EXHIBITS (PUBLIC VERSION)

SAN DIEGO GAS & ELECTRIC COMPANY COMMENTS TO THE RECIRCULATED DEIR

FOR THE

SOUTH ORANGE COUNTY RELIABILITY ENHANCEMENT PROJECT

STATE CLEARINGHOUSE NO. 2013011011

SEPTEMBER 24, 2015

SAN DIEGO GAS & ELECTRIC COMPANY
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Capistrano Preservation Alternative without Confidential Attachment A (Substation Drawings) and Attachment B (Chattel Report without Confidential Drawings)

1.0 INTRODUCTION

On April 29, 2015, the California State Historic Resources Commission's (SHRC) recommended that the existing utility structure located on the Capistrano Substation site be deemed eligible for the National Register of Historic Places (NRHP). The State Historic Preservation Office (SHPO) submitted the recommendation to the Keeper of the NRHP (Keeper) on July 17, 2015 and SDG&E submitted a formal objection on August 21, 2015. In a communication dated September 22, 2015, the Keeper declined to make a determination of eligibility and instead returned the nomination to the SHPO for substantive and technical revisions. In particular, the Keeper found that the nomination did not include an adequate analysis of the integrity of the original substation complex of which the Utility Structure was a part.

However, based on the SHRC's initial recommendation on April 29, 2015, SDG&E investigated the feasibility of a preservation alternative consistent with CEQA guidelines. As outlined in the CEQA Guidelines §§ 15064.5(b)(4) and 15126(a), a preservation alternative should be considered where a historical resource is identified. Therefore, SDG&E developed the Capistrano Preservation Alternative for the CPUC's consideration and inclusion in the Final EIR.

2.0 DESCRIPTION OF THE CAPISTRANO PRESERVATION ALTERNATIVE

2.1 Scope and Design – Capistrano Preservation Alternative

Following the SHRC recommendation, SDG&E identified and retained a historic preservation consulting firm, Chattel, Inc. (Chattel), to determine what would be necessary to avoid significant impact to the existing utility structure, assuming that the structure is ultimately deemed eligible for NRHP listing. Notwithstanding that the Keeper has declined to make a determination of eligibility at this time, based on the inadequacy of the nomination, SDG&E has nonetheless elected to develop the Capistrano Preservation Alternative and for purposes of SDG&E's comments on the Recirculated DEIR, it is assumed that the Utility Structure qualifies as an historical resource.

In coordination with Chattel, SDG&E developed the Capistrano Preservation Alternative to avoid a potentially significant impact on the existing utility structure (refer to Substation Design Drawings in Attachment A). As set forth in the Assessment of Capistrano Alternative prepared by Chattel (see Attachment B)[1], the Capistrano Preservation Alternative would not result in a substantial adverse change to the utility structure, and therefore would have a less-than-significant impact on the assumed historical resource, because the Capistrano Preservation Alternative has been designed, and would be implemented, in conformance with the Secretary of

[1] Chattel's September 22, 2015 report, entitled "Capistrano Substation Utility Structure, 31050 Camino Capistrano, San Juan Capistrano, California - Assessment of Capistrano Preservation Alternative" is attached hereto as Attachment B.

the Interior's Standards for the Treatment of Historic Properties with Guidelines for Preserving, Rehabilitating, Restoring, and Reconstructing Historic Buildings (the "Secretary's Standards") and otherwise would not materially impair the historic significance of the utility structure. Attachment A contains substation design drawings that depict the Capistrano Preservation Alternative's design and layout.

Based upon Chattel's recommendations (see Attachment B) the Capistrano Preservation Alternative avoids significant impact to the existing utility structure (assuming the structure qualifies as a historic resource). The west wing of the structure would be rehabilitated in conformance with the Secretary's Standards while the east wing of the structure (located away from Camino Capistrano, which is less visible from the street and has less architectural detail) would be removed. SDG&E would then utilize the remaining portion of the existing utility structure as part of utility operations.

Under the Capistrano Preservation Alternative, in order to incorporate the retained portion of the existing utility structure into the San Juan Capistrano Substation design,[2] modifications to the design, specifications, and layout of the substation are made compared to the San Juan Capistrano Substation design included in SDG&E's Proposed Project. The primary modification to the substation design is a reduction in the size of the rebuilt 138/12 kV substation located on the "lower pad" portion of the substation site. By reducing the ultimate distribution capacity of the proposed rebuilt Capistrano Substation from 120 MVA to 90 MVA, the proposed 230/138/12 kV substation can be constructed within SDG&E's existing property. This modification would reduce the number of distribution 138/12kV transformers, 12kV switchgear sections and 12kV capacitors from four to three each (with no space for future expansion). Attachment A, Substation Design Drawings, provides the substation site plan and other design drawings and figures for the San Juan Capistrano 230/138/12kV Substation under the Capistrano Preservation Alternative.

Under the Capistrano Preservation Alternative, like the Proposed Project, the Applicant would rebuild and expand the 138/12kV substation at the Capistrano site, and would also construct a new 230/138kV substation at the Capistrano site. All other elements of the Capistrano Preservation Alternative (new 230kV transmission lines, 138kV power line relocations and undergrounding west of the Capistrano Substation site, and 12kV distribution line relocations) would be the same as the design of the Applicant's Proposed Project (as refined).

Substation design modifications include:

- The existing earthen mounds, vegetation and trees along the western edge of the property (between Camino Capistrano and the existing utility structure) would be removed and replaced with landscaping that returns the existing utility structure's setting to an earlier appearance.

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[2] SDG&E proposes to name the rebuilt Capistrano Substation as the San Juan Capistrano Substation.

- Because the substation grade would be raised approximately 5 feet to accommodate vehicles carrying equipment, an approximately 5 foot tall retaining wall would be constructed parallel to the northern and eastern walls of the existing utility structure. The retaining wall would be set back a minimum of 5 feet from the existing utility structure walls providing a personnel access way on these sides of the building.

- The western perimeter of the substation (along Camino Capistrano) would have a masonry wall approximately 10 feet tall on the inside of the substation and when viewed from the exterior would vary from approximately 12 feet to 15 feet in height. This is due to the fact that the substation grade behind the wall is raised by approximately 5 feet. The lower approximately 5 feet is the retaining wall, which would be coupled with an upper approximately 10 feet of masonry wall to collectively serve as the substation security and screen wall. The northern and southern perimeter walls would remain at approximately 10 feet in height, identical to the Proposed Project.

- The security screen wall would abut the existing utility structure on the north and south sides terminating approximately 4 inches from the structure (refer to substation drawings in Attachment A) creating separation between the existing utility structure and the western perimeter wall.

- The southern and western walls of the retained portion of the existing utility structure would be located outside of the secured substation facility and would be visible from Camino Capistrano. The northern and eastern walls of the existing utility structure would effectively act as part of the substation security wall.

- New steel replacement doors would be installed in the southern, eastern and northern walls of the existing utility structure and would replace the existing doors at these locations. The northern and eastern doors will serve as part of the security wall.

- A driveway access to the existing utility structure would be constructed from the main substation access drive to the structure's southern door.

- The southern driveway's vehicle access gate to the rebuilt Capistrano Substation would be set back approximately 80 feet from Camino Capistrano.

- The northern driveway's access gate would remain (similar to the Proposed Project) set back approximately 35 feet from Camino Capistrano.

- The northern and southern vehicular access gates would be approximately 30 feet in width, each comprised of a pair of black wrought iron sliding gates, each approximately 15 feet in width.

- Grading and the phased site development, including cut and fill, would be similar to that of Proposed Project substation design.

With respect to the existing utility structure itself, the west wing would be retained and rehabilitated per the Secretary's Standards. The east wing would be removed to provide adequate room for redevelopment of the substation. The northern and eastern walls of the retained portion of the existing utility structure would serve as part of the security wall of the substation, and would only be entered from the exterior (which would be inside the substation security wall). Modifications to the existing utility structure include:

- East Wing Demolition –12 inches of roof and walls would be retained at the point where the east wing intersects the west wing of the existing utility structure. This work is designed to allow the remaining portion of the roof and wall visually to read as a "ghost" of the east wing once it is removed.
- West Wing Rehabilitation:
  - Western Wall –The exterior wall where earthen mounds are to be removed would be repaired and waterproofed. The concrete wall iron jacking would be repaired at locations where steel rebar is exposed at western interior wall. Window rehabilitation would include removal of existing glazing, repairing existing sash and frames, and reglazing with like-kind translucent wire glass. Security bars on all windows would be installed on the interior.
  - Northern Wall – Deteriorated, non-original doors, sidelights, and transom window would be replaced to match the original. Doors, sidelights and transom would be constructed of steel rather than wood for increased security. Due to lack of visibility from the street, it is not proposed to include glazing, but rather this door assembly would be constructed exclusively of steel following the original pattern. The northern wall and replacement door would serve as part of the security wall of the substation and would only be accessed from the exterior (i.e., from within the substation).
  - Eastern Wall –The interior door at the location of demolished east wing would be replaced with a new exterior door to match the original, but designed for exposure to the elements. Due to the lack of visibility from the street, it is not proposed that glazing be included in either the new exterior door or existing windows, but rather for these assemblies would be constructed exclusively of steel following the original pattern. The eastern wall, windows and replacement door would serve as part of the security wall of the substation and would only be accessed from the exterior (i.e., from within the substation).
  - Southern Wall – Deteriorated, non-original doors, sidelights, and transom window would be replaced to match the original. Doors, sidelights and transom would be constructed of steel rather than wood for increased security. Due to the visibility from the street, it is proposed to include translucent wire glass at the transom only, but otherwise the new door assembly would be constructed of steel following the original pattern. Where glazing occurs at the transom, security bars would be installed on the interior.

- Interior Window Sills - Damage to concrete would be repaired at windows sills where water infiltration has occurred.
- Interior Crane – The moveable crane would be retained.
- Lighting - Development and implementation of a lighting plan would include exterior wall sconces on the north and south walls. Such exterior wall sconces would operate manually.

Chattel determined that, assuming the utility structure subsequently qualifies as an historical resource, the Capistrano Preservation Alternative would not have a significant impact on the utility structure, in part because it conforms with the Secretary's Standards. However, to ensure conformance with the Secretary's Standards through final design and construction, Chattel recommended that SDG&E retain a qualified professional historic architect meeting the Secretary of the Interior's Professional Qualifications Standards to monitor those activities. Chattel also recommended that SDG&E prepare Historic American Building Survey (HABS) photographic documentation for the utility structure before the east wing is removed. Chattel concluded that these measures would further reduce the Capistrano Preservation Alternative's already less-than-significant impact on the utility structure (assuming that it is subsequently determined to be an historical resource under CEQA). SDG&E is agreeable to these measures, which should therefore be considered Applicant Proposed Measures.

As shown in San Juan Capistrano Substation drawings provided in Attachment A, the 138kV (GIS) switchgear building, the three 230/138kV transformers, the 230kV (GIS) switchgear building, and the 230kV capacitor banks would all have a design and be located on the substation property similar to the layout for the Proposed Project. Table 1, Key Substation Ultimate Design Differences highlights the key differences between the Proposed Project and the Capistrano Preservation Alternative San Juan Capistrano Substation design.

Table 1: Key Substation Ultimate Design Differences

Substation Design Element	Capistrano Preservation Alternative Design	Proposed Project Design
Former Utility Structure	Western portion retained with rehabilitation consistent with Secretary's Standards	Entire structure removed
138/12kV Transformers	Three transformers	Four transformers
12kV Switchgear	Three ¼ sections of switchgear (12 circuits)	Four ¼ sections switchgear (16 circuits)
12kV Capacitors	Three 12kV capacitors	Four 12kV capacitors

Table 1 (cont.): Key Substation Ultimate Design Differences

Substation Design Element	Capistrano Preservation Alternative Design	Proposed Project Design
Western Screen/Security Wall	Varies up to 15 feet tall from the exterior	10 feet tall
Southern Driveway	80 foot setback from the Camino Capistrano	35 foot setback from Camino Capistrano

The construction schedule for the San Juan Capistrano Substation, under the Capistrano Preservation Alternative, is anticipated to be approximately 51 months. Construction equipment and personnel would be similar to those identified for the Proposed Project in the Draft EIR, Section 2.4.1.

2.2 Consideration of CEQA Criteria

Consistent with CEQA Guidelines (Section 15126.6) and the South Orange County Reliability Enhancement Project Recirculated Draft Environmental Impact Report (RDEIR), the Capistrano Preservation Alternative was evaluated according to the following criteria:

1. Would the Capistrano Preservation Alternative accomplish most of the basic project objectives?
2. Would the Capistrano Preservation Alternative be economically, technically, and legally feasible?
3. Would the Capistrano Preservation Alternative avoid or substantially lessen one or more significant impacts identified for the Proposed Project?
4. Would the Capistrano Preservation Alternative increase the severity of any impact identified for the Proposed Project, or create a new potentially significant impact that was not identified for the Proposed Project?

Conformance with Project Objectives

The Capistrano Preservation Alternative would meet each of the Proposed Project objectives included within the DEIR (Section 1.3.1) as well as the Applicant’s objectives outlined in Proponent’s Environmental Assessment (PEA) Section 2.2. Similar to the Proposed Project, the Capistrano Preservation Alternative would provide the following benefits:

- Reduced risk of an uncontrolled outage of all of the South Orange County load;
- Reduced risk of a controlled interruption of a portion of the South Orange County load;
- Compliance with mandatory NERC, WECC, and CAISO transmission planning standards;
- Rebuild of the Capistrano Substation to replace aging equipment and increase capacity;

- Improved transmission and distribution operating flexibility;
- Provides a redundant second 230kV source for the South Orange County service area;
- Accommodates projected customer load growth in the South Orange County area; and
- Locates new and upgraded facilities within existing transmission corridors, SDG&E ROW, and utility owned property.

Feasibility

The Capistrano Preservation Alternative is feasible from a technological, legal, and economic perspective. SDG&E has conducted preliminary engineering and design (refer to Section 2.1 and Attachment A), and has determined that the Capistrano Preservation Alternative is in fact feasible from a technical, engineering, and construction perspective. While the cost of the Capistrano Preservation Alternative may increase in comparison to the cost of Proposed Project, such increase in cost would be minimal in relation to the overall cost of either the Capistrano Preservation Alternative or the Proposed Project. Therefore, the Capistrano Preservation Alternative is considered to be economically feasible. Finally, the Capistrano Preservation Alternative would utilize the same existing SDG&E property proposed for use by the Proposed Project. SDG&E has legal rights to the Capistrano Substation site as property owner and the CPUC would retain discretionary authority over the siting of the project, all in a similar manner as for the Proposed Project. Therefore, the Capistrano Preservation Alternative is considered to be legally feasible.

Environmental Advantages

As described above and detailed within Attachment B, the Capistrano Preservation Alternative would reduce potentially significant impacts to the potentially historical resource to a level less than significant. Therefore, if the Keeper ultimately finds that the existing utility structure is eligible for listing on the NRHP, the Capistrano Preservation Alternative would reduce at least one potentially significant impact in comparison to the Proposed Project.

Environmental Disadvantages

No environmental disadvantages have been identified with the Capistrano Preservation Alternative in comparison to the Proposed Project. As further described in Section 3.0 below, the Capistrano Preservation Alternative would not be anticipated to increase the severity of any impact identified for the Proposed Project and would not create any new impact not previously identified for the Proposed Project.

Conclusion

The Capistrano Preservation Alternative is feasible, would meet the basic objectives of the Proposed Project, and would reduce potentially significant impacts to a potential historical resource identified for the Proposed Project. Therefore, the Capistrano Preservation Alternative should be considered by the CPUC and included in the Final Environmental Impact Report.

3.0 COMPARISON OF THE CAPISTRANO PRESERVATION ALTERNATIVE

3.1 Methodology

As stated in Section 2.1 above, the Capistrano Preservation Alternative was analyzed to ensure that at least one potentially significant impact identified for the Proposed Project would be avoided or substantially reduced (to a level less than significant) by implementation of the Capistrano Preservation Alternative. The Capistrano Preservation Alternative was compared to the Proposed Project in terms of the resource areas that the DEIR/RDEIR found to be impacted by the Proposed Project.

While the focus of the Comparison of the Capistrano Preservation Alternative to the Proposed Project is the six potentially significant impacts identified within the RDEIR, the comparison included below also analyzes whether or not the Capistrano Preservation Alternative would increase impacts for other resources affected by the Proposed Project. The RDEIR and DEIR collectively identify six potentially significant impacts of the Proposed Project (air quality, biological resources, cultural resources, land use and planning, traffic and transportation, and cumulative impacts) with impacts to all other resource areas being less than significant.

For purposes of this Comparison, SDG&E presents the RDEIR findings with respect to the Proposed Project's impacts. SDG&E does not agree that the RDEIR has properly identified as significant impacts to biological resources, land use and planning, traffic and transportation, and cumulative impacts. The air quality impact would be similar for each Alternative considered.[3] With respect to traffic impacts, as stated in SDG&E's April 10, 2015 Comments on the Draft EIR, Detailed Comments at 3-4: "SDG&E's construction and engineering contractors do not expect a full closure of any of these roads during underground construction and SDG&E did not state there would be any full road closures in the PEA. The Project refinements identified in more detail in Attachment A - Minor Project Design Refinements will eliminate the temporary and cumulative traffic impacts." With respect to biological and land use impacts, as set forth in SDG&E's September 24, 2015 RDEIR Comments at Section IV, SDG&E is in full compliance with its Natural Communities Conservation Plan ("NCCP") and, with the Segment 4 Design Revisions set forth in Exhibit 2, bringing permanent transmission structures within SDG&E's existing easements, the United States Fish & Wildlife Service ("USFWS") has agreed that no conflict between the Proposed Project and recorded and potential conservation easements is expected. With respect to land use impacts on local height limitations, the Commission's General Order 131-D, CPUC Decision 94-06-014, and numerous court rulings confirm that the CPUC has exclusive jurisdiction over the construction of electric utility facilities, preempting local ordinances. Therefore the local ordinances cited in the RDEIR are not applicable to the Proposed Project. With respect to the potential historical resource, on August 21, 2015, SDG&E

[3] Rebuilding Capistrano Substation, at least as a 138/12 kV substation, is a reasonably anticipated outcome under all Alternatives considered in the RDEIR/DEIR. Therefore, each such Alternative will have a similar effect on air quality as the Proposed Project—and many alternatives require rebuilding two substations rather than just one.

submitted to the Keeper its objection to the proposed determination of eligibility of the existing utility structure for the NRHP, opposing the SHRC's recommendation. If the Keeper ultimately finds that the existing utility structure is not eligible for listing on the NRHP, then the Proposed Project would not have a significant effect on a historical resource.

SDG&E provides the Comparison below, based on the RDEIR's findings, without conceding that the RDEIR findings are accurate.

Table 2: Comparison Summary

Resource Area	Proposed Project	Pres. Alt.
Aesthetics	LTS	Similar
Agriculture & Forestry	LTS	Similar
Air Quality	S	Similar
Biological Resources	*S*[1]	Similar
Cultural Resources	S	Less
Geology, Soils, & Minerals	LTS	Similar
Greenhouse Gases	LTS	Similar
Hazards	LTS	Similar
Hydrology and Water Quality	LTS	Similar
Land use and Planning	*S*[2]	Similar
Noise	LTS	Similar
Population & Housing	LTS	Similar
Public Services and Utilities	LTS	Similar
Recreation	LTS	Similar
Transportation and Traffic	*S*[3]	Similar
Cumulative	*S*[3]	Similar

Notes:
LTS = less than significant
S = Significant
[1] Note that following initial consultation with USFWS, impacts would be LTS.
[2] As outlined in SDG&E's comments, CPUC jurisdiction preempts local ordinances and impacts would be LTS.
[3] Traffic control plans submitted on SDG&E's Minor Project Refinement (dated April 2015) reduce impacts to LTS.

3.2 Analysis of the Capistrano Preservation Alternative

An analysis of the environmental advantages and disadvantages of the Capistrano Preservation Alternative in comparison to the RDEIR's findings regarding the Proposed Project is contained within the following subsections. Table 2, Comparison Summary, summarizes the determinations of impacts to CEQA resources for the Capistrano Preservation Alternative in comparison to RDEIR's findings regarding the Proposed Project. As shown in Table 2 and detailed below, the Capistrano Preservation Alternative would have similar or less impacts than the Proposed Project for all CEQA resource areas.

Under the Capistrano Preservation Alternative, the San Juan Capistrano Substation would be rebuilt and expanded to allow for additional 138kV connections as well as for the connection to new 230kV transmission lines. As described in Section 2.1 above, the principal difference between the Capistrano Preservation Alternative and the Proposed Project is the retention and rehabilitation of the west wing of the existing utility structure and the reduced ultimate substation buildout for the distribution facilities.

Reduction of Potentially Significant Impacts

Historic Resources

As documented in Attachment B, the Capistrano Preservation Alternative would reduce impacts to historical resources to less than significant through the preservation and rehabilitation of the western wing of the existing utility structure in conformance with the Secretary's Standards, consistent with the assessment included within Attachment B (historic site 30-179873)[4]. Therefore, the Capistrano Preservation Alternative would have less impacts to historical resources when compared to the Proposed Project.

Air Quality

The DEIR identified short term, significant impacts relating to the emission of criteria pollutants. Emission of criteria pollutants is governed by the location, extent (area of disturbance), duration (length of construction), and intensity (amount of equipment required) of construction activities. These impacts were the direct result of construction activities, including the use of heavy construction equipment. The Capistrano Preservation Alternative would include construction activities very similar to the Proposed Project in location, extent, duration, and intensity. Therefore, Capistrano Preservation Alternative would have similar effects on air quality as the Proposed Project.

Biological Resources

The RDEIR found: "The proposed project may conflict with two conservation easements established within the Orange County Southern Subregion HCP and considered preserve areas under the SDG&E NCCP/HCP." As set forth in SDG&E's September 24, 2015 RDEIR Comments at Section IV, SDG&E is in full compliance with its Natural Communities Conservation Plan ("NCCP") and, with the Segment 4 Design Revision set forth in Exhibit 2, bringing permanent transmission structures and wires within SDG&E's existing easements, the United States Fish & Wildlife Service ("USFWS") has agreed to a process that would result in the Proposed Project being consistent (i.e. having no conflicts) with recorded and potential conservation easements and the Orange County Southern Subregion HCP. The Capistrano Preservation Alternative would have similar (less than significant) effects on biological resources as the Proposed Project.

Land Use and Planning

Like the Proposed Project, the Capistrano Preservation Alternative would include rebuilding and expanding the San Juan Capistrano Substation, including the construction of a 138kV gas insulated substation (GIS) structure (approximately 45 feet tall), and a 230kV GIS structure (approximately 50 feet tall). The RDEIR found in LU-2 that the "proposed project would directly conflict with applicable building height regulations defined within the San Juan Capistrano Municipal Code." The Commission's General Order 131-D, CPUC Decision 94-06-014, and numerous court rulings confirm that the CPUC has exclusive jurisdiction over the construction of electric utility facilities, preempting local ordinances. Therefore the local ordinances cited in the RDEIR are not applicable to the Proposed Project. The Capistrano

[4] Note that the potentially significant impact to historic resources was made in the RDEIR on the assumption that former utility structures would quality as a historic resource. However, the Keeper of NRHP has most recently declined to rule on the eligibility of the structure and has requested revisions to the nomination, including additional analysis concerning the integrity of the original substation complex.

Preservation Alternative would have an inconsistency with the inapplicable City of San Juan Capistrano zoning ordinance similar to that of the Proposed Project.

The RDEIR found in LU-3: "The proposed project may also conflict with two conservation easements established under the Orange County Southern Subregion HCP." As set forth in SDG&E's September 24, 2015 RDEIR Comments at Section IV, SDG&E is in full compliance with its Natural Communities Conservation Plan ("NCCP") and, with the Segment 4 Design Revision set forth in Exhibit 2, bringing permanent transmission structures and wires within SDG&E's existing easements, the USFWS has agreed to a process that would result in the Proposed Project being consistent with recorded and potential conservation easements and the Orange County Southern Subregion HCP. The Capistrano Preservation Alternative would have similar effects on LU-3 as the Proposed Project.

Traffic and Transportation

The Capistrano Preservation Alternative would include rebuilding and expansion of the Capistrano Substation, including the undergrounding of existing 13kV and 12kV lines west of the Capistrano Substation site that would result in temporary impacts to traffic circulation on Camino Capistrano and Calle San Diego. The Capistrano Preservation Alternative would include the same scope of work between the Talega Substation and up to the Capistrano Substation site. Therefore, similar impacts to traffic circulation would occur during stringing operations (for example – across the I-5 Freeway) and during underground construction at Vista Montana and Via Pamplona. The Capistrano Preservation Alternative would have similar impacts on traffic circulation as the Proposed Project. However, it is important to note that impacts to traffic circulation are actually less than significant, as detailed in SDG&E's comments on the DEIR. Specifically, SDG&E can construct underground lines at Vista Montana, Via Pamplona, and Calle San Diego without full road closures. Additionally, SDG&E's substation engineering consultant prepared draft traffic control plans for Camino Capistrano that would allow for construction to occur while retaining 3 lanes of travel, thus retaining roadway capacity and reducing impacts to traffic circulation to a less than significant level. Similarly, the Capistrano Preservation Alternative would not result in significant impacts to traffic circulation.

Cumulative Impacts

The Capistrano Preservation Alternative would include rebuilding and expansion of the Capistrano Substation, including the undergrounding of existing 13kV and 12kV lines west of the Capistrano Substation site that would result in temporary cumulative impacts to traffic circulation on Camino Capistrano. Therefore, the Capistrano Preservation Alternative would have similar cumulative impacts when compared to the Proposed Project. However, it is important to note that impacts to traffic circulation (including the cumulative impacts identified within the DEIR) are actually less than significant, as detailed in SDG&E's comments on the DEIR. Pursuant to the Draft traffic control plans submitted with SDG&E's comments on the DEIR, roadway capacity on Camino Capistrano could be maintained at three lanes, thus limiting impacts a less than significant level. Similarly, the Capistrano Preservation Alternative would not result in significant cumulative impacts to traffic circulation on Camino Capistrano.

Other Resource Areas

The Capistrano Preservation Alternative would have a very similar scope of work compared to the Proposed Project, and this would generally result in very similar impacts to CEQA resource areas, as summarized in Table 2 above. A comparison of such impacts is included below for each of the 10 resources areas with less than significant impacts.

Aesthetics

The Capistrano Preservation Alternative would have the same alignment as the Proposed Project for all distribution, power, and transmission lines to be installed, removed, or relocated. Therefore, impacts to aesthetic resources (including viewsheds, view corridors, scenic highways and roads, and scenic vistas) would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project. Similarly, impacts to visual character from the distribution, power, and transmission lines would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

Potential impacts relating to degradation of the existing visual character at the San Juan Capistrano Substation site would be similar (or less) for the Capistrano Preservation Alternative when compared to the Proposed Project. While the Capistrano Preservation Alternative includes a redesigned San Juan Capistrano Substation, the revisions are relatively minor and would actually result in less visual change from existing conditions when compared to the Proposed Project. As further described above and within Attachments A and B, the western wing of the existing utility structure would be retained, rehabilitated, and incorporated into the design of the new San Juan Capistrano Substation. The view of the San Juan Capistrano Substation would therefore not only be altered less under the Capistrano Preservation Alternative than under the Proposed Project, the design of the new substation under the Capistrano Preservation Alternative would also include positive measures such as wall design and landscaping that would increase the consistency of the site with the historic look and feel of the substation site. In addition, prominent existing visual features, including existing overhead 138kV structures, would be removed (138kV lines would be relocated to an underground position as they enter the substation, similar to the design of the Proposed Project) thus providing for a more unified landscaped as discussed within the DEIR (page 4.1-26, lines 40 and 41). Therefore, impacts relating to degradation of existing visual character for the Capistrano Preservation Alternative would be similar, or less, when compared to the Proposed Project.

Agriculture and Forestry Resources

The Capistrano Preservation Alternative would have the same physical footprint as the Proposed Project, thereby have the same potential to affect agricultural and forestry resources. Therefore, impacts to agricultural and forestry resources would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

Geology, Soils, and Mineral Resources

The Capistrano Preservation Alternative would have the same footprint as the Proposed Project, and would require a similar amount of grading, grubbing, and other earth disturbing activities as well as similar construction activities and equipment usage. Therefore, impacts relating to geologic hazards, seismic hazards, landslides, unstable and expansive soils, liquefaction, and soil erosion would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

Greenhouse Gases

The Capistrano Preservation Alternative would include similar construction activities, including duration, location, and intensity. Therefore, impacts associated with greenhouse gas emissions from construction would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

The San Juan Capistrano Substation design and operation under the Capistrano Preservation Alternative would be similar to the Proposed Project, and would actually contain a smaller ultimate buildout (less equipment) when compared to the Proposed Project. Therefore, impacts relating to the emission of greenhouse gases (including from the utilization of sulfur hexafluoride) would be similar or less for the Capistrano Preservation Alternative when compared to the Proposed Project.

Hazards and Hazardous Materials

The Capistrano Preservation Alternative would have the same footprint as the Proposed Project, and would require a similar construction equipment, materials, and equipment. Therefore, impacts relating to fire hazards, emergency response plans, evacuation routes, hazardous materials sites, and hazardous materials and waste handling and exposure would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

Hydrology and Water Quality

The Capistrano Preservation Alternative would have the same footprint as the Proposed Project, and would require a similar amount of grading, grubbing, and other earth disturbing activities. The Capistrano Preservation Alternative would also be subject to the same water quality related regulations and best management practices, such the SDG&E BMP Manual, NPDES Regulations (including preparation implementation of a SWPPP), and hazardous materials storage regulations (such as the preparation and implementation of SPCC plans). Therefore, the Capistrano Preservation Alternative would have similar impacts on water quality standards and waste discharge requirements when compared to the Proposed Project.

Because the Capistrano Preservation Alternative would have the same footprint as the Proposed Project, would include similar construction and operation activities, in the same locations, potential impacts relating flooding, flood hazards, tsunami hazards, mud flow hazards, and drainage patterns would be similar for the Capistrano Preservation Alternative and the Proposed Project.

The Capistrano Preservation Alternative would have a similar, low potential to require dewatering during construction activities. Similar to the Proposed Project, the Capistrano Preservation Alternative would not be anticipated to affect groundwater (either directly or indirectly) in any other ways. Therefore, potential impacts on ground water would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

Noise

Construction of the Capistrano Preservation Alternative would be similar to construction of the Proposed Project, including having a similar construction schedule and the same physical locations where construction activities would occur. Therefore, less than significant impacts associated with construction noise and groundborne vibration would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

The Capistrano Preservation Alternative would include the same scope of work as the Proposed Project in relation to operation of new 230kV overhead transmission lines. Therefore, potential impacts associated with corona noise would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

The revised ultimate substation layout under the Capistrano Preservation Alternative would include space for one less 138/12kV transformer, and the same number of 230/138kV transformers as the Proposed Project. The 230/138kV transformers would be located in the same location as the Proposed Project design. The location of the 138/12kV transformers have been shifted slightly; however, the noise emission from the 138/12kV transformers are lower in relation to the 230kV transformers and the 138/12kV transformers are located further from sensitive noise receptors. Therefore, impacts from transformers are anticipated to be similar for the Capistrano Preservation Alternative and the Proposed Project.

