Contact Person:	Barrie Kokanos Arizona Public Service Company P. O. Box 53999, Station 2259 Phoenix AZ 85072-3999 (602) 250-1370 (602) 250-1674 - fax barrie.kokanos@aps.com

52. Silver Peak - Control 55 kV



52. Silver Peak - Control 55 kV

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Southwestern Nevada/Central Eastern California
Definition:	Sum of flows: Line — Metered End Silver Peak-Control 55 kV — California-Nevada border
Transfer Limit:	Direction — Limit Silver Peak to Control — 17 MW Control to Silver Peak — 17 MW
Critical Disturbance that limits the transfer capability:	Limited by pre-disturbance voltage on the intertie caused by surge impedance loading of the line.
When:	Studies were performed in 1985 to establish this line rating.
System Conditions:	Historically, during peak loading conditions, flows on the intertie have been limited to 14 MW.
Study Criteria:	
Remedial Actions Required:	
Formal Operating Procedure:	
Allocation:	
Interaction w/Other Transfer Paths:	
Contact Person:	Edi Von Engeln Sr. ENGR. Regional Planning 6100 Neil Road M/S S3B40 Reno, NV 89511 (775) 834-4456 (775) 834-3047 - fax evonengeln@sppc.com

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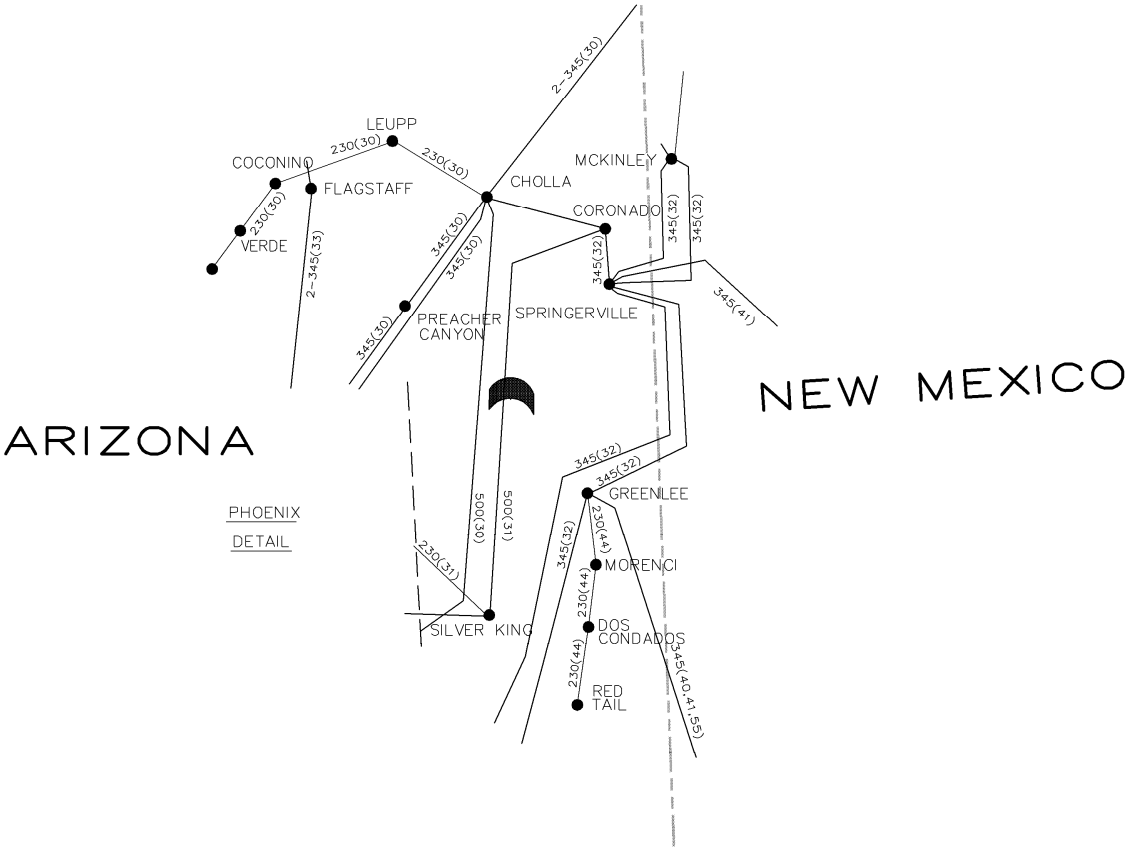
54. Coronado – Silver King

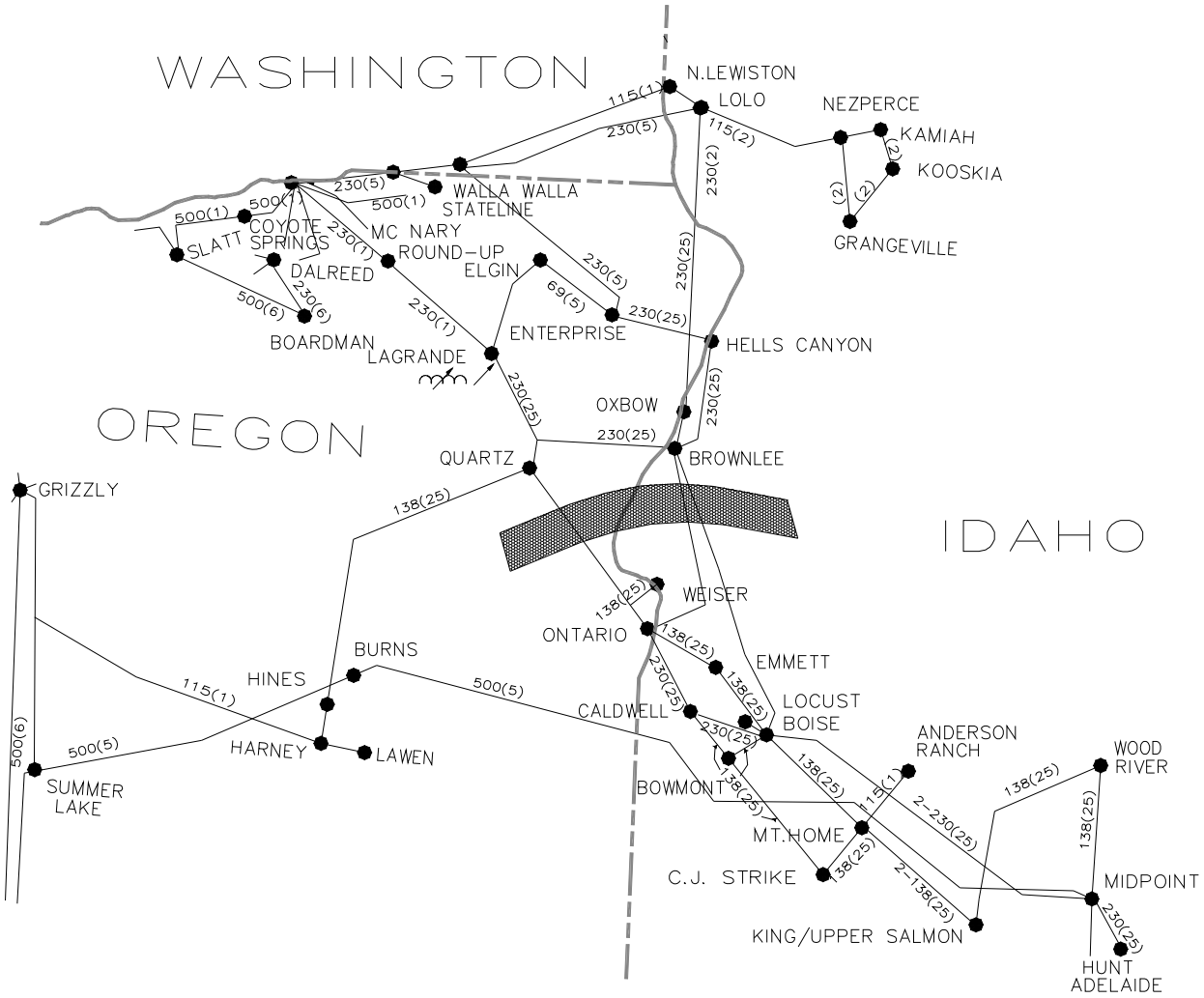


54. Coronado West

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Eastern Arizona
Definition:	Sum of flows on the following transmission lines: Line — Metered End Coronado-Silver King 500 kV — Coronado
Transfer Limit:	East to West: 1133 MW West to East: Not rated
Critical Disturbance that limits the transfer capability:	The critical disturbance is loss of the Coronado-Silver King 500 kV line which causes the Cholla-Preacher Canyon 345 kV line to reach the emergency rating.
When:	On January 30, 2007, Salt River Project (SRP) initiated the Rating Review Process for Path 54 (Coronado-Silver King 500 kV line) with an accepted rating of 1133 MW associated with the addition of Springerville Unit # 3. Phase II status was granted by TSS on April 10, 2007. The Accepted Rating was approved by the PCC Chairman on November 15, 2007.
System Conditions:	2007 Heavy Spring conditions. Pre and Post- Springerville #3 benchmark cases were developed in which the eastern Arizona transmission paths were stressed until a thermal, stability or post-transient limit was reached. However, the accepted rating will be valid under all system conditions.
Study Criteria:	WECC Reliability Criteria For Transmission System Planning
Remedial Actions Required:	None
Formal Operating Procedure:	Coronado-Silver King line operating procedure #45407. The revised and updated operating procedures will be developed if necessary.
Allocation:	Salt River Project
Interaction w/Other Transfer Paths:	None
Contact Person:	John Hernandez Salt River Project P.O. Box 52025 Phoenix, AZ 85072-2025 (602) 236-0969 (602) 236-3896 - fax johhny.hernandez@srpnet.com

55. Brownlee East



55. Brownlee East

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Southwest Idaho
Definition:	The transfer path is comprised of the following lines: Line — Metered End Brownlee-Boise Bench #1 230 kV — Brownlee Brownlee-Boise Bench #2 230 kV — Brownlee Brownlee-Boise Bench #3 230 kV — Brownlee Brownlee-Horse Flat-Boise Bench 230 kV — Brownlee Brownlee-Ontario 230 kV — Brownlee Oxbow-Starkey 138 kV — Oxbow Quartz-Ontario 138 kV — Quartz
Transfer Limit:	West to East: 1850 MW East to West: Not defined. However, this transfer path does not restrict east to west transfers through Idaho.
Critical Disturbance that limits the transfer capability:	Post transient reactive margin at the Boise Bench 230 kV following the loss of the Midpoint-Summer Lake 500 kV line, or the loss of two Jim Bridger lines with tripping of two Jim Bridger units, or the loss of two Brownlee-Boise Bench 230 kV lines. Thermal limits on the remaining two Brownlee-Boise Bench 230 kV lines for loss of the other two lines.
When:	In 1983, the Brownlee East transfer limit was established by Idaho Power Company and was revised in 1986 when the Northwest to Idaho transfer limit was restudied. After the July 2 and 3, 1996 disturbances, the Brownlee East transfer limit was restricted to 1560 MW. After the completion of the Brownlee-Boise Bench 230kV Project in 2001, the Brownlee East transmission path attained an Accepted Rating of 1750 MW West to East. The accepted rating was increased to 1850 MW West to East for the summer of 2004 when the final phase of the project, which included the 2nd Brownlee-Oxbow 230 kV circuit, was completed.
System Conditions:	The Brownlee East transfer limit was developed with high Northwest to Idaho imports and T E Roach Complex generation with low eastern thermal resources, and with heavy summer loads.
Study Criteria:	The WECC/NERC Reliability Criteria for Transmission System Planning and Idaho Power's post transient reactive margin criteria for N-1 and N-2 disturbances.
Remedial Actions Required:	At high flows East of Brownlee, the loss of two Brownlee-Boise Bench 230 kV lines requires overload mitigation measure of bypassing ½ series compensation in the remaining two Brownlee-Boise Bench 230 kV lines, and in the Brownlee-Ontario 230kV line.

Formal Operating Procedure:	None
Allocation:	The transfer capability of the path is allocated as follows: 2200 MW East to West: Ownership — Allocation IPC 733 MW (1/3) — 707 MW (1/3 Jim Bridger Generation) PacifiCorp 1467 MW (2/3) — 1493 MW (Remainder)
Interaction w/Other Transfer Paths:	None
Contact Person:	Mark D. Hanson Idaho Power Company P.O. Box 70 Boise, ID 83707 (208) 388-2253 (208) 388-6647 - fax mhanson@idahopower.com

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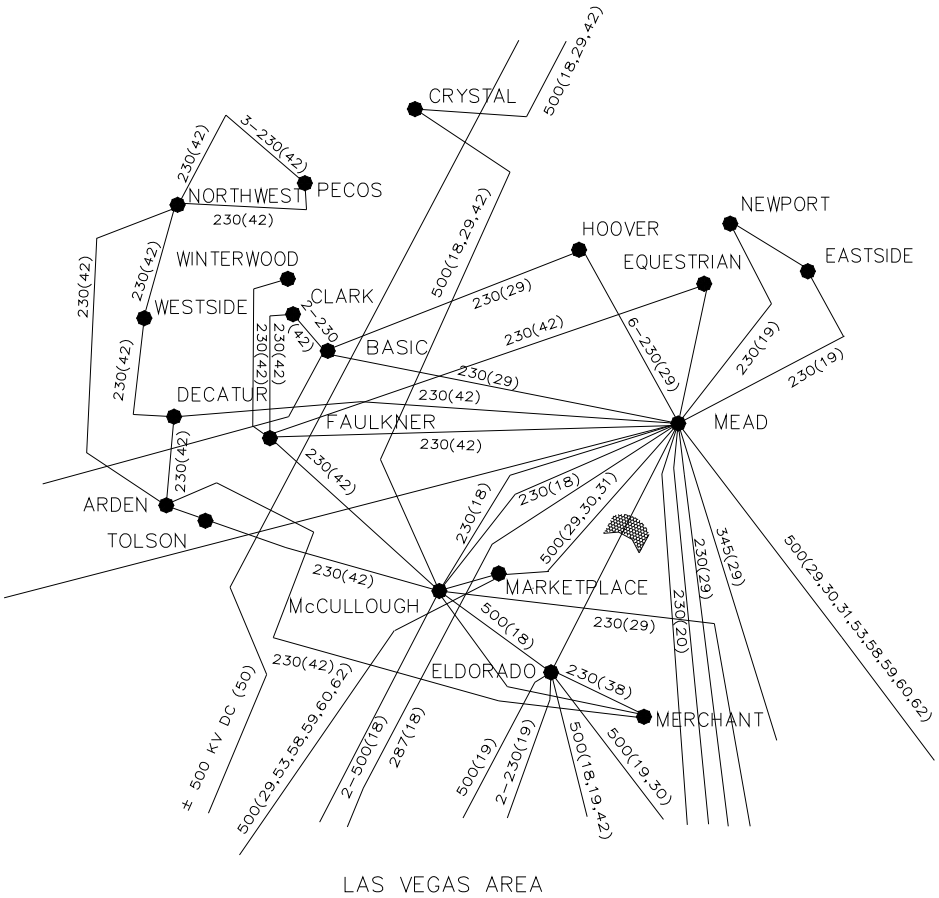
58. Eldorado - Mead 230 kV Lines

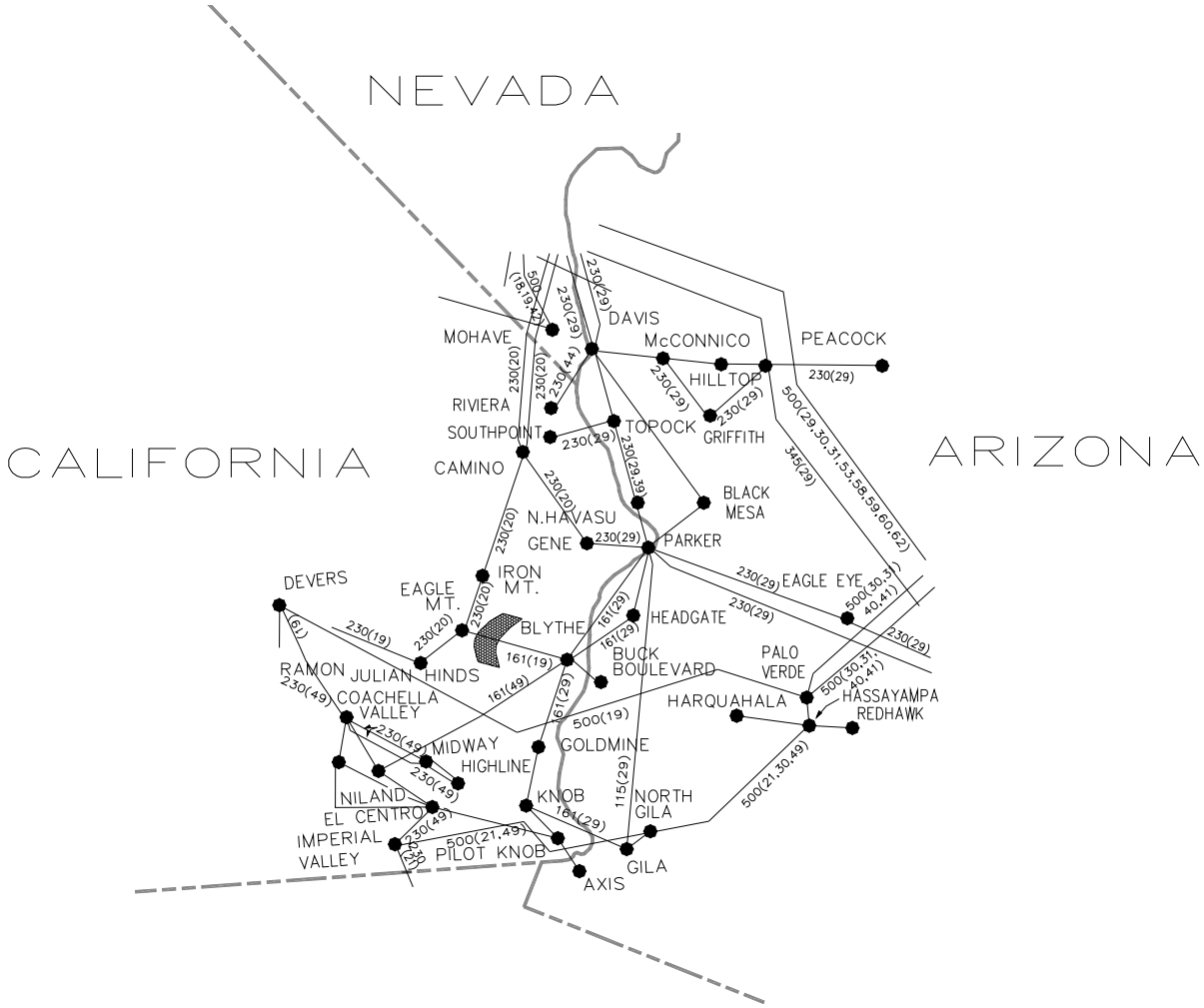


58. Eldorado - Mead 230 kV Lines

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Near Boulder City in southern Nevada
Definition:	Flows on the Eldorado-Mead 230 kV transmission lines 1 and 2.
Transfer Limit:	1140 MW
Critical Disturbance that limits the transfer capability:	The 1140 MW rating is limited by the likely contingency (emergency) thermal rating of the conductor. The critical disturbance, for which the 1140 MW rating is established, is outage of one of the two Eldorado-Mead 230 kV lines.
When:	The 1140 MW rating was established in 1969.
System Conditions:	Power may flow westbound or eastbound in varying levels throughout the year primarily due to Mohave and Hoover power deliveries.
Study Criteria:	WECC, SCE
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	Jointly owned by SCE (54.700%), NEVP (26.425%) and SRP (18.875%).
Interaction w/Other Transfer Paths:	None
Contact Person:	Patricia L. Arons Southern California Edison P. O. Box 800, Room 460 2131 Walnut Grove Avenue Rosemead, CA 91770 (626) 302-9644 (626) 302-9647 - fax patricia.arons@sce.com

59. WALC Blythe 161 kV Substation - SCE Blythe 161 kV Substation

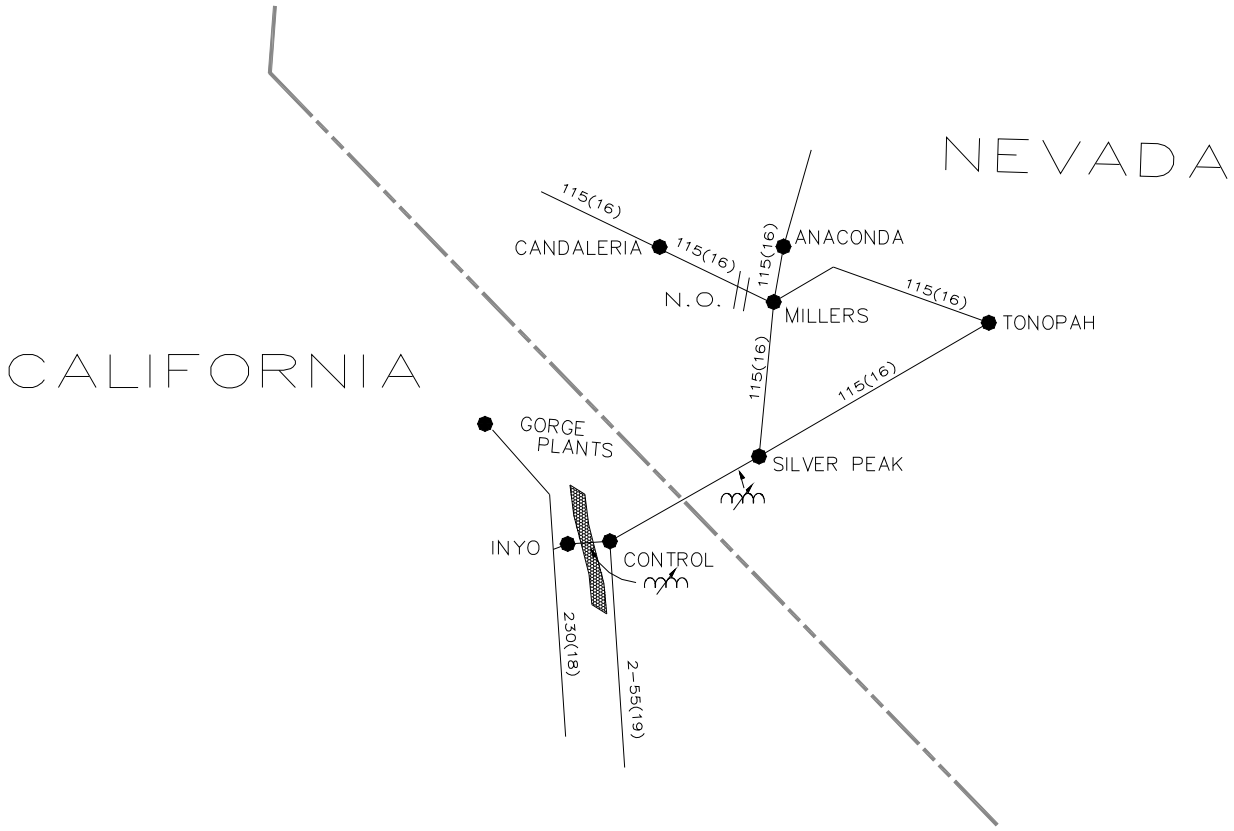


59. WALC Blythe 161 kV Substation - SCE Blythe 161 kV Substation

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Blythe substation is 5 miles west of the city of Blythe in Riverside County
Definition:	The bus tie-line between WALC Blythe 161 kV substation and SCE Blythe 161 kV substation. Metered at SCE Blythe 161 kV substation.
Transfer Limit:	East to West: 218MW -- The E-W transfer capacity of the path is limited by the continuous 168 MVA rating of the Eagle Mountain-Blythe (SCE) 161 kV line. The E-W flow across the bus tie-line between SCE Blythe 161 kV substation and WALC is partially consumed by the load on the Blythe (SCE) 161 kV bus first, and then, goes onto the Eagle Mountain-Blythe (SCE) 161 kV line.
Critical Disturbance that limits the transfer capability:	The path rating is limited by the continuous 168 MVA rating of the Eagle Mountain-Blythe (SCE) 161 kV line.
When:	In 1965, the path rating was established by SCE. In 2002, the path rating was increased due to the replacement of the 230/161 kV transformer at Eagle Mountain and upgrades to the Eagle Mountain-Blythe (SCE) 161 kV line. A letter from the PCC chair dated September 24, 2002 was distributed granting Phase III status and an accepted rating. At the January 2004 TSS meeting, the elimination of the path rating in the west to east direction was approved.
System Conditions:	
Study Criteria:	WECC, SCE, CISO
Remedial Actions Required:	None
Formal Operating Procedure:	Path 59 - WALC Blythe 161 kV Substation - SCE Blythe 161 kV Substation Tie vs. Blythe load east to west.
Allocation:	The transfer is allocated 100% to SCE
Interaction w/Other Transfer Paths:	None
Contact Person:	Patricia L. Arons Southern California Edison P. O. Box 800, Room 460 2131 Walnut Grove Avenue Rosemead, CA 91770 (626) 302-9644 (626) 302-9647 - fax patricia.arons@sce.com

60. Inyo - Control 115 kV Tie

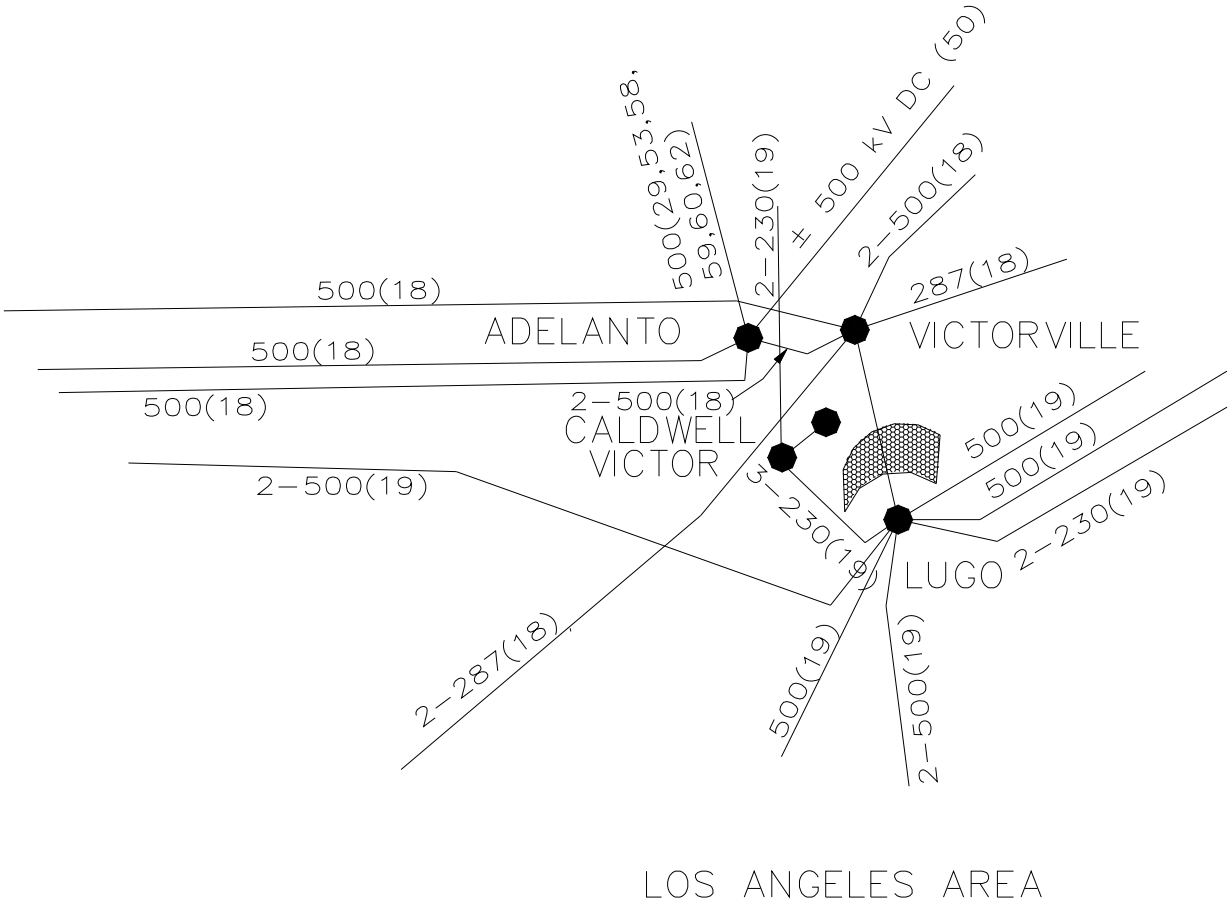


60. Inyo - Control 115 kV Tie

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Inyo substation is located 2 miles southwest of the town of Bishop
Definition:	The 115 kV phase shifter between SCE and LDWP. Metered at Control 115 kV bus.
Transfer Limit:	56 MW
Critical Disturbance that limits the transfer capability:	The path rating is limited by the continuous rating of the 56 MVA phase shifter.
When:	1976
System Conditions:	
Study Criteria:	WECC, SCE, LDWP
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	The transfer is allocated between SCE and LDWP.
Interaction w/Other Transfer Paths:	None
Contact Person:	Patricia L. Arons Southern California Edison P. O. Box 800, Room 460 2131 Walnut Grove Avenue Rosemead, CA 91770 (626) 302-9644 (626) 302-9647 - fax patricia.arons@sce.com Ly Le Los Angeles Dept. Of Water & Power P. O. Box 111, Room 1246 111 N. Hope Street Los Angeles, CA 90051 (213) 367-0302 (213) 367-3829 - fax ly.le@ladwp.com

61. Lugo - Victorville 500 kV Line

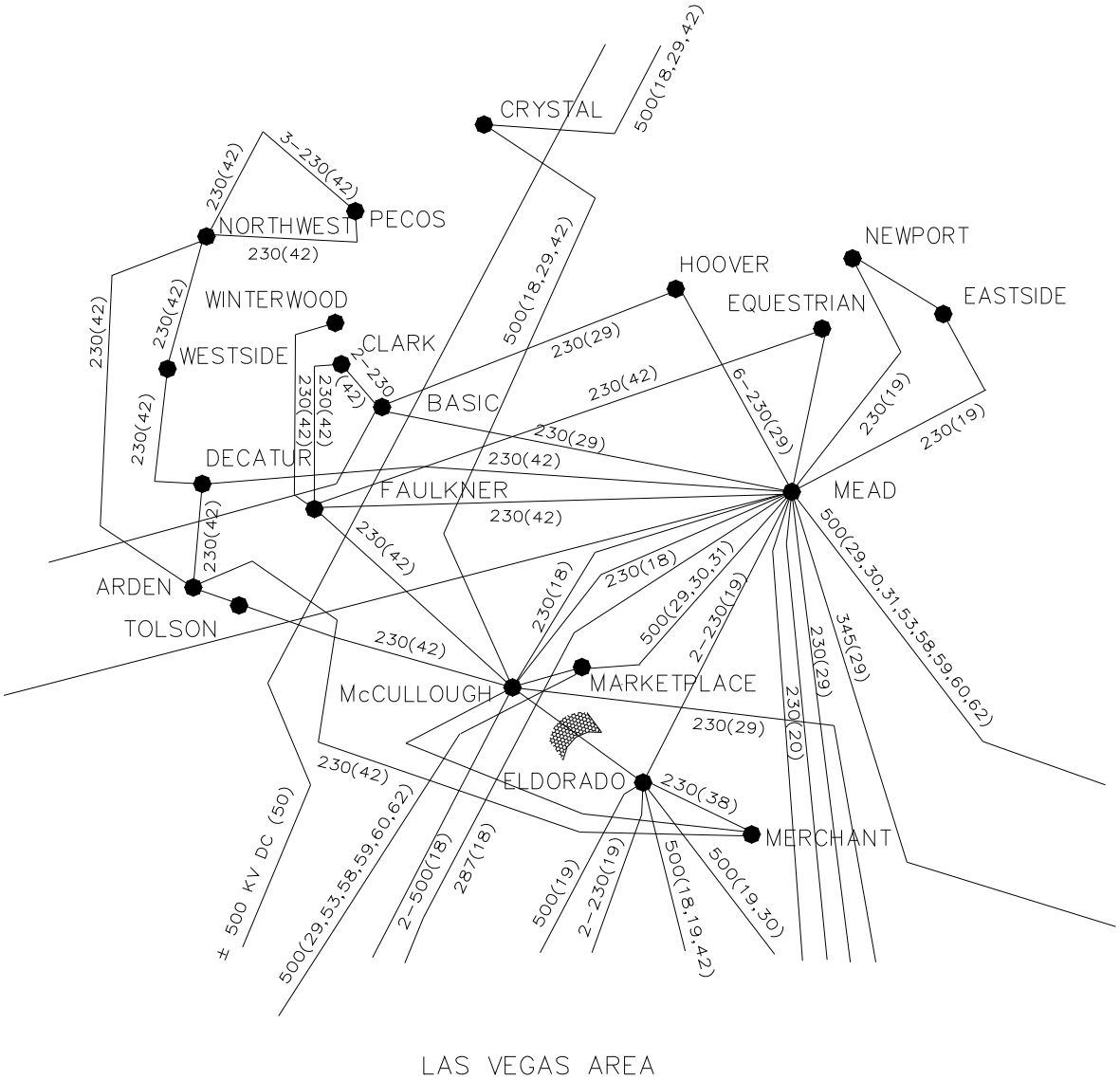


61. Lugo - Victorville 500 kV Line

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	500 kV transmission line from Victorville substation in LDWP's service area to Lugo substation in SCE's service area
Definition:	Line is owned independently from the midpoint of the line to the respective service areas of SCE and LDWP. Metered at Victorville 500 kV substation.
Transfer Limit:	Victorville to Lugo: 2400 MW Lugo to Victorville: 900 MW
Critical Disturbance that limits the transfer capability:	The 2400 MW rating is limited by the loss of the Mohave-Lugo or Eldorado-Lugo 500 kV lines in SCE's service territory. The 900 MW rating is limited due to thermal limitations on Inyokern-Searles 115 kV line under N-0 conditions.
When:	The Victorville-Lugo rating was established in 2001 and the Lugo-Victorville rating was established in 1995.
System Conditions:	Victorville to Lugo flows are high during high IPPDC and high EOR/WOR flows. Lugo to Victorville flows are high with low flows on EOR/WOR and low flows on the IPPDC.
Study Criteria:	WECC Reliability Criteria
Remedial Actions Required:	None
Formal Operating Procedure:	Flows on Victorville-Lugo may be limited depending on flows across the Sylmar auto-transformer banks. A dynamic nomogram has also been put in-place to monitor the actual flows on Eldorado-Lugo, Mohave-Lugo, Palo Verde-Devers and Palo Verde-N. Gila lines such that the outage of any one of these lines will not load the Victorville-Lugo line above the emergency rating of 2600 MVA.
Allocation:	The flows are allocated between LDWP, SCE, Anaheim and Riverside.
Interaction w/Other Transfer Paths:	Flow on this path is dependent on internal generation in SCE, and flows on IPPDC, EOR/WOR, Midway-Vincent 500 kV lines and north of Lugo paths.
Contact Person:	Ly Le Los Angeles Dept. Of Water and Power P. O. Box 111, Room 1246 111 N. Hope Street Los Angeles, CA 90051 (213) 367-0302 (213) 367-3829 - fax ly.le@ladwp.com Patricia L. Arons Southern California Edison P. O. Box 800, Room 460 2131 Walnut Grove Avenue Rosemead, CA 91770 (626) 302-9644 (626) 302-9647 - fax patricia.arons@sce.com

62. Eldorado - McCullough 500 kV Line



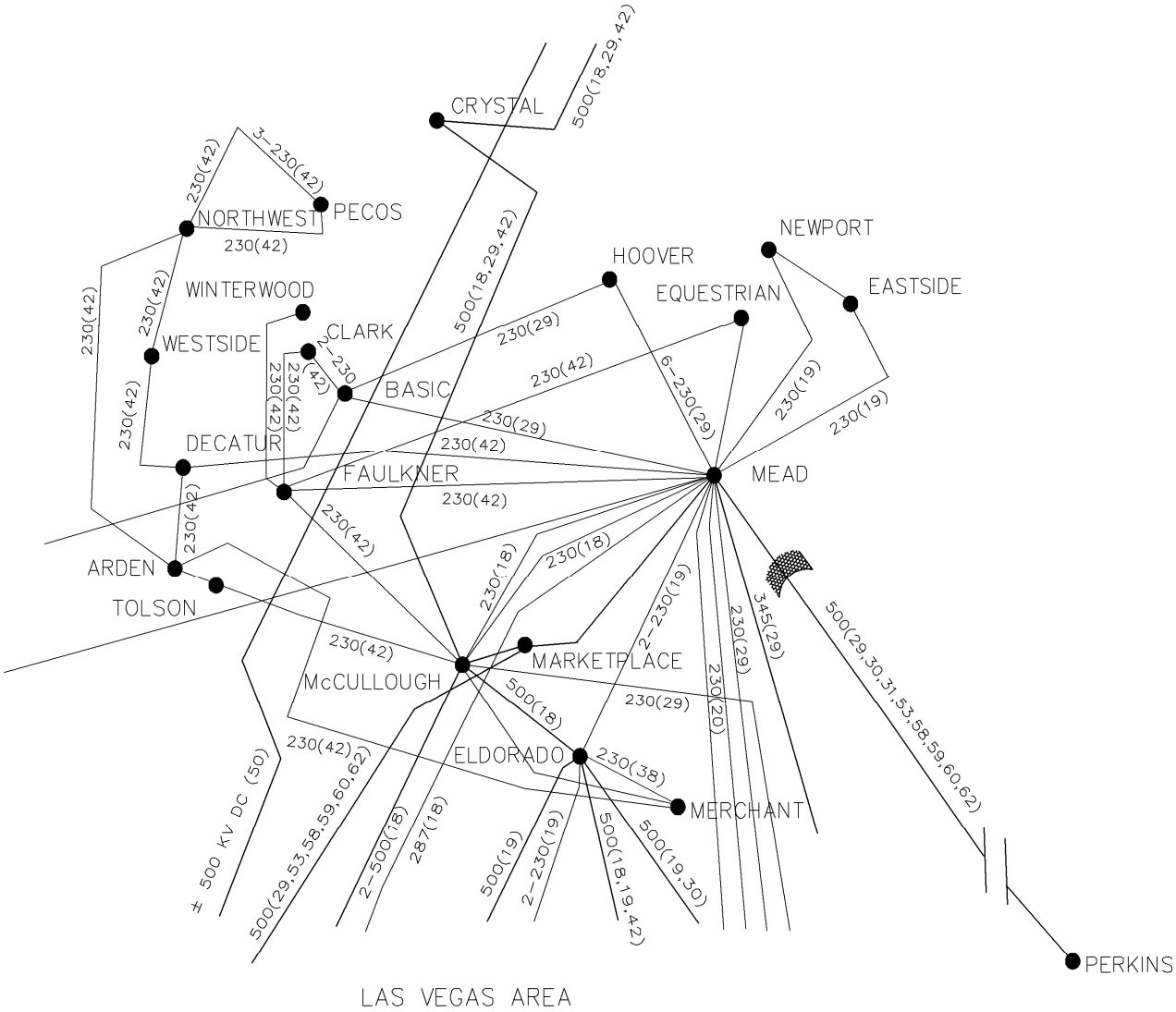
LAS VEGAS AREA

62. Eldorado - McCullough 500 kV Line

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	It is a 0.6 mile long 500 kV transmission line from McCullough substation in LDWP'S service area to Eldorado substation in SCE's service territory
Definition:	The line is owned by LDWP for the purpose of mutual support between LDWP and SCE.
Transfer Limit:	The line is limited to 2598 MVA (3000 Amperes) in either direction.
Critical Disturbance that limits the transfer capability:	The transfer is limited by the continuous rating of circuit breakers at the two substations.
When:	The rating was established in 1970.
System Conditions:	The power flows from McCullough to Eldorado almost all the time. The level of the flow is dependent on generation commitment, EOR/WOR schedules and the lines in service.
Study Criteria:	WECC, LDWP and SCE
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	The flows on the line are allocated between: LDWP, SCE, and cities of Burbank, Glendale, Pasadena, Azusa, Banning, Colton, Vernon, and Riverside.
Interaction w/Other Transfer Paths:	Flow across this line is dependent on unit commitment in southern California, southern Nevada and Arizona and flows across the EOR and the WOR paths.
Contact Person:	Ly Le Los Angeles Dept. Of Water and Power P. O. Box 111, Room 1246 111 N. Hope Street Los Angeles, CA 90051 (213) 367-0302 (213) 367-3829 - fax ly.le@ladwp.com Patricia L. Arons Southern California Edison P. O. Box 800, Room 460 2131 Walnut Grove Avenue Rosemead, CA 91770 (626) 302-9644 (626) 302-9647 - fax patricia.arons@sce.com

63. Perkins - Mead 500 kV Line



63. Perkins - Mead 500 kV Line

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Line from Perkins (Phoenix, AZ area) to Mead substation (Border City,Nevada)
Definition:	The path is redefined to include only the Perkins-Mead 500 kV AC line (Mead-Phoenix Project or MPP) which is 243 miles long with 70% series compensation of the line impedance between Perkins and Mead (35% at Perkins and 35% at Mead). The expedited WECC rating review process on the path redefinition was completed and obtained approval December 12, 2006. The Perkins-Mead line accepted rating is unchanged and remained one of the six components of the EOR path. The Mead-Phoenix Project also includes one 500/230 kV transformer at Mead, two 650 MVA 500 kV phase shifters installed, in parallel, at Perkins. A tie line between Mead and Marketplace and two 387.5 MVAR static var compensators located at Marketplace and Adelanto are jointly owned with the Mead-Adelanto Project (MAP). The Perkins-Mead portion of the line, according to the existing system interconnections, is considered part of the East-of-the-River (EOR) path. The metering point is at the Perkins end.
Transfer Limit:	East to West: Rating of 1300 MW West to East: Not rated The MPP is part of the Path 49 (EOR) transmission path and the redefined Path 63 remains 1300 MW rating even with EOR path rating increase due to its own thermal limitation. The WECC Accepted Rating of the EOR path is increased as reflected by the Path 49 Short Term Upgrade Project: East to West: 8055 MW West to East: Not rated (See "Path 49 EOR" for additional path rating information.)
Critical Disturbance That limits the Transfer Capability:	The critical disturbance is loss of the Palo Verde-Devers 500 kV line which causes the Perkins-Mead 500 kV line to reach the emergency ratings of both the line series capacitors and Perkins 500 kV phase shifters.
When:	For the historical perspective, the 1300 MW MPP rating, in conjunction with the MAP rating, was established in 1993 through the WECC Project Planning Project according with the WECC Interim Procedures for Regional Planning Project Review and Rating Transmission facilities. The PCC's acceptance of the completion of the WECC Project Planning Process and established a WECC Accepted Rating for the EOR path of 7000 MW from 5,700 MW. The 1300 MW incremental increase in the EOR rating is allocated to the MPP owners. The EOR path was further increased to become Accepted Rating 7550 MW in 1996. In 2004, CAISO sponsored Path 49 Short Term Upgrade Project studies within a joint WECC /WATS Review Group that led to approval of the Accepted Rating Report and was granted Accepted Rating of 8055 MW status by the January 10, 2005 letter from the PCC chairman.

	In any case, the study results revealed that the accepted rating of the Path 63 (Perkins-Mead 500 kV line) is still remained for 1300 MW.
System Conditions:	2006 Heavy Autumn conditions. Pre and Post Project benchmark cases were developed in which the EOR and Southern California Import Transmission (SCIT) Nomogram paths were stressed separately until a thermal, stability or post-transient limit was reached. See "East of the Colorado River (EOR)" for additional information on SCIT.
Study Criteria:	NERC/WECC Reliability Criteria for Transmission System Planning
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	Southern California Public Power Authority Anaheim 47 Azusa 3 Banning 3 Burbank 35 Colton 3 Glendale 28 LADWP 74 Pasadena 33 Riverside 12 Salt River Project 236 Arizona Public Service 236 Modesto-Redding-Santa Clara 150 Vernon 28 Western 412 Total 1300 MW
Interaction w/Other Transfer Paths:	See "East of the Colorado River (EOR)."
Contact Person:	John Hernandez Salt River Project P. O. Box 52025 Phoenix, AZ 85072-2025 (602) 236-0969 (602) 302-3896 - fax Johnny.hernandez@srpnet.com

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65. Pacific DC Intertie (PDCI)

65. Pacific DC Intertie (PDCI)

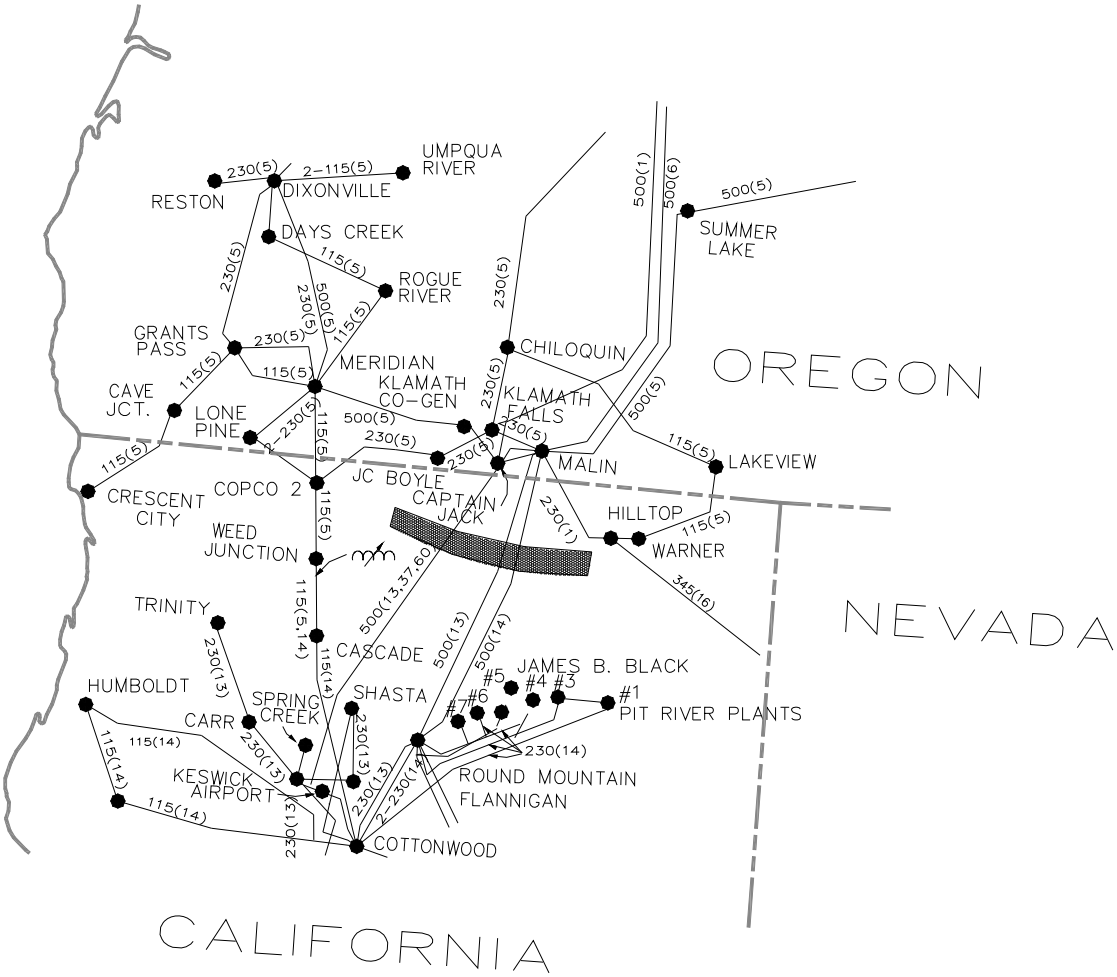
Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Line from Celilo station (Big Eddy area) in northern Oregon to Sylmar station in southern California
Definition:	The PDCI line is a ±500 kV DC multi-terminal system. This system is divided into the northern and southern systems, the demarcation point is the Nevada-Oregon state line border (NOB).
Transfer Limit:	Based on the sending end measured power: Celilo to Sylmar (North to South): 3100 MW Sylmar to Celilo (South to North): 3100 MW
Critical Disturbance that limits the transfer capability:	Loss of the PDCI bipole line.
When:	North to South: The rating upgrade from 2000 MW to 3100 MW was through the DC Expansion Review Group studies performed in 1985-1988 and the 1100 MW Expansion Project progress reports of March 25, 1985 and September 26, 1985. The DC Expansion Review Group was established by a letter to PCC on March 28, 1984. The Expansion Project was put in commercial operation on May 4, 1989. The rating was established by the Los Angeles Department of Water and Power, and the Bonneville Power Administration. South to North: The 3100 MW rating was based on the publication of the "3100 MW South-to-North Pacific DC Intertie Rating" report of July 1992. The rating was established by the Los Angeles Department of Water and Power, and the Bonneville Power Administration, in conjunction with the California Power Pool.
System Conditions:	North to South: The system transfer capability is most sensitive to the power flow level on the COI. High level of northern California hydro on line is also important for voltage support of 3100 MW bipole outage if the static VAR devices in the Northwest and PG&E areas are out of service. South to North: The system transfer capability is sensitive to the south to north power flow levels on the COI, the Midway-Vincent lines, and the east to west transfer levels on the Idaho-Northwest lines (West-of-Borah flows).