Population and Housing

The Capistrano Preservation Alternative would include a similar work force (both for construction and operation) as the Proposed Project and would have the same potential to indirectly induce growth through the improved electrical transmission system the Capistrano Preservation Alternative would provide. Therefore, impacts to population and housing would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

Public Service and Utilities

The Capistrano Preservation Alternative would include a similar work force (for both construction and operation) as the Proposed Project, would include the same physical footprint as the Proposed Project, and would have the same potential for use of public services including law enforcement, fire protection, parks, schools, and other public services. Therefore, impacts would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

The Capistrano Preservation Alternative would result in similar requirements for water use, wastewater, and solid waste. Therefore, impacts upon these services would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

The Capistrano Preservation Alternative would occupy the same footprint as the Proposed Project, with no substantial difference in new impervious areas or anticipated runoff volumes. While retention of a portion of the existing utility structure would increase impervious area when compared to the Proposed Project substation design, the reduction in equipment would offset some of that increase. Therefore, impacts to stormwater retention and drainage facilities would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

Recreation

The Capistrano Preservation Alternative would not induce increased substantial new use of existing recreational facilities such that existing facilities would be degraded. The Capistrano Preservation Alternative would include a similar work force (for both construction and operation) as the Proposed Project. Therefore, impacts to recreational facilities would be similar for the Capistrano Preservation Alternative when compared to the Proposed Project.

Determination

The Capistrano Preservation Alternative would result in fewer potentially significant impacts as the existing utility structure (historic site 30-179873) would be preserved in accordance with the Secretary's Standards, with the west wing retained and rehabilitated, and incorporated into the design and future use of the San Juan Capistrano Substation (refer to Attachments A and B). Impacts associated with traffic and cumulative traffic would be similar for the Capistrano Preservation Alternative and the Proposed Project and, as noted in SDG&E's comments on the DEIR and again summarized in SDG&E's comments on the RDEIR, these impacts can be reduced to a level less than significant. Similarly, the Capistrano Preservation Alternative would result in the same impacts to land use and planning and biological resources identified for the Proposed Project within the RDEIR. However, as stated within SDG&E's comments to the RDEIR, these impacts should be considered less than significant for the Proposed Project, and as such would be less than significant for the Capistrano Preservation Alternative. Due to the substantially similar construction scenario between the Capistrano Preservation Alternative and the Proposed Project, similar temporary, significant impacts related to the emission of criteria pollutants would be anticipated to result. Finally, the Capistrano Preservation Alternative would be anticipated to have similar or less, impacts to the remaining CEQA resource areas identified by the DEIR to have less than significant impacts under the Proposed Project.

In addition, the Capistrano Preservation Alternative would meet the basic project objectives, including providing for a redundant second 230kV source that could adequately support the South Orange County load in the event of the loss of the Talega Substation, complying with mandatory NERC, WECC and CAISO reliability standards, and rebuilding Capistrano Substation so that it can provide reliable electric service to the citizens of San Juan Capistrano.

ATTACHMENT A

Substation Design Drawings (OMITTED - CONFIDENTIAL)

ATTACHMENT B

Assessment of Capistrano Preservation Alternative
(Chattel September 22, 2015)

without Confidential Drawings

CAPISTRANO SUBSTATION UTILITY STRUCTURE
31050 CAMINO CAPISTRANO, SAN JUAN CAPISTRANO, CALIFORNIA
ASSESSMENT OF CAPISTRANO PRESERVATION ALTERNATIVE

Prepared for
San Diego Gas and Electric Company

Prepared by
Chattel, Inc.
Historic Preservation Consultants

September 22, 2015

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I. INTRODUCTION

This report evaluates the Capistrano Preservation Alternative (the Preservation Alternative) prepared by San Diego Gas & Electric Company (SDG&E). It was developed for the Capistrano Substation located at 31050 Camino Capistrano in San Juan Capistrano, Orange County, California (the Property) as part of SDG&E's comments on the Recirculated Draft Environmental Impact Report (RDEIR) prepared for the California Public Utilities Commission (CPUC) for the South Orange County Reliability Enhancement Project (the SOCRE Project). The CPUC originally circulated a Draft Environmental Impact Report Draft EIR) for the SOCRE Project on February 23, 2015. The proposed SOCRE Project analyzed in the Draft EIR included, among other regional utility improvements, substantial modifications to the Property and the existing improvements thereon, including demolition of an existing onsite utility structure ((the Utility Structure). The CPUC circulated the RDEIR for public comment on August 10, 2015. The objective of this report is to evaluate the Preservation Alternative with respect to its historical resources impact on the Utility Structure under the California Environmental Quality Act (CEQA).

The Utility Structure is the only building currently located on the Property. It was formerly used to house functions related to the Property's function as an electrical substation. However, while the substation continues to function as such today, the Utility Structure has played no role in the operation of the substation for decades and now sits vacant. The Utility Structure has been the subject of multiple historical resource assessments over the past several years. Three qualified consultants, including one retained by the CPUC, concluded that the Utility Structure was not eligible for listing on the National Register of Historic Places (National Register) and did not qualify as an "historical resource" under CEQA.[1]

Recently, however, the Utility Structure was nominated by a private citizen to the National Register. In the nomination, the Utility Structure was described as significant under Criterion A for its association with electrical power distribution in Southern California. Subsequently, on April 29, 2015, the State Historical Resources Commission (SHRC) recommended that the State Historic Preservation Officer (SHPO) nominate the Utility Structure as eligible for listing on the National Register. That recommendation was forwarded to the Keeper of the National Register (Keeper) on July 17, 2015. On August 21, 2015, SDG&E submitted to the Keeper its objection to the proposed determination of eligibility. Most recently, in a communication dated September 22, 2015 (the Keeper Communication), the Keeper declined to make a determination of eligibility and instead returned the nomination to the SHPO for substantive and technical revisions. In particular, the Keeper found that the nomination did not include an adequate analysis of the integrity of the original substation complex of which the Utility Structure was a part.

However, the CPUC completed the RDEIR prior to the Keeper's review of the nomination. As a result,the based upon the SHRC recommendation, the RDEIR states: "Because the former utility structure's eligibility for listing in the NRHP [National Register] has not yet been determined, it is assumed for the purposes of this analysis that the structure will be determined to be eligible for listing in the NRHP."[2]

Notwithstanding that the Keeper has now declined to make a determination of eligibility based on the inadequacy of the nomination, SDG&E has nonetheless elected to develop the Preservation Alternative and for purposes of this report, it is assumed that the Utility Structure qualifies as an historical resource. It is, however, uncertain whether and when (1) the nomination will be further

[1] Ecology and Environment, Inc., *South Orange County Reliability Enhancement Project Recirculated Environmental Impact Report (RDEIR),* August 2015, 2-97.

[2] Ibid, 2-97.

revised in accordance with the Keeper's comments and (2) the Keeper will find those revisions acceptable and make a determination of eligibility.

Notwithstanding that the RDEIR found that the demolition of the Utility Structure would be considered a significant impact under CEQA because the structure is potentially an historical resource, the RDEIR did not include a preservation alternative to reduce or avoid the significant impacts on that assumed historical resource. Therefore, SDG&E determined that it would prepare the Preservation Alternative for the CPUC's consideration. SDG&E retained Chattel, Inc., a historic preservation consulting firm, to help formulate the Preservation Alternative in a manner that avoids a significant impact on the Utility Structure. Consequently, in coordination with Chattel, Inc., SDG&E developed the Preservation Alternative, which has been designed to conform with the *Secretary of the Interior's Standards for the Treatment of Historic Properties with Guidelines for Preserving, Rehabilitating, Restoring, and Reconstructing Historic Buildings* (the *Secretary's Standards*), while still meeting key objectives of the proposed SOCRE Project. Projects that alter historical resources in conformance with the *Secretary's Standards* are considered to have a less-than-significant impact under CEQA.

The Preservation Alternative is described in a set of drawings prepared by NV5 engineers dated September 2015 (the Drawing Set). The Drawing Set is attached as **Exhibit A**. As shown on the Drawing Set, the Utility Structure includes a west wing along Camino Capistrano (the West Wing) and an east wing that is largely not visible from Camino Capistrano (the East Wing). The Preservation Alternative entails the retention and rehabilitation of the West Wing and the removal of the majority of the East Wing to provide adequate room to rebuild the substation, all in conformance with the *Secretary's Standards*. The East Wing is less architecturally articulated than the more publically-oriented West Wing, and it is less visible from the street, as it is located away from Camino Capistrano and the West Wing blocks views of it. Following the removal of the East Wing, the proposed 230/138/12 kV substation would be constructed within the existing Property by reducing the ultimate distribution capacity of the proposed rebuilt Capistrano Substation from 120 MVA to 90 MVA. This represents a modification of the project originally proposed by SDG&E, as it would reduce the number of distribution 138/12kV transformers, 12kV switchgear sections and 12kV capacitors from four to three each. All other elements (new 230kV transmission lines, 138kV power line relocations and undergrounding west of the Property, and 12kV distribution line relocations) would be the same as the project originally proposed by SDG&E, as analyzed in both the Draft EIR and the RDEIR as the SOCRE "Proposed Project".

This report evaluates the impact of the Preservation Alternative on the Utility Structure and its conformance with the *Secretary Standards,* and concludes that the Preservation Alternative would not result in a substantial adverse change in the significance of the Utility Structure, and that the Preservation Alternative does conform with the *Secretary's Standards*, as discussed in detail in Section VII, below. Therefore, the Preservation Alternative would not have a significant impact on an historical resource under CEQA.

II. INFORMATION SOURCES

The Property has been previously surveyed multiple times for historic and architectural significance (McKenna, Moomjian, and TRC). Historic context information was synthesized, verified, and further supplemented by Chattel, Inc.'s own research. Robert Chattel and Gabrielle Harlan attended a site visit of the Property on July 17, 2015, and Ms. Harlan also attended a site visit on March 26, 2015. Primary research materials include: the Southern California Edison Company Collection and the Southern California Edison Records, 1848-1989 Manuscript Collection at the Huntington Library in San Marino, California; Sanborn fire insurance maps; historical background data available online from the San Diego Historical Society and the City of San Juan Capistrano history files; and historic drawings of the Property made available by SDG&E. In addition, the history of SDG&E was compiled from aforementioned surveys and several published works on the history of the company, including Iris Engstrand and Kathleen Crawford's *Reflections – A History of the San Diego Gas & Electric Company 1881-1991,* and William A. Myers*, Iron Men and Copper Wires – Centennial History of the Southern California Edison Company.*

III. PROPERTY HISTORY

The Utility Structure was constructed as part of a larger Capistrano Substation complex (the Substation Complex) on the Property, which is a large parcel of land adjacent to Camino Capistrano, a primary thoroughfare through San Juan Capistrano. The Property originally was owned by the Buchheim family. They were ranchers, and they had large orange groves in the area. However, by 1917, the Southern California Edison Company (SCE) had acquired the Property, and it soon began construction of its new Substation Complex, which was completed in 1918. A historic photograph illustrating the original Substation Complex, as well as historic photographs of the Utility Structure, are included as **Exhibit B**.

The original Substation Complex served as a connection point between SCE's 50 Hertz (Hz) transmission system and the 60 Hz system of San Diego Consolidated Gas & Electric Company. The electrical equipment in the Substation Complex included both indoor and outdoor components that were interdependent, and operated together as an integrated system.

The Utility Structure was the main structure in the Substation Complex. It was referred to in early construction drawings as the "indoor substation." However, the Substation Complex included several other structures. The Utility Structure was designed to have the most public presence on the street, as it was the only one that faced onto Camino Capistrano. Directly to the rear of the Utility Structure was a garage, which is no longer extant. All that remains of the garage structure is its scored concrete footprint. The original Substation Complex also included three residential structures, which were all located on the northern edge of the Property. The largest and most architecturally elaborate of the three was the Chief Operator's Cottage, and this residential unit was located in the closest proximity to the Utility Structure. The necessity for constructing the cottage on the Property was the fact that the chief operator was on call 24 hours a day. The other two cottages, which were substantially smaller and less architecturally elaborate, were workmen's cottages, which provided housing for the staff who helped to operate and maintain both the Substation Complex and other facilities in the region.

As is evidenced by historic site maps of the Property, another cottage was constructed sometime in the 1930s, bringing the total of residential cottages constructed as part of the substation to four. This later cottage was located in close proximity to the other two workmen's cottages. None of these cottages remain extant on the Property today.[3] Historic site maps illustrating the development of the Property are included as **Exhibit C**.

The Substation Complex also included outdoor equipment that was more industrial in nature than the structures and not enclosed in any interior space. Instead, the equipment was designed to withstand an outdoor environment . As such, the equipment is referred to as components of the "outdoor substation" in early drawings. The outdoor substation components included high and low

[3] According to the recent National Register nomination prepared for the Utility Structure, one of the four cottages on the Property was demolished or removed in 1960 when it was no longer needed for the operation of the Substation Complex. At approximately the same point in time, two of the cottages were relocated to the area of the Los Rios neighborhood in San Juan Capistrano. In 2002, the garage and the remaining cottage were also demolished. See Ilse Byrnes, *San Diego Gas & Electric Capistrano Substation Revised Nomination to the National Register of Historic Places*, 2014, Section Eight, Page 8.

voltage power lines that connected certain internal components of the substation (e.g., the frequency changer and switching station), racks and large transformers, control cables, circuit breakers, and meters. A cooling tower was located immediately adjacent to the Utility Structure on its north side (at the crux of the west and east wings of the structure) and a water tower was located at the northeast corner of the Property.

Also located to the immediate north of the Utility Structure was an equipment track, which was comprised of two metal rail lines set parallel to one another and oriented in a roughly north-south direction. The track traversed the small portion of the Property that lay between the outdoor substation and the Utility Structure. On this equipment track, equipment could be conveyed easily to and from the interior of the Utility Structure through doors located on its north side. The equipment track penetrated into the interior of the Utility Structure a distance of approximately five feet.

Other than foundation remnants and the outdoor portion of the equipment track, none of the outdoor substation structures or equipment is extant today.

The Utility Structure itself was designed in the shape of a “T” with two wings that were set perpendicular to one another. The structure also was functionally divided into two sections that corresponded to these two wings. The first section is rectangular-shaped and aligned with Camino Capistrano, the street that lies immediately to the west. This section was known historically as the "Converter Room,” and is referred to in this report as the “West Wing.” A lower rectangular section intersects with the West Wing at its midpoint on the east elevation. This section of the structure was historically known as the “Switch Room,” and is referred to in this report as the “East Wing.”

The West Wing housed a large piece of machinery called a transmission converter or "frequency changer." This piece of equipment is no longer extant today. The frequency changer served as the connecting point between SCE and SDG&E’s electrical systems. Its function was to provide conversion between the 50 Hz system of SCE and the 60 Hz system of SDG&E. This allowed electricity to flow from one company's power grid to the other. The high voltage power lines of both companies fed directly into the frequency changer; the lines of SCE arrived to it from the north while the lines of SDG&E came in from the south. In addition to housing this piece of machinery, it also appears that the interior space of the West Wing functioned to provide for the movement and temporary storage of other heavy equipment necessary to the regular maintenance and operation of the frequency changer. Such movement of heavy equipment on a fairly regular basis was apparently required due to the nature of the Property, which was perceived as somewhat constrained in size. The equipment track conveyed heavy equipment from the outdoor substation into the Utility Structure’s interior. Once inside, the machinery could be further conveyed to virtually any location within the interior of the West Wing by means of a Maris Bros. Hoist (i.e., a crane), which was installed as an integral part of the Utility Structure.

The East Wing, or “Switch Room”, housed a distribution switching station with small distribution controls for the 4kV system that fed the distribution circuits. Power lines feeding into the outdoor substation carried electricity over long distances. Therefore, for ease and efficiency in transport, this electricity needed to be at a high voltage. However, once the electricity arrived at the Substation Complex, it needed to be stepped down to a lower voltage before being delivered to customers. It was the function of the outdoor transformers to perform this stepping down, and this process worked both to reduce the loss of electricity and to make the system operate efficiently. The switch room located inside the East Wing was connected to the 4kV power lines located to the exterior by means of cables connected to low voltage circuit breakers. This set-up allowed for the Chief Operator and the workmen inside the Utility Structure to control, isolate, and repair electrical problems along the 4kV system almost immediately as they came up.

IV. REGULATORY SETTING

Federal and state law provides a framework for determining if (1) a structure is a historical resource for purposes of CEQA analysis, and (2) a proposed project, or alternative to that project, would result in a significant impact on an historical resource.

A. National Register of Historic Places (National Register)

The National Register is the nation's official list of historic and cultural resources worthy of preservation. Authorized under the National Historic Preservation Act of 1966, as amended, the National Register is part of a national program to coordinate and support public and private efforts to identify, evaluate, and protect the country's historic and archaeological resources. Properties listed in the National Register include districts, sites, buildings, structures, and objects that are significant in American history, architecture, archaeology, engineering, and culture. The National Register is administered by the National Park Service (NPS), which is part of the U.S. Department of the Interior. Resources are eligible for the National Register if they:

A) are associated with events that have made a significant contribution to the broad patterns of our history;
B) are associated with the lives of significant persons in our past;
C) embody the distinctive characteristics of a type, period, or method of construction, or that represent the work of a master, or that possess high artistic values, or that represent a significant and distinguishable entity whose components may lack individual distinction; or
D) have yielded or may be likely to yield, information important in history or prehistory.[4]

Once a resource has been determined to satisfy one of the above-referenced criteria, then it must be assessed for "integrity." Integrity refers to the ability of a property to convey its significance, and the degree to which the property retains the identity, including physical and visual attributes, for which it is significant under the four basic criteria listed above. The National Register recognizes seven aspects or qualities of integrity: location, design, setting, materials, workmanship, feeling, and association. To retain its historic integrity, a property normally must possess most of these aspects.

The National Register includes only those properties that retain sufficient integrity to accurately convey their physical and visual appearance from their identified period of significance. Period of significance describes the period in time during which a property's importance is established. It can refer simply to the date of construction, or it can span multiple years, depending on the reason the property is important. The period of significance is established based on the property's relevant historic context and as supported by facts contained in the historic context statement.

Relationship to Preservation Alternative

The Property is not currently listed in the National Register and has not been determined eligible for listing on the National Register. As previously discussed, the SHRC has recommended that the Keeper determine that the Utility Structure is eligible for listing, but the Keeper has thus far declined to make a determination of eligibility and has returned the nomination to the SHPO for substantive and technical revisions. However, for purposes of this report, consistent with the RDEIR, it is assumed that the Utility Structure qualifies as an historical resource .

[4] *National Register Bulletin #15: How to Apply the National Register Criteria for Evaluation* (National Park Service, 1990, revised 2002).

B. Secretary of the Interior's Standards for Treatment of Historic Properties

The Secretary of the Interior's Standards for the Treatment of Historic Properties with Guidelines for Preserving, Rehabilitating, Restoring, and Reconstructing Historic Buildings or the Secretary of the Interior's Standards for Rehabilitation and Guidelines for Rehabilitating Historic Buildings (Weeks and Grimmer, 1995) (previously defined as the *Secretary's Standards*), were promulgated pursuant to the National Historic Preservation Act, 16 U.S.C. 470 et seq. and provide general guidance on treatments for historical resources and their immediate surroundings or setting. The NPS identifies four treatment approaches, which include preservation, rehabilitation, restoration and reconstruction. These treatments, in hierarchical order, are described as follows:

> **Preservation** focuses on the maintenance and repair of existing historic materials and retention of a property's form as it has evolved over time.
>
> **Rehabilitation** acknowledges the need to alter or add to a historic property to meet continuing or changing uses while retaining the property's historic character.
>
> **Restoration** depicts a property at a particular period of time in its history, while removing evidence of other periods.
>
> **Reconstruction** re-creates vanished or non-surviving portions of a property for interpretive purposes.[5]

The *Secretary's Standards* are not prescriptive or technical, but "are intended to promote responsible preservation practices" and "provide philosophical consistency" regarding treatments for historical resources (NPS, 2003). The *Secretary's Standards* are intended to be flexible and adaptable to specific project conditions to balance continuity and change while retaining historic building fabric to the extent feasible. Their interpretation requires the exercise of professional judgment and balance of the various opportunities and constraints of any given project based on use, materials retention and treatment, and compatibility of new construction. Not every standard necessarily applies to every aspect of a project, nor is it necessary to comply with every standard to achieve conformance.

Relationship to Preservation Alternative

As discussed in greater detail below, CEQA utilizes the *Secretary's Standards* as a means of determining whether a project, or alternative to a project, would have a significant, or less than significant, impact on an historical resource. In determining whether the Preservation Alternative is in conformance with the *Secretary's Standards*, the rehabilitation standard has been used, as detailed in Section VII.B, below.

C. California Register of Historical Resources (California Register)

The California Register is the State's version of the National Register program. It was enacted in 1992, and became official on January 1, 1998.

The California Register was established to serve as an authoritative guide to the State's significant historical and archaeological resources (California Public Resources Code (PRC) §5024.1). State law provides that the California Register shall include historical resources that the SHRC determines are significant and meet any of the following four criteria (which parallel National Register criteria):

[5] http://www.nps.gov/tps/standards/four-treatments.htm (accessed 22 September 2015)

1. Is associated with events that have made a significant contribution to the broad patterns of California's history and cultural heritage;
2. Is associated with the lives of persons important in our past;
3. Embodies the distinctive characteristics of a type, period, region, or method of construction, or represents the work of an important creative individual or possesses high artistic values; or
4. Has yielded, or may be likely to yield, information important in prehistory or history.

The California Register also includes properties which have been formally determined eligible for listing in, or are listed in, the National Register.

Relationship to Project

The Property is not currently listed in the California Register.

D. California Environmental Quality Act (CEQA, Public Resources Code § 21000 et seq.)

According to CEQA, an historical resource is a resource listed in, or determined eligible for listing in, the California Register.

If a proposed project is expected to cause a substantial adverse change in a historical resource, that constitutes a significant impact on the historical resource. "Substantial adverse change in the significance of an historical resource means the physical demolition, destruction, relocation, or alteration of the resource or its immediate surroundings such that the significance of an historical resource would be materially impaired" (PRC §15064.5 (b)(1)). Section 15064.5 (b)(2) of the PRC provides that an historical resource is *materially impaired* when a project:

(A) demolishes or materially alters in an adverse manner those physical characteristics of an historical resource that convey its historical significance and that justify its inclusion in, or eligibility for, inclusion in the California Register…;
(B) demolishes or materially alters in an adverse manner those physical characteristics that account for its inclusion in a local register... or its identification in an historical resources survey... unless the public agency reviewing the effects of the project establishes by a preponderance of evidence that the resource is not historically or culturally significant; or
(C) demolishes or materially alters those physical characteristics of an historical resource that convey its historical significance and that justify its inclusion in, or eligibility for, inclusion in the California Register... as determined by a lead agency for the purposes of CEQA.

CEQA utilizes the *Secretary's Standards* as a means of evaluating when a proposed project will generally be found to have a less-than-significant impact on an historical resource. Section 15064.5(b)(3) of the State CEQA Guidelines provides:

> Generally, a project that follows the Secretary of the Interior's Standards for the Treatment of Historic Properties with Guidelines for Preserving, Rehabilitating, Restoring, and Reconstructing Historic Buildings or the Secretary of the Interior's Standards for Rehabilitation and Guidelines for Rehabilitating Historic Buildings (1995), Weeks and Grimmer, shall be considered as mitigated to a level of less than a significant impact on the historical resource.

Similarly, Section 15126.4(b)(1) of the State CEQA Guidelines states:

> Where maintenance, repair, stabilization, rehabilitation, restoration, preservation, conservation or reconstruction of the historical resource will be conducted in a manner consistent with the Secretary of the Interior's Standards for the Treatment of Historic Properties with Guidelines for Preserving, Rehabilitating, Restoring, and Reconstructing Historic Buildings (1995), Weeks and Grimmer, the project's impact on the historical resource shall generally be considered mitigated below a level of significance and thus is not significant.

<u>Relationship to Preservation Alternative:</u>

The Preservation Alternative has been evaluated in order to determine if it would result in a significant impact on the Utility Structure. As discussed in Section VII.A, below, the Preservation Alternative would not materially impair the Utility Structure, and therefore would not cause a substantial adverse change in its historic significance. This conclusion is reinforced in Section VII.B, below, where it is demonstrated that the Preservation Alternative would not cause a substantial adverse change in the historic significance of the Utility Structure because the Preservation Alternative conforms to the *Secretary's Standards*.

V. PROPERTY ASSESSMENT

A. Physical Description

<u>Overview</u>

The Utility Structure is a single-story building with a "T"-shaped footprint. It is one-story in height, and it has a flat roof with parapet walls. The walls, roof and floor are poured-in-place reinforced concrete. The windows are metal sash, multi-light divided casements. Contemporary photographs of the Utility Structure and the Property as they currently exist today are included as **Exhibit D**.

The Utility Structure is divided into two wings, in terms of both its architectural articulation and its historic function—the West Wing (the portion of the structure that runs parallel to Camino Capistrano) and the East Wing. Architecturally, the two wings are differentiated from each other in terms of both the amount of architectural decoration that they possess and in their physical massing. The West Wing measures 87 feet, 4 inches in length and 32 feet, 4 inches deep. The East Wing is a rectangular mass that is set perpendicular to the West Wing, intersecting the West Wing at its midpoint. It is the shorter of the two wings, measuring only 73 feet, 6 inches long. However, it has approximately the same width as the West Wing at 32 feet, 8 inches in width. The West Wing is the taller of the two wings, with walls that are 30 feet, 8 inches in height. The East Wing, which is set to the rear of the Property and away from the street, is significantly lower. Its walls are 22 feet, 10 inches in height.

The two wings are differentiated from each other in terms of architectural decoration as well. The West Wing has a restrained use of the Neoclassical Revival style. Elements of Classical Revival style architecture include the strict symmetry of the wing's façade, especially in relation to its fenestration pattern, as well as the decorative cornice that runs around its entire perimeter. In contrast, the East Wing is relatively stark and unadorned, although it too displays a strong sense of symmetry in its fenestration pattern. The only exterior ornamentation on the East Wing is a horizontal band at the top of its parapet wall that is of board-formed concrete and some "blind panels", also constructed of concrete, that are located under each of the windows on its north and south facades.

The interior of the Utility Structure is divided into two primary spaces that correspond to the structure's massing, as they are large, rectangular volumes connected by a pair of interior doors. The space of the West Wing is essentially one large, voluminous room, while the space of the East Wing is currently subdivided into a series of compartmentalized interior spaces divided by gypsum-board partition walls.

In its design, the Utility Structure features practices common to industrial buildings of its era; the West Wing with its detailed façade and large windows is intended as the public face of the structure, while the East Wing is more utilitarian. In comparison to the East Wing is relatively unfenestrated, with much smaller windows placed high upon its north and south facades. The East Wing was designed as a large box with small exterior openings to allow for the greatest amount of wall surface for the placement of switching of equipment. This pattern is typical of electrical utility buildings of the era, including the Pacific Gas & Electric Company (PG&E) Powerhouse in Sacramento and the Jessie Street Substation in San Francisco, both of which are considered exemplars of this building type.

In architectural historian Mark D. Kessler's book, titled *The Early Public Garages of San Francisco: An Architectural and Cultural Study, 1906-1929*, he dedicates a brief section to the architectural development of electrical substations at the turn of the twentieth century. Although Kessler's work focuses on the design of electrical substations in northern California, and particularly substations in San Francisco designed for the PG&E, his work is applicable to substation design throughout the State during this era. Many architects in California designed electrical substations of similar design to those erected by PG&E.

In his book, Kessler explains how the design of substations represented a curious dichotomy, one in which there was a distinct tension between the way that the exterior of a structure was represented to the public and the manner in which it functioned and was designed on the interior. In regard to substation structures at the turn-of-the-century, Kessler writes as follows: "…the substation is related to the exposition building, in a manner similar to the link between the garage and the train station."[6] The Utility Structure conforms to the description provided by Kessler of a typical substation as a smaller structure "of reinforced concrete faced in stucco," and the appearance of being a miniaturization of a larger prototype.

As Kessler writes, "the exterior [of substation structures] focused exclusively on the representation of the client [the power company that commissioned the building] to the public, the interior determined solely by the dictates of efficiency and utility." Therefore, the challenge for architects of substation facilities at the turn of the century was to design a structure that presented a formal and decorative appearance to the public that connoted qualities such as reliability and dependability—such as might be found on a more publically-oriented building such as a bank building, and which would invite the public into its interior—while also working to accommodate the technical functions of a working substation in the structure's interior, a decidedly non-public function.

The Utility Structure, which was part of the original Substation Complex, illustrates the dichotomy described by Kessler. The front of the structure, the West Wing that faces onto Camino Capistrano, exhibits the care that was taken by its unknown architect to present a dignified and public face to the street. As described in the recent National Register nomination, the "detailed primary façade was the most prominent and visible aspect of the substation complex, intended to be viewed by the community in front of the more prosaic and utilitarian elements of the complex."[7] In contrast, the East Wing is utilitarian and represents the purely functional, rather than the semi-public, aspect of the

[6] See Mark D. Kessler, *The Early Public Garages of San Francisco: An Architectural and Cultural Study, 1906-1929*. Jefferson (North Carolina: McFarland & Company, Inc., 2013), 174.

[7] See Byrnes, Section 8, Page 10.

Utility Structure. This dichotomy between the West Wing and the East Wing is illustrated in a Significant Spaces Diagram that is attached as **Exhibit D**. The Substation Complex worked as an integrated whole in order to provide electrical service to the public; however, it was the West Wing of the Utility Structure that conveyed to the public the image of the electrical company.

<u>Detailed Description of the Exterior Elevations of the Utility Structure</u>

West Wing – West Elevation

The west elevation, or front façade, of the Utility Structure, which is part of the West Wing, faces Camino Capistrano. This elevation exhibits five large metal sash, divided-light casement windows with transom windows above them. These windows are placed symmetrically upon the elevation. In their design, they are windows typical of industrial applications during the early twentieth century; they have wire glass panes. Today, the window frames are covered with plywood to the exterior of the structure in order to protect the glass panes from breakage and to secure the structure from entry and vandalism. However, the windows are still in place behind the plywood. To the interior of the West Wing, the casement windows have a wheel and pulley system mechanism that allows all five windows to be opened at once. A band molding runs parallel to the exterior window sills. Beneath the band molding is a concrete band suggesting a plinth. Above the windows is an architrave and a frieze containing the words “SAN DIEGO GAS & ELECTRIC” beneath the projecting cornice.