Study Criteria:	North to South: System intact: • Series capacitor loading within normal continuous rating on the PG&E's South-of-Tesla lines. Single contingency outage conditions: (bipole outage) • VAR margin of 300 MVAR (subsequently changed to 400 MVAR) and minimum 500 kV voltage of 480 kV in PG&E's system for post-transient conditions. • General WECC reliability criteria. South to North: System intact: • Series capacitor loading within normal continuous rating on the PG&E's South-of-Tesla lines. Single contingency outage conditions: (bipole outage) • With minimum operating voltage profile in Idaho & Northwest areas, VAR margin of 250 MVAR at Idaho's critical bus (generally Midpoint, Borah or Kinport) for post-transient conditions. • Series capacitor loading within emergency thermal rating on the PG&E's South-of-Tesla lines. • WECC reliability criteria. (8/11/87 version)
Remedial Actions Required:	North to South: Generator dropping in the Northwest, and series capacitor fast insertion on the Pacific Intertie AC lines are remedial actions used for partial and full loss of the PDCI intertie. Mechanically switched capacitors (MSC) have been installed in the Northwest and COI systems for post-transient voltage support for loss of the 3100 MW PDCI bipole system. South to North: Load dropping remedial action scheme in the Northwest is implemented for loss of the 3100 MW PDCI bipole system. The Northwest and COI MSCs will also be activated for post-transient voltage support.
Formal Operating Procedure:	North to South: Arming of the generation dropping is performed by Northwest (BPA) by monitoring the actual power flow on the DC line and the available generation for dropping. South to North: Load-dropping in the Northwest is implemented. PDCI power flow monitoring and load dropping arming is performed by the Northwest (BPA).
Allocation:	The percentage ownership and scheduling allocations of the line is as follows: Ownership / Scheduling SCE 50.00 38.22 LADWP 40.00 23.28 San Diego 3.5 PG&E 21.6 Glendale 3.85 3.85 Burbank 3.85 3.85 Pasadena 2.30 2.30 Vernon 3.4

Interaction w/Other Transfer Paths:	North to South: A nomogram showing the relationship between the transfers on the BC Hydro-TransAlta Intertie and the PDCI was developed prior to the completion of COTP. Studies now conducted by BPA indicate that with the COTP in service, no nomogram is required. These new results are in the process of being reviewed. South to North: There is close dependence with the transfer on the Pacific AC Intertie (between Los Banos and Midway) and the Idaho transfer to the Northwest (West-of-Borah).
Contact Person:	Ly Le Los Angeles Department of Water and Power P. O. Box 111, Room 1246 111 North Hope Street Los Angeles, CA 90051 (213) 367-0302 (213) 367-3829 - fax ly.le@ladwp.com

66. COI


UMPQUA RIVER
RESTON
DIXONVILLE
DAYS CREEK
ROGUE RIVER
SUMMER LAKE
GRANTS PASS
CHILOQUIN
MERIDIAN
KLAMATH CO-GEN
KLAMATH FALLS
OREGON
CAVE JCT.
LONE PINE
MALIN
LAKEVIEW
CRESCENT CITY
COPCO 2
JC BOYLE
CAPTAIN JACK
HILLTOP
WARNER
WEED JUNCTION
TRINITY
CASCADE
JAMES B. BLACK
HUMBOLDT
SPRING CREEK
SHASTA
CARR
PIT RIVER PLANTS
KESWICK AIRPORT
ROUND MOUNTAIN
FLANNIGAN
COTTONWOOD
NEVADA
CALIFORNIA

Location:	Between Oregon and northern California
Definition:	<u>Line</u> / <u>Owner</u> / <u>Metered End</u> Malin to Round Mt. 500 kV (2 lines) (Pacific AC Intertie) / Joint / Malin (north end) Captain Jack-Olinda 500 kV line (COTP) / Joint / Captain Jack (north end)
Transfer Limit:	4800 MW North to South 3675 MW South to North
Critical Disturbance that limits the transfer capability:	With north to south transfers, the critical outage is the loss of two Palo Verde units or the DC Bipole outage. The critical outage for the California portion of the COI when transfers are north to south is the south of Table Mt. 500 kV outage (Table Mt. To Tesla and Table Mt. To Vaca-Dixon). With south to north transfers, the critical outages are (1) single line outage of the Captain Jack-Meridian 500 kV line or the PDCI, (2) a double line outage of the Malin-Round Mt. 500 kV lines, and (3) a double line outage of the Ashe-Marion and Buckley-Marion 500 kV lines (this latter outage is limiting with high west-side loads in Oregon). Most of these critical outages were limiting due to voltage stability margin.
When:	The 4800 MW north to south rating was established in 1986 through the WECC Annual Progress Report Procedure. Update reports were submitted each year since through 1992. The 3675 MW south to north limit was established in November 1992.
System Conditions:	Six cases were studied (Heavy Summer; Heavy Spring; Light Winter; PG&E importing; PG&E exporting; BPA spring). • The PDCI is 3100 MW (n-s) in the N-S cases, 2000 MW (n-s) in the PG&E import case and 2000 MW (s-n) in the S-N cases. • Northern California hydro is at 60% in the BPA spring case and 90% in other cases. • Cases were developed showing both 1 and 2 units on line at Diablo for the Spring and Summer. The light winter case had 2 units on line as does the PG&E import case. The PG&E export case has 1 Diablo unit on line.
Study Criteria:	All facilities loaded within normal ratings under normal system conditions. All facilities loaded within emergency ratings under outage conditions. The system meets the WECC voltage stability criteria recommended by TSS. Fully meets WECC reliability criteria in effect at time rating was established. The study's results meet the reliability criteria of all utilities in the Northwest and northern California.

Remedial Actions Required:	Depending on the outage and the magnitude and direction of flow, one or more of the following remedial actions may be used: Northwest generator dropping Chief Jo Brake insertion Fort Rock Series Capacitor insertion Northwest load dropping Feather River generator dropping Northern and central California pump dropping Round Mt 500/230 kV transformer bank opening Series capacitor bypassing on the Olinda-Tracy 500 kV line Series capacitor bypassing on the Malin-Round Mt. #1 and #2 500 kV lines MSC insertion at Malin, Table Mt, Olinda, and/or Tracy 500 kV stations Shunt reactors switching at Olinda and Tracy 500 kV stations NE/SE Separation Scheme Northwest Shunt Reactive Switching
Formal Operating Procedure:	BPA Standing Order 306 and California ISO T-102 (COI/PDCI/North of John Day Nomogram Operation) California ISO T-120 (Adverse Operating Conditions)
Allocation:	Northwest: BPA (58.8%), PacifiCorp (8.3%), PGE (17.7%), NW capacity Owners (15.1%) California: PACI participants (2/3), COTP Participants (1/3)
Interaction w/Other Transfer Paths:	Nomograms are routinely developed to identify simultaneous operating constraints between this path and other paths including: the Pacific DC Intertie (Path 65), North of John Day(Path 73), Montana-Northwest (Path 8), Idaho-Northwest (Path 14), and Reno-Alturas (Path 76).
Contact Person:	California: Kang-Ling Ching, PG&E, Mail Code B15A, P.O. Box 770000, San Francisco, (415) 973-7637, (415) 973-8804 - fax, kxc5@pge.com Phil Sanchez, WAPA, 114 Parkshore Drive, Folsom, CA 95630, (916) 353-4478, (916) 985-6438 - fax, sanchez@wapa.gov Dilip Mahendra, SMUD, MS DB303, P. O. Box 15830, Sacramento, CA 95852, (916) 732-6180, (916) 732-7517 - fax, dmahend@smud.org Northwest: Kyle Kohne (TPP-DITT-2), BPA, 5411 NE Hwy 99, P.O. Box 491, Vancouver, WA 98666-0491, (360) 418-8429, (360) 418-2258 - fax, krkohne@bpa.gov George Hutcherson, PGE, 121 S. W. Salmon Street 3WTC0506, Portland, OR 97204, (503) 464-8027, (503) 464-8178 - fax, george.hutcherson@pgn.com Tom Tjoelker, PacifiCorp, Lloyd Ctr Tower Rm 1800, 825 NE Multnomah, Portland, OR 97232, (503) 813-6887, (503) 813-6508 -fax, tom.tjoelker@pacificorp.com

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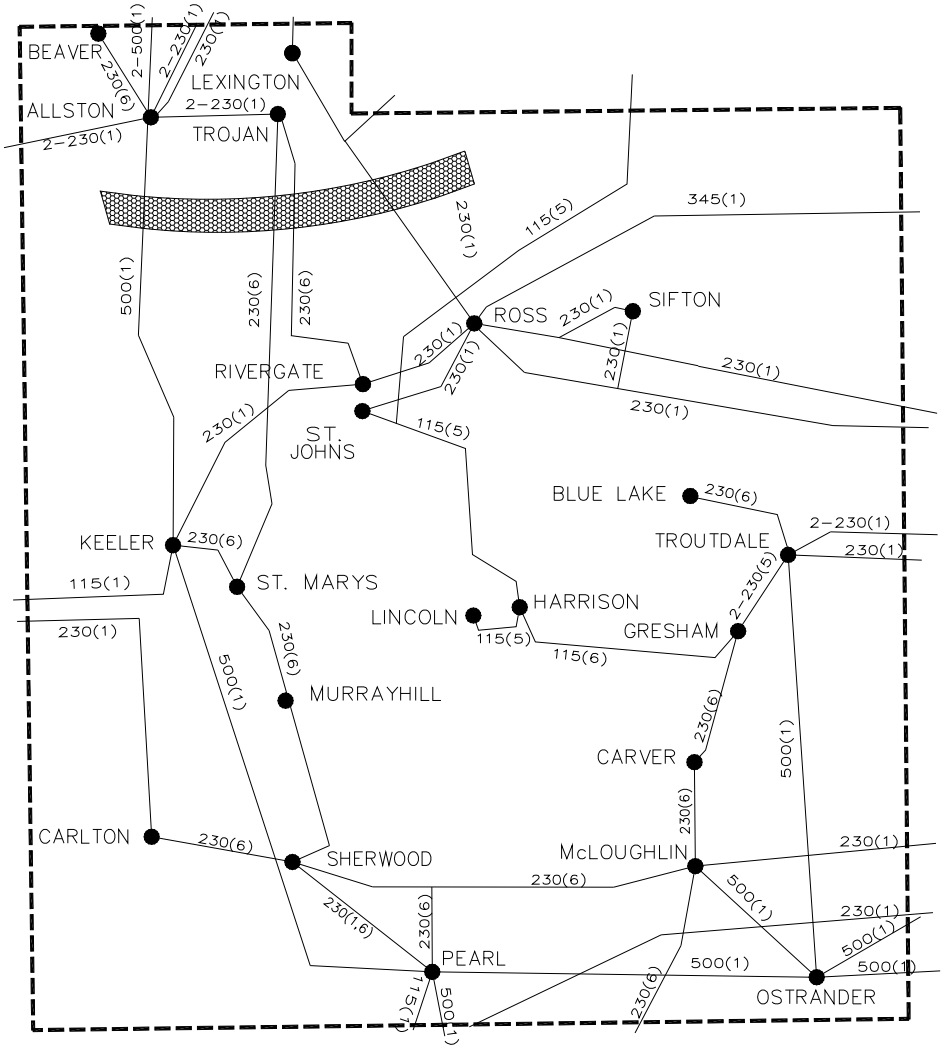
71. South of Allston



PORTLAND AREA DETAIL

71. South of Allston

Accepted Rating ☐
Existing Rating ☐
Other ☒

Location:	Southwestern Washington/Northwestern Oregon
Definition:	Sum of the flows on the following lines: Line — Owner — Metered End Allston-Keeler 500 kV — BPA — Allston Allston-Rainier 115 kV — BPA — Allston Astoria Tap-Seaside 115 kV — PAC — Astoria Tap Merwin-View 115 kV — PAC — Merwin Trojan-Rivergate 230 kV — PGE — Trojan Trojan-St Marys 230 kV — PGE — Trojan Woodland Tap-Ross 230 kV — BPA — Woodland Tap
Transfer Limit:	Current SOL transfer limit is 3430 MW
Critical Disturbance that limits the transfer capability:	Allston-Keeler 500 kV line Keeler-Pearl 500 kV line Trojan-Rivergate 230 kV and Trojan-St Marys 230 kV line Allston-Trojan #1 and #2 230 kV lines Trojan –St Marys 230 kV and St Marys-Keeler 230 kV lines Longview-Lexington #2 230 kV
When:	
System Conditions:	Heavy summer loadings Canada - NW – high north to south flow California - Oregon Intertie – high north to south flow Pacific DC Intertie – high north to south flow Upper Columbia generation high Lower Columbia generation low I-5 Corridor generation high
Study Criteria:	BPA, PGE, PAC and WECC/NERC
Remedial Actions Required:	Generation dropping on available I-5 corridor thermal generation (Chehalis, Big Hanaford and Fredrickson) Generation ramping on Lewis River (Swift and Yale) Generation dropping in B.C. Hydro Generation dropping on Upper Columbia (Coulee and Chief Joseph)
Formal Operating Procedure:	BPA Dispatcher Standing Order No. 309 (updated seasonally)
Allocation:	All of the Capacity is allocated to BPA, PAC and PGE.
Interaction w/Other Transfer Paths:	None

Contact Person:	Kyle Kohne (TOP-PPOC2-2) Bonneville Power Administration 5411 NE Hwy 99 P.O. Box 491 Vancouver, WA 98666-0491 (360) 418-8429 (360) 418-2258 –fax krkohne@bpa.gov George Hutcherson Portland General Electric 121 S. W. Salmon Street, 3WTC0506 Portland, OR 97204 (503)464-8027 (503) 464-8178 – fax george.hutcherson@pgn.com Tom Tjoelker PacifiCorp, Lloyd Center Tower Room 1800 Transmission Planning 825 NE Multnomah Portland, OR 97232 (503) 813-6887 (503) 813-6508 – fax tom.tjoelker@pacificorp.com

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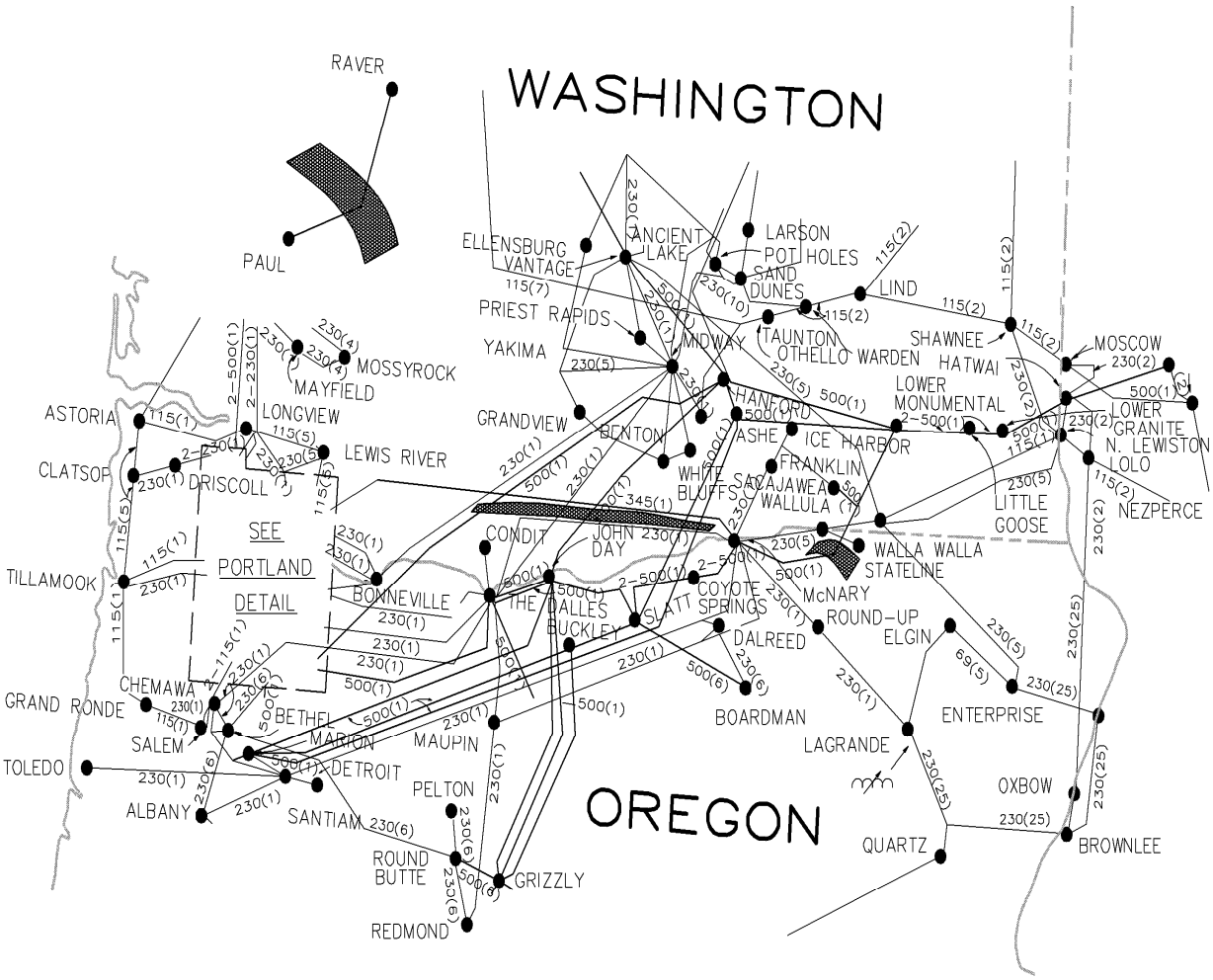
73. North of John Day



73. North of John Day

Accepted Rating ☐
Existing Rating ☐
Other ☒

Location:	Southern Washington/Northern Oregon
Definition:	Sum of the flows on the following lines: Line — Metered End Raver-Paul 500 kV — Raver Wautoma-Ostrander 500 kV — Wautoma Wautoma-John Day 500 kV — Wautoma Ashe-Marion 500 kV — Ashe Ashe-Slatt 500 kV — Ashe Lower Monumental-McNary 500 kV — McNary
Transfer Limit:	8400 MW established in OTC studies
Critical Disturbance that limits the transfer capability:	Two Palo Verde unit loss PDCI Bipole
When:	OTC studies done 2002
System Conditions:	Load: light winter, heavy spring, and heavy summer California-Oregon Intertie (north to south) - 4800 Pacific DC Intertie (north to south) - 3100 MW Coulee generation - 5600 MW - 7000 MW Lower Columbia generation low (spring and summer fish flush levels)
Study Criteria:	All applicable BPA and WECC/NERC criteria.
Remedial Actions Required:	Third AC RAS - Gen Drop at Chief Jo, Coulee, John Day, McNary/Chief Jo Brake. RAS Reactive Switching in the Northwest. FACRI - Fort Rock series capacitors and Malin MSC.
Formal Operating Procedure:	Accepted COI vs NJD seasonal operating nomograms developed by NOPSG for winter, spring, and summer. Refer to BPA Dispatcher Standing Order #306, "COI/NW-Sierra, PDCI, North of John Day nomogram operation with north to south powerflow and NOPSG reports for COI+Alturas/PDCI vs. NJD nomograms.
Allocation:	
Interaction w/Other Transfer Paths:	COI (Path 66) PDCI (Path 65)
Contact Person:	Kyle Kohne (TOP-PPOC2-2) Bonneville Power Administration 5411 NE Hwy 99 P.O. Box 491 Vancouver, WA 98666-0491 (360) 418-8429 (360) 418-2258 - fax krkohne@bpa.gov

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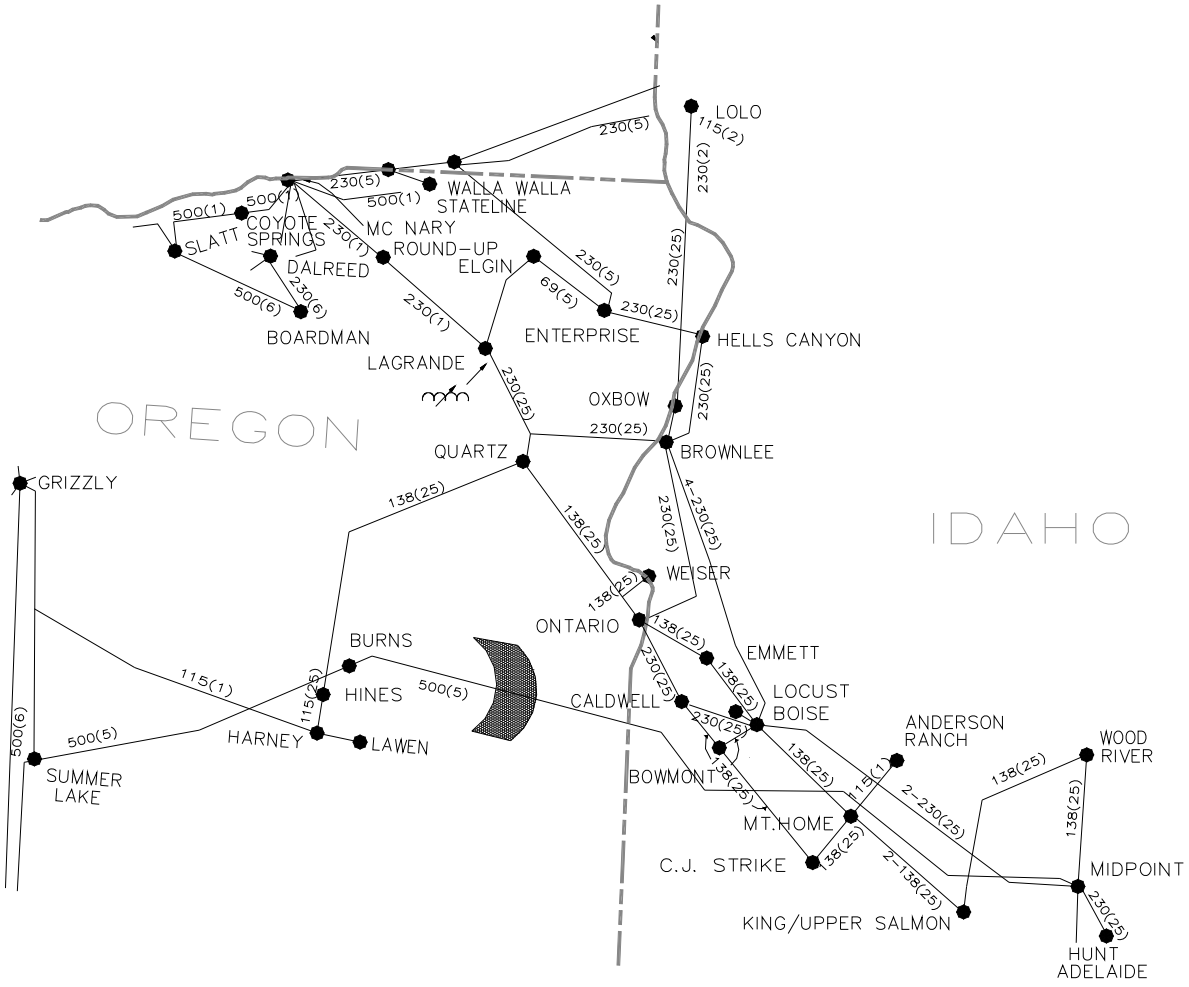
75. Midpoint - Summer Lake