West Wing – North Elevation

This elevation includes a pair of doors, as centered upon it, which provide access to the interior of the West Wing. The current doors are replacement doors, but originally, they were frame doors with glass panes to the interior. Over each door was a single transom, and over the transoms was located a 5/5 divided light transom. To each side of the doors were sidelights that spanned the height of both the doors, the single transom, and the divided light transom. These sidelights were comprised of two different windows on each side of the door. The bottom portion was a divided light window in a 2/6 configuration. The upper window was arranged in a 2/2 configuration. While the doors, single-pane transoms, and the lower portion of the sidelights are no longer extant, the upper divided-light transom and upper 2/2 sidelights appear to remain in place behind a plywood covering. There is also a projecting cornice on this elevation. Originally, exterior light fixtures were placed on either side of the entry doors, but these are no longer extant.

West Wing – East Elevation

The eastern elevation of the West Wing was designed to accommodate two windows that match those on the west elevation. These two windows flank the East Wing as it intersects with the midpoint of the West Wing. Each window is symmetrically placed on the wall in relation to the midpoint of the West Wing in its north-south orientation. There is also a projecting cornice on this elevation.

West Wing – South Elevation

The south elevation of the West Wing mirrors the north elevation in size and massing. The main entry on the south elevation was constructed exactly like that on the northern elevation. It is comprised of two paired doors. As originally designed, these paired doors were topped with single-pane transoms, a divided-light transom above that, and sidelights. However, like the north elevation, the paired doors are replacements, the single-pane transoms and lower portions of the sidelights are no longer extant. However, the upper portions of the sidelights and the upper, divided-light transoms are still extant and simply covered with plywood. Like the north elevation, the two light fixtures that once flanked the doors are no longer extant. There is also a projecting cornice on this elevation.

West Wing – Interior

The interior of the West Wing is one large, voluminous space. On the east wall, it has an interior doorway that serves to connect the space with that of the adjacent East Wing. As illustrated in the 1917 architectural drawings for the Utility Structure, the doorway was designed to consist of two matching metal doors with a transom window above it. The doors and transom remain extant, although it appears that a wood barrier has been placed on one side of them (if not two) to prevent access. The floor of the West Wing is scored concrete. To the north end of the space, the equipment track that exists to the exterior of the north elevation comes into the West Wing a distance of 5-10 feet. The equipment track is comprised of steel rails embedded into the concrete floor, with which they are almost flush. The ceiling is exposed concrete beams. At the plane of the ceiling there is a built-in ledge that supports a Maris Bros. hoist of steel.

<u>East Wing</u>

East Wing – North Elevation

The north elevation features seven metal sash windows in a 4/4 configuration. They are similar in design to the primary windows on the West Wing (those located on the west and east elevations). However, they are much smaller and located high on the wall, and at the same level as the divided-light upper transom located above the doors on the north elevation of the West Wing. At the very top of the walls is a narrow concrete band of board-formed concrete; it is at the same level as the architrave on the West Wing. Beneath the sill of each of these seven windows is a recessed concrete panel, or “blind panel,” that is intended to suggest that the window opening is much larger than it actually is (likely an effort, in effect, to more closely match the dimensions of the windows located on the West Wing). Also located on the north elevation, below the fourth and fifth of the seven windows (left to right), are two small windows. These two windows originally opened into the restroom and to the office space to the East Wing’s interior. Today, like the rest of the windows on the north elevation of the East Wing, they are covered in plywood. One of the blind panels, the second from the east end of this elevation, has been altered in order to accommodate a new exterior door with a ramp, as well as a small gable-roofed porch enclosure over this new entry. The first blind panel from the east end of this elevation has also been altered to accommodate the opening for a loading dock.

East Wing – East Elevation

The east elevation of the East Wing features a single, centrally placed doorway. It has a single wide, solid panel door. Originally, there was a transom window above it in a 3/3 configuration, but it is no longer extant. As originally designed, this doorway was flush with the finished floor level of the structure’s interior. However, today, this door rests on a small stoop located outside the doorway. The stoop is flanked with pipe metal railings that appear to date from the late 1920s or 1930s, as they are vaguely Streamline Moderne in their design. At the very top of the wall is a narrow concrete band of board-formed concrete.

East Wing –South Elevation

The south elevation of the East Wing essentially mirrors that of the northern wing as originally designed, with the exception of the two windows that were integrated into the design of the blind panels. There are seven metal sash, divided-light windows in a 4/4 configuration with recessed, blind panels of concrete placed below them in order to give the impression of larger window openings, similar to the ones located on the West Wing. At the very top of the wall is a narrow concrete band of board-formed concrete.

East Wing – Interior

The interior of the East Wing was originally designed as a large open space with the exception of a small office and restroom that were placed in the center of the north wall, as shown on the original floor plans for the structure. Subsequently, however, a mezzanine level was added and the space on both levels broken up into a series of compartmentalized rooms, divided by gypsum board partition walls. These rooms are generally arranged to an open space to the center of the wing. An interior stair was also added adjacent to the original restroom in order to access the mezzanine level. These alterations remain in place today.

At the western end of the East Wing, the interior space of the East Wing connects with that of the West Wing by means of an interior doorway. As illustrated in the 1917 architectural drawings for the Utility Structure, the doorway was designed to consist of two matching metal doors with a transom window above it. The doors and transom remain extant, although it appears that a wood barrier has been placed on one side of them to prevent access. At the eastern end of the East Wing, at the location of the single door that leads to the exterior, is an interior stair comprised of three steps, which appears to be an addition that was added when the concrete pad, or stoop, to the exterior of the door was added.

B. Alterations

What follows is a list of the known alterations that have occurred at both the former Utility Structure and the rest of the Substation Complex since the original construction of the Substation Complex in 1918. They are as follows:

<u>Alterations to the Utility Structure</u>

West Wing

- Replacement of the door and sidelights located on the north and south elevations (the transom window located above both of these doors appears to be intact).

- Removal of the frequency changer located inside the West Wing.

- The infill of the “pit" located at the northern end of the interior of the West Wing (as shown on the original architectural drawings).

- The alteration, at an unknown point in time (but likely sometime soon after June 8, 1928, when the Substation Complex was transferred from Southern California Edison to the San Diego Consolidated Gas and Electric Company), of the painted signage on the frieze located on the front of the structure. To reflect the change in ownership, it was altered to read “San Diego Gas & Electric.” The original signage reflected the original ownership of the structure and read as follows: “Southern California Edison Company.”

- Addition of plywood covering on windows located on the west and east elevations, as well as over the transoms above the doors on the north and south elevations.

- Removal of the two exterior light fixtures that flanked the exterior doors located on the north and south elevations (four light fixtures, total).

- Removal of interior light fixtures.

- Removal of rain gutters.[8]

East Wing

- Addition of interior mezzanine level at an unknown date (but likely within the last two decades).

- Addition of interior stairway to access mezzanine level.

- Removal of original electrical switching equipment located to the interior of the East Wing.

- Removal of original fixed ladder system to access the roof (as shown in the original architectural drawings).

- Division of large undifferentiated space to the interior of the East Wing into compartmentalized rooms, as divided by gypsum-board covered walls and as arranged around a central open space.

- Addition of plywood covering over the exterior window openings located on the north and south facades.

- Alteration of an original concrete "blind panel" located on the north elevation to become an exterior door entry.

- Alteration of an original concrete "blind panel" located on the north elevation to allow the construction of a loading dock.

- Addition of a covered entrance porch and ramp at the location of the altered "blind panel" located on the north elevation.

- Replacement of a historic exterior door located on the east elevation.

- Removal of the transom window located above the exterior door located on the east elevation.

- Addition of a concrete pad with steps adjacent to the exterior door located on the east elevation.

- Addition of a pipe metal railing at the location of the exit door located on the east elevation .

- Removal of interior light fixtures.

[8] There is no evidence on the original architectural drawings that the Utility Structure was originally constructed with rain gutters; however, it is quite possible that there were rain gutters or that they were installed shortly after the building's completion, in which case they likely would still be considered a historic feature. Jeannette McKenna's report contends that there were originally rain gutters on the building, but no evidence has been located to substantiate that assertion. See McKenna, 33.

- Removal of rain gutters.[9]

Alterations to the Property

- Expansion of the Property on September 19, 1940 through acquisition of a parcel located to the immediate east of the original substation property.

- Removal of original outdoor substation equipment (which was first removed and replaced in the 1940s, then completely removed at a later date).[10]

- Addition of an outdoor substation on the eastern portion of the Property.

- Removal of the Chief Operator's cottage and the three workmen's cottages.

- Installation of contemporary landscaping, including a berm and trees located to the west of the Utility Structure in the front-yard setback adjacent to Camino Capistrano (this appears to have occurred sometime in the 1970s or 1980s based on undated, but contemporary, landscape drawings).

- Addition of wood fencing along the northwest side of the Property (adjacent to Camino Capistrano).

- Addition of metal barrier/gate along the west side of the Property (adjacent to Camino Capistrano) and south of the Utility Structure.

- Addition of wood fencing along the west side of the property (adjacent to Camino Capistrano) and north of the Utility Structure.

C. Character-Defining Features

The NPS defines character-defining features as "the overall shape of the building, its materials, craftsmanship, decorative details, interior spaces and features, as well as the various aspects of its site and environment."[11] Establishing character-defining features is helpful in determining whether a project will result in material impairment that results in the loss of those physical characteristics that convey the significance of an historical resource. In *Preservation Brief 17: Architectural Character: Identifying the Visual Aspects of Historic Buildings as an Aid to Preserving Their Character*, the NPS recommends a three-step process to identify a building's visual character and is employed below.

Overall visual aspects:

- Prominence of the West Wing, orientation to and setback from the street.
- Open front-yard setback (landscape has been altered from original).
- T-shaped plan comprised of the West Wing and the East Wing.

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[9] There is no evidence on the original architectural drawings that the Utility Structure was originally constructed with rain gutters; however, it is quite possible that there were rain gutters or that they were installed shortly after the building's completion, in which case they likely would still be considered a historic feature. Jeannette McKenna's report contends that there were originally rain gutters on the building, but no evidence has been located to substantiate that assertion. See McKenna, 33.

[10] The Substation Complex ultimately required full replacement after higher voltage substations were constructed to the north in Orange and Los Angeles Counties, and to the south in Oceanside and San Diego County, and the electrical grid grew.

[11] See Lee H. Nelson, FAIA, "Preservation Brief 17: Architectural Character Identifying the Visual Aspects of Historic Buildings as an Aid to Preserving Their Character," National Park Service, Technical Preservation Services.

- Neoclassical Revival style and decorative detailing on the West Wing.
- Symmetrical design of all of the elevations (with the exception of the north elevation of the East Wing, which has been altered).
- Regular pattern of divided-light, operable steel windows with wire glass panes on the West Wing, including the wheel and pulley system that operated all five windows on west elevation with one mechanism, as well as fixed-transom windows located above the operable sash.
- Door fenestration on the north and south elevations of the West Wing (original doors, sidelights and transoms have all been altered).
- Flat roof.

Visual character at close range:

- Smooth plaster finish on the exterior as well as the board-formed concrete finish visible in some locations.

Visual character of interior spaces, features and finishes:

- Open quality of the interior of the West Wing; the equipment track (or rails) located to the exterior and interior of the north side of the West Wing.
- Maris Bros. hoist (i.e., crane) on the interior of the West Wing.
- Interior paired doors with transom above that connects the West and East Wings.

D. Integrity

The Utility Structure has a fairly high degree of integrity, particularly the West Wing. There, the only real alterations to the structure include the replacement of the doors on the north and south elevations. The only other significant alterations relating to the West Wing are in regard to its setting. At an unknown date, most likely in the 1970s or 1980s, based on the style of some undated landscape plans for the Utility Structure that are in the drawing collection of SDG&E, earthen berms and trees were added to the site that are not in keeping with the structure's historic appearance as a public presence along Camino Capistrano. Instead, these landscaping additions obscure the West Wing from public view and, in addition, introduce potential water infiltration issues into the structure's interior. Other modifications to the structure in the area of the West Wing are relatively insignificant, as they are easily reversible. These modifications include the addition of a plywood covering over all of the structure's windows and the installation of security bars over the windows to the structure's interior.

The East Wing has a lesser degree of integrity than the West Wing, although it is still moderately high. Alterations to the East Wing include the modification of one of the "blind panels" on the north elevation to accommodate an entry door and the construction of a covered entry porch with ramp in this location. Another alteration is the modification of the adjacent "blind panel" on the same elevation in order to provide a loading dock located to the East Wing's exterior. Other alterations to the East Wing include the replacement of the single door located on the east elevation, the removal of the transom above the door, the addition of a mezzanine level to the interior and the addition of a staircase to provide access to the mezzanine level, and the compartmentalization of what was once one large volume of space through the addition of gypsum board partition walls throughout the space.

The original Substation Complex has a low degree of integrity overall. Alterations to the Property include the removal of the original outdoor substation equipment (and related outdoor components such as the water tower, circuit breakers, high and low voltage power lines, racks and large transformers, control cable, meters, a water tower; and cooling tower) and the garage, the Chief Operator's cottage, the two workmen's cottages constructed in 1918, the additional workman's cottage constructed in the 1930s, as well as the small orchard that existed on the site.

VI. PRESERVATION ALTERNATIVE

The Preservation Alternative involves the retention and rehabilitation of the West Wing for continued use, the removal of most of the East Wing, and related improvements at the Property. The East Wing includes significantly less architectural articulation and public orientation than the West Wing, which faces the street. As previously described, the East Wing is located to the rear of the West Wing and was not intended to be seen from the street in the same manner as the West Wing. However, given that most of the East Wing would be removed, the Preservation Alternative seeks to balance continuity and change through rehabilitation of the retained portion, the street-facing West Wing.

In order to incorporate the retained portion of the existing Utility Structure into the design of the proposed rebuilt substation, the Preservation Alternative includes modifications to the design, specifications, and layout of the substation. The primary modification to the substation design is a reduction in the size of the rebuilt 138/12 kV substation that would be located on the "lower pad" portion of the Property. As previously discussed, the analysis below of the Preservation Alternative is based on the Drawing Set for the Preservation Alternative attached as **Exhibit A**.

Substation design modifications include:

- The existing earthen mounds, vegetation and trees along the western edge of the Property (between Camino Capistrano and the existing Utility Structure) would be removed and replaced with landscaping that returns the appearance of the existing Utility Structure's setting to one strongly reminiscent of its original appearance.
- Because the substation grade would be raised approximately 5 feet to accommodate vehicles carrying equipment, an approximately 5-foot-tall retaining wall would be constructed parallel to the northern and eastern walls of the retained West Wing. The retaining wall would be set back a minimum of 5 feet from the existing West Wing walls to provide a personnel access way on these sides of the building.
- The western perimeter of the Property (along Camino Capistrano) would be improved with have a masonry wall approximately 10 feet tall on the inside of the rebuilt substation and when viewed from the street would vary from approximately 12 feet to 15 feet in height. This is due to the fact that the substation grade behind the wall would be raised by approximately 5 feet. The lower approximately 5 feet is the retaining wall, which would be coupled with an upper masonry wall approximately 10 feet in height to collectively serve as a substation security and screen wall. The northern and southern perimeter walls would remain at approximately 10 feet in height, identical to the Proposed Project.
- The security screen wall would abut the existing Utility Structure on the north and south sides, terminating approximately 4 inches from the structure (refer to Attachment 42) and creating separation between the existing Utility Structure and the western perimeter wall.
- The southern and western walls of the retained portion of the existing Utility Structure would be located outside of the secured substation facility and would be visible from Camino Capistrano. The northern and eastern walls of the existing Utility Structure would effectively act as part of the substation security wall.
- New steel replacement doors would be installed in the southern, eastern and northern walls of the existing Utility Structure and would replace the existing doors at these locations. The northern and eastern doors would serve as part of the security wall.

- A driveway access to the existing Utility Structure would be constructed from the main substation access drive to the structure's southern door.
- The southern driveway's vehicle access gate to the rebuilt substation would be set back approximately 80 feet from Camino Capistrano.
- The northern driveway's access gate would remain (similar to the Proposed Project) set back approximately 35 feet from Camino Capistrano.
- The northern and southern vehicular access gates would be approximately 30 feet in width, each comprised of a pair of black wrought iron sliding gates, each approximately 15 feet in width.
- Grading and the phased site development, including cut and fill, would be similar to that of Proposed Project substation design.

With respect to the existing Utility Structure itself, the West Wing would be retained and rehabilitated in accordance with the *Secretary's Standards*. The East Wing would be removed to provide adequate room for redevelopment of the substation. The northern and eastern walls of the retained portion of the existing Utility Structure would serve as part of the security wall of the rebuilt substation, and could only be entered from the exterior (which would be inside the substation security wall). Proposed modifications to the existing Utility Structure include the following:

- East Wing Demolition – 12 inches of the East Wing roof and walls would be retained at the point where the East Wing intersects the West Wing. This work is designed to allow the remaining portion of the roof and wall visually to read as a "ghost" of the East Wing once it is removed.

- West Wing Rehabilitation:
  - Western Wall – The exterior wall adjacent to where earthen mounds would be removed would be repaired and waterproofed. The concrete wall iron jacking would be repaired at locations where steel rebar is exposed at western interior wall. Window rehabilitation would include removal of existing glazing, repairing existing sash and frames, and reglazing with like-kind translucent wire glass. Security bars or polycarbonate security glass as storm windows would be installed on all windows on the interior.
  - Northern Wall – Deteriorated, non-original doors, sidelights, and transom windows would be replaced to match the original. Doors, sidelights and transoms would be constructed of steel rather than wood for increased security. Due to lack of visibility from the street, glazing is not proposed, but rather this door assembly would be constructed exclusively of steel following the original pattern. The northern wall and replacement door would serve as part of the security wall of the rebuilt substation and would only be accessed from inside the substation (i.e., inside the security walls).
  - Eastern Wall – The interior door located at the juncture of the East Wing with the West Wing would be replaced with a new exterior door to match the original, but designed for exposure to the elements. Due to the lack of visibility from the street, glazing would not be included in either the new exterior door or existing windows, but rather these assemblies would be constructed exclusively of steel following the original pattern. The eastern wall, windows and replacement door would serve as part of the security wall of the rebuilt substation and would only be accessed from inside the substation (i.e., inside the security walls).
  - Southern Wall – Deteriorated, non-original doors, sidelights, and transom windows would be replaced to match the original. Doors, sidelights and transoms would be constructed of steel rather than wood for increased security. Due to the visibility from the street, it is proposed to include translucent wire glass at the transom only, but otherwise the new door assembly would be

constructed of steel following the original pattern. Where glazing occurs at the transom, security bars would be installed on the interior.

- o Interior Window Sills – Damage to concrete would be repaired at windows sills where water infiltration has occurred.
- o Interior Crane – The moveable crane would be retained.
- o Lighting – Development and implementation of a lighting plan to include exterior wall sconces on the north and south walls, which would operate manually.

VII. REVIEW OF PRESERVATION ALTERNATIVE

The Preservation Alternative was reviewed in detail in order to determine its potential for causing a substantial adverse change to the Utility Structure. To make this determination, pursuant to the State CEQA Guidelines, the Preservation Alternative was assessed for its potential to materially impair the Utility Structure and, as part of that inquiry, whether it conforms with the *Secretary's Standards*.

As detailed in the analysis below, the Preservation Alternative would not result in a substantial adverse change to the Utility Structure, and therefore would have a less-than-significant impact on the assumed historical resource, because the Preservation Alternative has been designed, and would be implemented, in conformance with the *Secretary's Standards* and otherwise would not materially impair the Utility Structure.

A. Material Impairment/Substantial Adverse Change

The following discussion assesses whether or not the Preservation Alternative would result in material impairment of the Utility Structure through alteration of those physical characteristics that convey its historical significance and justify its assumed eligibility for listing on the National Register under Criterion A. These physical characteristics are the character-defining features identified in Section VI.C, above.

Overall visual aspects:

- *Prominence of the West Wing, orientation to and setback from the street*
  Under the Preservation Alternative, the West Wing and its relationship to the street would be unchanged.

- *Open front-yard setback (landscape has been altered from original)*
  The open front-yard setback would be retained and enhanced by the restoration of the original grade to be consistent with the historic appearance. This area would be further improved with landscape planting that is strongly reminiscent of the original appearance.

- *T-shaped plan comprised of a West Wing and East Wing*
  Most of the East Wing would be removed, but a small portion would be retained to reference the original T-shaped plan. As previously discussed, the East Wing has a substantially more utilitarian design than the West Wing. The East Wing was designed as a more utilitarian container, or box, the primary purpose of which was only to house equipment supportive of the operations of the Substation Complex. In comparison to the West Wing, which fronts on Camino Capistrano and has therefore always been visible to the public, the East Wing is located further from the street and largely unnoticed because the view of it is largely blocked by the West Wing. Moreover, while the East Wing has a moderately high degree of integrity, it is somewhat compromised by alterations to the exterior and interior and therefore has substantially less integrity than the West Wing. The retained portion of the Utility Structure, the West Wing, would continue to serve both primary use as the public face of the electric

company as well as the secondary use of providing space for support of substation operations.

- *Neoclassical Revival style and decorative detailing on the West Wing*
  The West Wing and its Neoclassical Revival style and decorative detailing would be retained and rehabilitated.

- *Symmetrical design of all of the elevations (with the exception of the north elevation of the East Wing, which has been altered).*
  The West Wing would retain its symmetry when viewed from the street.

- *Regular pattern of divided-light, operable steel windows with wire glass panes on the West Wing, including the wheel and pulley system that operated all five windows on west elevation with one mechanism, as well as fixed-transom windows located above the operable sash*
  The West Wing would retain its fenestration. Windows facing the street will be restored including the wheel and pulley system.

- *Door fenestration on the north and south elevations of the West Wing (original doors, sidelights and transoms have all be altered)*
  New doors, sidelights and transoms on the north and south elevations would match the historic pattern, but would be constructed of steel rather than wood for increased security.

- *Flat roof*
  The flat roof on the retained West Wing would be unaltered.

Visual character at close range:

- *Smooth plaster finish on the exterior as well as the board-formed concrete finish visible in some locations*
  Exterior wall finishes would be restored on the retained West Wing.

Visual character of interior spaces, features and finishes:

- *Open quality of the interior of the West Wing; the equipment track (or rails) located to the exterior and interior of the north side of the West Wing*
  The open interior of the West Wing would be retained in support of the electrical substation. 5' of the exterior equipment track to the north of the West Wing, as well as the entirety of the equipment track to the interior of the structure, would be retained.

- *The Maris Bros. hoist (i.e., crane) on the interior of the West Wing*
  The hoist would be retained.

- *Interior paired doors with transom above that connects the West and East Wings*
  The interior door at the location of the removed East Wing would be replaced with a new exterior door to match the original, but designed for exposure to the elements. It would be constructed of steel rather than wood for increased security following the original pattern.

For these reasons, the Preservation Alternative would not materially impair the ability of the Utility Structure to convey its historical significance and, therefore, the development of the Preservation Alternative would not cause a substantial adverse change in the historic significance of the Utility Structure.

B. Conformance with the *Secretary's Standards*

As previously discussed, another way to demonstrate that a project would not materially impair an historical resource is to show that the project conforms with the *Secretary's Standards.* Pursuant to Sections 15064.5(b)(3) and 15126.4(b)(1) of the State CEQA Guidelines, a project that follows the *Secretary's Standards* generally has a less-than–significant impact on an historical resource.

The appropriate, overarching treatment in judging the Preservation Alternative's impact on the Utility Structure is rehabilitation, which is defined as "the act or process of making possible a compatible use for a property through repair, alterations, and additions while preserving those portions or features which convey its historical, cultural, or architectural values."[12] The Preservation Alternative conforms with each of the applicable rehabilitation standards in the *Secretary's Standards* for the following reasons:

1. *A property will be used as it was historically or be given a new use that requires minimal change to its distinctive materials, features, spaces, and spatial relationships.*

   In conformance with Standard 1, the Property would continue to be used for its historic purpose in support of an electrical substation. While Standard 1 does allow for some flexibility in use if the historic use cannot be maintained, it also stresses that new uses should always be compatible with the historic use. This is because introducing a new use into a structure—even a new use identified as compatible—has the potential to change, obscure, or destroy character-defining spaces, materials, features, or finishes to a greater extent than maintaining the use for which a structure was originally designed. Therefore, in preservation practice, keeping the historic use is almost always preferable to introducing a new use. The continued use and operation of the retained portion of the Utility Structure as a functioning element of the rebuilt electrical substation for which it was designed is not only consistent with its historic use, but also with what is generally considered best preservation practice.

   If the Keeper concurs with the recommendation of the SHRC that the Utility Structure is eligible for listing on the National Register, it will be found eligible for significance under Criterion A for its association with electrical power distribution in Southern California. As described in the nomination for the Property to the National Register, the original Substation Complex "was the original location where electrical power distribution networks in Los Angeles and San Diego were connected, providing long-range distributed electrical power to this portion of Orange County for the first time," and the Utility Structure " is directly associated with the Southern California Edison Company's expansion and growth in the wake of regional efforts to expand hydroelectric power capacity in the Los Angeles area, and its presence facilitated the suburban growth of San Juan Capistrano through reliable transmission of electrical power."[13] Just as the construction of the original Substation Complex was prompted by population growth and technological innovations during the 1910s, the Preservation Alternative responds to the need for expanded capacity of electrical power due to growth and technological advances of the present era. Providing expanded capacity at this location is entirely consistent with the Property's historical association with regional efforts to expand power capacity between Los Angeles and San Diego.

[12] See Kay D. Weeks, "The Secretary of the Interior's Standards for the Treatment of Historic Properties with Guidelines for Preserving, Rehabilitating, Restoring & Reconstructing Historic Buildings" (National Park Service, 1995).

[13] See Byrnes, Section 9, Page 13.

The Preservation Alternative is consistent with the Property's historical use as a substation, and the Utility Structure, which was designed to be the public face of the power company for which it was constructed, would continue to serve in exactly this same role. Moreover, its visibility as the public face for the electrical company to which it belongs would be strengthened by restoring the immediate setting around the Utility Structure to one resembling its historic appearance and improve the building's visibility on Camino Capistrano. This visibility would be enhanced with the removal of a non-original earthen berm and trees located to the front of the Property, which currently serve to obscure the structure from full public view. The increased visibility of the structure with the removal of the non-historic elements, in addition to the improvements to the landscape in the immediate vicinity of the Utility Structure to one reminiscent of the historic appearance, results in strong conformance with this rehabilitation standard with respect to the West Wing.

The loss of most of the East Wing would result in the removal of limited historic materials and features, but the overall Preservation Alternative conforms with Standard 1. The East Wing was not generally visible from the street, nor was it originally intended to be so. This is evident in the design of the East Wing, which has a low-slung massing in comparison to the taller West Wing. It is also evidenced by the fact that the East Wing exhibits very little architectural articulation as far as decorative detailing, and it is relatively unfenestrated. While the West Wing was designed to serve as the public face for the electrical company for which it was built, the East Wing was designed as a more utilitarian container, or box, the primary purpose of which was only to house equipment supportive of the operations of the Substation Complex. Moreover, while the East Wing has a moderately high degree of integrity, it is somewhat compromised by alterations to the exterior and interior and therefore has substantially less integrity than the West Wing. The interior of the retained portion of the Utility Structure, the West Wing, would continue to serve both primary use as the public face of the electric company, as well as the secondary use of providing space for support of substation operations. The rehabilitation of the retained West Wing also would balance the limited loss of historic materials and features associated with the East Wing and achieve overall conformance with Standard 1.

2. *The historic character of a property will be retained and preserved. The removal of distinctive materials or alteration of features, spaces, and spatial relationships that and therefore has characterize a property will be avoided.*

In conformance with Standard 2, the utilitarian character of the Property, as derived from its function as an electrical facility, would be maintained in the Preservation Alternative. Outdoor equipment would occupy the majority of the Property in much the same manner as it did historically. Changes in the specific equipment does not constitute an impact because it is only the Utility Structure itself that was found to be historically significant, not the original equipment housed inside it. The continued presence of electrical operations proximate to the Utility Structure would support its historic function and maintain its context.

While most of the East Wing would be removed, the retention and rehabilitation of the West Wing would preserve the essential features, spaces and spatial relationships of the Utility Structure that characterize its function as the public face of the Property. The west and south elevations of the Utility Structure would remain open to public view. Windows and doors in all elevations of the retained West Wing would be rehabilitated or reconstructed with new materials consistent with the historic pattern, but with greater attention to security to meet contemporary needs. Regrading and new landscape improvements in the front yard setback would return the setting along the street to an earlier appearance. See discussion of Standard 5 regarding retention of character-defining features.

3. *Each property will be recognized as a physical record of its time, place, and use. Changes that create a false sense of historical development, such as adding conjectural features or elements from other historic properties, will not be undertaken.*

   In conformance with Standard 3, the Preservation Alternative would not create a false sense of historical development and would not add conjectural features from other historic properties.

4. *Changes to a property that have acquired historic significance in their own right will be retained and preserved.*

   The only feature of the Property that has historic significance is the Utility Structure. There are no other features of the Property that are extant or that have acquired significance in their own right. In conformance with Standard 4, as discussed under Standard 1, key features of the Utility Structure and its setting would be retained and rehabilitated.

5. *Distinctive materials, features, finishes, and construction techniques or examples of craftsmanship that characterize a property will be preserved.*

   In conformance with Standard 5, the Preservation Alternative preserves the majority of the distinctive materials, features, finishes and construction techniques that characterize the Utility Structure and are considered character-defining features. Identification of such features includes three broad categories: the overall visual aspects; visual character of interior spaces, features and finishes; and, visual character at close range. Section VII.A, above, provides a detailed assessment of the Preservation Alternative's potential impact on each of the character-defining features and demonstrates conformance with Standard 5.

6. *Deteriorated historic features will be repaired rather than replaced. Where the severity of deterioration requires replacement of a distinctive feature, the new feature will match the old in design, color, texture, and, where possible, materials. Replacement of missing features will be substantiated by documentary and physical evidence.*

   In conformance with Standard 6, the Preservation Alternative includes the repair of the reinforced concrete exterior walls and windows of the retained portion of the Utility Structure. Since existing non-historic doors have deteriorated and historic doors are well documented, replacements would closely match the character of the original doors (see discussion of Standard 2). Window glazing has generally deteriorated beyond repair and would be replaced in kind or with additional steel required to ensure security of the Utility Structure.

7. *Chemical or physical treatments, if appropriate, will be undertaken using the gentlest means possible. Treatments that cause damage to historic materials will not be used.*

   In conformance with Standard 7, treatments would use the gentlest means possible. Mitigation for design review and construction monitoring would include review of proposed treatments and implementation by a historic preservation architect meeting the *Secretary of the Interior's Professional Qualifications Standards*.

8. *Archeological resources will be protected and preserved in place. If such resources must be disturbed, mitigation measures will be undertaken.*

   Standard 8 does not apply to the Preservation Alternative.

9. *New additions, exterior alterations, or related new construction will not destroy historic materials, features, and spatial relationships that characterize the property. The new work will be differentiated from the old and will be compatible with the historic materials, features, size, scale and proportion, and massing to protect the integrity of the property and its environment.*

   The immediate setting of the Utility Structure along the street, once the non-historic berms and trees are removed, would create a relatively flat and uniform area that approximates the level of the original grade as shown in historic photographs of the Property (i.e., nearly level with the sidewalk along Camino Capistrano that fronts the Utility Structure). The proposed new retaining walls that would be located proximate to the northern and eastern walls of the Utility Structure would be physically separated from the retained portion of the Utility Structure and not visible from the street. The north and east walls of the West Wing would serve as part of the security wall of the substation, thereby reducing the amount of new construction required in proximity to the retained portion of the Utility Structure. The proposed new security walls would complete the enclosure of the Property, but would be physically separated from the retained portion of the Utility Structure.

   The SOCRE Project also includes the construction and installation of outdoor switchgear, capacitors, transformers and two indoor gas insulated substations on the Property, but outside the immediate vicinity of the retained portion of the Utility Structure. These elements would not only be physically separated from the retained portion of the Utility Structure, but they are also compatible with the utilitarian features of an improved electrical facility. The two indoor gas insulated substations have been sensitively placed in a manner that maintains a substantial distance between them and the retained portion of the Utility Structure. Moreover, they would be located uphill from the Utility Structure, outside its immediate setting, so that they do not visually compete. The outdoor equipment replaces similar equipment that has existed over time at the Property. The indoor gas insulated substations, located at some distance from the retained portion of the Utility Structure, introduces a new element to the Property that is complementary to the historic use, allows for the continued viability of the substation, and would not detract from the Utility Structure's historic character.

10. *New additions and adjacent or related new construction will be undertaken in such a manner that, if removed in the future, the essential form and integrity of the historic property and its environment would be unimpaired.*

    In conformance with Standard 10, the Preservation Alternative would improve the Property in a manner consistent with its historic use as an electrical substation. No additions is proposed to the retained portion of the Utility Structure, and the proposed new retaining and security walls would be physically separated from it to allow for future removal without impact to the Utility Structure. The development of the two indoor gas insulated substations would not impact the immediate setting of the Utility Structure because these facilities would be located some distance from the Utility Structure.

C. Proposed Measures

The Drawing Set for the Preservation Alternative evaluated in this report has been found by a qualified professional historic architect to be in conformance with the *Secretary's Standards* and otherwise not to materially impair the historical significance of the Utility Structure. Therefore, the Preservation Alternative would not result in a substantial adverse change in the Utility Structure's historical significance and, accordingly, would have a less-than-significant impact on the Utility Structure under CEQA.

In order to ensure conformance with the *Secretary's Standards* through final design and construction, a measure for ongoing design review and construction monitoring by a qualified professional historic architect is recommended, as set forth below. In addition, a measure is recommended for Historic American Building Survey (HABS) documentation with respect to the removal of the East Wing, as set forth below. It is industry practice when a portion of a potential historical resource is removed to prepare HABS documentation to provide a high-quality record of the Property before alteration. There are many historic photographs that document the original construction of the Utility Structure, and HABS photographs would supplement them. These recommended measures would further reduce the Capistrano Preservation Alternative's already less-than-significant impact on the Utility Structure (assuming that it is subsequently determined to be an historical resource under CEQA) and, if agreeable to SDG&E, would be considered Applicant Proposed Measures.

<u>Recommended Measure for Continued Design Collaboration and Construction Monitoring</u>
SDG&E shall retain a qualified professional historic architect meeting the Secretary of the Interior's Professional Qualifications Standards (36 Code of Federal Regulations Part 61) to review and comment on design and construction drawings and monitor construction to ensure conformance with the *Secretary's Standards*. The role of the historic architect will include collaboration on a range of items relating to materials selection, construction methods, design of exterior and interior alterations, and monitoring of construction activities. The historic architect will participate in a pre-construction meeting with the general contractor and subcontractors and periodically monitor construction to completion of construction. The historic architect shall notify SDG&E and the CPUC if any unforeseen circumstance arises during construction that could potentially result in nonconformance with the *Secretary's Standards*. The historic architect, SDG&E and CPUC shall resolve any unforeseen circumstance in a manner that conforms with the *Secretary's Standards*.

<u>Recommended Measure for Historic American Building Survey (HABS) Documentation</u>
SDG&E shall retain a qualified professional photographer to prepare HABS documentation. This documentation shall record the existing appearance of the Utility Structure in large and medium format HABS photographs. All documentation components shall be completed in accordance with the Guidelines for Architectural and Engineering Documentation (HABS standards). The photographs shall consist primarily of large format, 4-inch by 5-inch, black and white negatives (one set), contact prints (one set) and 8-inch by 10-inch prints (two sets), archivally processed and printed on fiber-based paper. The set of original negatives shall be made at the time the photographs are taken. The original, archivally-sound negatives and prints shall be and distributed as follows: (1) the Library of Congress in Washington, DC through the National Park Service (one set of negatives and contact prints); and (2) Huntington Library in San Marino, California (one set of 8-inch by 10-inch prints). The draft documentation shall be assembled and submitted to the SDG&E for review and approval prior to submittal to the repositories. The HABS documentation shall be completed prior to the start of the removal of the East Wing.

VIII. Bibliography

Byrnes, Ilse. *San Diego Gas & Electric Capistrano Substation Revised Nomination to the National Register of Historic Places*, 2014.

California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387.

Ecology and Environment, Inc., *South Orange County Reliability Enhancement Project Recirculated Environmental Impact Report*. August 2015.

Engstrand, Iris and Kathleen Crawford. *Reflections – A History of the San Diego Gas & Electric Company 1881-1991*. San Diego: San Diego Historical Society and San Diego Gas & Electric, 1991.

Kessler, Mark D. *The Early Public Garages of San Francisco: An Architectural and Cultural Study, 1906-1929*. Jefferson, North Carolina: McFarland & Company, Inc., 2013.

McKenna, Jeannette, et al. *Historic Property Evaluation: The San Diego Gas & Electric Company San Juan Capistrano Sub-Station at 31050 Camino Capistrano, San Juan Capistrano, Orange County*. 2008.

Moomjian, Scott A. *Historical Assessment of the SDG&E Company SJC Substation, 31050 Camino Capistrano, San Juan Capistrano, California 92675.* 2014.

Myers, William A*. Iron Men and Copper Wires – Centennial History of the Southern California Edison Company*. Glendale, Calif.: Trans-Anglo Books, 1983.

National Register Bulletin #15, *How to Apply the National Register Criteria for Evaluation*. National Park Service, 1990. Revised 2002.

TRC Solutions, Inc. *Historic Integrity Assessment of the Capistrano Substation Complex, 31050 Camino Capistrano, San Juan Capistrano, California*. 2015.

IX. QUALIFICATIONS

This report was prepared by Chattel, Inc., a 20 plus year old historic preservation-consulting firm. Comprised of professionals meeting the *Secretary of the Interior's Professional Qualifications Standards* (36 CFR Part 61, Appendix A) in history, architectural history and historic architecture, the firm offers a variety of professional services, including historical resources evaluation and project effects analysis, and consultation on federal, state and local historic preservation statutes and regulations.

Chattel staff members engage in a collaborative process and work together as a team on individual projects. For preparation of this report, firm president Robert Chattel, AIA, and principal associate, Gabrielle Harlan, assumed lead roles, while consulting principal planner, Susan O'Carroll, provided support services. Robert Chattel, as historic architect, provided design consultation services to SDG&E's engineering team on how to design the Preservation Alternative to ensure conformance with the *Secretary's Standards* and drafted the conformance section of this report. Gabrielle Harlan, as architectural historian, was responsible for conducting the initial onsite assessment of the Utility Structure, and researching, writing and assembling this report. Susan O'Carroll provided input and editorial assistance.

Robert Jay Chattel, AIA
President / Historic Architect
Both a licensed general contractor and architect in California with more than 30 years' experience in planning, design and construction, Robert Chattel's unique qualifications include meeting the *Secretary of the Interior's Professional Qualifications Standards* in architectural history and historic architecture. Robert has experience working for non-profit, government, and for-profit entities. He holds a B.A. in Architecture from U.C. Berkeley and a M.S. in Historic Preservation from Columbia University. As President, He specializes in applying the *Secretary's Standards* and interpreting federal, state and local historic preservation law and regulations.

Gabrielle Harlan, Ph.D.
Principal Associate / Architectural Historian
With a Ph.D. in the History of Art and Architecture and an M.A. in Architectural History (both awarded from the University of Virginia), and a B.Arch. in Architecture from the University of Arizona, Gabrielle meets the *Secretary of the Interior's Professional Qualifications Standards* in historic architecture, architecture, history, and architectural history. Her role at Chattel includes preparing Historic Structures Reports, researching and writing historic contexts, and conducting architectural assessments and surveys.

Susan O'Carroll, Ph.D.
Consulting Principal Planner
Susan O'Carroll has over 25 years of planning experience, and has worked as a CEQA specialist managing preparation of environmental impact reports, negative declarations, and environmental document critiques. She has a M.Pl. and Ph.D. in Planning from the University of Southern California.

ROBERT JAY CHATTEL, AIA
PRESIDENT / PRINCIPAL, PRESERVATION ARCHITECT/ARCHITECTURAL HISTORIAN

PROFESSIONAL QUALIFICATIONS
Meets the Secretary of the Interior's Professional Qualifications Standards in Architectural History, Architecture and Historic Architecture.

PROFESSIONAL EXPERIENCE
PRESIDENT, CHATTEL, INC. JUNE 1994-PRESENT

SELECTED PROJECTS

BOYLE HOTEL (East Los Angeles Community Corporation) - Collaborate on exterior and interior treatments with project architect, and prepare Investment Tax Credit application.

MISSION SANTA BARBARA (Old Mission Santa Barbara, Inc and California Missions Foundation) - Prepare Historic Structure Report and prioritize work associated with Save America's Treasures grant.

THE MOB MUSEUM (City of Las Vegas) - Perform historic resources assessment and prepare a reuse feasibility analysis, in collaboration with cultural planner Carol Goldstein, for the 1933 former U.S. Post Office and Court House located downtown. Research and write National Register amendment documenting the building's association with an event of national significance. Consult with local, state, and federal agencies to ensure conformance with *Secretary's Standards* for certified rehabilitation and Save America's Treasures grant.

9936 DURANT (City of Beverly Hills) - Complete historic resources assessment and participate in preparation of Environmental Impact Report with range of alternatives considered for reducing historic resources impact of proposed project.

SOUTHERN CALIFORNIA GAS COMPANY COMPLEX (CIM Group) - Prepare National Register and local (Los Angeles) landmark nominations. Compile documentation for certified rehabilitation involving conversion of four buildings into residential lofts. Perform environmental review and write cultural resource section of environmental impact report.

CANNERY ROW CONSERVATION DISTRICT (Cannery Row Company) - Collaborate with Winter and Company to prepare conservation district design guidelines and incentives, boundaries and other criteria for protecting four potential historic districts identified in historic resources survey and providing for appropriate infill development.

901 S. BROADWAY (Neighborhood Effort) - Design collaboration on rehabilitation of former Blackstone's Department store as mixed income and affordable housing with ground floor retail, and preparation of Investment Tax Credit application.

242 S. BROADWAY (Neighborhood Effort) - Preparation of Parts 2 and 3 of Investment Tax Credit application and design collaboration on rehabilitation of former Victor Clothing Company building for use as affordable housing.

CHATEAU ARNAZ CONDOMINIUM PROJECT (City of Beverly Hills) - Cultural resources analysis for EIR analyzing impact of replacing four apartment buildings with condominium building.

PRESERVATION ORDINANCE (City of Carmel-by-the-Sea) - Prepared historic preservation ordinance and provide peer review of historic preservation element in update of General Plan.

MARE ISLAND (Lennar Mare Island LLC) - Participated in strategic planning for Lennar Mare Island, LLC, master developer, and City of Vallejo on rehabilitation and reuse of 650-acre historic district at former Mare Island Naval Shipyard.

STUART COMPANY PLANT AND OFFICE BUILDING (BRE Properties, Inc.) - Review project for conformance with the *Secretary's Standards* and assist with local (Pasadena) design and environmental review. Participate in design collaboration with project architect, structural engineer, and landscape architect, and conduct construction monitoring.

LOS ANGELES UNIFIED SCHOOL DISTRICT - Prepare historic resources policies for California Environmental Quality Act reviews used in 29 cities within district boundaries. Act as master reviewer for projects involving historic resources. Perform environmental review and write cultural resource section of Ambassador Hotel (Central Los Angeles Area Learning Center #1) environmental impact report.

BREED STREET SHUL (Breed Street Shul Project, Inc.) - Provide design review and construction monitoring for Phase 1 seismic stabilization and stained glass window restoration. Prepare National Register nomination and historic review documentation for local (Los Angeles) environmental review. Consult with federal agencies on Section 106 compliance.

TWOHY BUILDING (CIM Group) - Compile documentation for certified rehabilitation involving conversion of former office building into 36 apartment units with ground floor retail in San Jose. Prepare National Register nomination.

ADDITIONAL EXPERIENCE

PROJECT MANAGER, HISTORIC RESOURCES GROUP	1994 -1995
ASSET MANAGER, H.T. GREENE & ASSOCIATES	1988 - 1994
ASSOCIATE CITY PLANNER, COMMUNITY REDEVELOPMENT AGENCY	1984 -1988
DIRECTOR OF PROGRAMS, LOS ANGELES CONSERVANCY	1983 -1984

EDUCATION

COLUMBIA UNIVERSITY IN THE CITY OF NEW YORK
Master of Science in Historic Preservation — MAY 1983

UNIVERSITY OF CALIFORNIA AT BERKELEY
Bachelor of Arts in Architecture — JUNE 1980

PROFESSIONAL LICENSES
California Architect License Number C 27398
California Class B General Contractor License Number B 692817

PROFESSIONAL AFFILIATIONS
Architect Member, American Institute of Architects

MEMBERSHIPS
President's Circle Member, California Preservation Foundation
Life Member, Southern California Chapter of the Society of Architectural Historians (SAH/SCC)

AWARDS
Preservation Award, (Pacific Electric Railway – El Prado Bridge), Los Angeles Conservancy, 2015
Design Award (Railroad Square), California Preservation Foundation, 2014
Preservation Honor Award (Boyle Hotel), National Trust for Historic Preservation, 2013
Design Award (Jane B. Eisner School), California Preservation Foundation, 2013
Preservation Award (Compton City Hall), Los Angeles Conservancy, 2013
Governor's Historic Preservation Award (City of Orange Cultural Resources and Historic Preservation Element of the General Plan), Office of Historic Preservation, 2012
President's Award (Johnnie's Broiler), Los Angeles Conservancy, 2010
Preservation Award (Breed Street Shul stabilization), Los Angeles Conservancy, 2005
Design Award (Twohy Building), California Preservation Foundation, 2004
Preservation Award (Far East Building), Los Angeles Conservancy, 2004
Award (Plaza Preservation Project), Old Towne Preservation Association, Orange, 2002
Award of Excellence (Breed Street Shul), Cultural Heritage Commission, Los Angeles, 2000
Pauline Hirsh Memorial Award, Jewish Historical Society of Southern California, 2000
President's Award (Beverly Hills Waterworks), California Preservation Foundation, 1991
Award (Earthquake Hazard Reduction: Cumulative Impacts on Historic Buildings), California Preservation Foundation, 1987
Faculty Award for Outstanding Work in Preservation Design (Beverly Hills Water Works), Columbia University, 1983
First Place (Residential Design and Architectural Model), California State Fair, 1976

COMMUNITY INVOLVEMENT

Vice President, Sam and Alfreda Maloof Foundation for Arts and Crafts (SAMFAC)	2012-2013
Member, Board of Directors, SAMFAC	2011-2014
Vice President, Advocacy Committee Chair, California Preservation Foundation (CPF)	2012-2013
Member, Board of Trustees, Advocacy Committee Chair, CPF	2010-2013
President Emeritus, California Historical Society (CHS)	2014-present
President, California Historical Society	2012-2014
Member, Facilities and Operations Committee Chair, Board of Trustees, CHS	2005-2014
Vice President, Breed Street Shul Project, Inc.	1999-2011
Vice President, Jewish Historical Society of Southern California	1989-2010
Member, Board of Directors, Jewish Historical Society of Southern California	1985-2010
Co-Chair, California Preservation Conference, Los Angeles	1989
President, Southern California Chapter of the Society of Architectural Historians (SAH)	1987-1989
Member, Board of Directors, SAH	1985-1989

Recent Presentations

"Medicinal Masterpiece: Rehabilitation and Adaptive Reuse of the Stuart Building," speaker, "From the Field: Conserving Southern California's Modern Architecture," Getty Conservation Institute, December 2014.
"Sputtering About Sputniks: Evaluating Modern Resources," session panelist, California Preservation Conference, May 2013
"The Atomic Wild, Wild West," guest speaking engagement on issues facing modern resources, School of the Art Institute of Chicago, February 2013
"Historic Preservation and New Construction in Pasadena," mobile workshop presenter, American Planning Association National Conference, April 2012
"Incentivize It! Santa Monica's Incentives and Development Trends," mobile workshop moderator, California Preservation Conference, Santa Monica, May 2011
"CEQA and Alternatives for Greater Historic Preservation," session panelist, California Preservation Conference, Santa Monica, May 2011
"Context and Issues Surrounding Historic District Designations in Urban Environments," workshop panelist, California Preservation Foundation, Berkeley, January 2011.
"Make History: Public-Private Partnerships to Rehabilitate Historic Buildings," workshop panelist, California Preservation Foundation, South Pasadena, February 2010.
"Financing Historic Preservation," workshop panelist, California Preservation Conference, Palm Springs, April 2009.
"Financing Historic Preservation" workshop panelist, California Preservation Foundation annual conference, Napa, April 2008.
"40 Forward," James Marston Fitch Colloquium to celebrate pioneering preservation teaching, research and advocacy at Columbia University, New York, March 2005.
"Far East Building Rehabilitation: Mixed Use Case Study," Secretary of the Interior's Standards for the Treatment of Historic Properties workshop, California Preservation Foundation, Sacramento, June 2003.
"Breed Street Shul," Power of Place: Cultural Landscapes workshop, Little Tokyo Service Center and University of Southern California, Los Angeles, March 2003.

Teaching Experience

"Historic Preservation: Principles and Practice", Urban Planning Department, UCLA, Fall 2007
"Historic Preservation: Principles and Practice", Urban Planning Department, UCLA, Spring 2007
"Undiscovered Los Angeles: Water and Steel," UCLA Extension, Spring 2001
"Undiscovered Los Angeles: Downtown LA Bike Tour," Summer 1999
"Historic Preservation: State of the Art," Spring 1999
"Historic Preservation: A Studio," UCLA Extension, Summer 1998
"Historic Preservation: State of the Art," UCLA Extension, Spring 1998
"Undiscovered Los Angeles: Water and Steel," UCLA Extension, Fall 1997
"Historic Preservation: State of the Art," UCLA Extension, Summer 1997
"Historic Preservation: State of the Art," UCLA Extension, Spring 1997

Publications

"Preserving Place in Los Angeles," with Gabrielle Harlan, *Urbanisme*, July/August 2008

EXHIBIT A: DRAWINGS OF THE CAPISTRANO
PRESERVERVATION ALTERNATIVE

CAPISTRANO SUBSTATION UTILITY STRUCTURE
31050 CAMINO CAPISTRANO, SAN JUAN CAPISTRANO, CA

CONFIDENTIAL -
DOCUMENTS OMITTED

EXHIBIT B: HISTORIC PHOTOGRAPHS

CAPISTRANO SUBSTATION UTILITY STRUCTURE
31050 CAMINO CAPISTRANO. SAN JUAN CAPISTRANO, CA

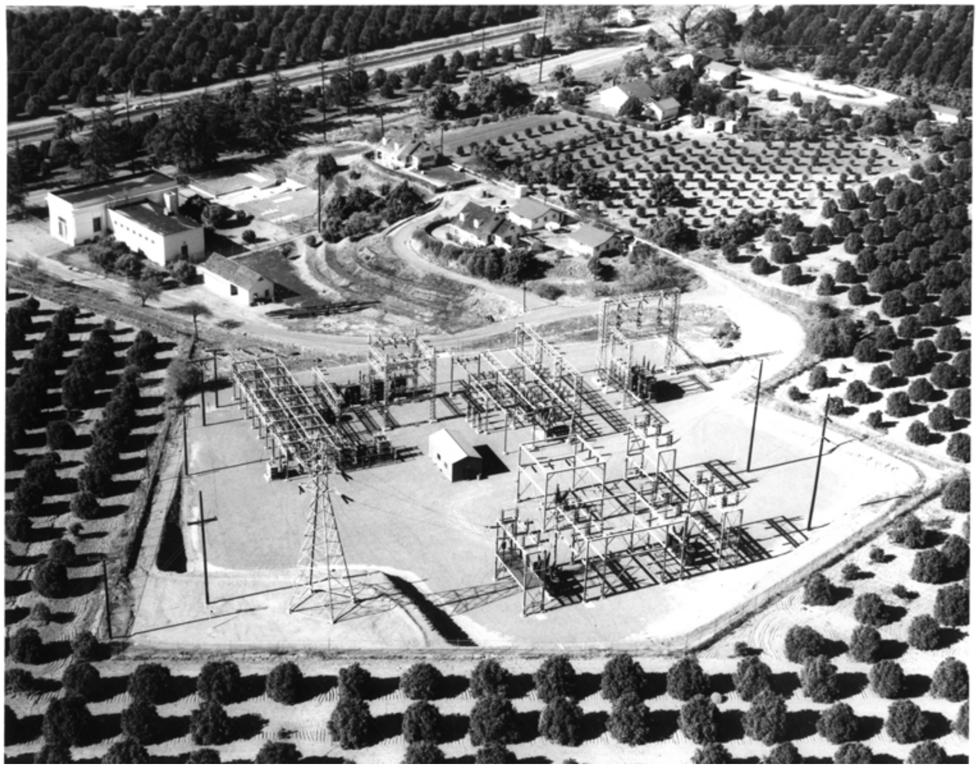


Figure 1: Capistrano Substation, view northwest, date unknown (Photo source: San Diego Gas & Electric Company)

Figure 2: Subject property prior to construction of the substation, 1917
(Photo credit: Huntington Library, San Marino, CA)

Figure 3: Construction materials on the subject property prior to completion of the substation, 1918
(Photo credit: Huntington Library, San Marino, CA)

Figure 4: Photograph of the construction of the Utility Structure, north elevation of the East Wing (left) and West Wing (right), view south, 1918 (Photo credit: Huntington Library, San Marino, CA)

Figure 5: Photograph of the construction of the Utility Structure, south elevation of the West Wing (left) and East Wing (right), view north, 1918 (Photo credit: Huntington Library, San Marino, CA)

Figure 6: Photograph of the construction of the Utility Structure, south elevation of the West Wing (left) and East Wing (right), view northwest, 1918 (Photo credit: Huntington Library, San Marino, CA)

Figure 7: Scaffolding and formwork to the interior of the West Wing for the construction of the exterior walls, view north, 1918 (Photo credit: Huntington Library, San Marino, CA)

Figure 8: Excavation of the interior to accommodate the concrete pad for the 5,000 kw frequency changer placed to the interior of the West Wing, view south, ca. 1918 (Photo credit: Huntington Library, San Marino, CA)

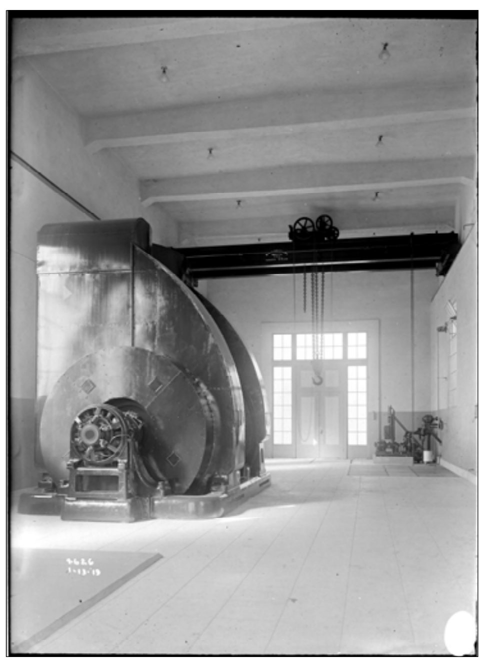


Figure 9: Photograph showing the interior of the West Wing with the 5,000 kw frequency changer installed, view north, ca. 1918
(Photo credit: Huntington Library, San Marino, CA)

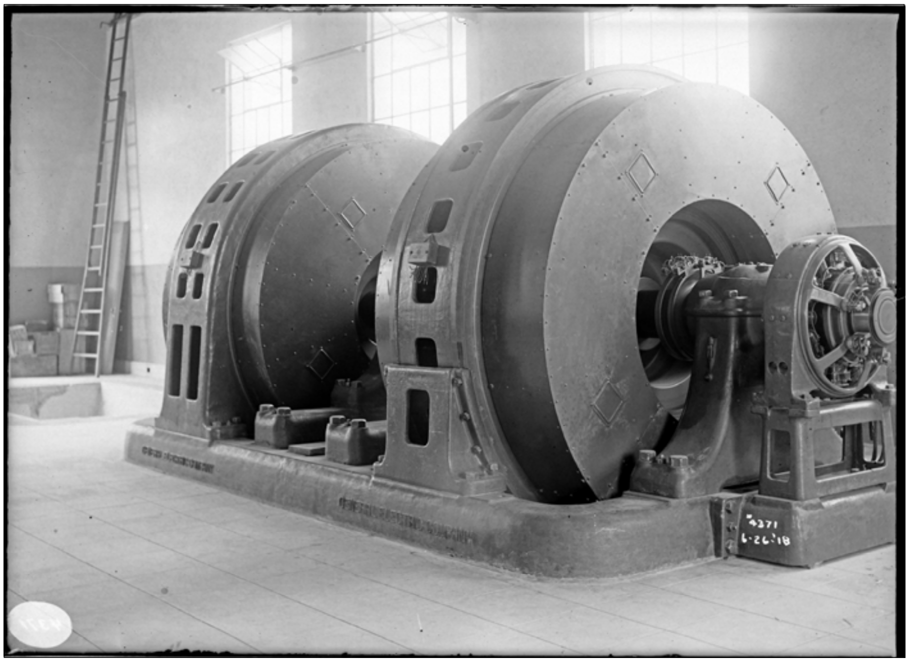


Figure 10: Photograph of the 5,000 kw frequency changer located to the interior of the West Wing, view southwest, ca. 1918
(Photo credit: Huntington Library, San Marino, CA)

Figure 11: Excavation of the interior of the East Wing before being finished with scored concrete flooring surface, view east, 1918
(Photo collection: Huntington Library, San Marino, CA)

Figure 12: Construction of the permanent scaffolding system from which to suspend the electrical panels, interior of the East Wing, view west, 1918 (Photo credit: Huntington Library, San Marino, CA)

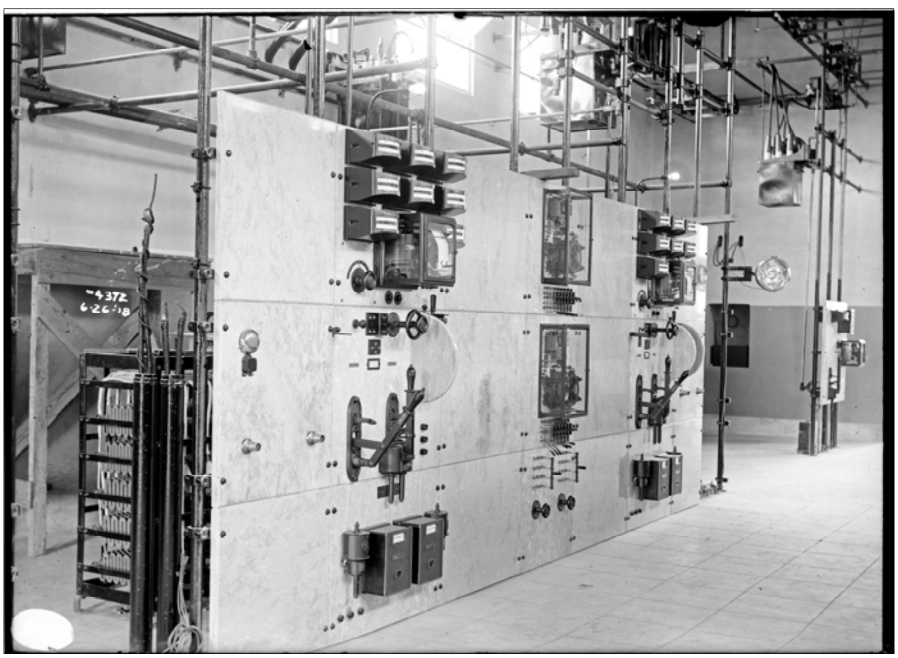


Figure 13: Photograph of the electrical panel installation located to the interior of the East Wing, exact direction of view unknown, ca. 1918 (Photo credit: Huntington Library, San Marino, CA)

Figure 14: Photograph of the Utility Structure temporary tent camp erected at the site during construction of the utility structure, view west, 1918

Figure 15: Photograph of the site with the temporary tent camp erected during construction of the Utility Structure shown to far right, view southwest, ca. 1918 (Photo credit: Huntington Library, San Marino, CA)

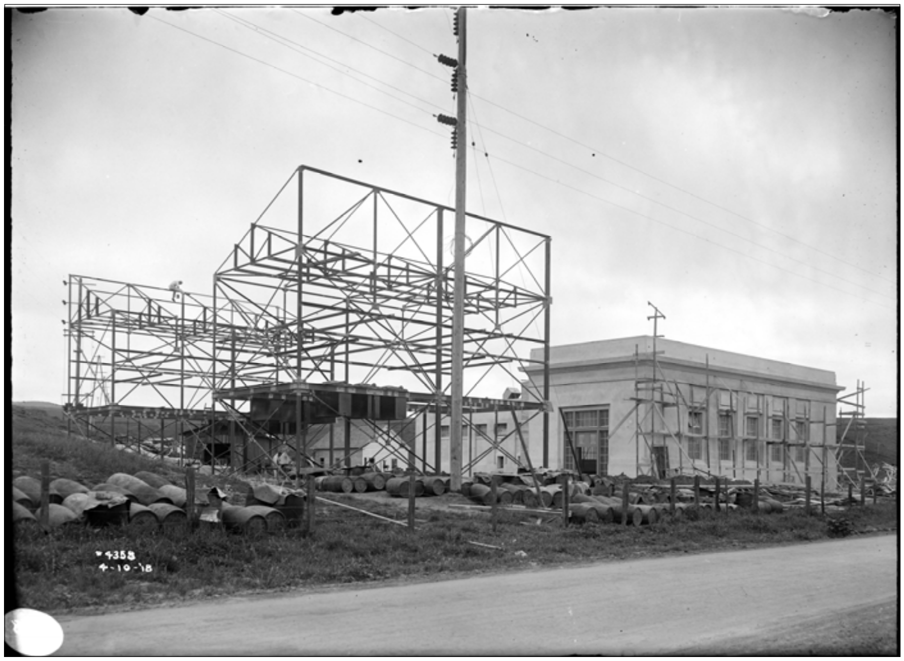


Figure 16: Photograph of the completed substation Utility Structure and the open rack system located to the north, view southeast, 1918
(Photo credit: Huntington Library, San Marino, CA)