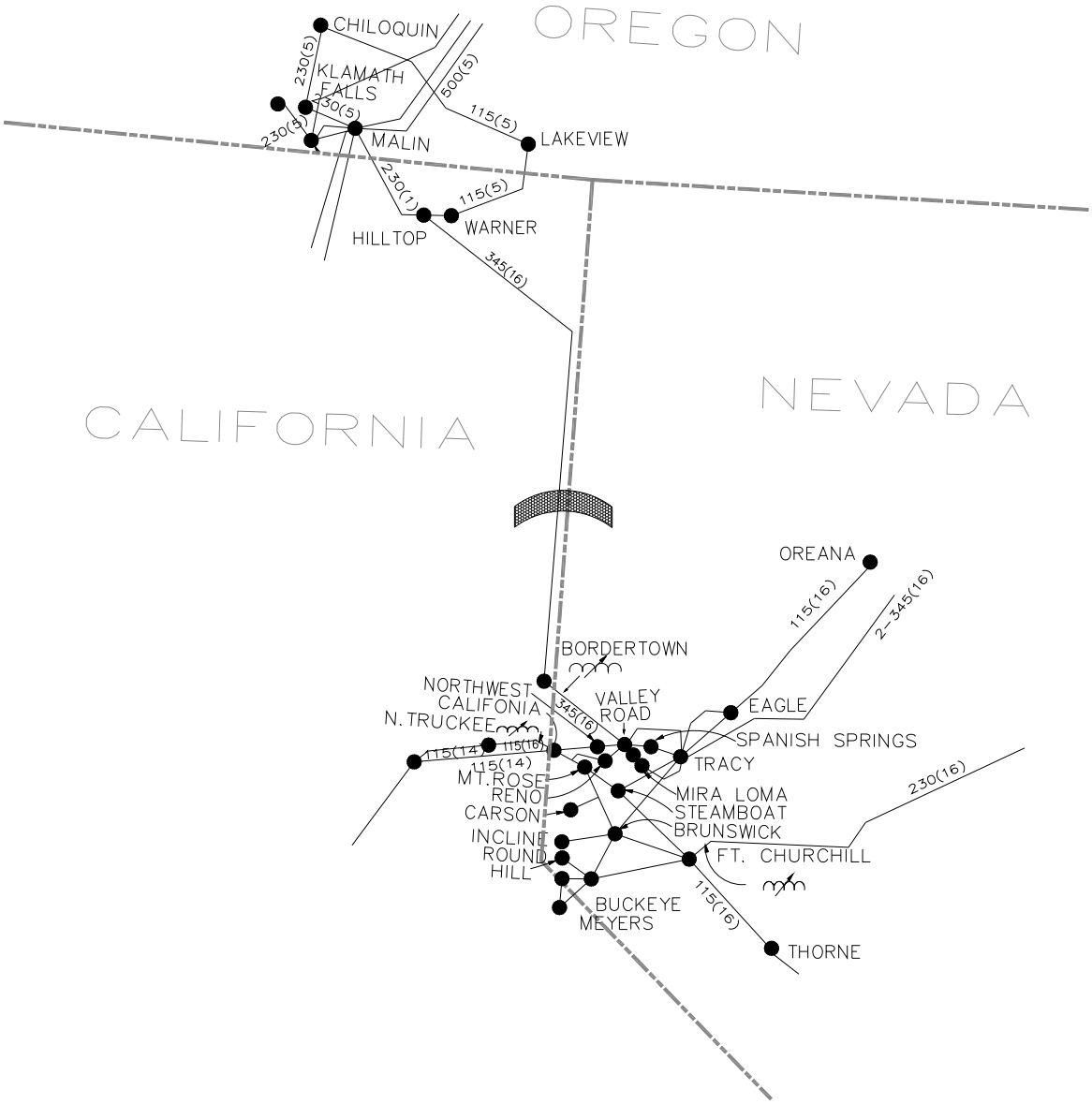
75. Midpoint - Summer Lake

Accepted Rating ☐
Existing Rating ☐
Other ☒

Location:	Southwest Idaho and eastern Oregon
Definition:	Midpoint-Summer Lake 500 kV metered at the Midpoint 500 kV. Note: The path is also within the Idaho-Northwest Path.
Transfer Limit:	East to West: 1500 MW West to East: 400 MW
Critical Disturbance that limits the transfer capability:	East to West: Transient voltage dip at LaGrande, and post-transient voltage at LaGrande and Hines following the loss of the Midpoint-Summer Lake 500 kV line. West to East: The thermal overload of the Lolo-Oxbow 230 kV line is the limiting condition for an outage of the Midpoint-Summer Lake 500 kV line. Under heavy Brownlee to Boise Bench 230 kV line flow, post transient reactive margin at Boise Bench may be more constraining for the loss of the Midpoint-Summer Lake 500 kV line.
When:	The east to west rating is limited by thermal ratings of Midpoint 345/500 kV transformer and series capacitor in the line. It was established along with the 2400 MW east to west rating of Idaho to Northwest path in August, 1989 with the publication of Idaho Power Company to Pacific Northwest Intertie Capacity Study. The WECC Notification Procedures for Changes in Facility Rating and/or Operating Procedures was followed. The east to west rating was conducted jointly by: Bonneville Power Administration (BPA) Idaho Power Company (IPCO) PacifiCorp (PAC) Avista Corp. (AVA) The west to east rating is based on the 1998-2002 OTC (formerly OCSG) Spring Operating Studies.
System Conditions:	The east to west transfer rating was studied with light load conditions in Idaho with heavy eastern thermal resources, and moderate generation on the remaining hydro plants in Idaho. Studies were performed with both north to south and south to north on the PACI and near maximum transfers on parallel paths; i.e., transfers to Northwest and Arizona to California. The west to east transfer rating was studied with high hydro conditions in the Northwest with low to moderate eastern thermal resources. In addition, the west to east rating may not be fully utilized simultaneous with heavy Hells Canyon Complex generation because of steady state thermal overloads and/or post disturbance voltage change in Idaho Power's internal transmission system.
Study Criteria:	WECC Reliability Criteria for Transmission System Planning.

Remedial Actions Required:	Remedial action schemes are required to achieve the 2400 MW east to west transfer capability on the Idaho-Northwest path under which this path is operated. An outage of the Midpoint-Summer Lake 500 kV line requires Jim Bridger unit(s) tripping. Bridger tripping is only needed for the Midpoint-Summer Lake 500kV outage for East-West transfers. No RAS is required for West-East transfers.
Formal Operating Procedure:	Under certain generation and load conditions, 2400 MW Idaho to Northwest transfers, simultaneous with heavy Northwest to California transfers, may cause overloading of the Midpoint-Summer Lake line. During these conditions, one-half of the Burns series capacitors can be bypassed to reduce Midpoint-Summer Lake loading but it results in reduced Bridger West capacity.
Allocation:	The transfer capability of the path is allocated among the interconnections as follows: • 1500 MW East to West 1187 MW PacifiCorp - IPCO Interconnection • 400 MW West to East PacifiCorp
Interaction w/Other Transfer Paths:	Path 75 has an interaction with the Idaho-NW path (Path #14), as the Midpoint-Summer Lake line is part of Path 14. Path 75 also has an interaction with COI, as illustrated by the COI Nomogram which is dependent upon flows on the Midpoint-Summer Lake 500 kV line.
Contact Person:	Gil Coulam PacifiCorp 1407 West North Temple Suite 275 Salt Lake City, UT 84116 (801) 220-2954 (801) 220-2842- fax Gilbert.coulam@pacificorp.com

76. Alturas Project



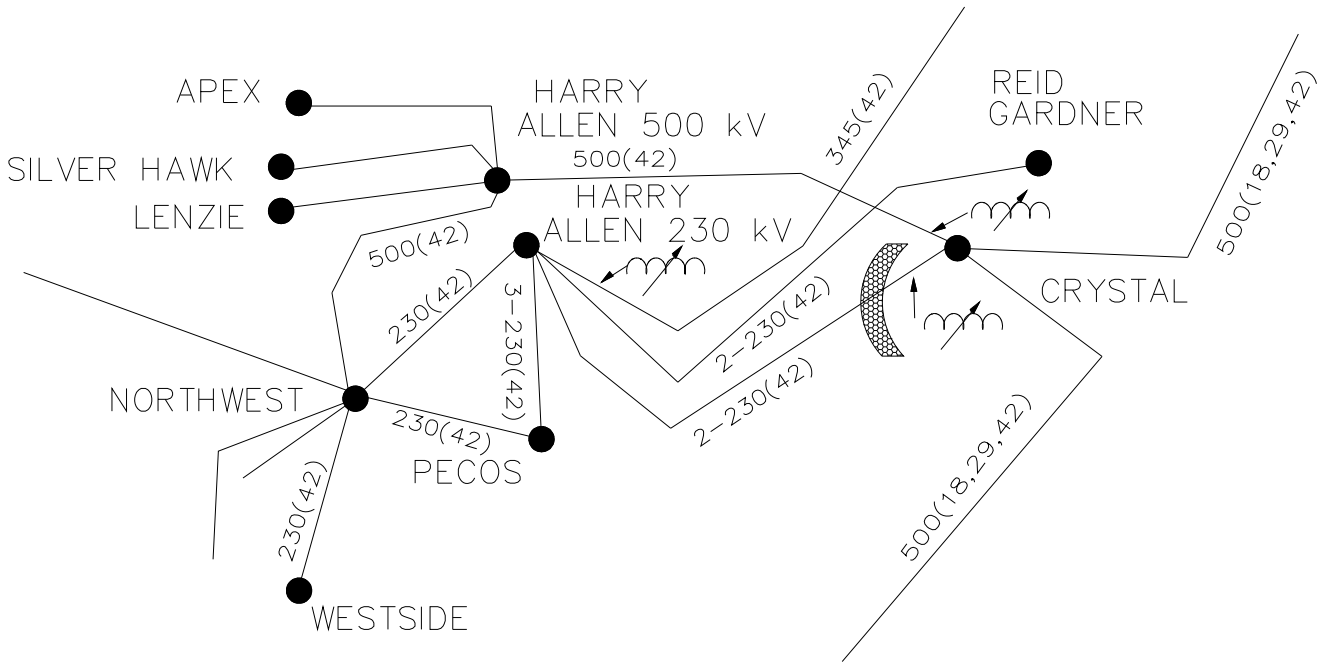
76. Alturas Project

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Line between northeastern California and western Nevada
Definition:	Hilltop (near existing Warner Substation) 230/345 kV-Bordertown 345 kV and Bordertown-N. Valley Road 345 kV. Point of interconnection between Bonneville Power Authority (BPA) and Sierra Pacific Power Company (Sierra) is the Hilltop 230 kV. Metered at Bordertown 345 kV.
Transfer Limit:	North to South: 300 MW South to North: 300 MW
Critical Disturbance that limits the transfer capability:	North to South: Post-disturbance voltage deviation on the Malin-Hill top 230kV system and/or the Warner-Chiloquin 115kV system for a midpoint-Humboldt 345kV outage or an outage of the Malin-Hill Top 230kV line. South to North: Post-disturbance line flows in the Reno 120kV system following a Tracy-Valley Road 345kV outage.
When:	The February 1995 Alturas Project Phase II rating report established the ratings for this project. PCC formally approved these ratings in July of 1995. A Phase II review group was formed in August of 1997 to amend the report's North to South rating due to events that demonstrated limits in transfers in from the Pacific Northwest. This amendment was accepted and approved by PCC in June 1998.
System Conditions:	North to South: The 300 MW rating was determined with heavy Northwest exports to California and heavy loads in the southern Oregon and Sierra areas. South to North: The 300 MW rating was determined with simultaneous heavy transfers consistent with high Pacific Northwest imports for winter loads.
Study Criteria:	WECC Reliability Criteria for Transmission System Planning
Remedial Actions Required:	Direct transfer tripping of the Hilltop-Bordertown 345kV line for loss of the Malin-Hilltop 230kV under certain transfer conditions.
Formal Operating Procedure:	None
Allocation:	Sierra 100%
Interaction w/Other Transfer Paths:	An operating nomogram was developed in the amendment for the Phase II Report that shows safe areas of simultaneous operation between this path and COI. The loads in the Alturas-Chiloquin 115 kV loop affect the north to south capability of this intertie.

Contact Person:	Edi Von Engeln Sr. ENGR. Regional Planning 6100 Neil Road M/S S3B40 Reno, NV 89511 (775) 834-4456 (775) 834-3047 - fax evonengeln@sppc.com

77. Crystal - Harry Allen

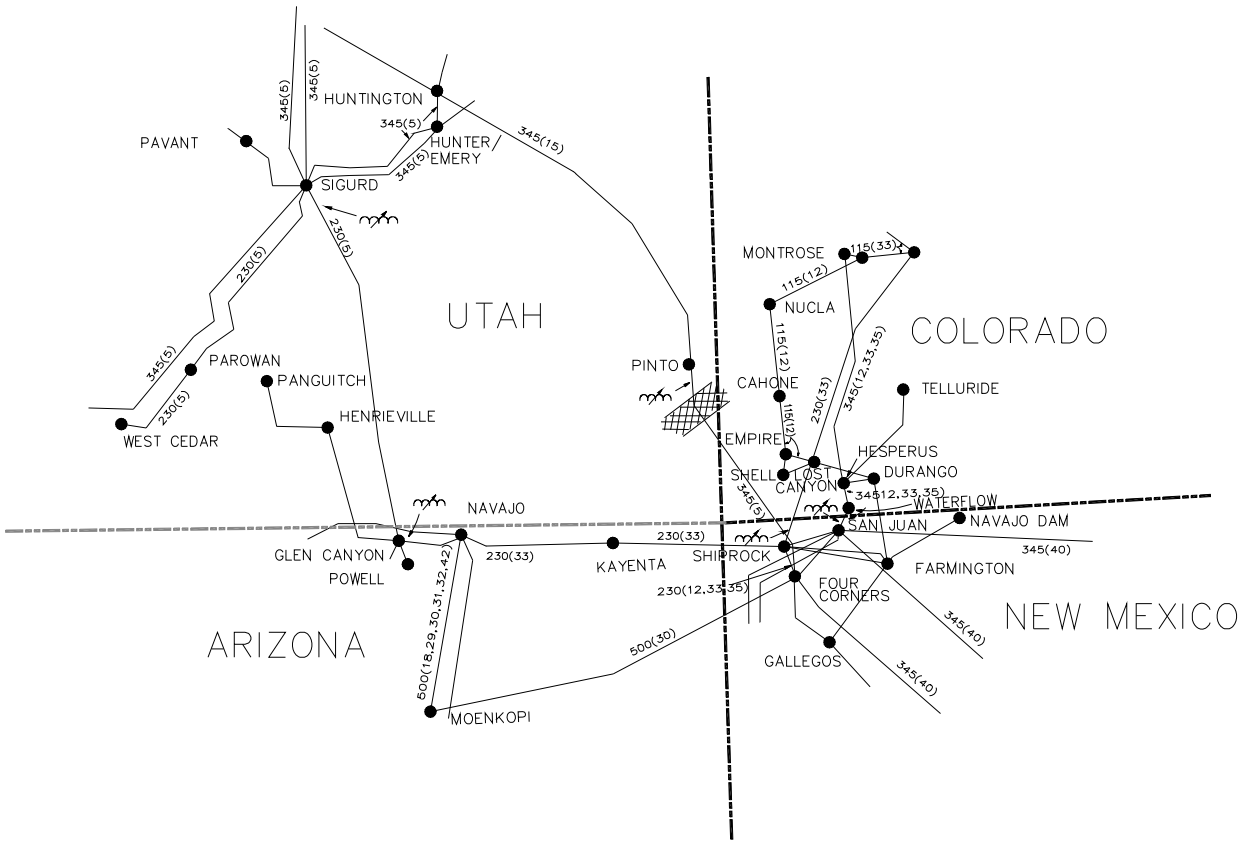


77. Crystal – Harry Allen

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Southern Nevada
Definition:	Sum of the flows on the two 500/230 kV transformer banks at Crystal switching station, metered at the 500 kV bus.
Transfer Limit:	Crystal to Harry Allen: 950 MW Harry Allen to Crystal: Not defined
Critical Disturbance that limits the transfer capability:	Under conditions of maximum transfers from Harry Allen into the Las Vegas Valley (i.e., all resources feeding into the Harry Allen substation at rated capacity - Reid Gardner 1-4, H. Allen 3, Red Butte-Harry Allen 345 kV and Crystal at 950 MW) the Pecos 230/138 kV autotransformers will be loaded to a level where loss of the #3 or #4 bank will load the #1 bank to its emergency rating (275.1 MVA).
When:	The *Crystal Transmission Project Phase 2 Review Group Report* published in February 1999 established the rating for the project. PCC formally approved this rating in April 1999.
System Conditions:	The Crystal-Allen 950 MW rating has been evaluated under peak summer load conditions under maximum southern Nevada imports, and under heavy autumn conditions with maximum EOR or WOR path flows.
Study Criteria:	WECC and Nevada Power Company Reliability Criteria for System Design
Remedial Actions Required:	None
Formal Operating Procedure:	Operating and Clearance Procedures, Nevada Power Company - Crystal Substation 500/230 kV, dated December 7, 1998.
Allocation:	The transfer capability is wholly owned by Nevada Power Company.
Interaction w/Other Transfer Paths:	The Crystal progress report identified an interaction between the EOR and WOR transfer paths. There is also an interaction with the Red Butte-H. Allen 345 kV line (TOT2C path) due to the Crystal and H. Allen phase shifter interrelationship.
Contact Person:	Edi Von Engeln Sr. ENGR. Regional Planning 6100 Neil Road M/S S3B40 Reno, Nevada 89511 (775) 834-4456 (775) 834-3047 - fax evonengeln@sppc.com

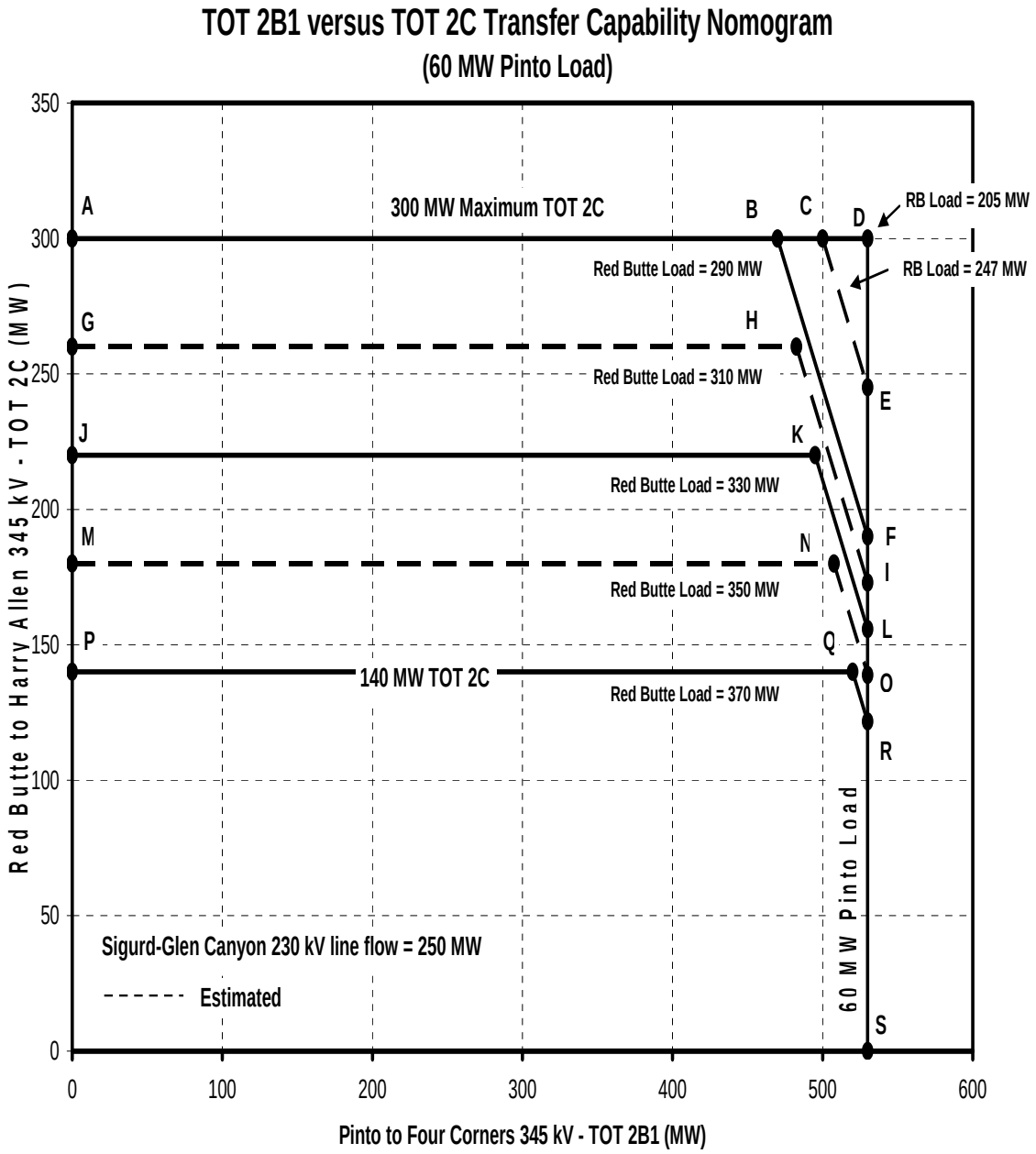
78. TOT 2B1


HUNTINGTON
PAVANT
HUNTER/
EMERY
SIGURD
345(5)
345(15)
230(5)
UTAH
PAROWAN
PANGUITCH
HENRIEVILLE
WEST CEDAR
PINTO
MONTROSE
115(33)
115(12)
NUCLA
COLORADO
CAHONE
230(33)
345(12,33,35)
TELLURIDE
EMPIRE
HESPERUS
SHELL
LOST
CANYON
DURANGO
WATERFLOW
NAVAJO
SAN JUAN
NAVAJO DAM
GLEN CANYON/
POWELL
KAYENTA
SHIPROCK
FARMINGTON
FOUR
CORNERS
NEW MEXICO
ARIZONA
GALLEGOS
MOENKOPI
500(18,29,30,31,32,42)
500(30)
230(12,33,35)
345(40)

78. TOT 2B1

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Southern Utah to N. Arizona/W. New Mexico
Definition:	Pinto-Four Corners 345 kV Line. This line, combined with the Sigurd-Glen Canyon 230 Line, make up the TOT 2B Path. Formerly reported as the combined TOT 2B Path.
Transfer Limit:	North to South (so. end): 530 MW (up to 560 MW with low Pinto load South to North (so. end): 600 MW
Critical Disturbance that limits the transfer capability:	Non-simultaneous: Pre-disturbance voltage at Pinto 345 bus. Simultaneous: Huntington-Pinto-Four Corners 345 line outage, Sigurd-Red Butte-Harry Allen 345 line outage.
When:	Ratings established prior to January 1994. Two 32 MVAR capacitor banks added at Pinto 138 bus in 1999 to compensate for Pinto area load growth.
System Conditions:	Non-simultaneous capability is a function of Pinto load. Moderate flow levels on parallel lines.
Study Criteria:	WECC Reliability Criteria for System Design PacifiCorp Internal Reliability Criteria
Remedial Actions Required:	None.
Formal Operating Procedure:	TOT 2B/2C Nomogram (see attachment) TOT 2 OTC limits.
Allocation:	PacifiCorp
Interaction w/Other Transfer Paths:	TOT 2B2, TOT 2C, IPPDC, PDCI, COI
Contact Person:	William R. Hall PacifiCorp 1407 W. North Temple - Suite 275 Salt Lake City, UT 84116 (801) 220-4274 (801) 220-2842 - fax William.hall2@pacificorp.com

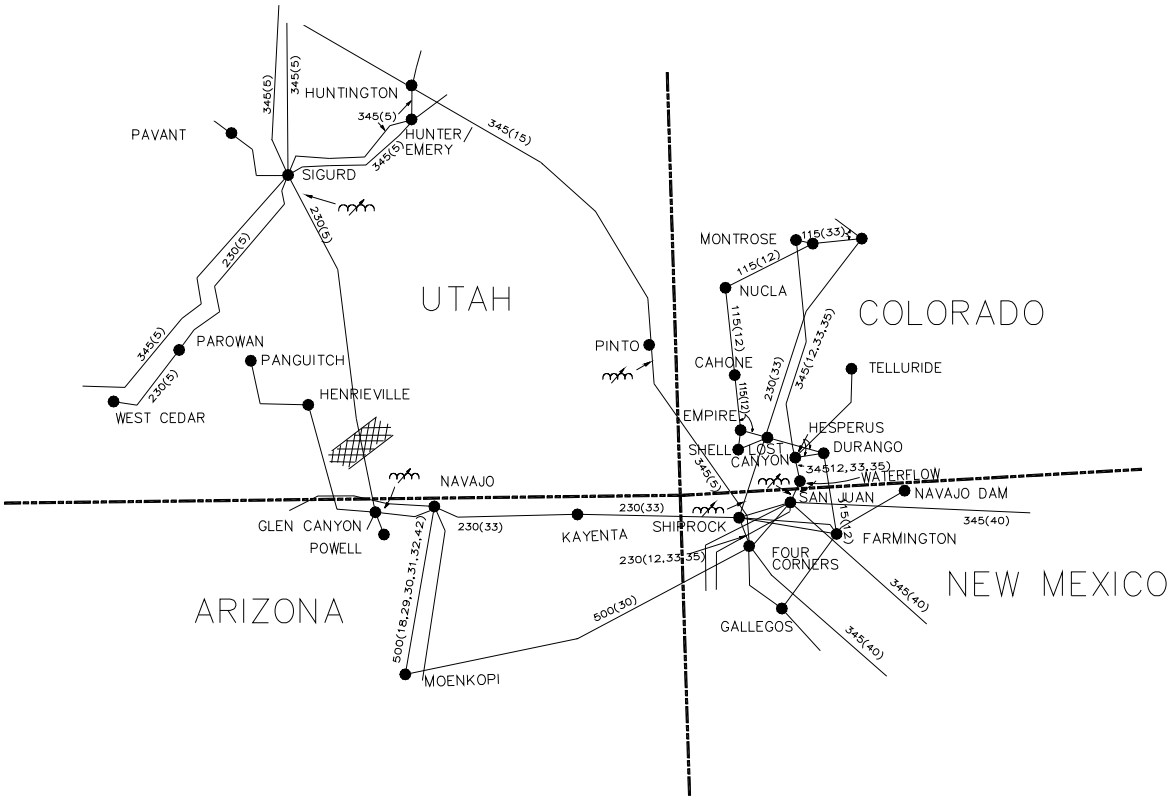


TOT 2B: Pinto-Four Corners* 345
Sigurd-GCanyon* 230
TOT 2C: Red Butte-Harry Allen* 345

Note: This is a representative nomogram. Red Butte load varies from 60 to 210 MW, affecting TOT 2C capability.