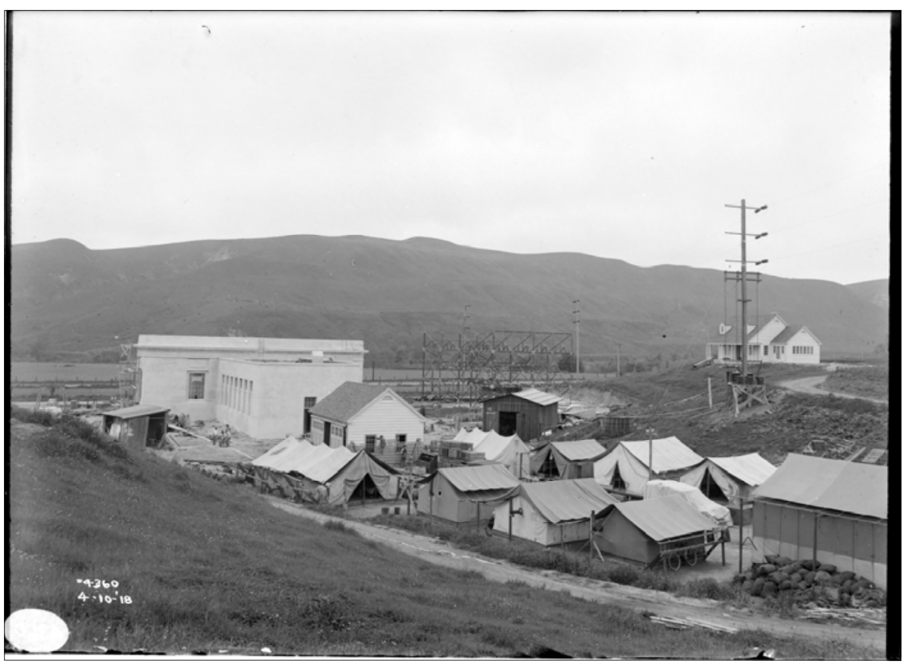


Figure 17: Photograph showing the temporary tent city erected during construction with the east and south elevations of the completed Utility Structure in the background, 1918
(Photo credit: Huntington Library, San Marino, CA)

Figure 18: The interior of the completed East Wing, view west, ca. 1918
(Photo credit: Huntington Library, San Marino, CA)

Figure 19: Construction of the interior view east, 1918
(Photo credit: Huntington Library, San Marino, CA)

Figure 20: Capistrano Substation Utility Structure, 1918
(Photo credit: Huntington Library, San Marino, CA)

Figure 21: The open racks located to the north of the Utility Structure, view northeast, 1918
(Photo credit: Huntington Library, San Marino, CA)

Figure 22: The two workmen's cottages erected on the subject property, 1918 (Photo credit: Huntington Library, San Marino, CA)

Figure 23: North and west elevations of the West Wing, with a small portion of the East Wing visible to the rear, view southeast, 1921 (Photo credit: Huntington Library, San Marino, CA)

Figure 24: West and south elevations of the West Wing of the Utility Structure, with a small portion of the East Wing visible, view northeast, 1921 (Photo credit: Huntington Library, San Marino, CA)

Figure 25: Interior of the East Wing, view east, 1923 (Photo credit: Huntington Library, San Marino, CA)

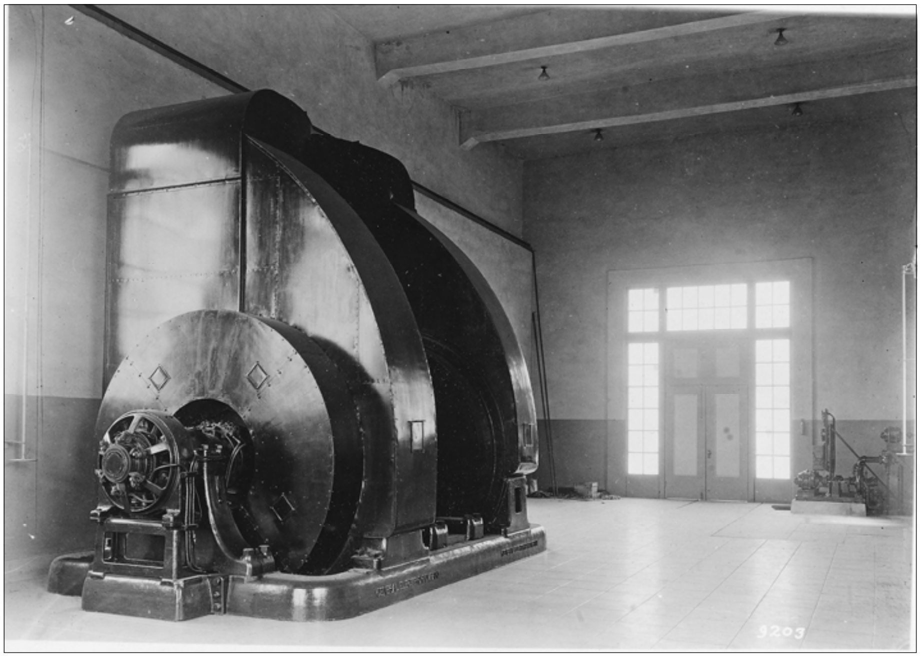


Figure 26: Interior of the West Wing, view north, 1923 (Photo credit: Huntington Library, San Marino, CA)

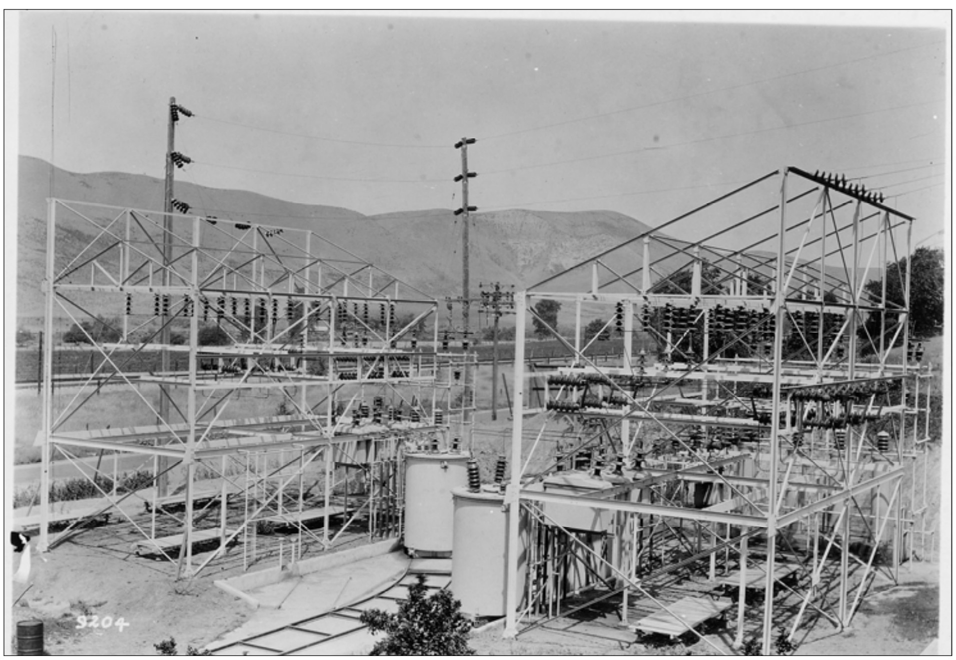


Figure 27: The outdoor rack located to the north of the Utility Structure, view northwest, 1923 (Photo credit: Huntington Library, San Marino, CA)

Figure 28: The Utility Structure and the outdoor rack located to the north of it, view southwest, 1923 (Photo credit: Huntington Library, San Marino, CA)

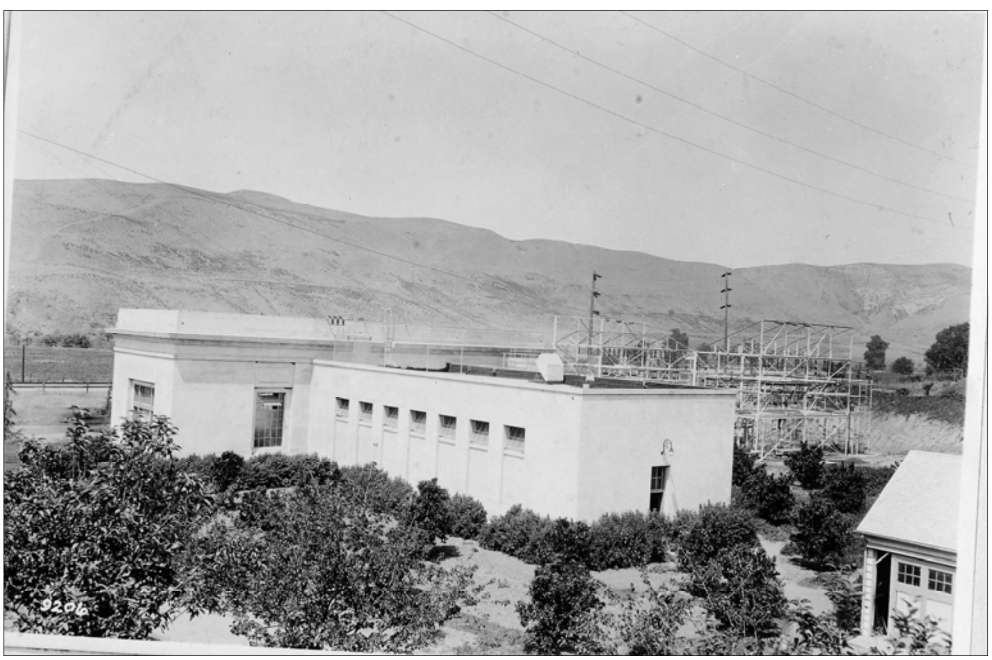


Figure 29: The Utility Structure with the outdoor rack located to the north of it, view northwest, 1923 (Photo credit: Huntington Library, San Marino, CA)

EXHIBIT C: MAPS

CAPISTRANO SUBSTATION UTILITY STRUCTURE
31050 CAMINO CAPISTRANO, SAN JUAN CAPISTRANO, CA

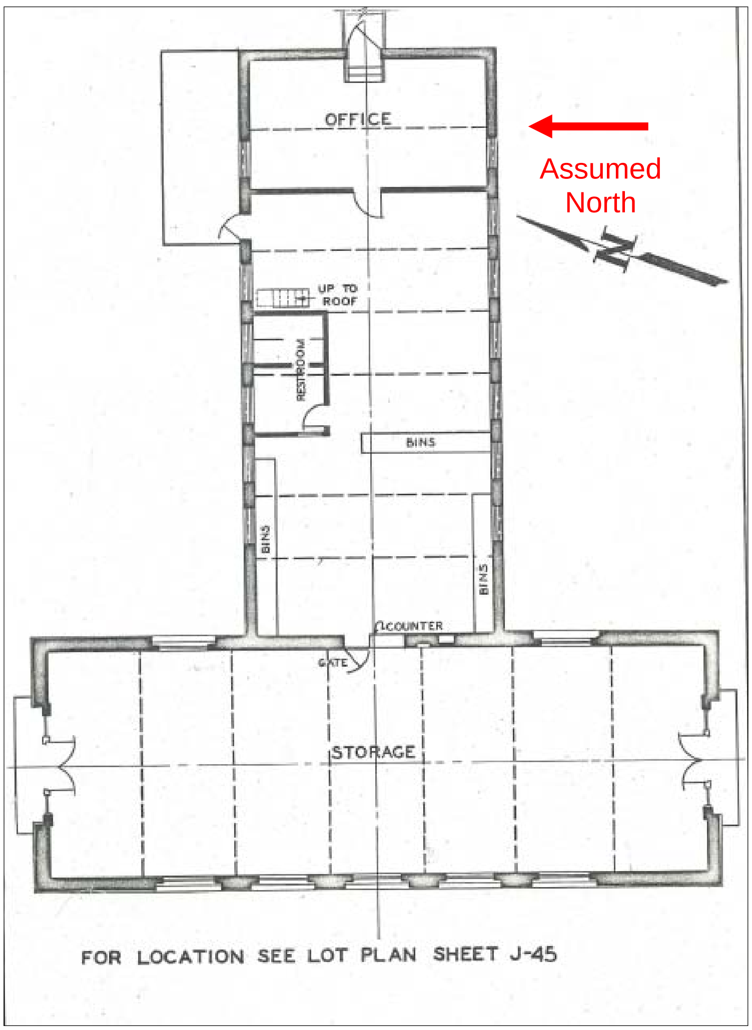


Figure 1: Floor plan of the Capistrano Substation Utility Structure (circa 1933)

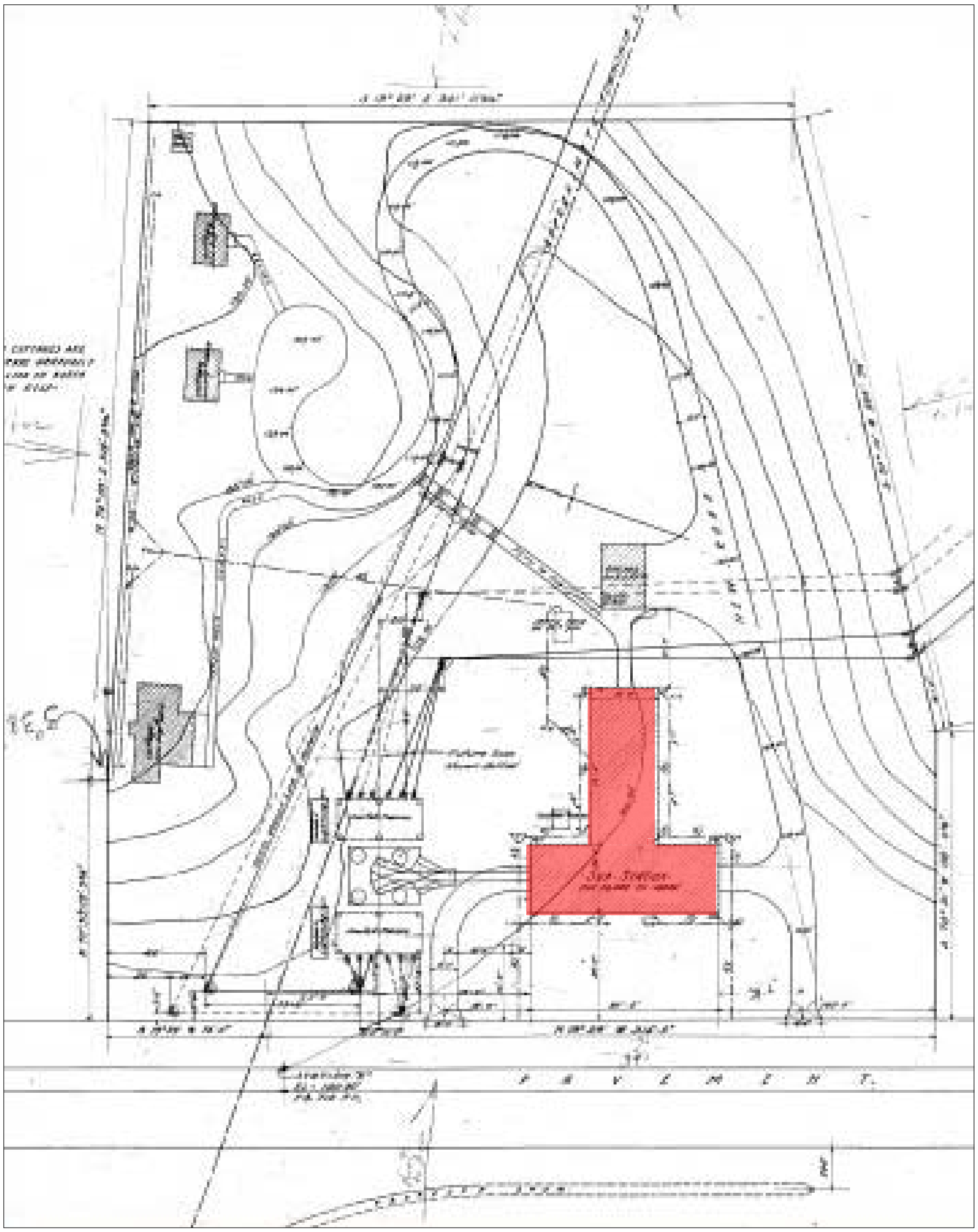


Figure 2: 1917 Assessor's map showing the subject property with the Utility Structure in red

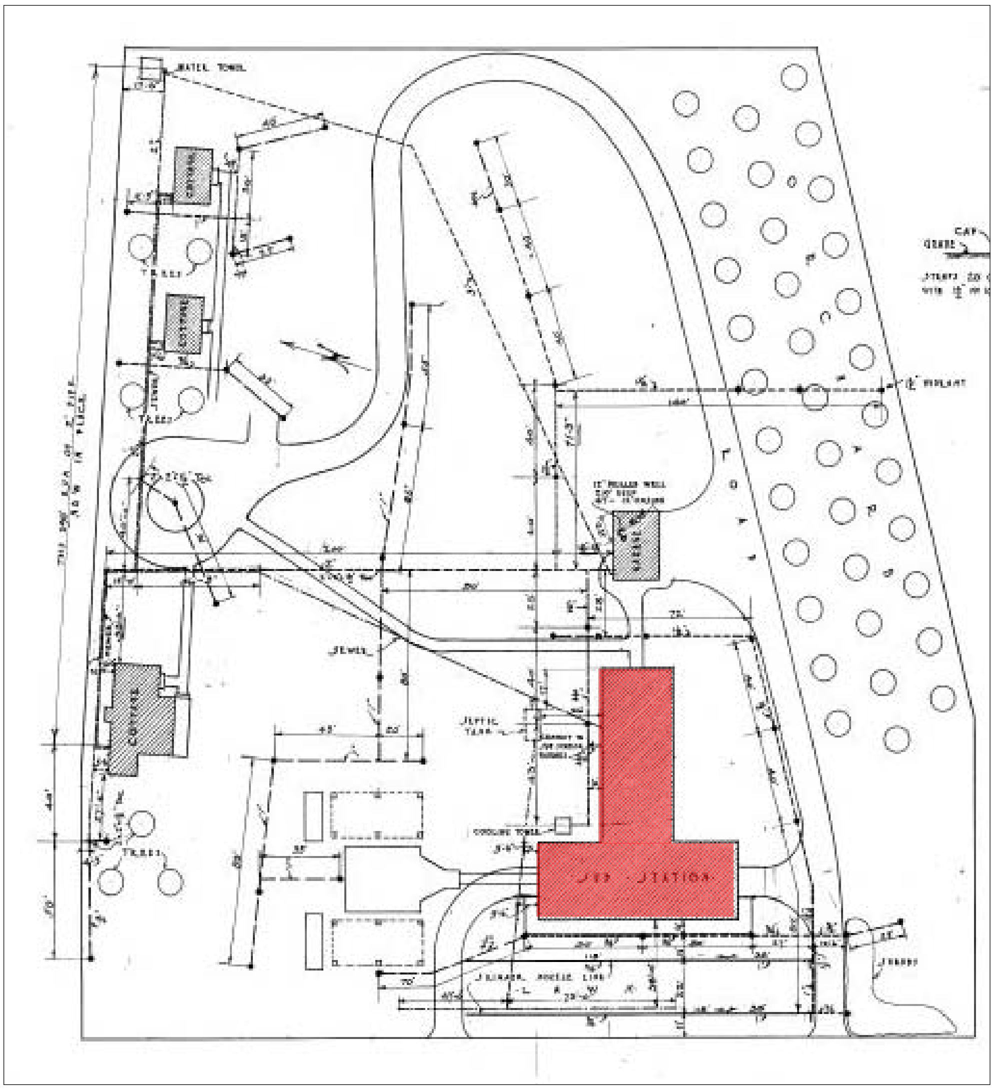


Figure 3: 1918 Assessor's map showing the subject property with the Utility Structure in red

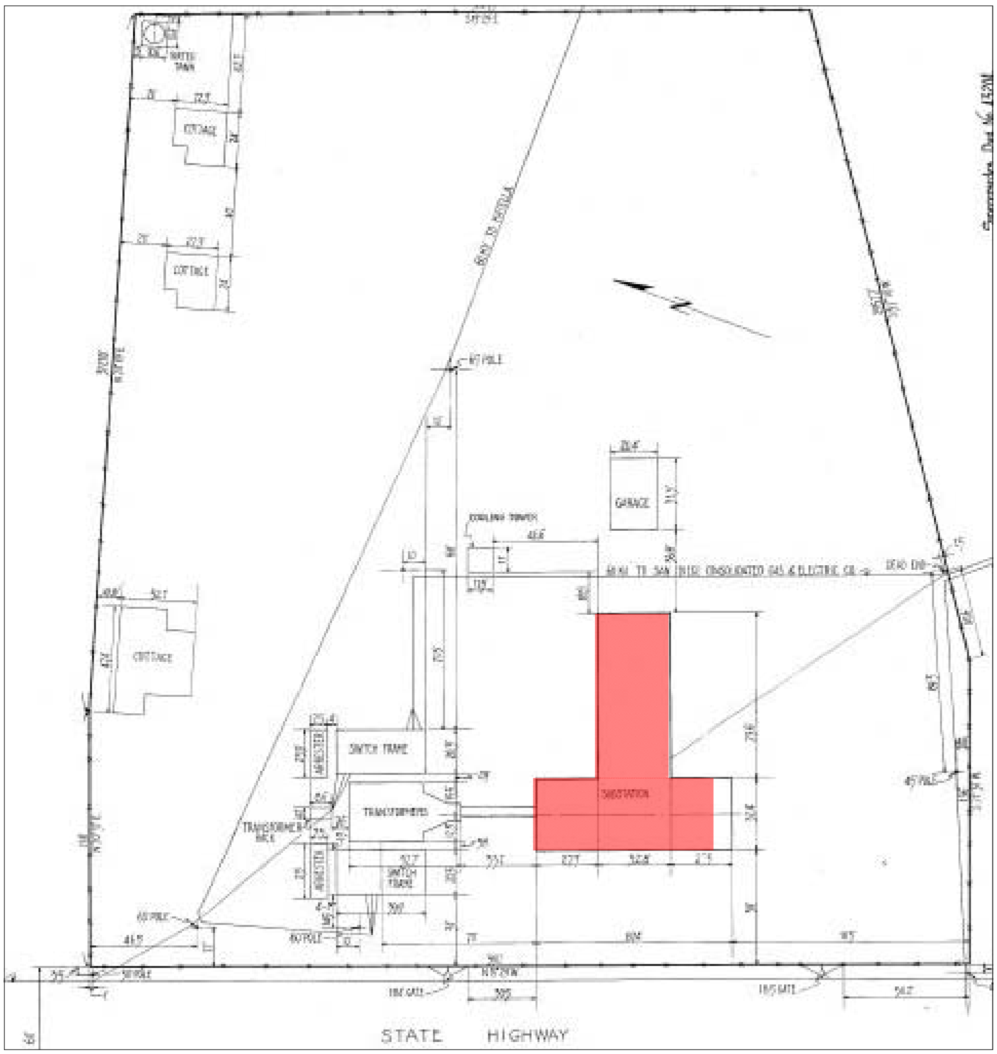


Figure 4: 1924 Assessor's map showing the subject property with the Utility Structure in red

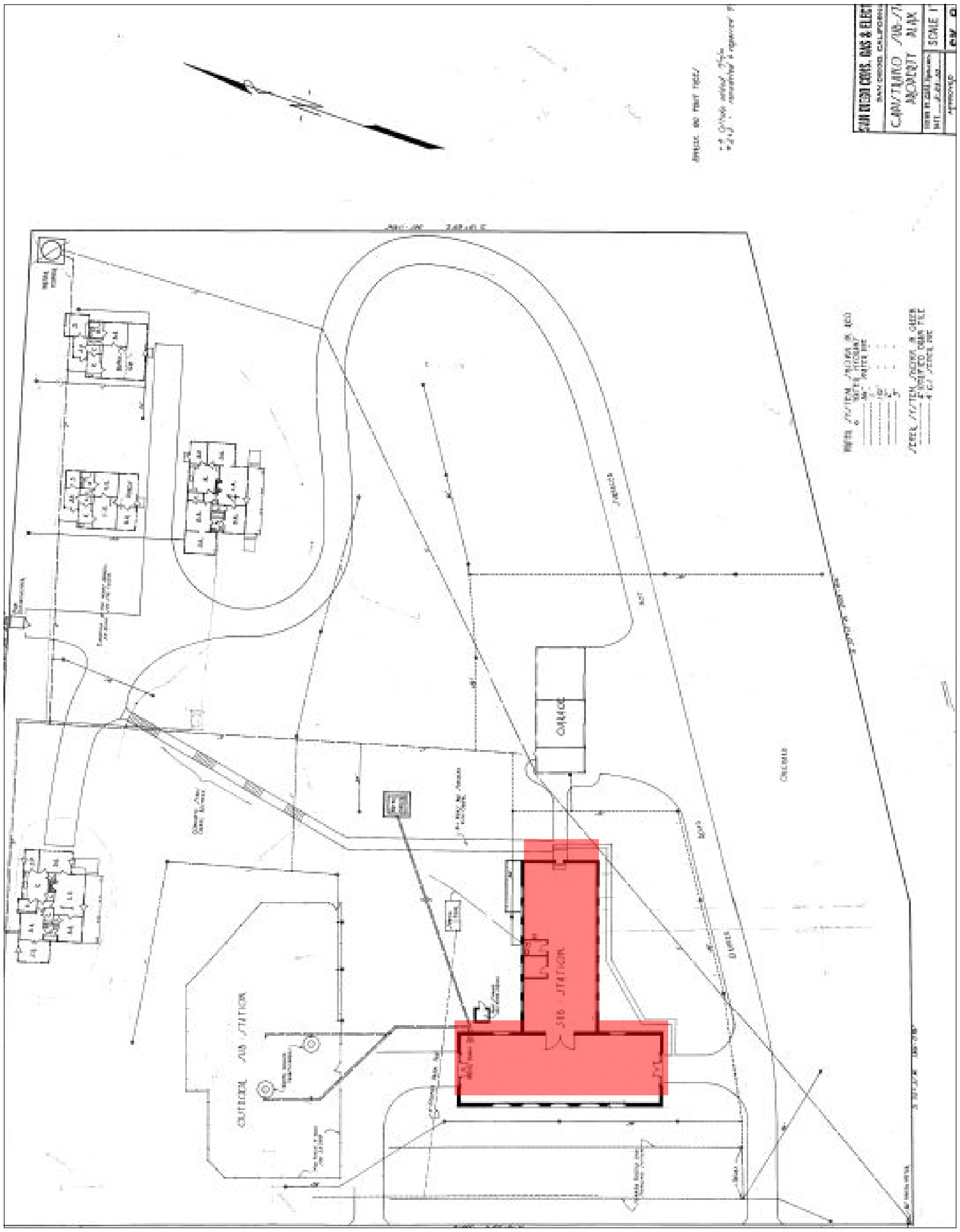


Figure 5: 1933 Assessor's map showing the subject property with the Utility Structure in red

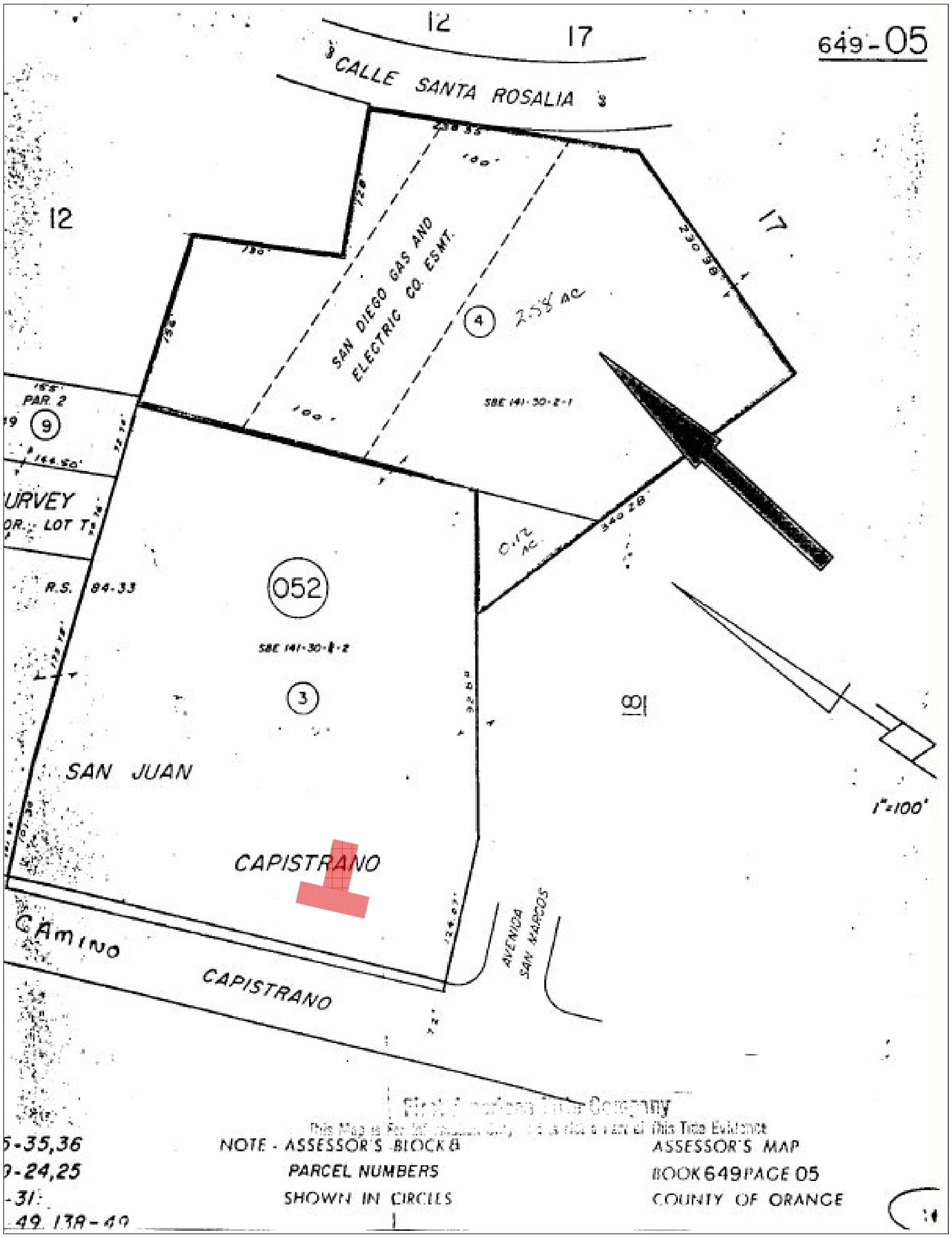


Figure 6: 1940 Assessor's map of the subject property with the approximate location of the Utility Structure shown in red. Also note the separate parcel located to the east of the site, to which the large black arrow is pointing, as that parcel would soon become part of the site.