*metered end

79. TOT 2B2


HUNTINGTON
PAVANT
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SIGURD
345(5)
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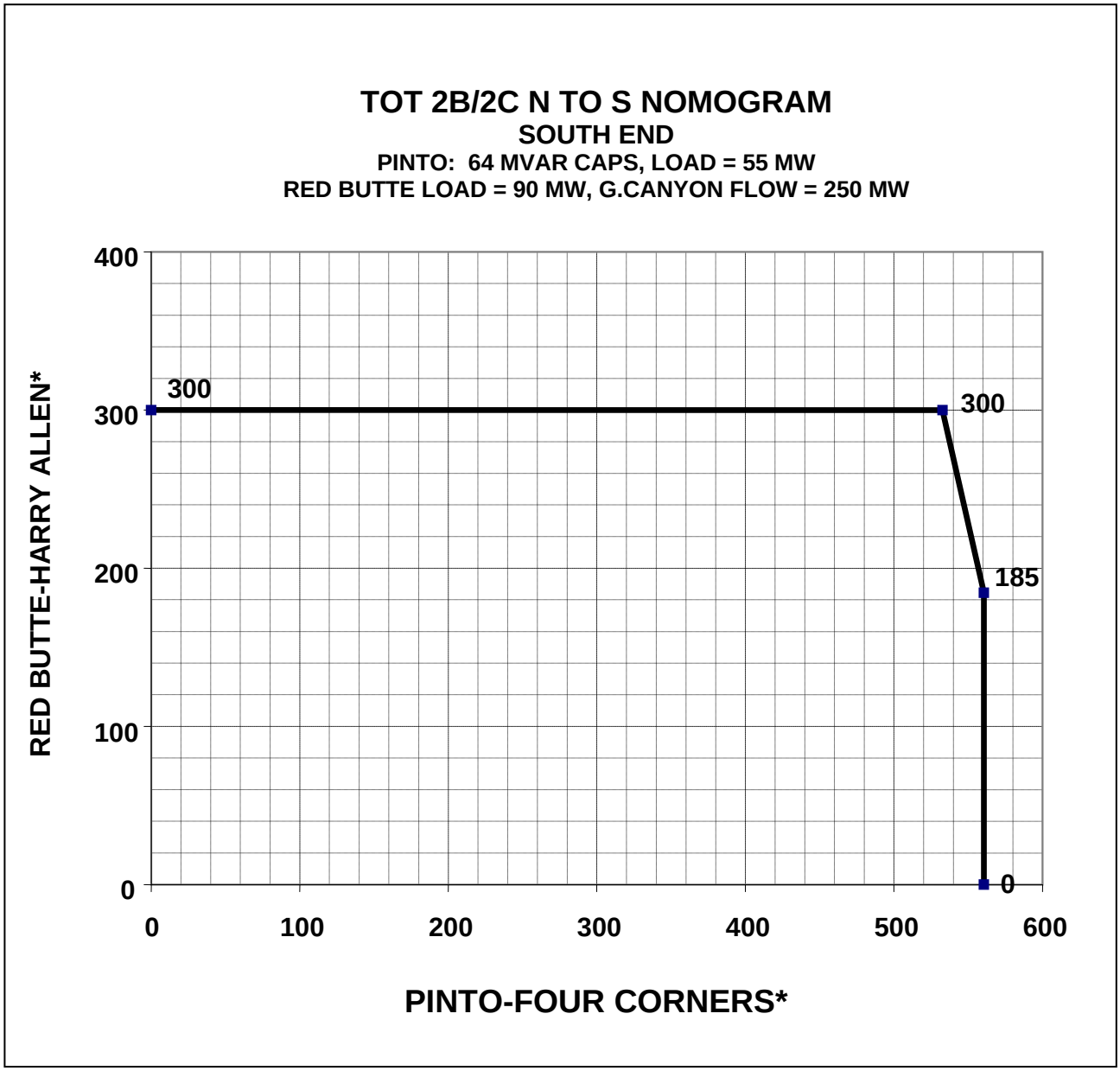
230(5)
UTAH
PAROWAN
PANGUITCH
HENRIEVILLE
WEST CEDAR
PINTO
MONTROSE
115(33)
115(12)
NUCLA
COLORADO
CAHONE
230(33)
345(12,33,35)
TELLURIDE
EMPIRE
HESPERUS
SHELL
LOST
CANYON
DURANGO
WATERFLOW
SAN JUAN
NAVAJO DAM
NAVAJO
GLEN CANYON/
POWELL
KAYENTA
SHIPROCK
FARMINGTON
FOUR
CORNERS
GALLEGOS
NEW MEXICO
ARIZONA
MOENKOPI
500(30)
500(18,29,30,31,32,42)
230(12,33,35)
345(40)

79. TOT 2B2

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Southern Utah to N. Arizona
Definition:	Sigurd-Glen Canyon 230 kV Line. This line, combined with the Pinto-Four Corners 345 kV Line, make up the TOT 2B Path. Formerly reported as the combined TOT 2B Path.
Transfer Limit:	North to South (so. end): 265 MW South to North (so. end): 300 MW
Critical Disturbance that limits the transfer capability:	Non-simultaneous: Normal thermal limit of Sigurd phase-shifting transformer. Simultaneous: Huntington-Pinto-Four Corners 345 line outage, Sigurd-Red Butte-Harry Allen 345 line outage.
When:	Ratings were established prior to January 1994.
System Conditions:	Parallel lines are at moderate levels. This line is limited to 250 MW when parallel lines are heavy.
Study Criteria:	WECC Reliability Criteria for System Design PacifiCorp Internal Reliability Criteria
Remedial Actions Required:	None
Formal Operating Procedure:	TOT 2B/2C Nomogram (see attachment) TOT2 OTC limits.
Allocation:	PacifiCorp
Interaction w/Other Transfer Paths:	TOT 2B1, TOT 2C, IPPDC, PDCI, COI
Contact Person:	William R. Hall PacifiCorp 1407 W. North Temple - Suite 275 Salt Lake City, UT 84116 (801) 220-4274 (801) 220-2842 - fax William.hall2@pacificorp.com

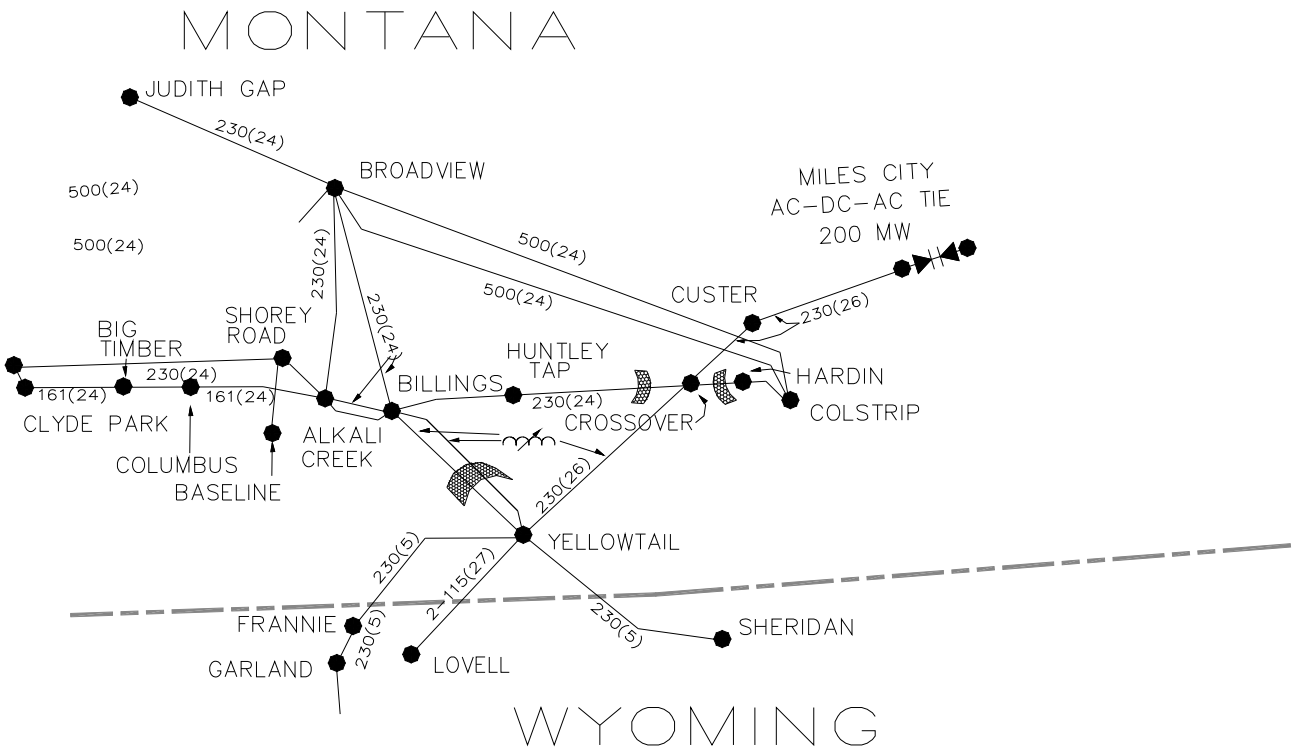


TOT 2B: Pinto-Four Corners* 345
Sigurd-GCanyon* 230
TOT 2C: Red Butte-Harry Allen* 345

*metered end

Note: This is a representative nomogram. Red Butte load varies from 60 to 210 MW, affecting TOT 2C capability.

80. Montana Southeast



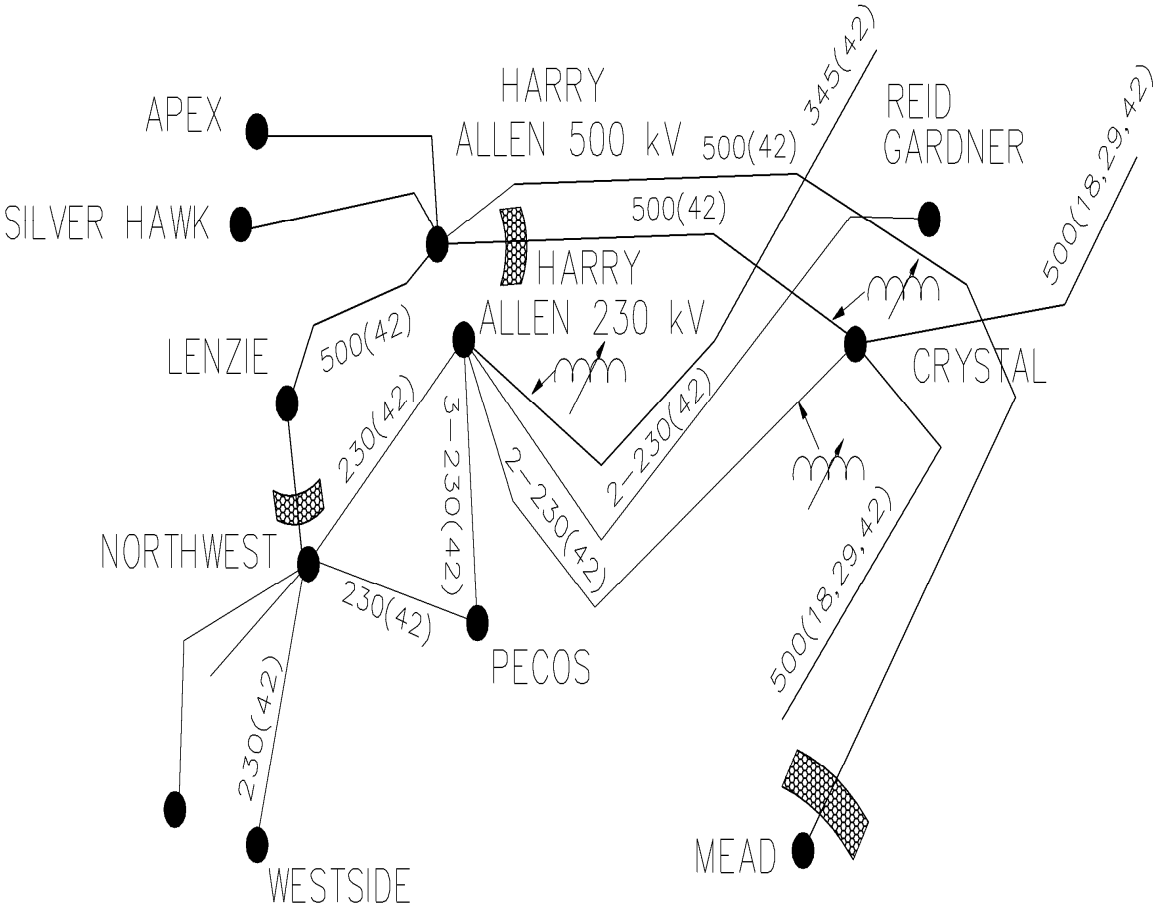
Added February 2005

80. Montana Southeast

Accepted Rating ☐
Existing Rating ☐
Other ☒

Location:	Southeast Montana
Definition:	1. Billings-Yellowtail 230 kV 2. Rimrock-Yellowtail 161 kV 3. Hardin-Crossover 230 kV 4. Huntley-Crossover 230 kV Note: The metered end is underscored.
Transfer Limit:	The path has a rating of 600 MW for both imports and exports from the Montana Control area. The OTC for imports may be much lower depending on Yellowtail generation, Miles City DC tie flow, and loads in Northern Wyoming. The OTC nomogram is published through NOPSG.
Critical Disturbance that limits the transfer capability:	The critical disturbance for imports is a three-phase fault at the Broadview 500 kV bus followed by the loss of both Broadview-Garrison 500 kV lines.
When:	This path rating is based primarily on OTC study work that has been performed since 1999 through the NOPSG committee.
System Conditions:	This path has been studied for all seasons and load conditions. The most important parameters that govern the OTC are Yellowtail generation, Miles City DC tie flow, and loads in Northern Wyoming. There is an operational nomogram for imports.
Study Criteria:	WECC performance criteria are met when the path is operated below the OTC nomogram. The principal criterion that governs the OTC for import is the transient voltage dip criterion.
Remedial Actions Required:	The ATR is in service at all times. This RAS protects for the critical contingency.
Formal Operating Procedure:	NWE (NWMT) operators monitor the MTSE path to assure that it is operated below the OTC nomogram on a real-time basis.
Allocation:	
Interaction w/Other Transfer Paths:	The flow on this path may be constrained by reaching limits on other paths first. Examples of such paths are South of Yellowtail and West of Broadview.
Contact Person:	Charles A. Stigers Northwestern Energy 40 East Broadway Butte, MT 59701 (406) 497-4538 (406) 497-3393 - fax chuck.stigers@northwestern.com

81. Centennial



81. Centennial

Accepted Rating ☒
Existing Rating ☐
Other ☐

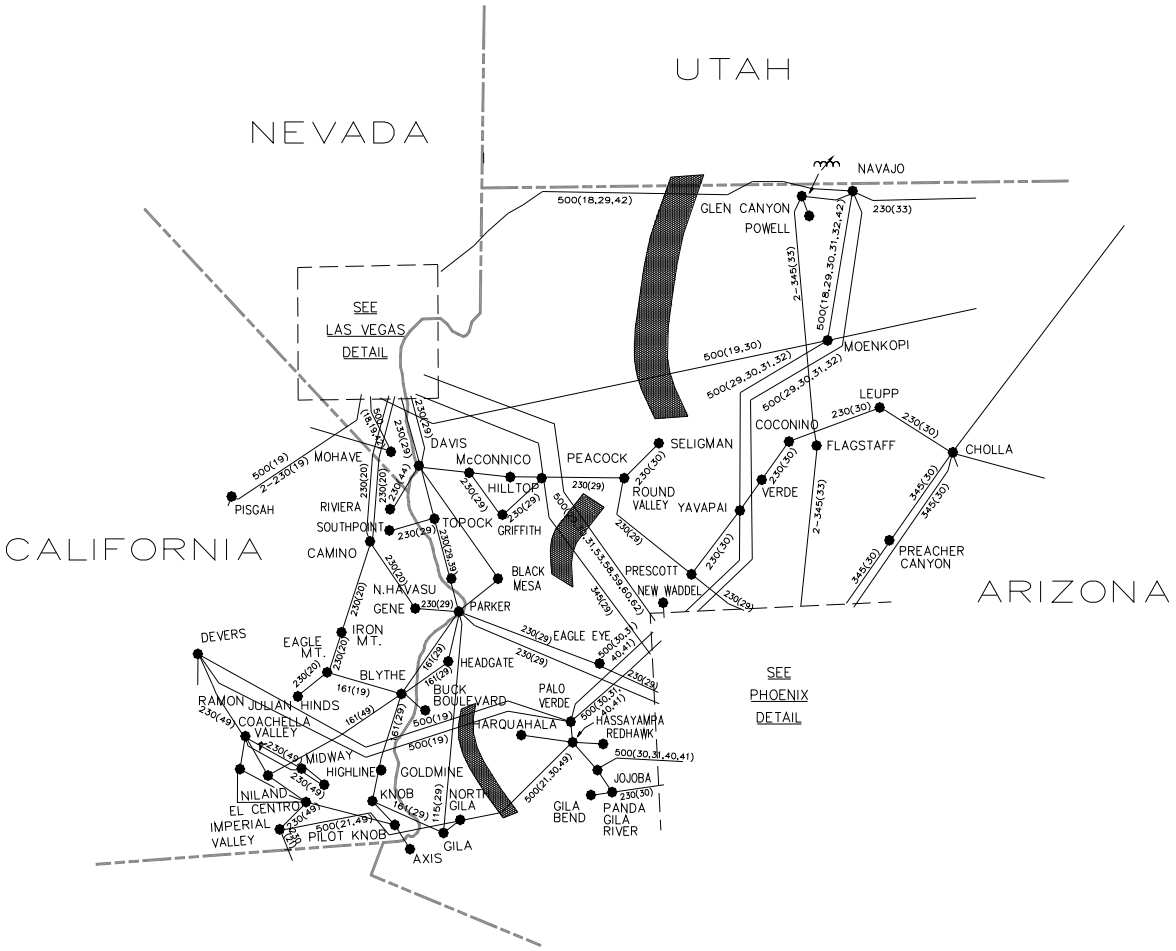
Location:	Southern Nevada
Definition:	Sum of flows on the following three 500 kV lines: Line — Measuring Point Harry Allen-Crystal 500 kV — Harry Allen Lenzie-Northwest 500 kV — Northwest Harry Allen (or future Sunrise tap)-Mead 500 kV — Mead
Transfer Limit:	3000 MW (outbound from Harry Allen)
Critical Disturbance that limits the transfer capability:	For original definition: • The Northwest 500/230 kV autotransformer and/or Crystal 500 kV phase shifters reach their emergency limit during loss of Harry Allen-Mead 500 kV line For redefinition: • Mead-Marketplace 500 kV lines reaches its continuous and emergency limits during loss of Crystal-McCullough 500 kV line or Palo Verde-Devers 500 kV line
When:	The path was defined with *The Centennial Plan: Western Arizona Transmission Studies Task Force Report*, which was approved by WATS in April 2004. PCC approved study work in April 2004 and was given a Phase 3 path rating in May 2004. Redefined in June 2007. Went through the WECC Expedited Review Process in March through May 2007. Approved by WATS in May 2007. PCC and TSS approved this redefinition on July 25, 2007. Centennial Project was completed on April 18, 2007 when KT2A 500/230 kV transformer at Western's Mead 500 kV substation was put in service by WALC (Western). This also signified completion of Phase 3.
System Conditions:	The path rating was evaluated during peak summer loading conditions and light winter loading conditions. In addition, it was also evaluated under heavy autumn conditions with maximum EOR flows, SCIT imports, and southern Navajo flows. For rating acceptance, 3000 MW of generation was modeled at Harry Allen. Five redefinition sensitivity cases have been considered and compared with the benchmark cases (based on the approved by WATS for the original Centennial, EOR and DPV2 Project studies). The cases considered maximum EOR, WOR and "Mead Hub" (includes Mead-Perkins (Path #63) and Mead – Marketplace lines) flows.
Study Criteria:	WECC and Nevada Power Company Reliability Criteria for System Design
Remedial Actions Required:	None
Formal Operating	Operating procedures developed jointly by Nevada Power Company, Western Area Power Administration and the Mead-Phoenix Participants for

Procedure:	interconnection of Harry Allen-Mead 500kV line (HAM). Included defining of the HAM OTC and mitigations to maintain it: usage of Crystal and Perkins PST and tripping of the HAM line
Allocation:	Nevada Power Company: 100%.
Interaction w/Other Transfer Paths:	
Contact Person:	Alex Fratkin Nevada Power Company, MS S3B40 6100 Neil Road Reno, NV 89511 (775) 834-4897 (775) 834-3047 - fax afrantkin@sppc.com

Phase III Projects

III-1. Devers-Palo Verde #2 Path 49 Rating

Revised November 2007



III-1. Devers-Palo Verde #2 (DPV2) Path 49 Rating

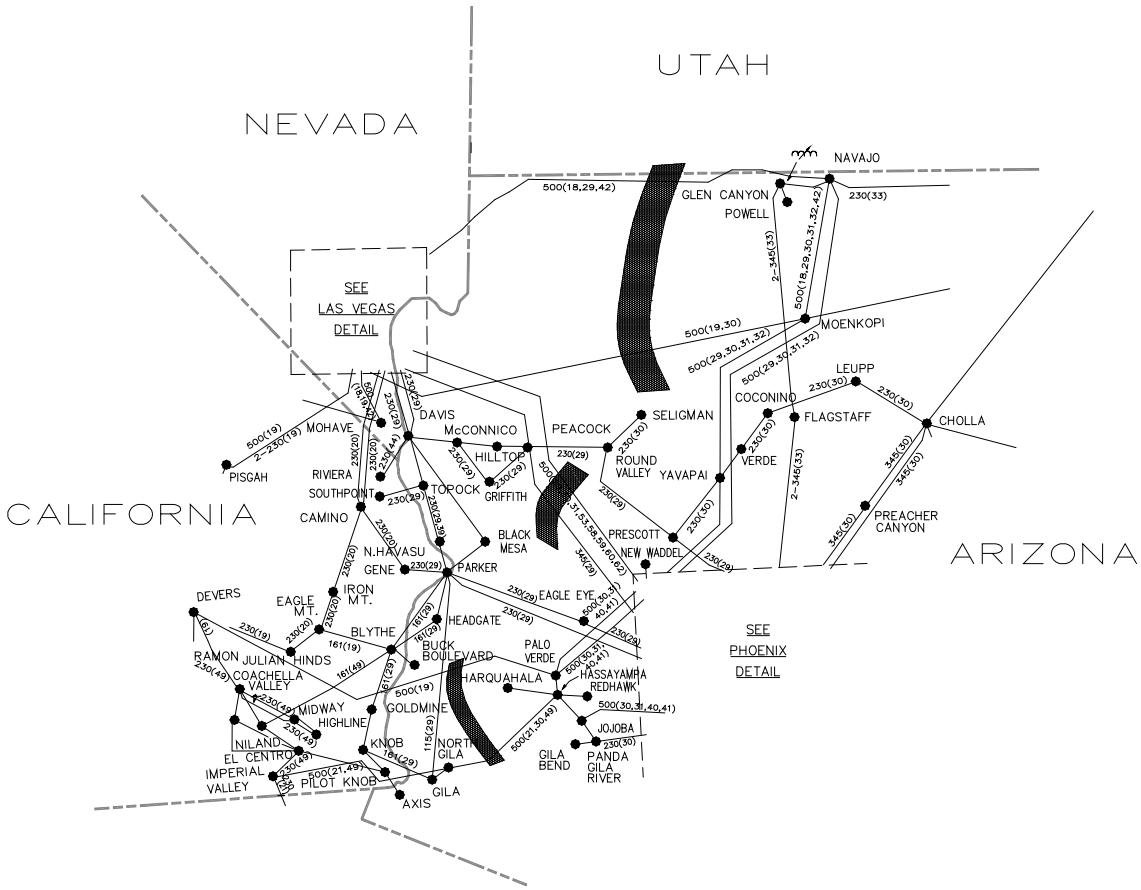
Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Western Arizona
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Navajo-Crystal-McCullough 500 kV — Navajo Moenkopi-Eldorado 500 kV — Eldorado Liberty-Peacock-Mead 345 kV — Liberty Palo Verde-Devers 500 kV — Palo Verde Palo Verde-Devers 500 kV #2 Hassayampa-North Gila 500 kV — Hassayampa Perkins-Mead 500 kV — Perkins
Transfer Limit:	East to West: 9255 MW (Non-simultaneous) West to East: Not rated
Critical Disturbance that limits the transfer capability:	
When:	The non-simultaneous transfer rating was established in 2005 by the Western Arizona Transmission Systems (WATS) Task Force. The Task Force was comprised of members from the following companies: Arizona Public Service Company El Paso Electric Company DOE-Western Area Power Administration Imperial Irrigation District Los Angeles Department of Water and Power Nevada Power Company Public Service Company of New Mexico Salt River Project San Diego Gas and Electric Company Southern California Edison Company Southern California Public Power Authority Tucson Electric Power Company SCE sponsored studies conducted within a WECC Review Group that led to approval of the Accepted Rating Report, and was granted Accepted Rating Status by the August 30, 2005 letter from the PCC Chairman.

System Conditions:	
Study Criteria:	WECC Reliability Criteria for Transmission System Planning
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	
Interaction w/Other Transfer Paths:	The simultaneous transfer limit into southern California is governed by the Southern California Import Transmission (SCIT) Nomogram, and is partly a function of the EOR flow. The SCIT Nomogram varies seasonally and is limited by post transient and transient conditions.
Contact Person:	Steve Mavis Southern California Edison G03-3rd-G10 2131 Walnut Grove Rosemead, CA 91770 (626) 302-8175 (626) 302-9647 - fax steven.mavis@sce.com

III-2 East of the Colorado River 9300 MW Project

Accepted Rating ☒
Existing Rating ☐
Other ☐



III-2. East of the Colorado River 9300 MW Project

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Western Arizona
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Navajo-Crystal-McCullough 500 kV — Navajo Moenkopi-Eldorado 500 kV — Eldorado Liberty-Peacock-Mead 345 kV — Liberty Palo Verde-Devers 500 kV — Palo Verde Hassayampa-North Gila 500 kV — Hassayampa Perkins-Mead 500 kV — Perkins
Transfer Limit:	East to West: Rating of 9300 MW West to East: Not rated The EOR path is currently rated at 8055 MW. In 2004, CAISO sponsored Path 49 Short Term Upgrade Project studies within a joint WECC /WATS Review Group that led to approval of the Accepted Rating Report and was granted Accepted Rating of 8055 MW status by the January 10, 2005 letter from the PCC chairman. The WECC Accepted Rating of the EOR path is further increased to 9300 MW by the EOR 9300 MW Upgrade Project with the thermal upgrade of both the Perkins-Mead and Navajo-Crystal 500 kV line series capacitors.
Critical Disturbance that limits the transfer capability:	The critical disturbance is loss of the Navajo-Crystal 500 kV line which causes the Moenkopi-Eldorado 500 kV line to reach the emergency rating of its line series capacitors.
When:	The non-simultaneous transfer rating was established by the Joint WECC Peer Review Group and Western Arizona Transmission Systems (WATS) Task Force. The WATS Task Force was comprised of members from the following companies: Arizona Public Service Company El Paso Electric Company DOE-Western Area Power Administration Imperial Irrigation District Los Angeles Department of Water and Power Nevada Power Company Public Service Company of New Mexico Salt River Project San Diego Gas and Electric Company Southern California Edison Company Southern California Public Power Authority

	Tucson Electric Power Company SRP sponsored the EOR 9300 EOR Upgrade Project studies conducted within a WECC Review Group that led to approval of the Accepted Rating Report and was granted Accepted Rating Status by the September 12, 2005 letter from the PCC Chairman. Currently, the Project is in the WECC Project Planning and Accepted Rating Phase 3 status. The in-service date is expected to be April, 2009.

System Conditions:	2009 Heavy Autumn conditions. Pre and Post Project benchmark cases were developed in which the EOR and Southern California Import Transmission (SCIT) Nomogram paths were stressed separately until a thermal, stability or post-transient limit was reached. See "East of the Colorado River (EOR)" for additional information on SCIT.
Study Criteria:	NERC/WECC Reliability Criteria for Transmission System Planning
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	
Interaction w/Other Transfer Paths:	The simultaneous transfer limit into southern California is governed by the Southern California Import Transmission (SCIT) Nomogram, and is partly a function of the EOR flow. The SCIT Nomogram varies seasonally and is limited by post transient and transient conditions.
Contact Person:	John Hernandez Salt River Project P. O. Box 52025 Phoenix, AZ 85072-2025 (602) 236-0969 (602) 236-3896 - fax Johnny.hernandez@srpnet.com

III-3 Palo Verde-Devers #2/ Path 46 Rating

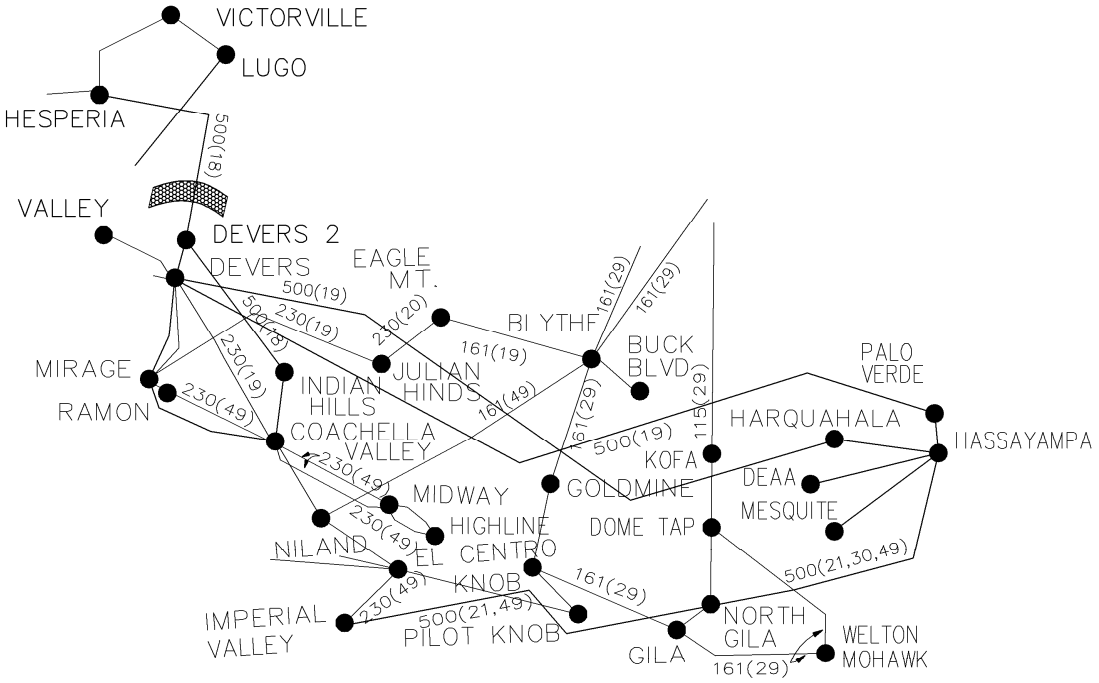
III-3 Palo Verde-Devers #2/ Path 46 Rating

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	The WOR lines interconnect southern Nevada and Arizona to southern California
Definition:	The sum of the flows on the following transmission lines: Line — Metered End (Northern System) Eldorado-Lugo 500 kV — Eldorado Eldorado-Lugo 230 kV lines 1 & 2 — Eldorado Mohave-Lugo 500 kV — Mohave Julian Hinds-Mirage 230 kV — Mirage McCullough-Victorville 500 kV lines 1 & 2 — McCullough Hoover-Victorville 287 kV — Hoover Marketplace-Adelanto 500 kV — Marketplace (Southern System) North Gila-Imperial Valley 500 kV — North Gila Palo Verde-Devers 500 kV — Devers Palo Verde-Devers 500 kV #2 (Underlying System) El Centro-Imperial Valley 230 kV — Imperial Valley Ramon-Mirage 230 kV — Mirage Coachella-Devers 230 kV — Devers
Transfer Limit:	11,823 MW
Critical Disturbance that limits the transfer capability:	Loss of the Palo Verde-North Gila or Palo Verde-Devers 500 kV lines.
When:	By letter dated May 17, 2006, Palo Verde #2, Path 46 Rating was granted Phase III status by the PCC Chair.
System Conditions:	Rating valid under all system conditions.
Study Criteria:	NERC/WECC Reliability Standards
Remedial Actions Required:	None
Formal Operating Procedure:	

Allocation:	
Interaction w/Other Transfer Paths:	
Contact Person:	Steve Mavis Southern California Edison Company G03-3rd-G10 2131 Walnut Grove Rosemead, CA 91770 (626) 302-8175 (626) 302-9647 Fax steven.mavis@sce.com

III-4. Indian Hills-Upland (Green Path North)



III-4. Indian Hills Upland (Green Path North)

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Southern California- Between Imperial Valley and Los Angeles
Definition:	Devers II – Hesperia 500 kV line, metered at Devers II 500
Transfer Limit:	East to West: 1200 MW West to East : Not rated
Critical Disturbance that limits the transfer capability:	None.
When:	The non-simultaneous transfer rating was established by the Joint WECC Peer Review Group and Western Arizona Transmission Systems (WATS) Task Force. The WATS Task Force was comprised of member form the following companies: Arizona Public Service Company El Paso Electric Company DOE-Western Area Power Administration Imperial Irrigation District Los Angeles Department of Water and Power Nevada Power Company Public Service Company of New Mexico Salt River Project San Diego Gas and Electric Company Southern California Edison Company Southern California Public Power Authority Tucson Electric Power Company LADWP Sponsored the Green Path North Project studies conducted within a WECC review Group that led to approval of the Accepted Rating Report. By the WECC PCC Chair's letter dated August 06, 2007, Green Path North Rating was granted Phase III status.
System Conditions:	The rating was studied under 2010 heavy autumn conditions with all lines in service and would be applicable year round.
Study Criteria:	NERC/WECC Transmission Planning Reliability Criteria.

Remedial Actions Required:	None.
Formal Operating Procedure:	None.
Allocation:	TBD
Interaction w/Other Transfer Paths:	None.
Contact Person:	Ly Le Los Angeles Department of Water and Power P.O. Box 111, Room 1246 111 North Hope Street Los Angeles, CA 90051 Phone: (213) 367-0302 Fax: (213) 367-5132 ly.le@ladwp.com

Revised November 2007

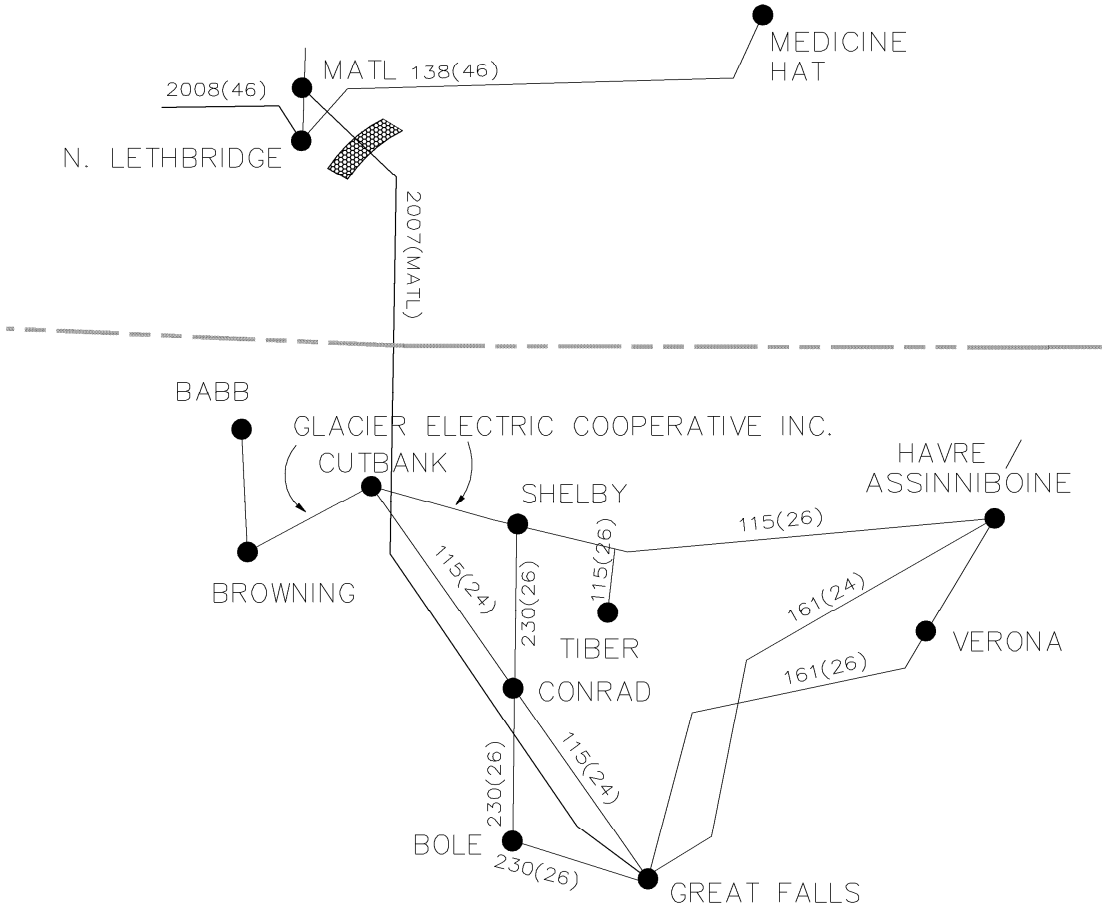
III – 5. Intermountain Power Project DC Line Upgrade

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Line from Intermountain station the central Utah to Adelanto station in southern California (IPPDC)
Definition:	The IPPDC line is a _+500 kVDC bipole system Power flow on the DC line is measure at the Intermountain end.
Transfer Limit:	Intermountain to Adelanto (NE-SW):2400 MW
Critical Disturbance that limits the transfer capability:	Loss of the IPPDC bipole line.
When:	The non-simultaneous transfer rating was established by the Joint WECC Peer Review Group and Western Arizona Transmission Systems (WATS) Task Force. The WATS Task Force was comprised of member form the following companies: Arizona Public Service Company El Paso Electric Company DOE-Western Area Power Administration Imperial Irrigation District Los Angeles Department of Water and Power Nevada Power Company Public Service Company of New Mexico Salt River Project San Diego Gas and Electric Company Southern California Edison Company Southern California Public Power Authority Tucson Electric Power Company LADWP Sponsored the Path 27 Project studies conducted within a WECC review Group that led to approval of the Accepted Rating Report. By the WECC PCC Chair's letter dated October 03, 2007, Path 27 Upgrade Rating was granted Phase III status.
System Conditions:	The rating was studied under 2008 Heavy Summer conditions with all lines in service and would be applicable year round.
Study Criteria:	NERC/WECC Transmission Planning Reliability Criteria.

Remedial Actions Required:	Update the existing The Intermountain Power Project (IPP) Contingency Arming System (CAS) to include the Southwest Utah Wind generation.
Formal Operating Procedure:	The IPPC CAS consists of arming charts where real-time power output of the IPP generation units and the southwest Utah wind generation along with the IPPDC line flows will be used to select the number of IPP units and the southwest Utah wind farm arming of remedial actions.
Allocation:	TBD
Interaction w/Other Transfer Paths:	None.
Contact Person:	Ly Le Los Angeles Department of Water and Power P.O. Box 111, Room 1246 111 North Hope Street Los Angeles, CA 90051 Phone: (213) 367-0302 Fax: (213) 367-5132 ly.le@ladwp.com

III-6. Montana Alberta Tie Line



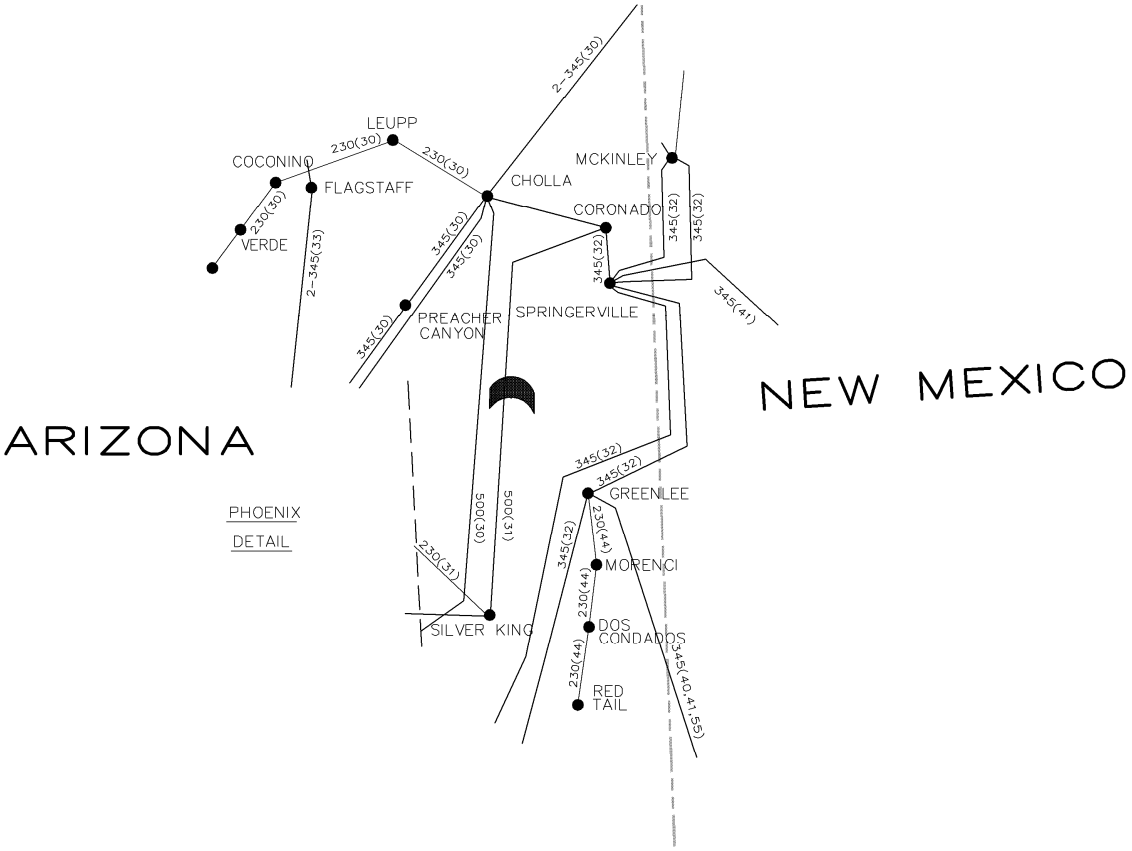
III-6. Montana Alberta Tie Line

Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Between Lethbridge, Alberta and Great Falls, Montana
Definition:	Line / Owner / Metered End MATL 120S-Marias-Great Falls 230 kV / MATL / MATL 120S (north end)
Transfer Limit:	325 MW north to south (metered at MATL 120S) and 300 MW south to north (metered at MATL 120S)
Critical Disturbance that limits the transfer capability:	None. The limit is determined by the steady state thermal rating of the MATL Phase shifting transformer.
When:	Both the North to south and south to north ratings were established on August 28, 2007. This date marked the conclusion of Phase 2 of the MATL WECC Project Rating Review Process.
System Conditions:	Heavy summer and light spring conditions were studied for the non-simultaneous analysis. For the Path 1 simultaneous analysis, only heavy summer conditions were studied. For the Path 3 simultaneous analysis, both heavy summer and light spring conditions were studied. For the Path 8 simultaneous analysis, only light spring conditions were studied.
Study Criteria:	NERC/WECC Planning Standards- April 10, 2003 AESO Transmission Reliability Criteria – Version 0
Remedial Actions Required:	RAS is required to trip the MATL line to prevent out-of-step conditions for the following contingencies: 1. loss of Langdon- Cranbrook 500 kV 2. loss of Cranbrook- Selkirk 500 kV 3. loss of both Selkirk-Ashton Creek and Selkirk- Vaseux Lake 500 kV lines, 4. loss of both Ingledow-Custer 500 kV lines, and 5. loss of both Custer- Monroe 500 kV lines.
Formal Operating Procedure:	A formal operating procedure will be developed prior to project energization. Operating Agreements are under negotiations for the following: Path Operator: Alberta Electrical System Operator (AESO) Control Area Operators: - North of the CAN/US Border-AESO - South of the CAN/US Border- NorthWestern Energy
Allocation:	All capacity is owned by MATL and has been allocated to various parties via a FERC approved open season. Short-term capacity rights may be available on the MATL OASIS. Long term contracts are: • Great Plains Wind and Energy – 120 MW (40%) south bound

	• Energy Logics USA – 180 MW (60%) south bound • Invenergy Wind Montana LLC – 180 MW (60%) south bound • Wind Hunter LLC – 120 MW (40%) south bound
Interaction w/Other Transfer Paths:	Under some conditions, the MATL phase shifting transformer will have insufficient angle range to hold schedules (e.g., high northbound schedules on MATL with medium west bound flows on Path 8, high westbound flows on Path 1, and high southbound flows on Path 3). There are also simultaneous interactions with Path 1, Path 3, and possibly Path 8.
Contact Person:	MATL: Mark Abraham Technical Manager Montana Alberta Tie, Ltd. 800, 615 Macleod Trail S.E. Calgary, AB T2G 4T8 Phone: (403) 264-4465 FAX: (403) 265-1299 mark.abraham@matl.ca www.matl.ca

III-7. Path 54 Uprate (Springerville #4)



III-7. Path 54 Uprate (Springerville #4)