Figure 7: 1967 Assessor's map of the subject property showing the approximate location of the Utility Structure in red

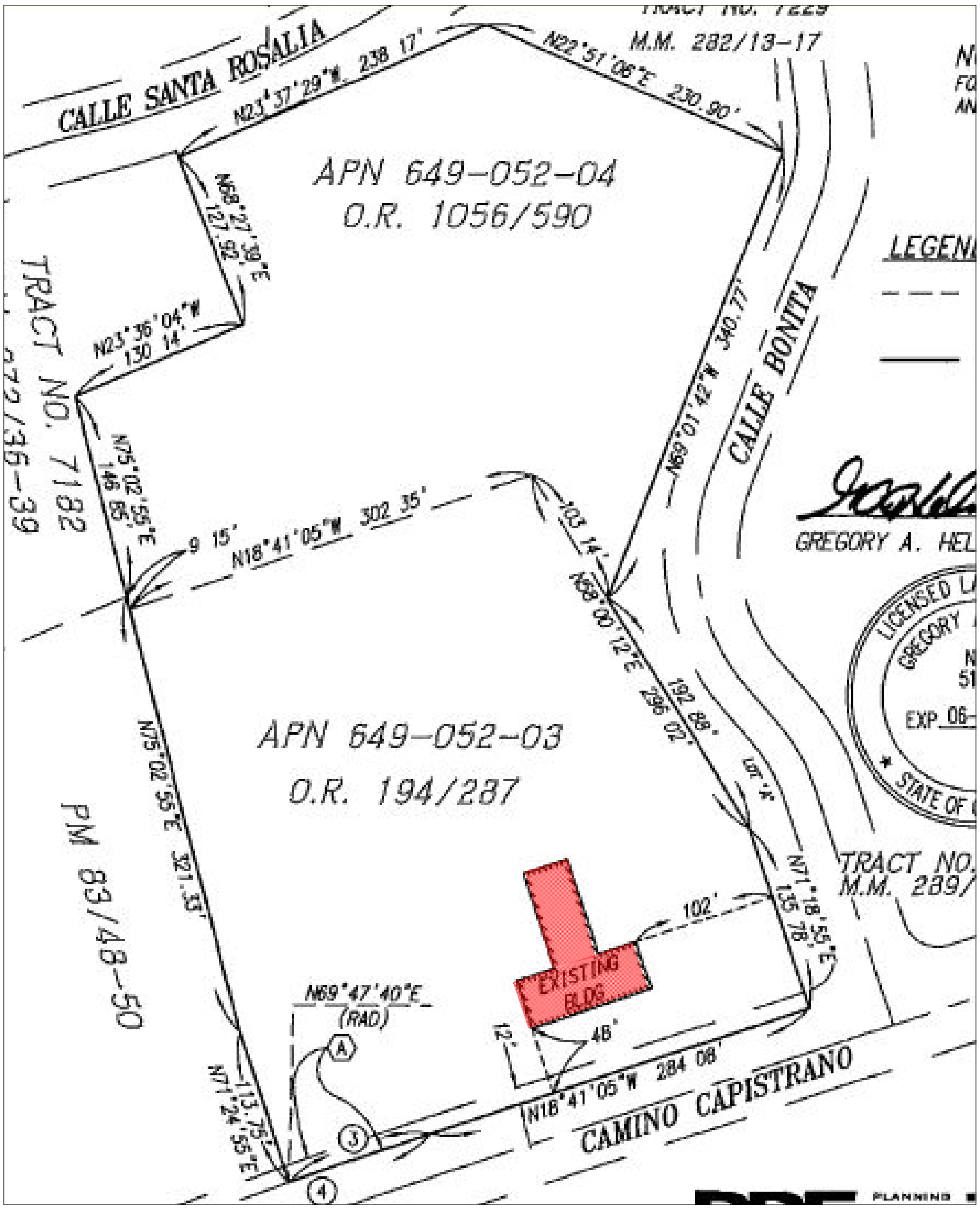


Figure 8: 2004 Assessor's map of the subject property showing the location of the Utility Structure in red

Exhibit D: Contemporary Photos

Capistrano Substation Utility Structure
31050 Camino Capistrano, San Juan Capistrano, CA

Photo 1: Aerial photo of the Capistrano Substation Complex (as outlined) with the Utility Structure located to the west of the site (Google Earth Map, 2015)

Photo 2: Utility Structure, west elevation of the West Wing, view southeast (Chattel 2015)

Photo 3: Utility Structure, detail of the landscaping adjacent to both the west elevation of the West Wing (left) and to Camino Capistrano (right) with contemporary, non-original berm and trees, view south (Chattel 2015)

Photo 4: Driveway entrance from Camino Capistrano to the site as located to the north of the Utility Structure, view east (Chattel 2015)

Photo 5: Utility Structure, north elevation of the West Wing (right) and north elevation of the east wing beyond (left), view south east (Chattel 2015)

Photo 6: Utility Structure, north elevation of the West Wing (right) with partial north elevation of East Wing beyond (left), view south (Chattel 2015)

Photo 7: Utility Structure, detail of the rail lines located in front of the entrance doors on the north elevation of the West Wing, view east (Chattel 2015)

Photo 8: Utility Structure, the north elevation of the East Wing, view south (Chattel 2015)

Photo 9: Utility Structure, the alteration of the "blind panel" to accommodate an entry on the north elevation of the East Wing, view southwest (Chattel 2015)

Photo 10: Utility Structure, detail of windows and "blind panels" on the north elevation of the East Wing, view southwest (Chattel 2015)

Photo 11: Utility Structure, the East Wing of the building (left) with the West Wing beyond, view southwest (Chattel 2015)

Photo 12: Utility Structure, south elevation with West Wing (left) and East Wing (right) (Chattel 2015)

Photo 13: Utility Structure, south elevation of the West Wing (left) and East Wing (right) (Chattel 2015)

Photo 14: Utility Structure and view east of the subject property at driveway located to the south of the structure (Chattel 2015)

Photo 15: Detail of the foundation of the demolished garage that lies east of the Utility Structure (Chattel 2015)

Photo 16: Utility Structure and view west towards Camino Capistrano from the southeastern edge of the subject property (Chattel 2015)

Photo 17: View north towards the location where the four residential cottages once stood on the northeast portion of the subject property (Chattel 2015)

Photo 18: View southwest towards Utility Structure from the location where the four residential cottages once stood on the northeastern portion of the subject property (Chattel 2015)

Photo 19: Utility Structure, interior of West Wing, view north (Chattel 2015)

Photo 20: Utility Structure, interior of West Wing, view south. Note the Maris Bros. hoist (i.e. crane) located at the plane of the ceiling. (Chattel 2015)

Photo 21: Utility Structure, interior of West Wing, detail of connecting doors to East Wing, view east (Chattel 2015)

Photo 22: Utility Structure, interior of West Wing, detail of window, view east (Chattel 2015)

Photo 23: Utility Structure, interior of West Wing, detail of doors and transom at south end of wing, view south (Chattel 2015)

Photo 24: Utility Structure, interior of West Wing, detail of windows on west wall, view west Chattel 2015)

Photo 25: Utility Structure, ground floor level interior photo of the East Wing, view east (Chattel 2015)

Photo 26: Utility Structure, mezzanine level interior photo of the East Wing, view southwest (Chattel 2015)

Photo 27: Utility Structure, ground floor level photo of the East Wing, view west (Chattel 2015)

Photo 28: Utility Structure, ground floor level photo of the East Wing, view north (Chattel 2015)

EXHIBIT E: SIGNIFICANT SPACES DIAGRAM

CAPISTRANO SUBSTATION UTILITY STRUCTURE
31050 CAMINO CAPISTRANO, SAN JUAN CAPISTRANO, CA

Figure 1: Significant Space Diagram of the Capistrano Substation Utility Structure shows that portion of the building that is of primary significance as well as the portion of the building that is of secondary significance

EXHIBIT 2

Segment 4 Design Revision with Attachment A (Figures)

INTRODUCTION

San Diego Gas & Electric Company (SDG&E) filed a Proponent's Environmental Assessment (PEA) as part of its application for a Certificate of Public Convenience and Necessity (CPCN) for the South Orange County Reliability Enhancement Project (Proposed Project) to the California Public Utilities Commission (CPUC) on May 18, 2012. Following publication of the Recirculated Draft Environmental Impact Report (RDEIR), SDG&E transmission engineering staff evaluated the possibility of refining the transmission and power line design for Segment 4 of the Proposed Project to minimize the need for new rights-of-way (ROW). Segment 4 crosses an area that the United States Fish and Wildlife Service (USFWS) and the CPUC's Energy Division have said will be subject to a proposed, unrecorded conservation easement relating to the existing Talega development (Talega Conservation Easement).

SDG&E has prepared a preliminary design that would remove several structures and electrical transmission and power lines from one large area of Segment 4 not owned by SDG&E or subject to an SDG&E easement, and instead would place all of them within existing SDG&E ROW, easements, and fee-owned property. See Figure 1, Segment 4 Design Revision Overview[1], which depicts the new structure and electric line locations and existing SDG&E ROWs, easements, and fee-owned property. By relocating proposed structures to be within existing SDG&E ROW, the amount of new ROW potentially required in Segment 4 of the Proposed Project would be significantly reduced, especially within the potential boundaries of the Talega Conservation Easement.[2]

Based upon the preliminary design, SDG&E anticipates only potentially needing new ROW within the potential boundaries of the Talega Conservation Easement within three small areas ("wedges") that occur between two existing SDG&E easements and immediately adjacent to fee-owned property (See Figure 2, Segment 4 ROW Map). While the design remains preliminary, and the final boundaries of property that will be subject to the Talega Conservation Easement are uncertain, SDG&E estimates that the area of required new ROW in Segment 4 would be reduced from 10.56 acres to approximately 2.22 acres, of which some portion could be subject to the Talega Conservation Easement.

[1] SDG&E has further engineering (civil and transmission) to perform to achieve a design level similar to the Proposed Project included in the Draft EIR. Placing all structures in the existing ROW presents more challenges from an outage coordination and construction standpoint. Costs also are likely to increase due to the need for some 69kV undergrounding, additional retaining walls and outage constraints. These issues, and the final location and extent of work pads and stringing sites, will be addressed in final engineering.

[2] Neither USFWS nor Energy Division have provided SDG&E with the final boundaries of the properties that will be subject to the Talega Conservation Easement, and therefore the affected areas outside of SDG&E ROW or fee-owned property but within the Talega Conservation Easement cannot be calculated precisely. However, as USFWS agrees, SDG&E's Proposed Project activities within SDG&E's ROW or fee-owned property are not subject to the Talega Conservation Easement.

OVERVIEW

The minor project changes that are included within the Segment 4 Design Revision are described in more detail under the *Segment 4 Design Revision* section of this attachment and are summarized below for each Proposed Project component.

Although the precise number of structures to be installed may be further refined during final engineering, the Segment 4 design revision described herein and the April 2015 revisions will result in the estimated quantity of transmission line structures to be reduced from 82 to 75 structures (50 230kV, 17 138kV, and 8 69kV) when comparing the Draft EIR Design (Design Date February 2015) to the Current Design (September 2015). Figure 3, Preliminary Segment 4 Design Revision Site Map, contains the preliminary design for construction including temporary and permanent work areas, retaining walls, access roads, and other project features. Figure 4, Impact Comparison Map, depicts a comparison of the Post-Draft EIR design (Design Date April 2015) with the current Segment 4 design revision, including differences in structure location and work areas.

SEGMENT 4 DESIGN REVISION

The elements of the Segment 4 Design Revision are described in detail below for each segment of the Proposed Project Alignment. For the purposes of analysis under CEQA, the Proposed Project was divided into segments as follows:

- Segment 1a (West-side Getaways): 138kV powerline relocations west of the Capistrano Substation.
- Segment 1b (East-Side Getaways and new 230kV Line): New 230kV between the Capistrano Substation and Rancho San Juan; relocated 138kV 12kV lines (getaways) between the Capistrano Substation (west) and I-5 freeway.
- Segment 2 (230kV Underground at Rancho San Juan): Install new 230kV underground within Vista Montana road at the Rancho San Juan development.
- Segment 3 (new 230kV between Rancho San Juan and the Talega Hub): Install new 230kV line in an overhead position between the Rancho San Juan development and the Talega Hub.
- Segment 4 (new 230kV and relocations of 138 and 69kV): New 230kV lines would be installed in an overhead position between the Talega Hub and the Talega Substation. Existing 138 and 69kV lines would be relocated between the Talega Hub and Talega Substation.
- San Juan Capistrano Substation: The existing 138/12kV Capistrano Substation would be rebuilt and expanded (at the existing site) to be a new 230/138/12kV substation.
- Talega Substation: Minor modifications would be made at the Talega Substation.

Changes for each of these Proposed Project segments resulting from the Segment 4 Design Revision are detailed below for each segment.

Segment 1a

No changes from SDG&E's Minor Project Design Refinements dated April 2015 and submitted as Attachment A to SDG&E's comments on the Draft EIR.

Segment 1b

No changes from SDG&E's Minor Project Design Refinements dated April 2015 and submitted as Attachment A to SDG&E's comments on the Draft EIR.

Segment 2

No changes from SDG&E's Minor Project Design Refinements dated April 2015 and submitted as Attachment A to SDG&E's comments on the Draft EIR.

Segment 3

No changes from SDG&E's Minor Project Design Refinements dated April 2015 and submitted as Attachment A to SDG&E's comments on the Draft EIR.

Segment 4

The Proposed Project alignment within Segment 4 was reconfigured to minimize the amount of new ROW required within Segment 4 where a new conservation easement is being proposed (the Talega Conservation Easement). The Segment 4 Design Revision relocated all structures in Segment 4, as needed, that are west of the Talega Substation and expected to be within property subject to the Talega Conservation Easement, to be within existing SDG&E ROW, easement, or fee-owned property (refer to Figures 1 and 4).[3] The specific design changes are detailed below for each aspect of the Proposed Project Segment 4 (Talega Hub to Talega Substation).

230kV Transmission Line Refinements

- Structure Additions
  - Two new 230kV structures (Structures 43 and 46) were added to Segment 4 to ensure all structures and 230kV lines would be within existing SDG&E ROW. New structures were required as the utilization of existing ROW requires a slightly longer alignment and additional angles (turns) in the alignment that require additional support structures.
- Structure Relocations
  - Structures 44, 45, and 46 (now numbered 45, 47, and 48 respectively) were relocated to ensure that the new 230kV line would remain in existing SDG&E ROW (refer to Figure 4).

[3] 230kV Structure 49 would still require new ROW and was not relocated as there is no feasible alternative location that would not require new ROW. This structure location, however, is not anticipated to be within property subject to the yet-to-be recorded Talega Conservation Easement.

- Structure Removals
    - None.

138kV Power Line Refinements

- Structure Additions
    - None.
- Structure Relocations
    - Structure 11a was relocated approximately 300 feet west-southwest to a location within existing SDG&E ROW.
- Structure Removals
    - Structures 13a and 19a were removed and replaced by Structure 15a.

Minor 69kV Power Line Refinements

- Structure Additions
    - New Structure 5b was added to Segment 4 to ensure that all 69kV lines remain within existing SDG&E ROW. The new structure was required to allow the 69kV line to navigate an additional angle point (turn) in the alignment.
- Structure Relocations
    - Structures 4b and 5b (now numbered 3b and 4b respectively) were relocated south to create room for the new 230kV structures (45 and 46) within existing SDG&E ROW.
- Structure Removals
    - None.
- Underground Lines
    - A small section (approximately 310 feet) of underground 69kV power line was added between structures 2b and 3b to allow for clearance of the larger voltage lines (138kV and 230kV).

Grading and Retaining Walls

- Grading Requirements
    - New grading would be required to construct construction and/or maintenance pads at new structure locations 43, 11a, 3b, 47, and 48 (refer to Figure 2).
    - Grading would no longer be required at structures 11a (old location), 44 (old location), 4b (old location), 5b (old location) and 45 (old location).
    - Grading requirements will remain similar for structures 16a (formerly structure 14a), and 49 (formerly structure 47).
- Retaining Walls
    - Retaining walls were added at structures 46 and 5b.
    - Retaining walls were removed from the design at structure 45 (which was relocated to Structure site 47 and no longer requires a retaining wall).
    - The retaining wall at structure 16a would be similar between the April and September 2015 designs.

Table 1, Updated Segment 4 Structure Table, summarizes the design change (if any) and the structure heights for all structures now within Segment 4 of the project design. Table 2, Summary of Impact Area, provides a summary of the estimated area of disturbance for the Draft EIR Proposed Project (February 2015), for SDG&E's revised project (Design Date April 2015) and for the current Segment 4 Design Revision (Design Date September 2015). Table 3, Summary of Impacts Outside of SDG&E ROW, provides a summary of the currently anticipated impacts that would occur outside of SDG&E existing ROW or fee-owned property along Proposed Project Segments 3 and 4.[4]

The remainder of this page is intentionally left blank.

[4] The existing and proposed Conservation Easements in the Project vicinity are located in the vicinity of Segments 3 and 4 only. Because the exact boundaries of the pending Talega Conservation Easement are not yet know, exact estimated impacts within the boundaries are not yet known but the parties have agreed to work to ensure there would not be any remaining significant impacts.

Table 1: Updated Segment 4 Structure Table

Pole No.[1]	Rating	Pole Height (feet)	Design Change (from April 2015 design[2])
42	230kV	130	No change
43	230kV	160	New Structure
44	230kV	135	No change (old structure 43)
45	230kV	95	Structure relocated ~410 feet southeast into SDG&E ROW (old structure 44)[3]
46	230kV	105	New Structure
47	230kV	95	Structure relocated ~170 feet into SDG&E ROW (old structure 45)
48	230kV	135	Structure relocated ~100 feet into SDG&E ROW (old structure 46)
49	230kV	125	Structure shifted slightly (~15 feet) (old structure 47)
50	230kV	135	No change (old structure 48)
9a	138kV	80	No change
10a	138kV	65	No change
11a	138kV	75	Structure relocated ~300 feet southwest into SDG&E ROW
12a	138kV	75	No change (old structure 15a)
13a	138kV	65	No change (old structure 16a)
14a	138kV	70	Structure shifted slightly (~45 feet) (old structure 17a)
15a	138kV	100	New structure (replaces old structures 13a and 19a)
16a	138kV	100	Structure shifted slightly (~25 feet) (old structure 14a)
17a	138kV	85	No change (old structure 23a)
1b	69kV	90	No change
2b	69kV	85	Structure is now a Cable Pole
3b	69kV	65	Structure shifted ~180 feet west-southwest and is now a Cable Pole (old structure 4b)
4b	69kV	75	Structure shifted ~180 feet west-southwest (old structure 5b)
5b	69kV	85	New Structure
6b	69kV	80	No change (old structure 7b)
7b	69kV	75	Structure shifted slightly (~20 feet) (old structure 8b)
8b	69kV	75	No change (old structure 9b)

Notes: Table contents based upon preliminary engineering.
[1] Structure locations shown on Figures 1 - 4.
[2] SDG&E provided the April 2015 Minor Project Design Refinements as part of the SDG&E's comments on the Draft EIR dated April 10, 2015.
[3] Old structure locations refer to the April 2015 design and are shown in Figure 4.

Table 2: Summary of Impact Area

Impact Type	Draft EIR Impact Area (February 2015)	Revised Impact Area (April 2015)	Current Impact Area (September 2015)	Delta (Sept. - April)
Temporary Impacts	23.36	35.93	36.53	(1.4)
Permanent Impacts	20.46	16.39	16.19	0.2

Table 3: Summary of Impacts Outside of SDG&E ROW for Segments 3 and 4

Impact Type	Impacts Outside of SDG&E ROW
Temporary Impacts[1]	9.48 acres
Permanent Impacts	1.27 acres
Notes: [1] Approximately 7.2 acres of the temporary impacts are associated with five potential staging yard locations.	

San Juan Capistrano Substation

No changes from SDG&E's Minor Project Design Refinements dated April 2015 and submitted as Attachment A to SDG&E's comments on the DEIR.

Talega Substation

No changes from SDG&E's Minor Project Design Refinements dated April 2015 and submitted as Attachment A to SDG&E's comments on the Draft EIR.

Construction Methods

No changes from SDG&E's Minor Project Design Refinements dated April 2015 and submitted as Attachment A to SDG&E's comments on the Draft EIR.

ELIMINATION OF ANY SIGNIFICANT ENVIRONMENTAL IMPACTS

The RDEIR states:[5] "The USFWS has indicated that establishing new ROW within the Talega Conservation Easement or impacting areas of the Prima Deshecha Landfill Conservation Easement that are outside of the applicant's existing ROW would directly conflict with the provisions of the aforementioned conservation easement(s), and thereby the provisions of the Orange County Southern Subregion HCP."

The Segment 4 Design Revision was prepared specifically to eliminate, reduce or avoid conflicts between the Proposed Project and the yet-to-be recorded, proposed Talega Conservation Easement, which the RDEIR found will be incorporated into the Orange County Southern Subregion HCP (which the RDEIR found is a "preserve" area under SDG&E's NCCP) such that

[5] RDEIR at pg. 2-77, lines 23 – 26.

impacts would be reduced to less than significant. As outlined above, the Segment 4 Design Revision would result in all new and relocated structures and electric power and transmission lines that would be located within the potential boundaries of the proposed Talega Conservation Easement being located within existing SDG&E ROW. This would greatly reduce the potential need for new ROW in order to construct and operate the Proposed Project.

SDG&E staff met with USFWS staff on September 11, 2015 to discuss SDG&E's existing easements and associated rights as well as USFWS concern that the Proposed Project may conflict with existing or proposed conservation easements located in the vicinity of the Proposed Project. During the meeting, SDG&E reviewed a map showing SDG&E's easements and the path of the Proposed Project, including the revised alignment included herein as the Segment 4 Design Revision (Design Date September 2015). SDG&E and USFWS discussed the preliminary redesign shown in Figures 1 and 3. According to USFWS, there are portions of permanent work pads and some temporary string sites and other temporary work areas that could occur within potential areas of the proposed and unrecorded Talega Conservation Easement that are outside of SDG&E's existing easements and ROW.

USFWS stated that, based on the proposed redesign, they would work with SDG&E and the Talega Conservation Easement stakeholders to ensure that the remaining Proposed Project impacts would be mitigated to a level acceptable to both SDG&E and the USFWS. Specifically, the USFWS proposed the following process (which is consistent with Mitigation Measure BR-10) to ensure that the Proposed Project would be consistent with the proposed and unrecorded Talega Conservation Easement (and thus the Orange County Southern Subregion HCP):

1. First, the USFWS would work with the Talega Conservation Easement stakeholders (Grantor and Grantees) to temporarily suspend recording the easement while the Proposed Project re-design of Segment 4 is finalized.
2. Once the design is finalized, the specifics of any temporary or permanent work areas located outside of existing SDG&E ROW would be incorporated into the Talega Conservation Easement as "allowed uses."
3. USFWS and SDG&E would then agree on mitigation for the permanent and temporary impacts that occur outside of existing SDG&E ROW and within the finalized boundaries of the Talega Conservation Easement.

With the Proposed Project thus being made consistent with the proposed and unrecorded Talega Conservation Easement and Orange County Southern Subregion HCP, Impacts BR-6 and LU-3 would be effectively reduced to a level less than significant.

As stated in the RDEIR:[6] "MM BR-10 would require the applicant to participate in further coordination with implementing agencies. While consultation with the USFWS may identify mechanisms for reducing potentially significant impacts to less than significant levels, MM BR-10 on its own does not adequately ensure consistency with an adopted HCP at this time. Therefore, impacts under this criterion are being treated as significant and unavoidable until additional information is gathered."

[6] RDEIR at pg. 2-77; lines 26-30.

The preliminary consultation between SDG&E and the USFWS has provided a "mechanism for reducing potentially significant impacts" relating to the Proposed Project's consistency with the proposed Talega Conservation Easement and the Orange County Southern Subregion HCP. The measures set out in the SDG&E NCCP/HCP, along with the Segment 4 Design Revision, will result in impacts being mitigated to a level less than significant.

ATTACHMENT A

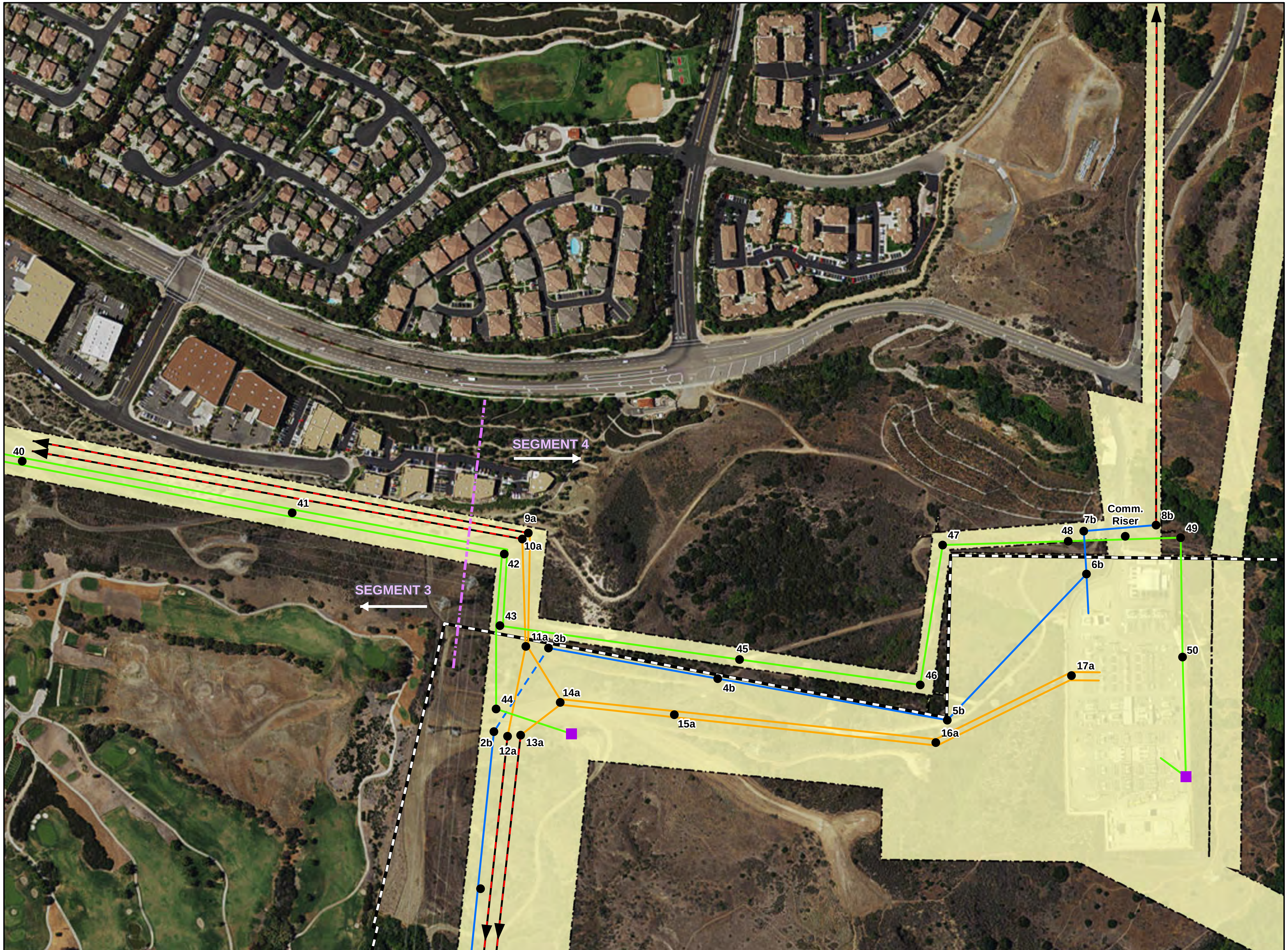
FIGURES

BASED ON PRELIMINARY ENGINEERING

Figure 1

Segment 4 Design Revision Overview

(Design Date September 2015)



Facilities

- Existing Structure to be Utilized in Place
- Proposed New Structure
- Existing Overhead Line
- 69kV Underground Power Line
- 69kV Overhead Power Line
- 138kV Overhead Power Line
- 230kV Overhead Transmission Line

Easements & Boundaries

- MCB Pendleton Boundary
- Existing SDG&E Easements, ROW, & Fee-Owned Property

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Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
Content may not reflect National Geographic's current map policy. Sources: National Geographic, Esri, DeLorme, HERE, UNEP-WCMC, USGS, NASA, ESA, METI, NRCAN, GEBCO, NOAA, increment P Corp.; SDG&E, 2015

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BASED ON PRELIMINARY ENGINEERING

Figure 2

Segment 4 ROW Map

(Design Date September 2015)

Easements & Boundaries

- MCB Pendleton Boundary
- Existing SDG&E Easements, ROW, & Fee-Owned Property
- New ROW Potentially Required
- ROW No Longer Required

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Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
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BASED ON PRELIMINARY ENGINEERING

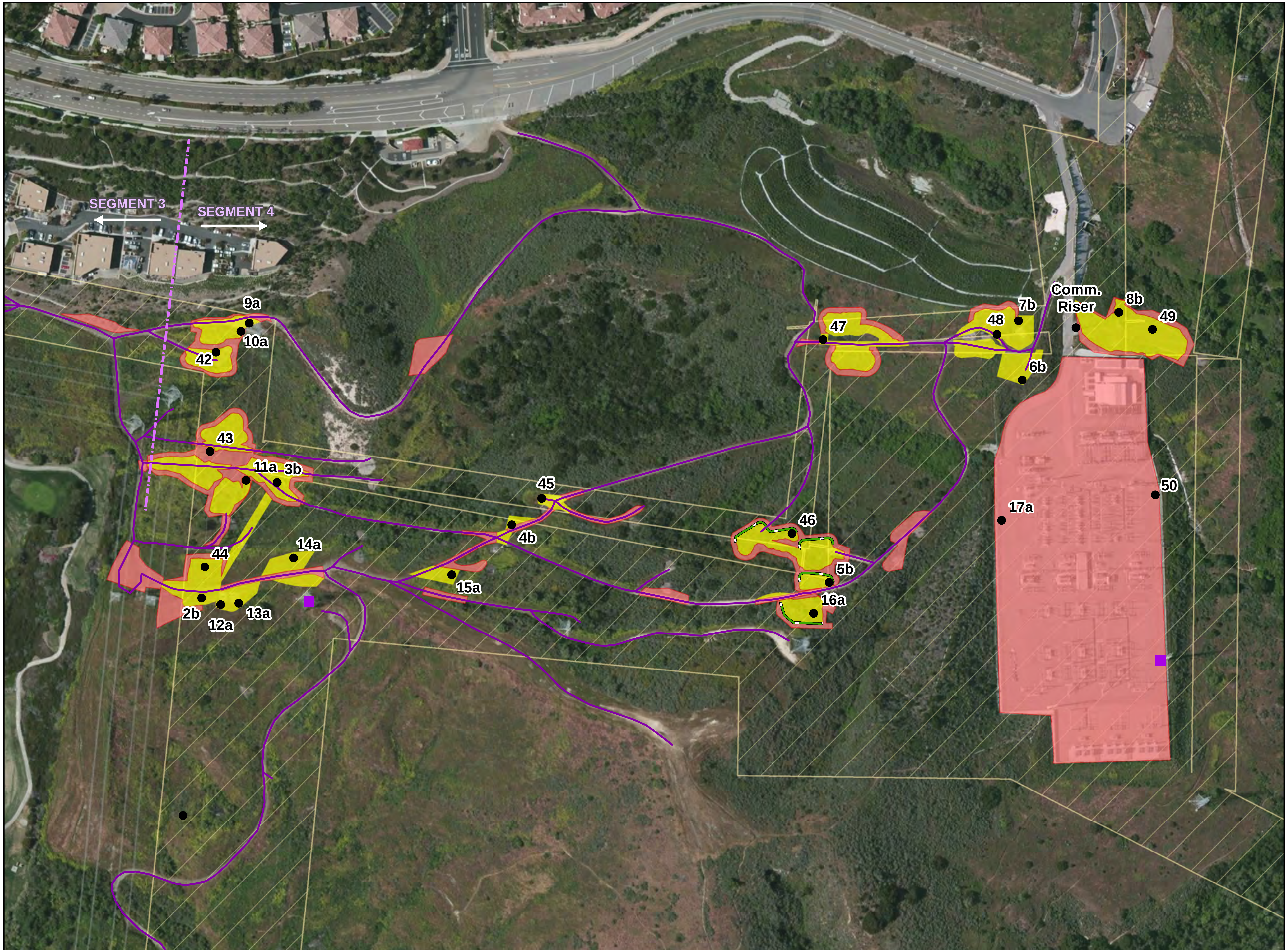

Figure 3

Preliminary Segment 4 Design Revision Site Map

(Design Date September 2015)