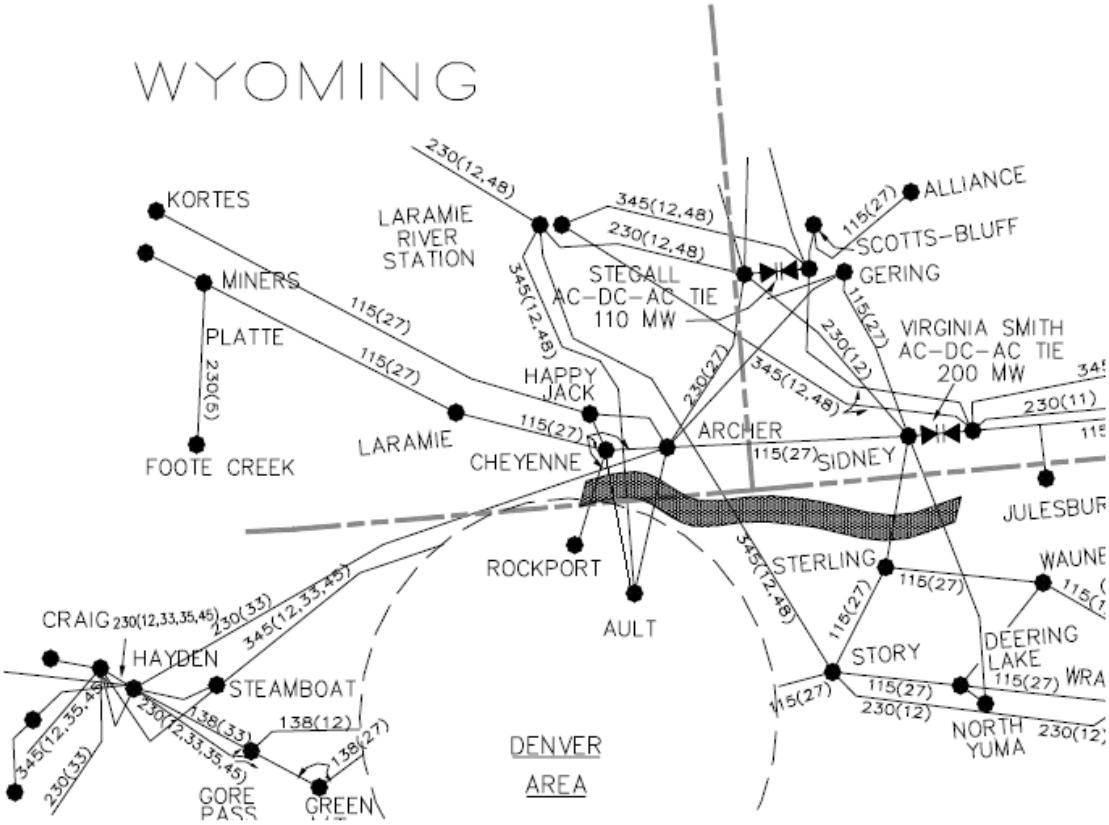
Accepted Rating ☒
Existing Rating ☐
Other ☐

(Tied with Springerville #4 Project-
April 1st, 2009 Transmission Upgrade in-Service)

Location:	Eastern Arizona
Definition:	Power flows on the following transmission line: Line Metered End Coronado-Silver King 500 kV Coronado
Transfer Limit:	Coronado to Silver King: 1494 MW Silver King to Coronado: Not rated
Critical Disturbance that limits the transfer capability:	The critical disturbance is loss of the Coronado-Silver King 500 kV line which causes the Cholla-Preacher Canyon 345 kV line to reach the emergency rating with the Coronado Unit 1 tripping.
When:	On March 12, 2007, Salt River Project (SRP) initiated the Rating Review Process for Path 54 (Coronado-Silver King 500 kV line) with an accepted rating of 1494 MW associated with the addition of Springerville Unit # 4 Phase II status was granted by TSS on June 20, 2007. The Accepted Rating was approved by the PCC Chairman on November 15, 2007.
System Conditions:	2008 Heavy Summer conditions. Pre and Post-Springerville #4 benchmark cases were developed in which the eastern Arizona transmission paths were stressed until a thermal, stability or post-transient limit was reached. However, the accepted rating will be valid under all system conditions.
Study Criteria:	NERC/WECC Reliability Criteria For Transmission System Planning
Remedial Actions Required:	Coronado Unit 1 tripping for the critical outage of the Coronado-Silver King 500 kV line.
Formal Operating Procedure:	Coronado-Silver King line operating procedure # 45407. Additional operating procedures may be required and will be developed in the future date.
Allocation:	Salt River Project
Interaction w/Other Transfer Paths:	Potential interaction with Path 22. If necessary, possible Path 22/ Path 54 operating nomogram limits will be developed.
Contact Person:	John Hernandez e-mail address: Salt River Project Johnny.hernandez@srpnet.com P.O. Box 52025 Phoenix, AZ 85072-2025 Phone: (602) 236-0969 FAX: (602) 236-3896

Revised November 2007

III-8. Path 36 Upgrade (Miracle Mile – Ault 230 kV Transmission Line)



Created on 10/30/07
Home
2010 HS WJQS Base Case
w/ MM-AU 230-kV Project
RWD 347 MW GROSS

TABLE 1-1A: TOT3 SYSTEM INTACT LIMITS

2010 Heavy Summer
CPP: 66 MW

	300 MW East to West	DC TIES 0 MW	300 MW West to East
LRS 1140 MW (Net) Pawnee 777 MW (Net)	a32 **TOT3 = 1680 MW** (Outage of Lar.Rivr-Story 345-kV line loaded Lar.Rivr-Ault 345-kV line to 100 % of 956 MVA rating)	b42 **TOT3 = 1543 MW** (Outage of Lar.Rivr-Ault 345-kV line caused Laramie 115-kV bus voltage to drop to 0.90 p.u.)	c31 **TOT3 = 1239 MW** (Outage Stegall-Sidney 230-kV line loaded Gering-McGrew 115-kV line to 100% of its 109 MVA rating)
LRS 570 MW (Net) Pawnee 777 MW (Net)	d38 **TOT3 = 1332 MW** (Outage of Snowy Range-Cheyenne 230-kV line loaded Snowy Range-Gem City Tap 115-kV line to 100 % of its 133 MVA rating)	e34 **TOT3 = 1123 MW** (Outage of other MBPP unit would not solve for TOT 3 transfers in excess of this limit)	f28 **TOT3 = 886 MW** (Outage Lar.Rivr-Dave Johnson 230-kV line loaded Dave Johnson-Stegall 230-kV line to 100% of its 319 MVA rating)
LRS 1140 MW (Net) Pawnee 280 MW (Net)	g11 **TOT3 = 1510 MW** (Outage Sidney-Spck loaded Peetz-Sterling 115-kV to 100% of normal 109 MVA rating)	h29 **TOT3 = 1603 MW** (Outage of Lar.Rivr-Story 345-kV line loaded Lar.Rivr-Ault 345-kV line to 100 % of 956 MVA rating)	i2 **TOT3 = 1088 MW** (Outage Stegall-Sidney 230-kV line loaded Gering-McGrew 115-kV line to 100% of its 109 MVA rating)
LRS 570 MW (Net) Pawnee 280 MW (Net)	j10 **TOT3 = 1188 MW** (Outage Sidney-Spck loaded Peetz-Sterling 115-kV to 100% of normal 109 MVA rating)	k22 **TOT3 = 1154 MW** (Outage of other MBPP unit would not solve for TOT 3 transfers in excess of this limit)	l10 **TOT3 = 790 MW** (Outage Stegall-Sidney 230-kV line loaded Gering-McGrew 115-kV line to 100% of its 109 MVA rating)

jgriffit@wapa.gov | Case Summary Report | Calculate New TOT3 Limits | WECC's "Accepted Rating" is <=1605 MW

III-8. Path 36 Upgrade

Revised November 2007

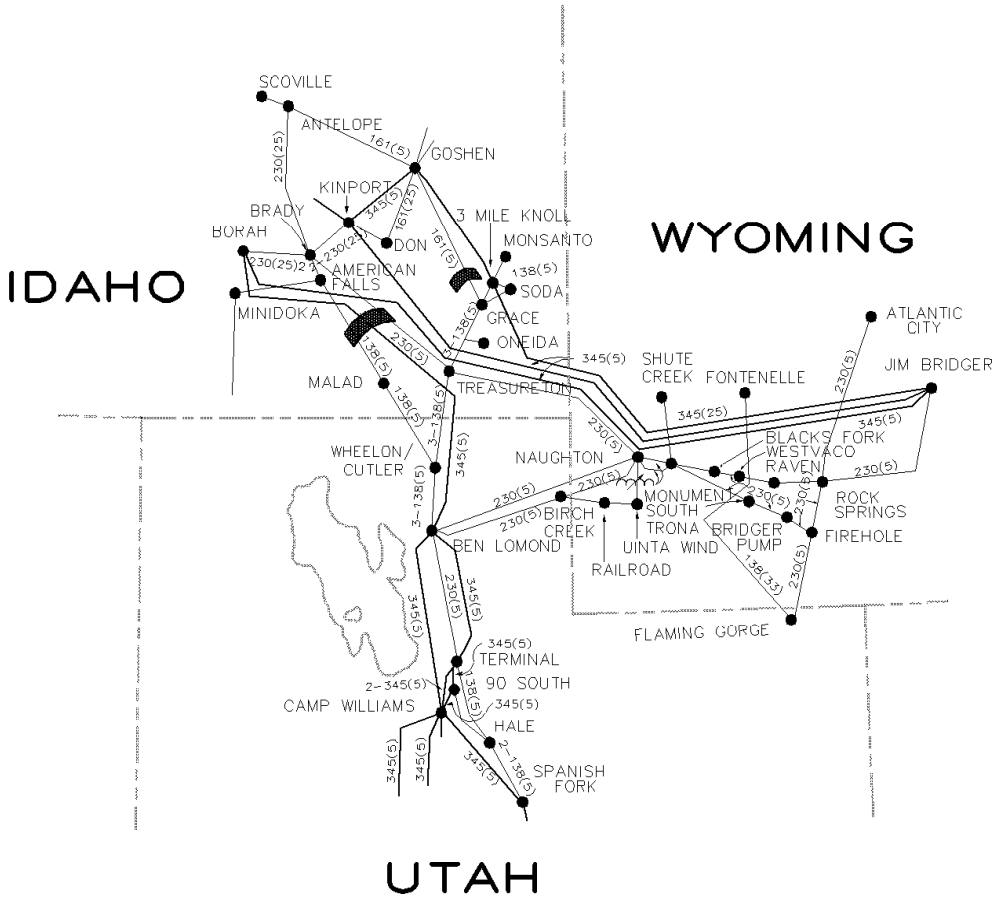
(Miracle Mile – Ault 230 kV Transmission Line)

Accepted Rating ☐
Existing Rating ☐
Other ☒

Location:	Border between Northeast Colorado and Southeast Wyoming
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Archer-Ault 230 kV — Archer Laramie River-Ault 345 kV — Laramie River Laramie River-Story 345 kV — Laramie River Cheyenne-Owl Creek 115 kV — Cheyenne Sidney-Sterling 115 kV — Sidney Sidney-Spring Canyon 230 kV — Sidney Cheyenne-Ault 230 kV — Cheyenne
Transfer Limit:	North to South: 1680 MW (Maximum Proposed) South to North: Not definded Depending on local generation levels, DC tie levels and direction, the real-time rating can range between a maximum of 1680 MW and a minimum of 790 MW. Typically, the real-time rating is calculated dynamically and updated every minute based on Table 1-1A.
Critical Disturbance that limits the transfer capability:	The critical disturbances and limiting elements vary with the various scenarios. Reference Table 1-1A for further information.
When:	Rating was first established in 1981. The proposed rating of 1680 MW is currently under review by a Project Review Group consisting of members from the following entities: Basin Electric Power Cooperative Black Hills Power & Light PacifiCorp Pascoe energy Platte River Power Authority Tri-State Generation & Transmission Inc. Public Service company of Colorado Utility System Efficiencies Inc. Western Area Power Administration

	Wyoming Infrastructure Authority
System Conditions:	This rating is independent of transfer levels between major areas of WECC. The transfer limit is impacted by local area generation and the direction and magnitude of DC tile flows. Historically, the flows have all been north to south across the path. Under certain operating conditions when TOT 3 is loaded to its limit, the TOT 5 capability cannot be used since additional schedule on TOT 5 will overload TOT 3.
Study Criteria:	(Summary) System Intact Per unit voltages between 0.95 p.u. and 1.05 p.u. All lines and transformers loaded to less than continuous rating. Single contingency outage conditions Per unit voltages between 0.90 p.u. and 1.10 p.u. All lines loaded to less than 15-minute emergency ratings. All transformers loaded to less than 30-minutes emergency ratings. Transient voltage swings down to 0.70 p.u. permitted.
Remedial Actions Required:	Remedial actions are required to achieve the rated transfer capability. Following an outage, all overloaded lines and transformers must have their loadings reduced schedules and adjusting generation.
Formal Operating Procedure:	There is a formal operating procedure dated November 1999. WAPA-Loveland is the operating agent and uses real-time flows to monitor the path.
Allocation:	The transfer capability of the path is divided between WAPA, Missouri Basin Power Project (MBPP), Public Service Company of Colorado (PSC), and Tri-State Generation & Transmission (TSGT). TSGT and BEPC are members of MBPP
Interaction w/Other Transfer Paths:	None.
Contact Person:	M. Jared Griffiths Western Area Power Administration Rocky Mountain Region P.O. Box 3700 Loveland, CO. 80538-3003 (970)461-7603 (970)461-7423 fax jgriffit@wapa.gov

III-9. Path C Upgrade
(Populus-Terminal Transmission Project)



III-9. Path C Upgrade

(Populus-Terminal Transmission Project)

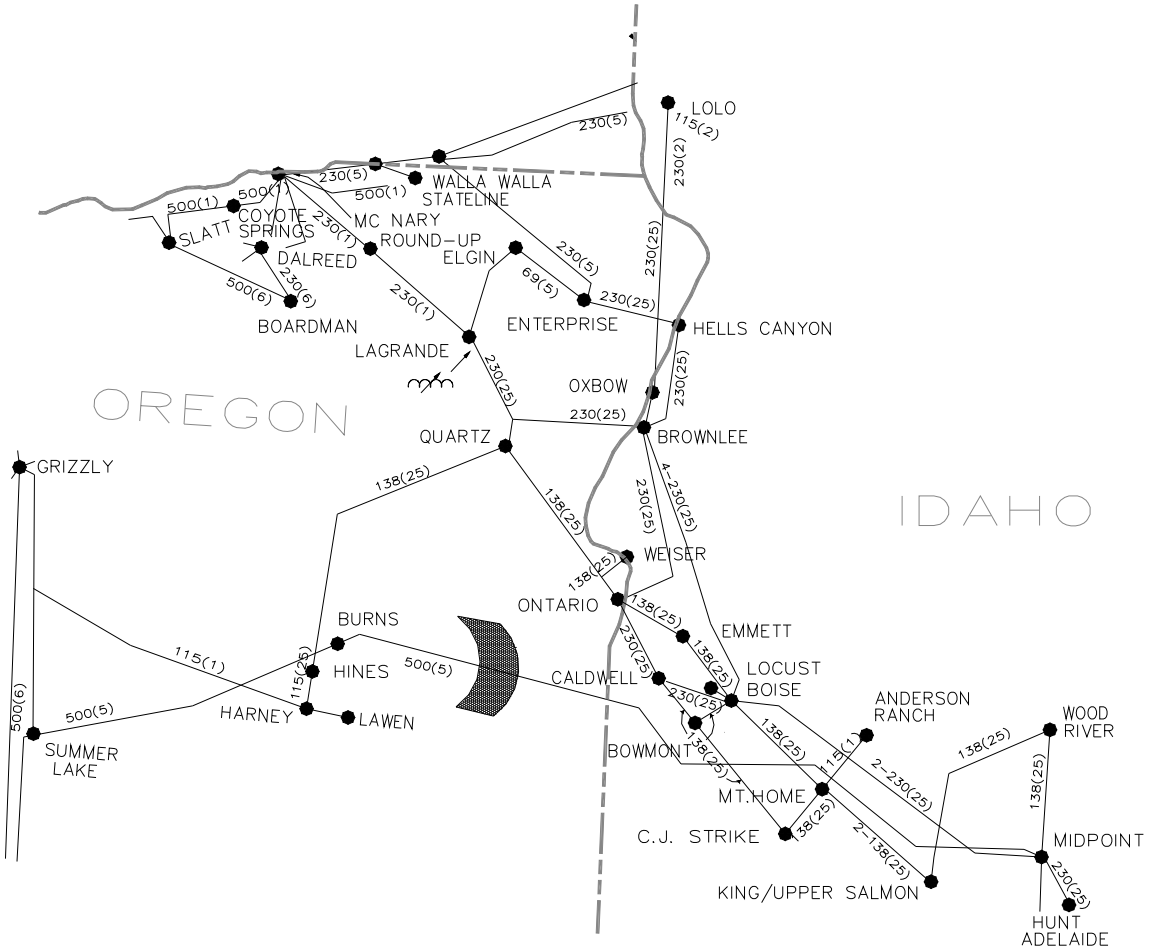
Accepted Rating ☒
Existing Rating ☐
Other ☐

Location:	Northern Utah/Southern Idaho
Definition:	Sum of the flows on the following transmission lines: Line Ben Lomond-Populus #1 345 kV Ben Lomond-Populus #2 345 kV Terminal-Populus 345 kV 3 Mile Knoll 138/345 kV Transformer 3 Mile Knoll 138/115 kV Transformer
Transfer Limit:	North to South: 1600 MW (nominal) South to North: 1250 MW (nominal) Operating limits are based on OTC studies. These ratings are expected to increase to +/- 2250 MW with the addition of the Energy Gateway West Project.
Critical Disturbance that limits the transfer capability:	N-2 Bridger system outages.
When:	Granted Phase III status 11/20/08.
System Conditions:	No limitations.
Study Criteria:	• Steady state pre disturbance voltages between .95 p.u. and 1.05 p.u. • Post-disturbance voltages between .90 p.u. and 1.10 p.u. • Post-disturbance line loadings less than "emergency ratings." • First-swing transient voltage dips not to exceed .80 p.u.
Remedial Actions Required:	None
Formal Operating Procedure:	None
Allocation:	PacifiCorp

Interaction w/Other Transfer Paths:	No nomogram relationship.
Contact Person:	Craig Quist PacifiCorp 1407 W. North Temple - Suite 275 Salt Lake City, UT 84116 (801) 220-2620 (801) 220-2842 - fax craig.quist@pacificorp.com

Phase II Projects

II-1 Midpoint - Summer Lake (Path 75 Re-rate)



II-1 Midpoint - Summer Lake (Path 75 Re-rate)

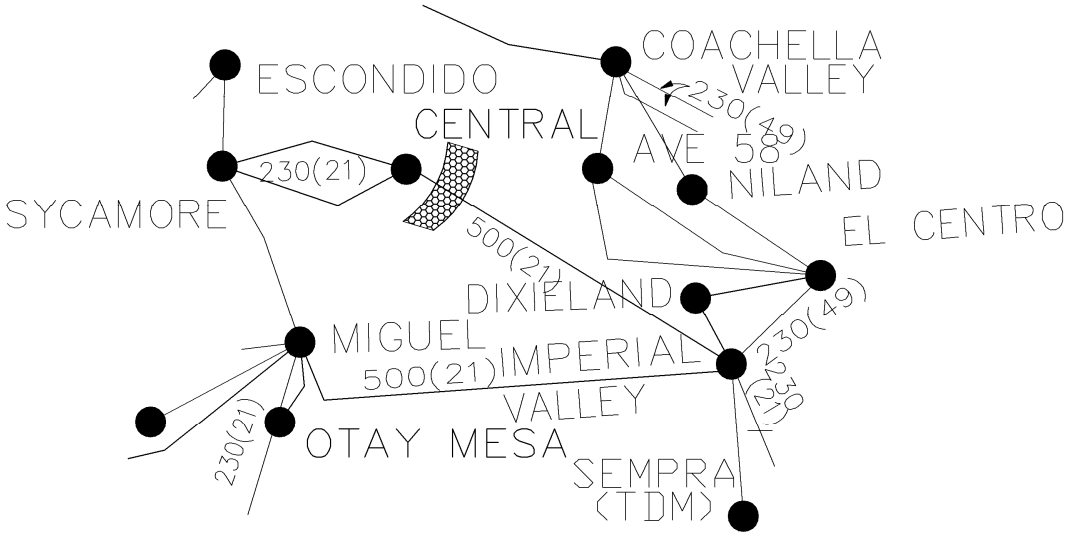
Accepted Rating ☐
Existing Rating ☐
Other ☒

Location:	Southwest Idaho and eastern Oregon
Definition:	Midpoint-Summer Lake 500 kV metered at the Midpoint 500 kV. Note: The path is also within the Idaho-Northwest Path.
Transfer Limit:	East to West:1500 MW West to East: 600 MW Studies are currently underway and have achieved Phase II status, to raise the W-E non-simultaneous rating to 600 MW.
Critical Disturbance that limits the transfer capability:	East to West: Transient voltage dip at LaGrande, and post-transient voltage at LaGrande and Hines following the loss of the Midpoint-Summer Lake 500 kV line. West to East: The thermal overload of the Lolo-Oxbow 230 kV line is the limiting condition for an outage of the Midpoint-Summer Lake 500 kV line. Under heavy Brownlee to Boise Bench 230 kV line flow, post transient reactive margin at Boise Bench may be more constraining for the loss of the Midpoint-Summer Lake 500 kV line.
When:	The east to west rating is limited by thermal ratings of Midpoint 345/500 kV transformer and series capacitor in the line. It was established along with the 2400 MW east to west rating of Idaho to Northwest path in August, 1989 with the publication of Idaho Power Company to Pacific Northwest Intertie Capacity Study. The WECC Notification Procedures for Changes in Facility Rating and/or Operating Procedures was followed. The east to west rating was conducted jointly by: Bonneville Power Administration (BPA) Idaho Power Company (IPC) PacifiCorp (PAC) Avista Corp. (AVA) The west to east rating is based on the 1998 OCSG Spring Operating Study.
System Conditions:	The east to west transfer rating was studied with light load conditions in Idaho with heavy eastern thermal resources, and moderate generation on the remaining hydro plants in Idaho. Studies were performed with both north to south and south to north on the PACI and near maximum transfers on parallel paths; i.e., transfers to Northwest and Arizona to California. The west to east transfer rating was studied with high hydro conditions in the Northwest with low to moderate eastern thermal resources. In addition, the west to east rating may not be fully utilized simultaneous with heavy Hells Canyon Complex generation because of steady state thermal overloads and/or post disturbance voltage change in Idaho Power's internal transmission system.
Study Criteria:	WECC Reliability Criteria for Transmission System Planning

Remedial Actions Required:	Remedial action schemes are required to achieve the 2400 MW east to west transfer capability on the Idaho-Northwest path under which this path is operated. An outage of the Midpoint-Summer Lake 500 kV line requires Jim Bridger unit(s) tripping. No Bridger unit tripping is required for West-East transfers.
Formal Operating Procedure:	Under certain generation and load conditions, 2400 MW Idaho to Northwest transfers, simultaneous with heavy Northwest to California transfers, may cause overloading of the Midpoint-Summer Lake line. During these conditions, one-half of the Burns series capacitors can be bypassed to reduce Midpoint-Summer Lake loading but it results in reduced Bridger West capacity.
Allocation:	The transfer capability of the path is allocated among the interconnections as follows: • 1500 MW East to West 1187 MW PacifiCorp – IPC Interconnection • 600 MW West to East PacifiCorp
Interaction w/Other Transfer Paths:	
Contact Person:	Don Johnson PacifiCorp 9951 S.E. Ankeny Street, 2nd Floor Portland, OR 97216-2315 (503) 251-5283 (503) 251-5228 - fax don.johnson@pacificorp.com