Facilities

- Existing Structure to be used in place
- Proposed New Structure
- Existing Access Roads

Work Areas (Impacts)

- Retaining Wall
- Permanent Impact
- Temporary Work Area

Easements & Boundaries

- Existing SDG&E Easements, ROW, & Fee-Owned Property

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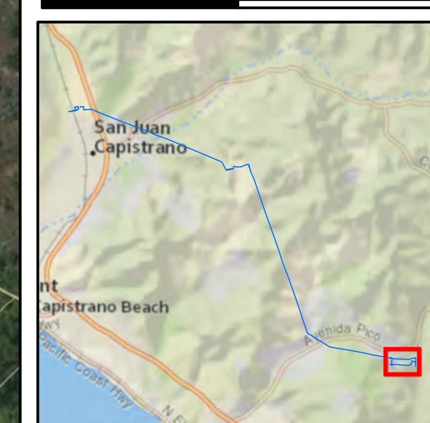

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
Content may not reflect National Geographic's current map policy. Sources: National Geographic, Esri, DeLorme, HERE, UNEP-WCMC, USGS, NASA, ESA, METI, NRCAN, GEBCO, NOAA, increment P Corp.; SDG&E, 2015

SDG&E A Sempra Energy utility

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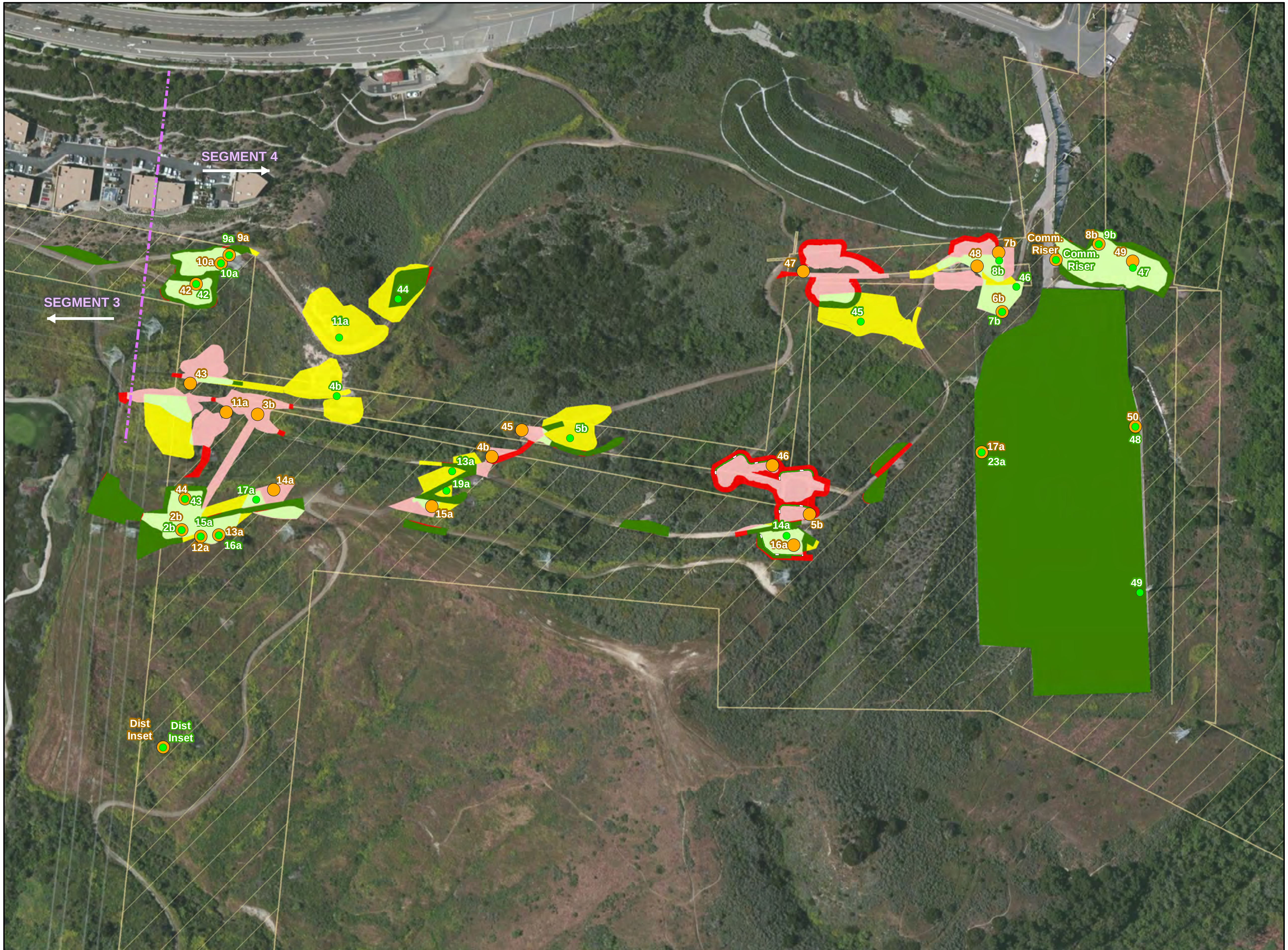

Figure 4

Impact Comparison Map

(Design Date September 2015)

Facilities

- Pole Locations (April 2015)
- Pole Locations (September 2015)
- RetainingWall

Same as April 2015 Design

- Permanent Impact
- Temporary Work Space

New Impacts

- Permanent Impact
- Temporary Work Space

Removed Impacts

- No Longer an Impact

Easements & Boundaries

- Existing SDG&E Easements, ROW, & Fee-Owned Property

0 220 440 Feet

N

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
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SDGE A Sempra Energy utility

EXHIBIT 3

SDG&E Corrected Opening Testimony with Attachments 1-7

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Exhibit No.: __________

In The Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) for a Certificate of Public Convenience and Necessity for the South Orange County Reliability Enhancement Project	Application 12-05-020

SAN DIEGO GAS & ELECTRIC COMPANY

CORRECTED PREPARED TESTIMONY OF

JOHN JONTRY, KARL ILIEV, AND

CORY SMITH

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

JANUARY 15, 2015

CORRECTED SEPTEMBER 10, 2015

TABLE OF CONTENTS

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CHAPTER 1: INTRODUCTION AND OVERVIEW (WITNESS: JOHN JONTRY)

Section 1. The Project Is Needed to Provide Reliable Electric Service to South Orange County, Now and In the Future

SDG&E's Proposed Project is needed to address a number of reliability concerns in SDG&E's South Orange County system, and ensure reliable electric service to the over 300,000 people dependent on SDG&E's electric service in that area. The SDG&E customers in southern Orange County are primarily residential and large commercial. The South Orange County's population has grown substantially over the past several decades[1]; the city of San Clemente in Southern Orange County alone grew at an average rate between 2000 and 2010 of almost 3% per year.[2] South Orange County is a geographically discrete local area which includes the following cities: Dana Point, San Clemente, San Juan Capistrano, Laguna Beach, Laguna Hills, Laguna Niguel and Mission Viejo.

After thorough study of the reliability issues by SDG&E and in the open stakeholder transmission planning process of the California Independent System Operator (CAISO), SDG&E proposed, and CAISO approved, the Proposed Project to address the following reliability concerns:

- SDG&E's South Orange County customers are dependent on single power source, the 230 kV supply to Talega Substation, which then supplies power via 138 kV transmission lines to the distribution substations within South Orange County. Any event that interrupted the 230 kV or 138 kV service at Talega Substation, such as equipment failure, fire/explosion, earthquake, or vandalism/terrorism,

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[1] According to the U.S. Decennial Census, the population of Orange County as a whole doubled between 1970 and 2000, to over three million people, and continues to grow at approximately 1% per year. (http://en.wikipedia.org/wiki/Orange_County,_California#Demographics).

[2] According to the U.S. Decennial Census, the population of San Clemente increased from 49,936 in 2000 to 63,249 in 2010. (http://en.wikipedia.org/wiki/San_Clemente,_California#Demographics).

would leave over 300,000 people in South Orange County without electricity until the damage was fixed. An extended outage of the 230 kV or 138 kV service at Talega Substation would threaten public safety and cause severe economic impacts to South Orange County. The Proposed Project addresses this problem by providing a second 230 kV connection at a rebuilt Capistrano Substation (re-named San Juan Capistrano Substation).

- Because Talega Substation is the sole power source for SDG&E's South Orange County system, and has a non-standard configuration that cannot be corrected within the existing footprint, planned outages for maintenance at Talega leave some or all South Orange County customers at risk that single forced outage of another element could interrupt their electric service. The need for maintenance at Talega Substation, which is over 35 years old, is increasing. A second 230 kV source at the new San Juan Capistrano Substation will allow maintenance at Talega without this risk.
- There are number of events, falling under Category B or Category C of the North American Electric Reliability Corporation (NERC) reliability standards, under which it is expected that outages of one or more elements will cause overloads on SDG&E's South Orange County transmission system and force SDG&E to interrupt customer service. Some of these events will result in SDG&E's transmission lines exceeding "Applicable Ratings," which is a violation of NERC TPL-003-0b. Other events will force SDG&E to "shed load," meaning to drop electric service to customers, to keep its transmission facilities within Applicable Ratings or, as required by the NERC standards, to prepare the system to remain

within Applicable Ratings in the event of another outage, which may be interpreted as a violation of NERC TPL-002-0b. The Proposed Project resolves these issues, and will avoid SDG&E having to interrupt customer service in these events.

- The existing Capistrano Substation, built in approximately 1954, needs to be rebuilt as its aging equipment and infrastructure is at or close to the end of its useful life, its outdated bus configuration does not meet SDG&E's reliability criteria, it does not meet SDG&E's current seismic and security standards, and it lacks the capacity to reinforce its neighboring substations. These problems cannot be fixed within the current substation footprint. The Proposed Project will rebuild the substation on SDG&E's existing substation property as the new San Juan Capistrano Substation, which will fix all of the above issues and allow it to be the second 230 kV source for the area.

SDG&E's Proposed Project includes the following three main components:

- Complete re-build of the 60 year-old 138/12-kV 60 megavolt ampere (MVA) air-insulated Capistrano Substation (2 acres) as a new 230/138/12-kV 784 MVA gas-insulated substation (6.4 acres) called San Juan Capistrano Substation. The rebuild would occur on SDG&E's existing substation property. Once complete, the San Juan Capistrano Substation would initially connect to six 138 kV transmission lines, two 230 kV transmission lines, and seven distribution lines;
- Minor alterations to the existing Talega Substation within the existing substation footprint including the removal of two 230/138 kV transformers and the removal of one 230 kV connection (which would instead connect to the new San Juan

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Capistrano Substation. To accommodate these changes, existing 138 kV and 230 kV structures within the Talega Substation would have to be re-arranged;

- Removal, installation, and relocation of multiple transmission lines within the existing, approximately eight-mile transmission corridor between the Capistrano and Talega Substations. This work includes a new double-circuit 230-kV transmission line (approximately 7.8-miles long) to the new San Juan Capistrano Substation.

Section 2. SDG&E's Project Objectives

To meet SDG&E's obligation to serve and to maintain reliable service to its over 300,000 customers in South Orange County, SDG&E seeks a Certificate of Public Convenience and Necessity authorizing construction and operation of SDG&E's Proposed Project. The Project's objectives are as follows:

1. Provide transmission system reliability:
   a. Reduce the risk of an uncontrolled outage to South Orange County customers.
   b. Reduce the risk of a controlled interruption of service to a portion South Orange County customers.
   c. Comply with mandatory North American Electric Reliability Corporation (NERC), Western Electric Coordinating Council (WECC) and CAISO transmission planning and operations standards.
2. Rebuild Capistrano Substation to replace aging equipment and increase capacity.
3. Improve transmission and distribution operating flexibility.
4. Accommodate customer load growth in the South Orange County area.

5. Locate proposed facilities within existing transmission corridors, SDG&E ROW and utility owned property.[3]

Section 3. Organization of SDG&E's Testimony

SDG&E's opening testimony on the issue of "need" is organized as follows:

- Chapter 2: SDG&E's Existing South Orange County Electric System
- Chapter 3: SDG&E Plans Its Transmission System To Provide Reliable Electric Service
- Chapter 4: SDG&E's Proposed Project Is Needed To Provide Reliable Transmission Service To SDG&E's South Orange County System
- Chapter 5: To Provide Reliable Electric Service, SDG&E's Capistrano Substation Needs To Be Rebuilt
- Chapter 6: Without SDG&E's Proposed Project, SDG&E's Talega Substation Needs To Be Modified To Provide Reliable Electric Service
- Chapter 7: Purpose and Need for South Orange County Reliability Project

[3] Application of San Diego Gas & Electric Company (U 902 E) For A Certificate Of Public Convenience And Necessity For The South Orange County Reliability Enhancement Project, A.12-05-020 ("Application") at 3-4.

CHAPTER 2: SDG&E'S EXISTING SOUTH ORANGE COUNTY ELECTRIC SYSTEM

Section 1: SDG&E's Customers in South Orange County (Witness: John Jontry)

SDG&E's South Orange County (SOC) service area is located at the northern end of SDG&E's service territory and has approximately 125,000 electric meters. This service area represents approximately 10 percent of SDG&E's total customer load of approximately 5000 megawatts (MW).

The customers served by SDG&E in South Orange County are primarily residential and large commercial. The South Orange County population has grown substantially over the past several decades, as the area has gone from a semi-rural region of orange groves and a few small beach towns, to a densely populated and affluent suburb of the Los Angeles and San Diego metropolitan regions. The aggregate population of Orange County doubled between 1970 and 2000, to over three million, and continues to grow at about 1% per year.

SDG&E serves 112,794 residential electric meters in South Orange County. The number of South Orange County residents dependent upon SDG&E's electric service is estimated to be over 300,000. SDG&E fully serves Dana Point (2013 estimated population 34,062), San Clemente (2013 estimated population 65,040) and San Juan Capistrano (2013 estimated population 35,852), and shares service with SCE in Aliso Viejo (2013 estimated population 50,175), Laguna Beach (2013 estimated population 23,250), Laguna Hills (2013 estimated population 30,880), Laguna Niguel (2013 estimated population 64,652) and Mission Viejo (2013 estimated population 96,346). In local unincorporated communities, SDG&E fully serves Ladera Ranch (2010 estimated population 22,980) and Las Flores (2010 estimated population 5,971) and partially serves Coto de Caza (2010 estimated population 14,866).[4] SDG&E also serves other unincorporated areas of South Orange County that are not included in the US Census, such as Wagon Wheel.

SDG&E also serves 11,967 commercial meters and 43 industrial meters in South Orange County. These businesses rely on SDG&E's electric service to provide work for employees and goods and services to their customers. These employees and customers may or may not reside in South Orange County.

Physically, the region served by SDG&E in South Orange County is somewhat land-locked, both by geographic features and by political and land-use boundaries. The region is bounded on the east and west by the Cleveland National Forest and Pacific Ocean, respectively; it is bounded on the north by various state parks and wilderness areas, and on the south by MCB Camp Pendleton. This is illustrated in Figure 2-1 below. Egress from the area is by way of a single freeway, Interstate 5.

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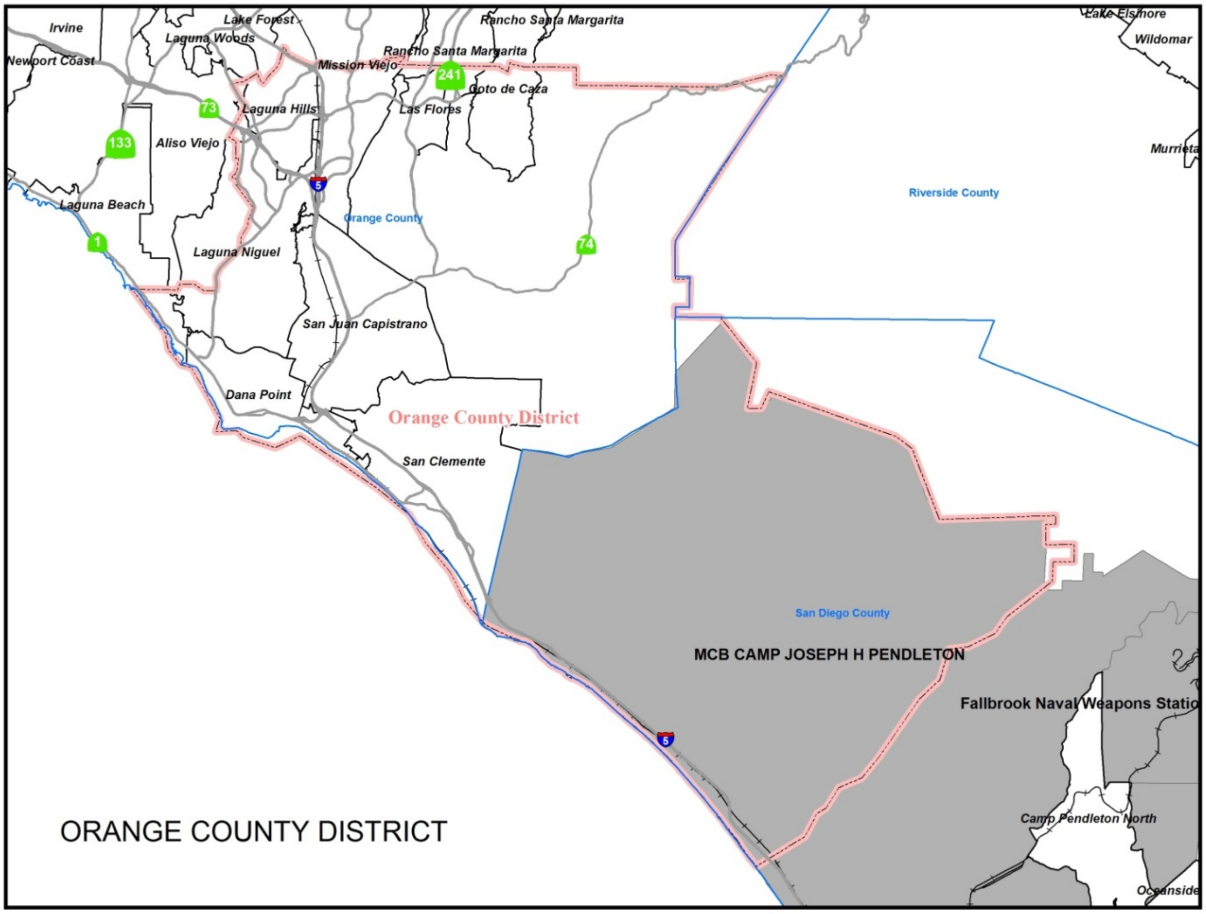
[4] Population estimates are the 2013 population estimates provided by the U.S. Census for each referenced city. http://quickfacts.census.gov/qfd/states/06000.html.

Figure 2-1 – South Orange County service area

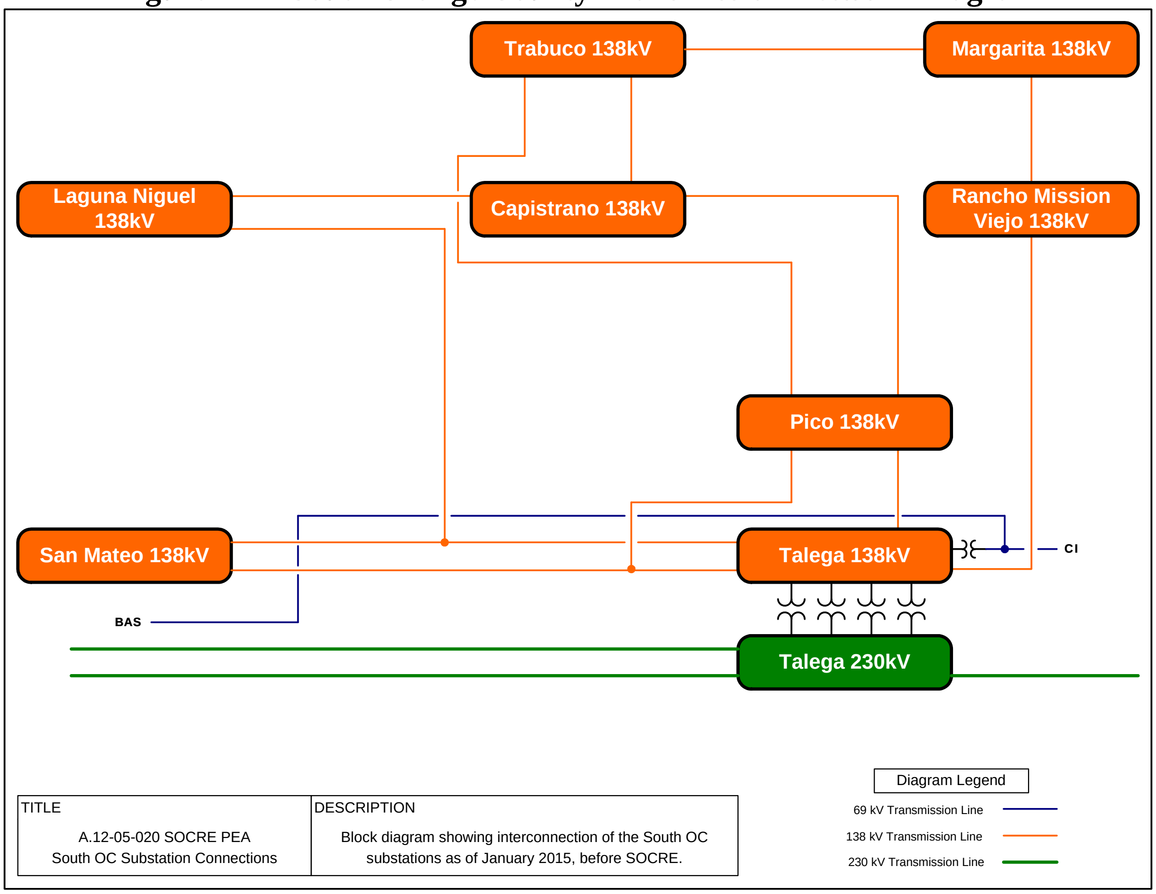


The South Orange County region is typical of Southern California in that it is subject to the risk of natural disasters in the form of earthquakes and wildfires. Portions of SDG&E's South Orange County service area lie within the CALFIRE Fire Threat Zone (FTZ), as modified by SDG&E. This area includes Talega Substation.

Section 2. SDG&E's Existing South Orange County Transmission System (Witness: John Jontry)

South Orange County's electric load is supplied by seven SDG&E 138/12 kilovolt (kV) distribution substations (Capistrano, Laguna Niguel, Margarita, Pico, San Mateo, Rancho Mission Viejo, and Trabuco). Each of these substations is fed from a local 138 kV network; the local network is in turn supplied from Talega Substation, which provides the sole 230/138 kV connection to the Southern California bulk power network. This local area network is operated by the California Independent System Operator (CAISO). The substation interconnection diagram shown in Figure 2-2, South Orange County 138 kV Substation Interconnection Diagram, illustrates how the distribution substations within the South Orange County service area are connected to each other and to Talega Substation.

Figure 2-2 – South Orange County Transmission Network Diagram



Currently, there is no significant generation of electric energy in South Orange County service area. Consequently, the only power source for this entire service area is the 230 kV transmission network at Talega Substation. If the connection to the 230 kV bulk power system at Talega is unavailable, there is no other source to provide electric service to SDG&E's South Orange County customers. SDG&E's Proposed Project addresses this reliability concern by adding a second 230 kV bulk power connection at Capistrano Substation so that, in the event of loss of either the 230 kV or 138 kV voltage levels at Talega, electric service to South Orange County customers would continue uninterrupted.

Even with Talega Substation in service, there are number of events, falling under Category C of the North American Electric Reliability Corporation (NERC) reliability standards, under which it is expected that outages of one or more elements will cause overloads on SDG&E's South Orange County transmission system. Some of these events will result in SDG&E's transmission lines exceeding "Applicable Ratings," which is a violation of NERC TPL-003-0b. Other events will force SDG&E to "shed load," meaning to drop electric service to customers, to keep its transmission facilities within Applicable Ratings or, as required by the NERC standards, to prepare the system to remain within Applicable Ratings in the event of another outage. The Proposed Project resolves these issues, and will avoid SDG&E having to interrupt customer service in these events.

Section 3. SDG&E's Existing Talega Substation (Witness: John Jontry)

As noted in Section 2 above, power from the 230 kV transmission network enters South Orange County at the Talega Substation 230 kV bus and flows through the substation's four 230/138 kV transformers to the substation's 138 kV bus. The Talega Substation 138 kV bus supplies power to the 138 kV transmission network, which supplies the distribution substations. If a failure occurs that requires the Talega Substation 230 kV or 138 kV buses to be removed from service, power flow to South Orange County would be interrupted and SDG&E's South Orange County customers would lose electric service.

This scenario actually occurred on July 18, 2013, resulting in all SDG&E customers in South Orange County losing electric service for a period of several hours. Fortunately, this event occurred in the early morning hours and there was little direct impact; however, had the event occurred during a busy working day, the economic and social impact would have been much more significant. Talega Substation has an unusual non-standard configuration in that two of the four 230/138 kV transformers are connected directly to the 230 kV bus instead of a connection to a circuit breaker then to the bus. This means that for loss of either of these two transformers, it is necessary to take the entire bus out of service to disconnect the failed equipment.

In addition to extreme events (fire, explosion, earthquake, vandalism or terrorism) that could result in the loss of all South Orange County load, the existing Talega Substation configuration restricts the conditions under which maintenance can be done and creates twenty-nine different outage scenarios during planned maintenance outages that would cause uncontrolled loss of the entire customer load in South Orange County. Because the Talega Substation is aging, maintenance needs are increasing.

Required maintenance at Talega Substation is not the only threat to South Orange County load. A contingency event during a planned maintenance outage at either Pico Substation, Rancho Mission Viejo Substation or Margarita Substations would lead to the outage of over 50% of South Orange County load.

As discussed in more detail in Chapter 6, Talega Substation presents a number of reliability concerns. The most significant arise from its non-standard configuration, space constraints, and role as the sole power source to SDG&E's South Orange County system. The Project addresses these issues by adding a second 230 kV bulk power connection at Capistrano Substation, allowing removal of two transformers from Talega Substation and reconfiguration of Talega within the existing substation footprint. The second source at Capistrano Substation and reconfiguration also mitigate risks during planned maintenance outages at Talega Substation.

Section 4. SDG&E's Existing Capistrano Substation (Witness: Karl Iliev)

Capistrano Substation is over 60 years old. Its infrastructure and equipment are at or near the end of their useful lives, its non-standard configuration does not meet SDG&E's current operating and reliability requirements, its infrastructure and some of its equipment do not meet current seismic standards, and its security measures do not meet SDG&E's current standards. For the reasons discussed further in Chapter 5, Capistrano Substation must be rebuilt to provide reliable electric service to SDG&E's customers served by that substation. SDG&E's Proposed Project will rebuild Capistrano Substation to not only provide reliable distribution service, but also to serve as a second 230 kV power source to SDG&E's network of South Orange County distribution substations.

SDG&E's Substation Equipment Assessment team has identified its aging equipment and infrastructure as beyond its useful life. Since 1997, Capistrano Substation has been on SDG&E's priority list, identifying substations that are in need of upgrades or replacement due to poor performance. This list was developed utilizing safety, condition of the equipment, probability of outages, and cost to maintain as key metrics.

Trending of the preventative and corrective maintenance labor hours on the Capistrano Substation equipment shows both types of maintenance trending upward, which is expected for aging equipment. Preventive and corrective maintenance at Capistrano Substation has been increasing since 1997, as has the need to replace failed equipment. Rising preventive and corrective maintenance issues are a strong indication of decreased equipment reliability and increased probability of failure. It also is a direct indication of rising costs to maintain the equipment.

Additionally, replaced equipment due to failure is another metric that is an indicator that remaining equipment on a site has reached the end of its useful life. Much of the significant equipment at Capistrano Substation ranks high on the replacements lists to be replaced before failure occurs.

Capistrano Substation has a non-standard configuration that does not meet current operating criteria or reliability requirements. When the substation was originally constructed, this configuration was the standard design. However, this design no longer meets the current operating criteria, and the layout and configuration has a number of non-standard aspects that reduce the reliability of electric service to SDG&E's customers. Within the current substation footprint, there is insufficient space to install 138 kV and 12 kV circuit breakers between elements as required by SDG&E's current standard design.

Further, Capistrano Substation is located in a high seismic activity area and it is SDG&E's standard practice to design substations and equipment that will have a high probability of withstanding seismic events to predefined ground acceleration levels. The existing Capistrano Substation was designed and constructed long before these standard practices and guidelines were established. Due to their age and type of construction, the existing structures, foundations, and equipment do not conform to the current recommended practices for seismic design of substations as provided in IEEE 693 and ASCE 113. The older existing electrical equipment does not meet the seismic withstand capability and has not been seismically qualified as provided in IEEE 693. Replacing equipment only does not allow for replacement of the existing structures and their foundations because current seismic requirements require more robust designs in equipment, foundations, and structures than aging substations can meet.

When Capistrano Substation was initially installed approximately 60 years ago, it met the design and equipment requirements of that time, and was adequate to meet system requirements based on projected loads at that time. Now, over 60 years later, its infrastructure and equipment is at or near the end of its useful life, and its design does not meet current operating and reliability criteria. Capistrano Substation, like other aging substations in SDG&E's service territory, must be rebuilt to meet current requirements and provide reliable electric service to SDG&E's customers.