II-2 Sunrise Powerlink

Added March 2007



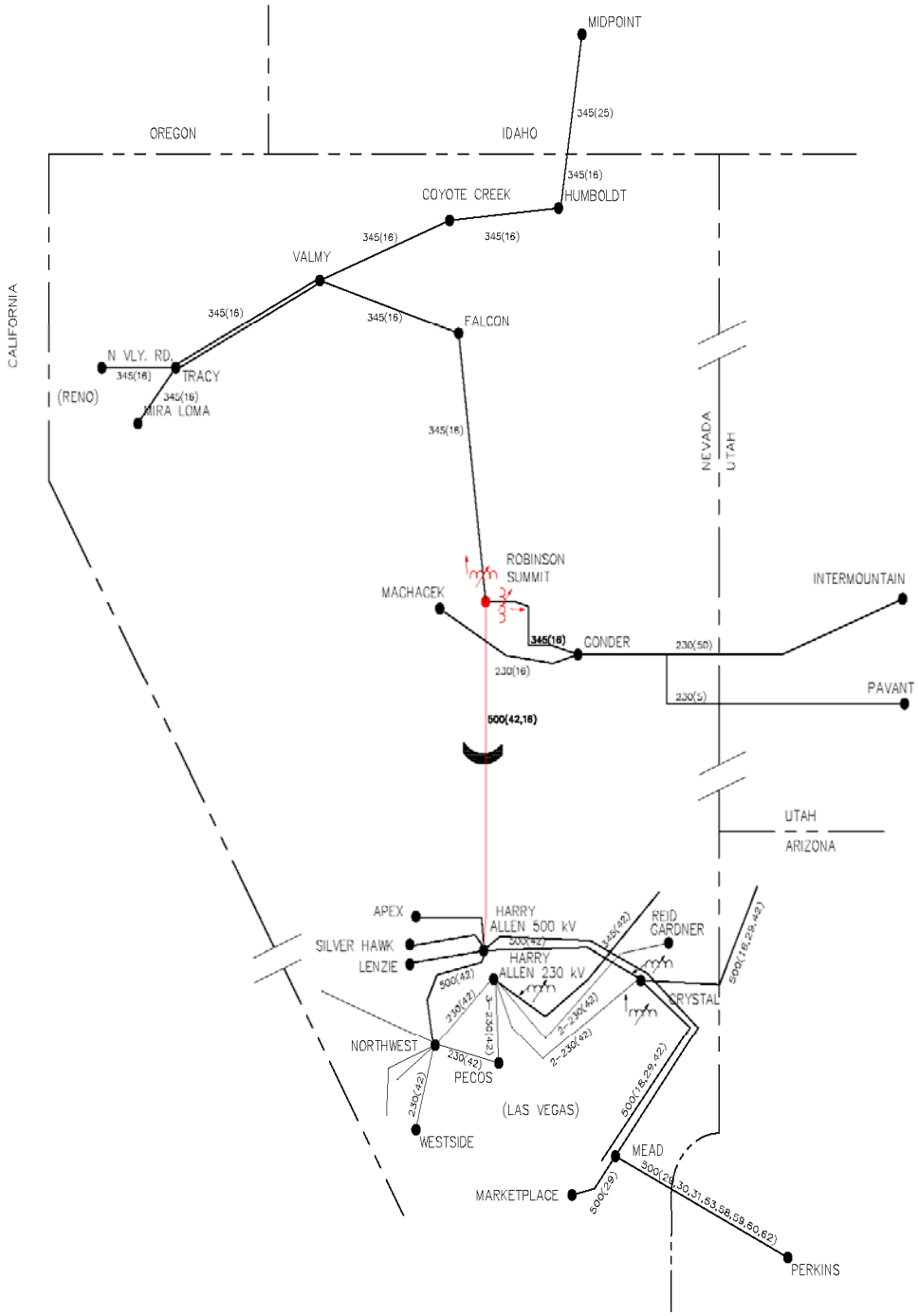
II-2 Sunrise Powerlink

Added March 2007

Accepted Rating ☒
Existing Rating ☐
Other: Phase II Project ☐

Location:	Southern California – Between Imperial Valley and San Diego
Definition:	Imperial Valley – Central 500 kV line, metered at Central 500 (Central is a proposed new substation).
Transfer Limit:	1000 MW east to west
Critical Disturbance that limits the transfer capability:	The outage of Imperial Valley – Miguel 500 kV line was identified as the critical contingency in the Phase I study. Further study in Phase II might or might not alter the most limiting factor or contingency.
When:	By letter dated May 2nd, 2006, WECC TSS Chair sent a letter to PCC and TSS stating Sunrise Powerlink path had achieved Phase 2 status.
System Conditions:	The rating was studied under heavy summer and heavy autumn conditions with all lines in service and would be applicable year round.
System Criteria:	WECC/NERC & CAISO Transmission Planning Reliability Criteria
Remedial Actions Required:	For the critical contingency, the need for the existing SPS will be reviewed, for conditions of high imports in to San Diego.
Allocation:	TBD. The CAISO will exercise operational control of the line and associated facilities
Interaction w/Other Transfer Paths	Not expected and will be verified in the phase 2 study.
Contact Person:	Linda Brown San Diego Gas and Electric 8316 Century Park Court, CP52A San Diego, CA 92123-1582 (858) 654-6477 (858) 654-1692 – Fax lpbrown@semprautilities.com

II–3 Eastern Nevada Transmission Intertie (EN-ti)



II–3 Eastern Nevada Transmission Intertie (EN-ti)

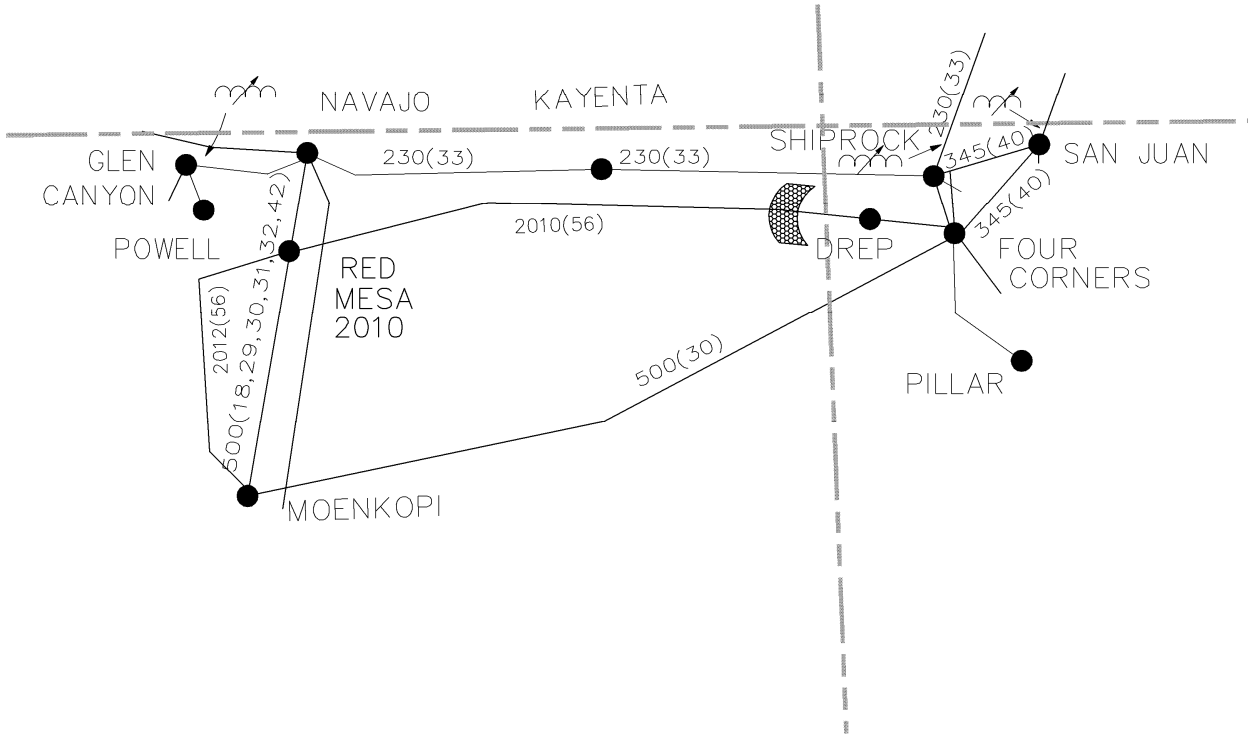
Accepted Rating ☐
Existing Rating ☐
Other ☐

Location:	Line between northeastern Nevada (new Robinson Summit substation near Ely Nevada) and southern Nevada (Las Vegas)
Definition:	Included lines: 500 kV line from Robinson Summit (Sierra Pacific Power Co.) to Harry Allen (Nevada Power Co.) substations (250 miles long, 70% series compensated). First tie between Nevada and Sierra systems. Metered End: Robinson Summit end of the line
Transfer Limit:	North to South: 2,000 MW (non-simultaneous) South to North: 1,000 MW (non-simultaneous)
Critical Disturbance that limits the transfer capability:	North to South: *Steady-state:* overvoltage due to the series compensation step-voltage at the Harry Allen end of the line. *Stability:* angular instability due to fault at Robinson Summit and subsequent loss of Robinson Summit -Harry Allen line. South to North: Thermal overload of a Robinson Summit 500/345 kV autotransformer due to loss of the other autotransformer
When:	Reviewed by PRG and WATS. Regional Project Report was approved by PCC on 02/26/2007. Phase II status was granted by PCC & TSS on 03/02/2007
System Conditions:	WECC 2014 heavy summer case was used as a base. North to South case: 2,000 MW EN-ti flow and forecasted summer peak loads in both Sierra and Nevada. South to North case: 1,000 MW EN-ti flow from south to north, maximum generation and reduced load in Nevada

Study Criteria:	WECC Reliability Criteria for Transmission System Planning

Remedial Actions Required:	For 1,000 MW max South to North transfer case: 1) Bypass EN-ti series compensation and adjust the two 345/345 kV PSTs at Robinson for overload of a Robinson Summit 500/345 kV autotransformer due to loss of the second autotransformer. 2) Adjust Robinson – Gonder 345/345 kV PST for overload of a Gonder 345/230 kV transformer due to loss of the second 345/230 kV transformer (for max West-to-East transfer on Path # 32) 3) Adjust Fort Churchill 120/120 kV PST for overload of a Fort Churchill 345/230 kV transformer due to loss of the Valmy – Falcon 345 kV line (and trip of the Falcon 345/120 kV transformer) (for max West-to-East transfer on Path # 32) 4) Adjust the two 345/345 kV PSTs at Harry Allen for overload of Path # 35 (TOT2C) North-to-South and Harry Allen 345/230 kV transformer due to loss of EN-ti
Formal Operating Procedure:	Will be developed to implement the remedial actions described above
Allocation:	Sierra Pacific and Nevada Power 100 %
Interaction w/Other Transfer Paths:	Paths # 32 and # 35 (as described in the "Remedial Actions" section)
Contact Person:	Alex Fratkin M/S S3B40 6100 Neil Road Reno, NV 89511 (775) 834-4897 AFratkin@sppc.com

II–4. Navajo Transmission Project
(segment 1)

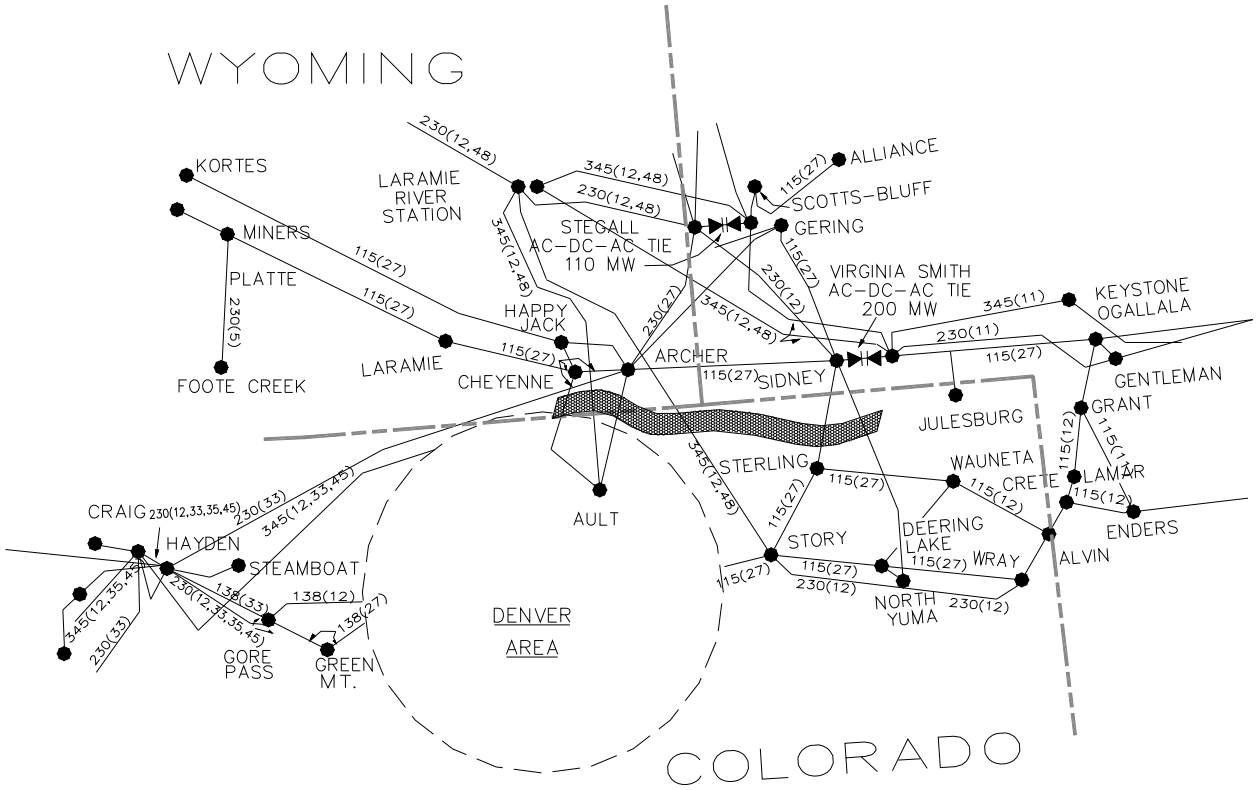


II–4. Navajo Transmission Project
(segment 1)

Accepted Rating ☐
Existing Rating ☐
Other ☒

Location:	Northeastern Arizona and Northwestern New Mexico
Definition:	DREP-Red Mesa East 500 kV line (metered at DREP 500 kV). The line will be part of a new 500 kV path composed of DREP-Red Mesa East 500 kV and Four Corners-Moenkopi 500 kV and known as Path 22A. The Four Corners-Cholla #1 & #2 345 kV lines will also become a new path known as Path 22B. Both Path 22A and 22B will have new ratings, which have and will be demonstrated in the NTP 1 WECC Project Rating Review studies.
Transfer Limit:	East to West: 1600MW West to East: undefined Studies for NTP 1 along with, Path 22A (500 kV portion of Path 22), and Path 22B (345 kV portion of Path 22) are currently underway. The three ratings have collectively achieved Phase II status
Critical Disturbance that limits the transfer capability:	East to West: (Thermal) Loss of the DREP-Red Mesa East 500 kV line loads the Four Corners-Moenkopi 500 kV line to its emergency rating.
When:	Since the plan of service for this project is new, the studies that are ongoing represent a new study effort.
System Conditions:	
Study Criteria:	NERC/WECC Planning Standards and criteria.
Remedial Actions Required:	None.
Formal Operating Procedure:	None.
Allocation:	Exact allocation of rights have yet to be determined.
Interaction w/Other Transfer Paths:	None.
Contact Person:	Barrie Kokanos Arizona Public Service Company P.O. Box 53999, Station 2259 Phoenix, AZ 85072-3999 Phone: (602) 250-1370 barrie.kokanos@aps.com

II-5. TOT3 Archer Interconnection Project



Revised February 2005

II-5. TOT3 Archer Interconnection Project

Accepted Rating ☐
Existing Rating ☐
Other ☐

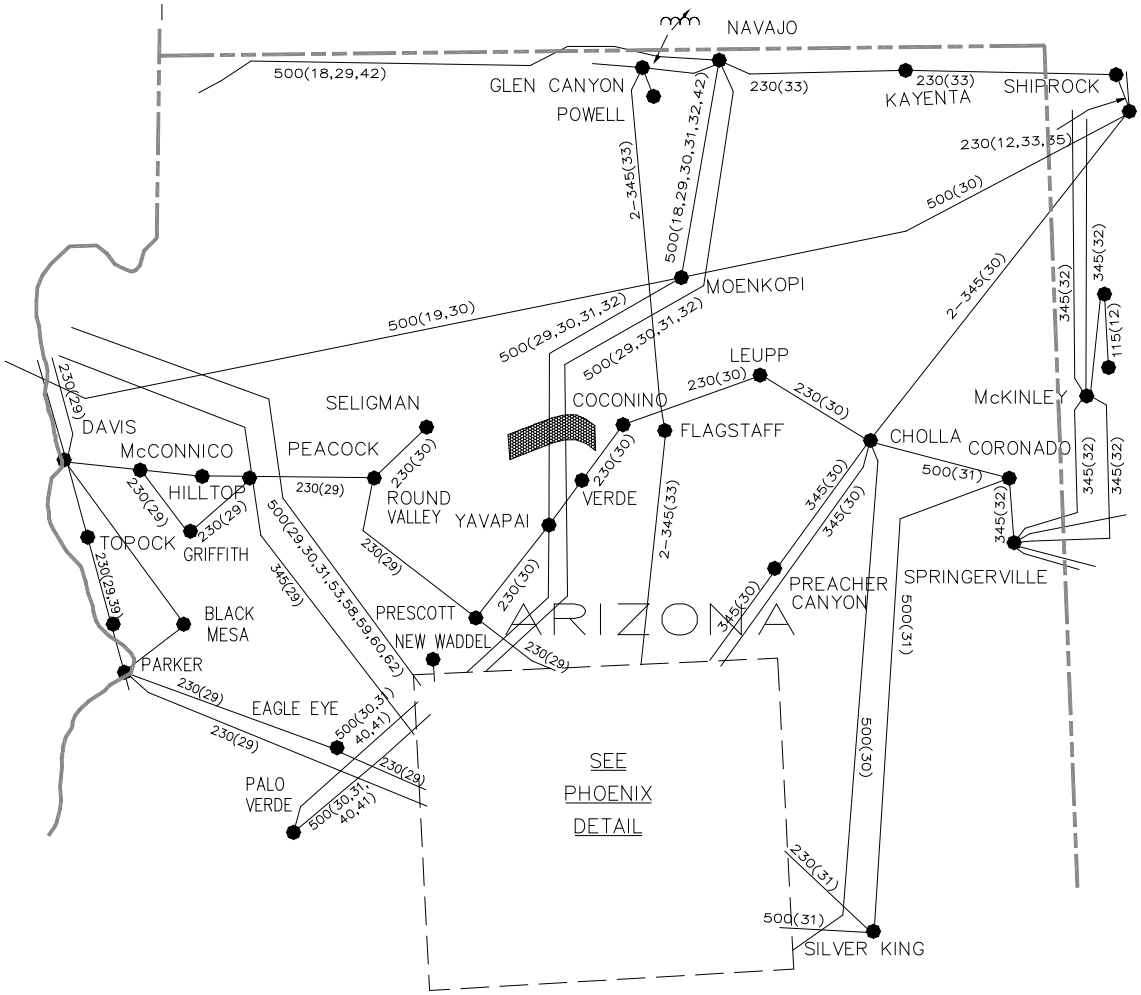
Location:	Border between Northeast Colorado and Southeast Wyoming
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Archer-Ault 230 kV — Archer Laramie River-Ault 345 kV — Laramie River Archer Tap-Story 345 kV — Archer Tap Cheyenne-Ault 115 kV — Cheyenne Sidney-Peetz 115 kV — Sidney Sidney-N. Yuma 230 kV — Sidney
Transfer Limit:	North to South: 1800 MW South to North: undefined
Critical Disturbance that limits the transfer capability:	The critical disturbances and limiting elements vary with the various generation scenarios. The TOT3 1880 limit is determined with LRS=140 MW, Pawnee=777 MW, and DC Ties=300mw E-W. At this generation point the critical outage is the Laramie River-Ault 345 kV line, and the loading on the Archer-Stegall 230 kV line is limiting. The Laramie River-Ault 345 kV, Sidney-Peetz 115 kV and Gering-McGrew 115 kV lines may require upgrades to accommodate this TOT3 transfer.
When:	Once Western Area Power Administration (WAPA) finalizes the WECC Path Rating Process for their Miracle Mile Project, Basin Electric will proceed with the WJQS Alternative C improvements. BEPC plans to increase the TOT3 transfer capability by an addition 200 MW. The WJQS Alt. C project includes tapping the LRS-Story 345 kV line at Archer, a new Archer 345/230 kV transformer, and Archer-Cheyenne 230 kV line.
System Conditions:	The transfer limit is impacted by local area generation, and the direction and magnitude of DC tie flows. Preliminary transmission studies have been completed for 3 of 24 points on the TOT3 generation matrix. As the WECC Path Rating Process proceeds the Maximum TOT3 transfer limit for each of the 24 generation points will be determined.
Study Criteria:	System intact: • Per unit voltages between 0.95 and 1.05 p.u. • All lines and transformers loaded to less than continuous rating. Single contingency outage conditions: • Per unit voltages between 0.90 p.u. and 1.10 p.u. • All lines loaded to less than 15-minute emergency ratings.

	• All transformers loaded to less than 30-minute emergency ratings. • Transient voltage swings down to 0.7 p.u. permitted.
Remedial Actions Required:	Remedial actions are required to achieve the rated transfer capability. Following an outage, all overloaded lines and transformers must have their loadings reduced to continuous ratings within 15 minutes. This is accomplished by reducing schedules and adjusting generation.
Formal Operating Procedure:	The current operating procedures will require updating to reflect the new path ratings.
Allocation:	The transfer capability of the path is divided between WAPA, Missouri Basin Power Project (MBPP), Public Service Company of Colorado (PSC), and Tri-State Generation and Transmission (TSGT). TSGT and BEPC are members of MBPP.
Interaction w/Other Transfer Paths:	None
Contact Person:	Shawn Carlson Basin Electric Power Cooperative Transmission Services 1717 East Interstate Ave Bismarck, ND 58503-0564 (701) 355-5626 (701) 224 5332- fax scarlson@bepc.com

II-6. Wyoming-Colorado Intertie (WCI) Project

Location:	WCI is located in Eastern Wyoming and Northeastern Colorado. WCI is planned to be comprised of three segments: 230 kV from Wyodak to Dave and 345 kV from LRS to Pawnee
Definition:	The Southern segment of WCI from LRS to Pawnee crosses TOT3 which is WECC Path 36
Transfer Limit:	The WCI Phase1 Comprehensive Progress Report indicates that WCI will add up to 900 MW of capacity across TOT3. WCI has been accepted into Phase 2 of the Path Rating Process with a Planned Rating of 900 MW.
Critical Disturbance that limits the transfer capability:	Phase I studies indicate that the limiting condition will be overloading the Cheyenne-Ault 230 kV for loss of the LRS-Ault 345 kV line. See Phase 1 report at www.wyia.org/wci/docs/R63-07-TransElect.pdf
When:	See Phase 1 report at www.wyia.org/wci/docs/R63-07-TransElect.pdf
System Conditions:	See Phase 1 report at www.wyia.org/wci/docs/R63-07-TransElect.pdf
Study Criteria:	See Phase 1 report at www.wyia.org/wci/docs/R63-07-TransElect.pdf
Remedial Actions Required:	None Assumed.
Formal Operating Procedure:	To be developed.
Allocation:	WCI's capacity will be held by a project company to be formed by Trans-Elect and the Wyoming Infrastructure Authority.
Interaction w/Other Transfer Paths:	To be determined in Phase 2 Studies.
Contact Person:	Bill Pascoe Consultant for WCI Phone: (406) 494-2075 bpascoe@trans-elect.com

II-7. Southern Navajo Upgrade Project



Revised November 2008

II-7. Southern Navajo Upgrade Project

Accepted Rating ☐

Existing Rating ☐
Other ☒

Location:	Northern Arizona
Definition:	Sum of the flows on the following transmission lines: Line — Metered End Moenkopi-Yavapai 500 kV — Moenkopi Navajo-Westwing 500 kV — Navajo In 2009, the Dugas 500/69 kV substation will be constructed just north of Westwing and will become the southern terminus for the Navajo-Westwing line. However, Dugas has been included in all recent studies and will not affect the proposed rating.
Transfer Limit:	North to South: 3200 MW South to North: Not rated Phase II studies are currently underway for achieving a new Accepted Rating for the path.
Critical Disturbance that limits the transfer capability:	The following disturbances are the critical contingencies for the path: • Loss of the Moenkopi-Yavapai 500 kV line • Loss of the Yavapai-Westwing 500 kV line
When:	The original rating of 2264 MW was established in 1994 and was verified in OTC studies in 1999.
System Conditions:	Resources from the Navajo Generation Station are normally needed to support flows on the path along with contributions from the east and west of Path 51.
Study Criteria:	Same as the WECC/NERC Planning Standards and criteria.
Remedial Actions Required:	None.
Formal Operating Procedure:	None.
Allocation:	Allocation remains the same as the present levels.
Interaction w/Other Transfer Paths:	None.
Contact Person:	Barrie Kokanos Arizona Public Service Company P. O. Box 53999, Station 2259 Phoenix AZ 85072-3999 (602) 250-1370 (602) 250-1674 - fax barrie.kokanos@aps.com