CHAPTER 3: SDG&E PLANS ITS TRANSMISSION SYSTEM TO PROVIDE RELIABLE ELECTRIC SERVICE (WITNESS: JOHN JONTRY)

SDG&E is subject to both mandatory reliability standards and an obligation to provide reliable electric service to customers within its service area. The Proposed Project helps SDG&E meet both of its obligations with respect to its customers in South Orange County.

As the Commission recently recognized:

California law repeatedly emphasizes the importance of maintaining the reliability of the electric grid. For example:

- "Reliable electric service is of utmost importance to the safety, health, and welfare of the state's citizenry and economy." (§ 330(g).)
- "It is important that sufficient supplies of electric generation will be available to maintain the reliable service to the citizens and businesses of the state." (§ 330(h).)
- "Reliable electric service is of paramount importance to the safety, health, and comfort of the people of California." (§ 334.)
- The CAISO "shall ensure efficient use and reliable operation of the transmission grid" (§ 345) and shall "ensure the reliability of electric service and the health and safety of the public." (§ 345.5(b).)
- The Commission "shall ensure that facilities needed to maintain the reliability of the electric supply remain available and operational." (§ 362(a).)

D. 14-03-004 at 13. SDG&E strives to plan its system to provide reliable electric service.

In setting the level of reliability to be provided to its customers, SDG&E must comply with the mandatory North American Electric Reliability Council (NERC) reliability standards, the mandatory California Independent System Operator (CAISO) planning standards, and the

Commission's direction. SDG&E also uses industry best practices to determine the level of reliability it is reasonable and prudent to provide its customers under specific circumstances.

Section 1. NERC Transmission Planning Reliability Standards

At the minimum, SDG&E is obligated to comply with all NERC reliability standards by, among other things, the Federal Power Act § 215 and its Transmission Control Agreement with CAISO.[5] NERC is the electric reliability organization certified by the Federal Energy Regulatory Commission (FERC) to establish and enforce reliability standards for the nation's bulk power system. NERC develops and enforces reliability standards that are approved by FERC. NERC also assesses system adequacy annually; and it monitors the bulk power system. The NERC reliability standards are mandatory and set a floor for utility owned transmission systems.

The NERC reliability standards for planning reinforcements for electric transmission systems are the transmission planning (TPL) standards. Among other things, the TPL standards establish the required system performance with all elements in service and upon the loss of one, two, or more elements of a transmission system. These system conditions are referred to as Categories A, B, C and D. The TPL standards set the minimum level of reliability required for the system.

NERC Category A planning criteria, as used in long-term planning, is defined in Requirement R1 as follows[6]:

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[5] http://www.caiso.com/Documents/TCA_Effective_20140601.pdf. The CAISO's Transmission Control Agreement is consistent with Public Utilities Code § 345: "The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council."

[6] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-001-0.1&title=System Performance Under Normal (No Contingency) Conditions (Category A)&jurisdiction=United States

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> 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.

Table I of the NERC standard is reproduced as Figure ~~1~~ 3-1 below. For the purposes of interpreting the NERC standard, the CAISO is the "Planning Authority" for the SDG&E service area and SDG&E is the "Transmission Planner." Category A, as applied in long-term planning, generally means that the system, with all elements in service, must be capable of meeting the maximum forecast demand during the applicable planning window, without exceeding the applicable ratings of any of the system elements. This is generally called the "N-0" requirement.

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Figure 3-1 - Table 1 of the NERC standard TPL-001-0.1

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlledc Planned/ Controlledc	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section	Evaluate for risks and consequences. May involve substantial loss of customer Demand and generation in a widespread area or areas. Portions or all of the interconnected systems may or may not achieve a new,stable operating point. Evaluation of these events may require joint studies with neighboring systems.
	3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault)	
	6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus Transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

NERC Category B planning criteria is defined in Requirement R1 as follows[7]:

> 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 (non-recallable 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.

The Category B requirement, as applied in long-term planning, generally means that the system must be capable of sustaining the loss of any single element (line, transformer, or generator) and meet the maximum forecast demand during the applicable planning window, without exceeding the applicable ratings of any of the system elements that remain in service. This is generally called the "N-1" requirement. Specifically, deliberate rejection of firm customer load ("load shedding") is not permitted.[8]

Note that are situations where, following the loss of a single transmission line or transformer, it may be necessary for system operator to shed customer load in order to prevent an overload that would occur following a subsequent contingency. This is referred to as "system readjustment". System readjustment can also take the form of adjusting generation dispatch; however, as noted elsewhere there is effectively no generation in South Orange County available for redispatch. If the system operator is forced to shed load after the first N-1 to prepare for the

[7] Attachment1 also found at: http://www.nerc.com/files/TPL-002-0b.pdf

[8] "Footnote b" of Table I is not an exception. It is a statement which explains that interruption of electric supply to customers served by an element will naturally be disconnected from the system if the element experiences a fault.

next N-1, this may be interpreted as a violation of the Category B requirement, as rejection of customer load is not permitted to secure the system following a single N-1 contingency.

NERC Category C planning criteria is defined in Requirement R1 as follows[9]:

> 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 (non-recallable 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.

The Category C requirement, as applied in long-term planning, generally means that the system must be capable of sustaining the loss of multiple single elements (lines, transformers, or generators) and meet the maximum forecast demand during the applicable planning window, without exceeding the applicable ratings of any of the system elements that remain in service. This is generally called the "N-1-1 or N-2" requirement. This standard also applies to loss of a single bus section at a bulk power substation. However, for NERC Category C contingencies, the use of "planned/controlled" load shedding may be used to achieve compliance with the NERC Category C requirement.

Finally, NERC Category D planning criteria do not require a specific performance level, but instead require the Planning Authority and Transmission Planner to assess and understand the consequences of severe system contingencies, as described in Requirement R1[10]:

> "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

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[9] Attachment2 also found at: http://www.nerc.com/files/TPL-003-0b.pdf
[10] Attachment 3 also found at: http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-004-0a.pdf

> consequences of a number of each of the extreme contingencies that are listed under Category D of Table I."

The loss of one voltage level at Talega Substation (138 kV or 230 kV), or the loss of the entire substation is considered a Category D contingency. The NERC Category D requirement instructs utilities to "[e]valuate for risks and consequences" such Category D events because they "[m]ay involve substantial loss of customer Demand and generation in a widespread area or areas."

Section 2. NERC Transmission Operations Reliability Standards

NERC also has set reliability standards for transmission operations. Of particular relevance here, NERC TOP-004-2, R1 provides: "Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs)."[11] The NERC Glossary of Terms defines a SOL as the most limiting value that ensures operation within acceptable reliability criteria. A facility thermal rating is an SOL. SDG&E is required by NERC Transmission Operating Standards to operate within SOLs, including thermal ratings.

Section 3. CAISO Mandatory Planning Standards

In addition to the applicable NERC reliability standards, CAISO may impose additional performance requirements. Pursuant to California law and a FERC-approved tariff,[12] CAISO is responsible for the planning and operation of the electric transmission system in California. Under Public Utilities Code § 345: "The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and

[11] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TOP-004-2&title=Transmission%20Operations&jurisdiction=United%20States.
[12] http://www.caiso.com/Documents/ConformedTariff_Nov1_2014.pdf.

operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council."

Under the CAISO's Transmission Control Agreement, Section 6.1.3: "In operating and maintaining its transmission facilities, each Participating TO shall take proper care to ensure the safety of personnel and the general public. It shall act in accordance with Good Utility Practice, applicable law, the CAISO Tariff, CAISO Protocols, the Operating Procedures, and the Applicable Reliability Criteria." The Applicable Reliability Criteria are defined as "The Reliability Standards and reliability criteria established by NERC and WECC and Local Reliability Criteria, as amended from time to time, including any requirements of the NRC."

CAISO has adopted Planning Standards as authorized by the CAISO Tariff and the Transmission Control Agreement, Section 5.1.5. The CAISO Planning Standards currently in effect are effective from September 18, 2014 to March 30, 2015. The CAISO Planning Standards recognize that the NERC reliability standards for transmission planning are the "minimum standards that ISO needs to follow in its planning process." The CAISO Planning Standards state: "The California ISO (ISO) tariff provides for the establishment of planning guidelines and standards above those established by NERC and WECC to ensure the secure and reliable operation of the ISO controlled grid. The primary guiding principle of these Planning Standards is to develop consistent reliability standards for the ISO grid that will maintain or improve transmission system reliability to a level appropriate for the California system."[13]

In addition to providing mandatory interpretations of the NERC TPL standards, the CAISO Planning Standards address other aspects of reliability, including: (1) circumstances

[13] See Attachment4 - California ISO Planning Standards (Effective September 18, 2014 to March 30, 2015)
at 3.

where new transmission may be appropriate to mitigate load dropping permitted by NERC reliability standards (Planning Standard 6); (2) whether load shedding is appropriate for local areas even when permitted by NERC reliability standards (Planning Standard 7); (3) whether Category D events should be mitigated based on a case-by-case assessment (Planning Standard 8); and (4) use of Special Protection Systems (Planning Guideline 1).

Section 4. Commission Direction

The Commission has endorsed the NERC reliability standards as the minimum level of reliability that California utilities should provide their customers. The Commission recently expressed its disapproval of long term system planning that relies upon load shedding. In Decision 14-03-004, the Commission considered the need for utilities to procure additional generation resources in light of the retirement of SONGS, and stated:

> Per § 345, the ISO is responsible for operating the transmission grid used by SCE, PG&E, and SDG&E "consistent with achievement of planning and reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Reliability [Corporation]." The Commission is responsible for service reliability and maintaining reasonable rates. In previous decisions, we rejected the notion of "reliability at any cost," indicating instead that "measures that are proposed to promote greater grid reliability should be evaluated by weighing their expected costs against the value of their expected contribution to reliability…"
>
> We do not find that long-term reliance on an SPS to resolve LCR need related to the retirement of SONGS is appropriate. We agree with SCE witness Chinn that "load shedding should only be used judiciously as mitigation for contingencies." We also agree with IEP that we should not make a "change to long-term resource planning policy to incorporate blackouts as a standard, planned response to N-1-1 contingencies, a response on par with supply or demand-side additions, to avoid procuring the resources needed to reduce the risk of blackouts."

D.14-03-004 at 44 (footnotes omitted). The Commission concluded that it was "prudent to wait to see what resources develop in the SONGS service area to determine whether an SPS or other load-shedding protocol need serve as a bridge until such resources are in place," but stated: "We agree with SDG&E and IEP that that it is not prudent to take a long-term system planning approach that assumes reliance on load shedding in a densely-populated urban area as mitigation for contingency events." D.14-03-004 at 45-46.

Here, as discussed in Chapter 4, SDG&E serves over 300,000 people in South Orange County who may be subjected to long-term load shedding under certain contingency events.

Section 5. SDG&E Models Its System Against NERC and CAISO Standards to Assess Risks to Reliability

SDG&E conducts annual planning analyses of the bulk power system serving the overall SDG&E service area generally, and the South Orange County area specifically. The purpose of this analysis is to ensure that the transmission system meets NERC, WECC, and CAISO Planning Standards. SDG&E and CAISO planning staff observe the following general principles when performing the annual analyses:

1) Ensure that the system is capable of meeting NERC Category A, B and C planning criteria for the ten-year planning window;
2) Evaluate the impact of severe system contingencies (NERC Category D) on the bulk power system and consider what mitigation is appropriate;
3) Use of a 1-in-10 California Energy Commission (CEC) coincident forecast for aggregate area studies, as directed to by CAISO planning staff; and
4) Use of non-coincident, individual substation load forecast for "load pocket" or local area studies.

Both SDG&E and CAISO perform their annual independent planning analyses of the bulk power system with the intent of meeting NERC criteria, but it is important to point out that these criteria are, in fact, a set of *minimum* criteria. The CAISO reserves the right, as the

Planning Authority, to implement planning criteria that are more stringent that the minimum criteria as defined in the applicable NERC standards. The CAISO and SDG&E also have the discretion to identify, select, and implement mitigations for identified NERC violations that may go beyond the minimum necessary to meet the criteria in order to provide a higher level of reliability for customers. This includes identifying mitigations for Category B or Category C contingencies that also address severe Category D events.

Section 6. The CAISO Determines Whether Reliability Projects are Needed

The CAISO Transmission Control Agreement, Section 11 provides: "The provisions of Sections 24 and 25 of the CAISO Tariff will apply to any expansion or reinforcement of the CAISO Controlled Grid affecting the transmission facilities of the Participating TOs placed under the Operational Control of the CAISO." Section 24 of the CAISO Tariff outlines the CAISO Transmission Planning process.

The CAISO prepares an annual transmission plan based on CAISO's evaluation of the transmission system. Under Section 24.4.6.2 of its FERC-approved Tariff, CAISO determines the solution to reliability driven system needs "that meets the identified reliability need in the more efficient or cost effective manner." With respect to SDG&E's Proposed Project, the CAISO considered the needs of SDG&E's South Orange County system and potential solutions since 2008 before approving the Proposed Project in its 2010-11 Transmission Plan.

As noted in Section 5 above, both the CAISO and SDG&E reserve the right to identify and implement mitigations to correct identified deficiencies in the bulk power system, including mitigations that may exceed the bare minimum as required with respect to the NERC reliability standards. Both SDG&E and CAISO, when evaluating the merit of each mitigation, examine several important criteria that are not addressed specifically by the NERC criteria but that go directly how effective and efficient a particular mitigation is. This evaluation included:

1. Long-Term Effectiveness – Will the mitigation address the identified issues for the duration of the planning window? As utility-scale projects tend to have long service lives, will it continue to be useful and effective in the decades afterwards?
2. Addresses Multiple Issues – Will the mitigation have a narrow effectiveness, requiring multiple mitigations, or will it be effective at addressing multiple system deficiencies and avoid piecemeal projects?
3. Addressing High Impact System Contingencies – Will the mitigation prevent customer impacts from severe system contingencies?
4. Constructability - Can the mitigation be successfully implemented in the field, using available technology and construction practices?
5. Timeliness – Can the project be constructed in a reasonable timeframe, allowing for the procurement of long lead time equipment, permitting, right of way acquisition, etc.

With respect to the Project, the answers to these questions are as follows:

1. Long-Term Effectiveness – The Proposed Project will continue to address NERC reliability, provide a second bulk-power source to South Orange County, and allow for operational flexibility not just for the duration of the planning window, but for decades afterwards.
2. Addresses Multiple Issues – The Proposed Project will address all five of the main project objectives (provide transmission system reliability, rebuild Capistrano substation, improve operational flexibility, accommodate load growth, and use of existing utility-owned ROW).

3. Addressing High Impact System Contingencies – The Proposed Project will eliminate the possibility of loss of all Southern Orange County load for a catastrophic loss of Talega substation.

4. Constructability – The Proposed Project will use common utility equipment and construction techniques.

5. Timeliness – The Proposed Project can be accomplished in a reasonable time.

Both SDG&E and the CAISO evaluated multiple mitigations for the reliability issues extant in South Orange County, and both concluded that the Proposed Project was the best alternative for meeting both the NERC reliability criteria and other important considerations as described above.

Because CAISO has approved the Proposed Project, pursuant to its agreement with CAISO,[14] SDG&E is required to seek authorization to construct, and to construct if authorized, the Proposed Project.

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[14] *See* Transmission Control Agreement § 4.3 ("Participating TOs shall be responsible for operating and maintaining those lines and facilities in accordance with this Agreement, the Applicable Reliability Criteria, the Operating Procedures, and other criteria, CAISO Protocols, procedures, and directions of the CAISO issued or given in accordance with this Agreement.")

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CHAPTER 4: SDG&E'S PROPOSED PROJECT IS NEEDED TO PROVIDE RELIABLE TRANSMISSION SERVICE TO SDG&E'S SOUTH ORANGE COUNTY SYSTEM

Section 1. Overview (Witness: John Jontry)

As discussed in Chapter 3, SDG&E has an obligation to provide reliable electric service to its over 300,000 customers in South Orange County. SDG&E has determined that the Proposed Project is needed to provide an appropriate level of reliability. In reaching that determination, SDG&E considered the various risks to its South Orange County electric service.

SDG&E considered compliance with the NERC reliability criteria and CAISO Planning Standards discussed in Chapter 3, which are mandatory. As discussed below, SDG&E's Proposed Project is necessary for SDG&E's South Orange County system to operate in compliance with the NERC TPL-003-0b requirement that the system remain within Applicable Ratings at all times.

Further; however, the NERC reliability standards provide a floor, not a ceiling, for the reliability of electric service. It is the job of the local authority, in this case the CAISO and its open stakeholder process, to determine when it is appropriate to shed customer load to remove transmission line overloads and when it is appropriate to create a project.

NERC and CAISO realize that there are other factors that need to be evaluated when looking at dropping firm demand customers. Thus, NERC TPL-004-0a requires utilities to "[e]valuate for risks and consequences" Category D events (Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements) with the understanding that such events "[m]ay involve substantial loss of customer Demand and generation in a widespread area or areas." Similarly, CAISO recognizes that the NERC reliability criteria are "minimum standards that ISO needs to follow in its planning process" and will adopt Planning Standards "to complement them where it is in the best interests of the security and reliability of the ISO controlled grid."[15] In reviewing transmission needs, CAISO has stated that it is its "intention to allow the build-up of transmission projects that are proven to have a positive benefit to ratepayers by reducing load drop exposure."[16] Utilities, regional transmission system operators, and state public utilities commissions must determine whether greater reliability serves the public interest under specific circumstances.

Here, both SDG&E and CAISO have determined that the reliability concerns in South Orange County justify the Proposed Project. Those concerns include: (1) because Talega Substation is the sole source of power to SDG&E's South Orange County system, a Category D event at Talega could interrupt service to all of SDG&E's over 300,000 customers in the area for a significant period of time; (2) because Talega is the sole source and has a non-standard configuration, 29 different maintenance events at Talega, which require a planned outage of certain equipment, leave all of SDG&E's South Orange County customers at risk of losing service if there is a forced outage during the maintenance event; and (3) there are many Category C events that would disconnect over half of the customers or force SDG&E to interrupt service to some of its South Orange County customers, including both single and double outage events.

SDG&E sets forth below, in order: (a) the history of SDG&E's and CAISO's determination that the Proposed Project is needed to provide adequate reliability to South Orange County, resulting in CAISO's 2011 approval of the Proposed Project; (b) SDG&E's updated modeling assumptions; (c) the reliability risk of Category D events at Talega Substation; (d) the reliability risk during maintenance events at Talega Substation; (e) the need for the Proposed Project to comply with TPL-003-0b's mandate to remain within Applicable Ratings during Category C events; (f) the reliability risk of additional Category C single and double outage

[15] California ISO Planning Standards (Effective September 18, 2014 to March 30, 2015) at 3.
[16] *Id.* at 16.

events; and (g) the reliability risk during maintenance events at other South Orange County substations.

Section 2. SDG&E And CAISO Concluded That SDG&E's South Orange County Transmission System Needs A Reliability Upgrade (Witness: John Jontry)

One of the primary objectives of the Proposed Project is to reduce the risk of a service interruption resulting from a transmission failure. The mandatory reliability standards put in place by the FERC after the August 14, 2003 Northeast blackout set the foundation for reducing the possibility of power system failures and support the need to construct new transmission infrastructure.[17] As discussed in Chapter 3, SDG&E must comply with mandatory NERC, WECC and CAISO reliability standards, as well as the Commission's direction. SDG&E and CAISO also consider the level of reliability that is reasonable and prudent to provide to utility customers in California.

The Proposed Project was determined to be necessary and appropriate through two processes:

1) SDG&E's transmission planning studies ("Grid Assessment" or "GA" studies).
2) The CAISO's 2010/2011 transmission planning process (an open stakeholder process defined by the CAISO's FERC tariff and business process manual).

A. Beginning in 2007, SDG&E Identified the Need to Enhance Reliability in South Orange County

The Project as presented herein was first identified and developed during the 2007-2008 Grid Assessment planning process by SDG&E's transmission planning personnel. The issues identified were as follows:

1) Forecast NERC Category B overloads on two 138 kV lines (TL13812 and

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[17] Energy Policy Act of 2005 and FERC Order No. 693 issued March 16, 2007.

TL13837);

2) Non-standard bus and breaker arrangement at Talega Substation, creating significant risks during forced outages and maintenance events;

3) A single bulk power source serving all of South Orange County load, exposing all SDG&E customers in the area to a loss of service if the 230 kV or 138 kV service at Talega Substation failed;

4) Radial (i.e., load pocket) arrangement of the 138 kV system serving South Orange County;

5) Common-structure arrangement of 138 kV lines in South Orange County leaving them vulnerable to N-2 outages;

6) Accommodating future load growth.

The basic objectives and need for the Proposed Project have not significantly changed since it was initially identified.

The Proposed Project was submitted to the CAISO as the South Orange County Reliability Upgrade (SOCRUP) for approval in December, 2008.

B. In 2011, CAISO Found the Project Is Needed to Enhance Reliability

The need for the Proposed Project was evaluated by CAISO, in accordance with the CAISO's FERC-approved transmission tariff and Business Process Manual. As a reliability project, the Proposed Project was evaluated as a part of CAISO's Transmission Planning Process (TPP). CAISO transmission planning staff evaluated whether the Proposed Project would allow the bulk power system to meet applicable NERC, WECC, and CAISO planning standards. CAISO staff also evaluated the overall reliability risks to South Orange County.

The Proposed Project was evaluated over several CAISO TPP planning cycles. As described in the CAISO's FERC-approved tariff and Business Process Manual, the TPP is an open stakeholder process. Typically, three to four public stakeholder meetings are held during each planning cycle, and the CAISO solicits stakeholder input at each stage of the process (development of study assumptions, performance of powerflow study work by CAISO and utility staffs, development and public presentation of proposed reliability, policy and economic projects, and development and approval of the annual expansion plan). Interested parties had ample opportunity to weigh in on the merits of the Proposed Project over a period of several years.

Based upon the planning assumptions for the 2010-11 planning cycle, including load forecasts, CAISO concluded:

> "The southern Orange County area in SDG&E's service territory demonstrates multiple Category C-driven issues by 2020. More than 40 combinations of contingencies can result in load shed in the southern Orange County area. Some of these problems are existing ones and there are SPSs to address these issues. Detailed contingency analysis results are presented in Appendix A. <u>There are more than 40 contingencies that result in overloads in 2020 and the number is more than 70 beyond 2025</u>. The ISO standards do not recommend using SPS that looks at more than six contingencies causing more than four elements to get overloaded. This highlights the need for a reliability upgrade in the area. Southern Orange County is fed by a single 230 kV source at Talega. <u>Failure of certain components in this area under maintenance conditions can result in loss of entire South Orange County load</u> which is expected to be about 523 MW by 2020. There are 16 combinations of credible contingencies just at Talega substation which result in loss of partial or complete Orange County load under maintenance condition. Historical planned outage data reveals that 'load at risk' notifications have been part of several planned outages in recent past. These notifications are issued when more than 100 MW of load is at risk during planned outage conditions. In 2009-2010, 'load at risk' notifications were issued on 50 days. This indicates that any maintenance work at Talega substation or at several other 138 kV facilities frequently results in an increased risk of loss of load on the southern Orange County system. Loss of this load is also an existing concern due to

> the topology in this area. The proposed solution and alternatives have proposed in-service date of June 2015."[18]

The CAISO transmission planning staff then evaluated three Project alternatives.[19]

- <u>Alternative 1:</u> Rebuild Capistrano 230 kV substation, build a new SONGS – Capistrano 230 kV line using existing right-of-way, and build a new Escondido to Capistrano 230 kV line using existing right-of-way. Estimated cost for this alternative is $454.8 million.
- <u>Alternative 2:</u> Rebuild Capistrano 138kV substation (aging infrastructure maintenance project), reconductor 138kV lines – Talega – Pico, Talega – Laguna Niguel, Talega – Trabuco, Capistrano – Trabuco, Talega – Rancho Mission Viejo, and upgrade SONGS – Talega 230 kV lines. Upgrade two 230/138 kV transformer banks at Talega. Estimated cost for this alternative is $347.6 million.
- <u>Alternative 3:</u> Rebuild Capistrano 230 kV substation, build a new SONGS – Capistrano 230 kV line using existing right-of-way, and tap off a 230 kV line to Capistrano from existing Escondido – Talega 230 kV line. Estimated cost for this alternative is $364.8 million.

After evaluating the three alternatives, CAISO staff reported, in the CAISO's *2010-2011 Transmission Plan*, as follows:

> "Power flow study results of the peak load scenarios identified numerous facility loadings that exceeded their rated capabilities under Category C contingencies beyond 2015. All three alternatives considered here can mitigate the loading issues for Category C contingencies. In order to determine the most effective alternative, aspects beyond just the NERC compliance were taken into consideration. Historical data for bus outages at Talega and planned outages that put load at risk was accumulated and

[18] Attachment 7 (CAISO 2010-2011 Transmission Plan, issued May 18, 2011, pg. 207) (emphasis added).
[19] Attachment 7 (CAISO 2010-2011 Transmission Plan, issued May 18, 2011, pg. 209).

> examined. It was quite evident that the lack of second source into southern Orange County puts more load at risk than the Category C issues noticed in the reliability assessment of the system. Hence, in order to improve the overall reliability of this system, it is important to bring another source into this area. The project submitted by SDG&E (Alternative 1) aims to achieve this, but Alternative 3 achieves similar reliability performance at a considerably lower cost. Alternative 2 mitigates the Category C issues through 2021, but fails to deliver another source into this area and hence fails to address the risk of load shedding due to contingencies at Talega. Alternative 3 provides another source into southern Orange County system at very little extra cost compared to Alternative 2. It also offers a potential for future upgrades in case of further load growth. After a comprehensive analysis, the ISO staff concluded that SOCRUP Alternative 3 as the most effective, feasible solution to meet the reliability needs of southern Orange County area. Therefore, the ISO has found that the SOCRUP Alternative 3 project is needed to address the reliability concerns in the southern Orange County area."[20]

The Proposed Project was approved by the CAISO Board as a reliability-driven project as a part of the 2010-2011 Transmission Plan on March 18, 2011.

Section 3. SDG&E Has Updated its Review of the South Orange County Transmission System (Witness: Cory Smith)

CAISO approved the Proposed Project in 2011. SDG&E filed its Application seeking a Certificate of Public Convenience and Necessity (CPCN) for the Proposed Project in May 2012. Given the passage of time, SDG&E updated its assessment of the reliability risks to South Orange County in 2013, again in late 2014 and most recently in 2015. This section presents the updated 2014 load, topology, and generation assumptions for the South Orange County area served by SDG&E's 138 kV transmission network.

[20] Attachment 7 (CAISO 2010-2011 Transmission Plan, issued May 18, 2011, pg. 209) (emphasis added).

A. SDG&E Updated its Load Forecast

SDG&E performs a non-coincident load forecast for each distribution circuit and substation in its system every year. This forecast is then used to perform capacity analysis on the distribution system for a one to ten year time frame. SDG&E's distribution system forecast is produced via a multi-step process. First, the previous year's peak load for each circuit and substation is documented, then the load is normalized for the weather experienced on that day. If the weather experienced on the peak day was cooler than normal, the peak load is adjusted upward; if warmer, it is adjusted downward. Once the peak loads are identified and normalized, the peak load is used as a baseline for the load forecast. A load forecast is created based on normal growth, as well as any specific load additions. These specific load additions can be, for example, a new shopping mall, housing tract, or industrial complex.

The total load for each future year is then adjusted using an "adverse factor," which adjusts the load from what is considered a "normal," or "1 in 2" year, to a "1 in 10" year. This 1 in 10 year load forecast is used to plan the distribution system. The distribution system forecast is considered a "non-coincident", summer adverse weather, peak load forecast. In other words, the forecast evaluates each substation and circuit during its respective peak, regardless of what happens on the overall system.

South Orange County is largely residential in nature, which results in South Orange County substations tending to peak together, instead of at different times. As such, it is appropriate to assess South Orange County's transmission network using the non-coincident substation load forecast. In addition, the fact that the area is presently served from one transmission source makes a non-coincident analysis even more important, as the transmission system will be required to serve the non-coincident peak load of South Orange County regardless of when the rest of the SDG&E system peaks.

SDG&E's non-coincident load forecast for South Orange County has decreased since 2011 for two reasons. First, SDG&E has changed its forecasting process. As described above, SDG&E now utilizes the previous year's peak load as a baseline when forecasting future growth. Previously, SDG&E utilized the all-time peak as a baseline when forecasting future growth in the system. This older method presumed that load growth is constant and that each year will have a higher peak than the previous year. When SDG&E originally proposed the SOCRE Project, it forecasted load growth using the 2007 all-time peak as a baseline for each substation in the South Orange County. SDG&E modified its forecasting baseline to reflect the previous year's peak on a normalized basis, with those normalizing factors getting updated each year.

For example, if the peak for a given year occurred during an exceptionally hot day (such as 2007) then the peak load would be adjusted downward, to reflect a "normal" year. If the peak occurred during a cooler than normal year, this peak load would be adjusted upward, again to reflect what is believed to be a normal year for the area served by that substation. This change to forecasting methodology resulted in a decrease to SDG&E's load forecast for South Orange County. While SDG&E made this change to avoid overstating likely demand, the connected load that created the peak demand experienced in 2007 are still there and the connected load capacity in South Orange County has actually increased 5% between 2007 and 2014.

Second, SDG&E has adjusted its forecast of development in Rancho Mission Viejo to spread growth further into the future based on economic conditions. This change also resulted in a decrease to the load forecast for South Orange County. As economic conditions improve, this load will come back and increase the future load forecast.

SDG&E's non-coincident forecast accounts for energy efficiency (EE) as a natural component of distribution load growth. That is, EE is not specifically called out in SDG&E's distribution system load forecast, but is captured in peak data and normal growth parameters. As more EE is incorporated in the electric system, each new peak reflects the greater efficiency, and growth factors are modified accordingly.

SDG&E's system wide non-coincident forecast also accounts for distributed generation (DG) on its distribution system. SDG&E identifies DG on its system and modifies that generation with a capacity factor to account for non-coincidence between peak generation and peak load. Typically SDG&E sees approximately 35% of nameplate for PV systems at peak load conditions. This 35% of nameplate is then added back into the load calculation to reflect the actual electrical load being served by SDG&E and installed DG. This is appropriate for the study of South Orange County. As discussed above, South Orange County is largely residential and residential load reaches its peak late in the day just as solar production is decreasing.

For its 2014 evaluation of the need for the Proposed Project, SDG&E used its non-coincident load forecast for South Orange County, which is set forth in Table 4-1 below:

Table 4-1 - 2014 Distribution Planning, Individual Non-Coincident Substation Load Forecast, Summer Adverse Weather (Load in MW)

Substation	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capistrano	52.0	52.5	53.1	53.6	54.1	54.6	55.2	55.7	56.2	56.7
Laguna Niguel	95.2	95.7	96.1	96.6	97.1	97.5	97.9	98.2	98.6	99.0
Margarita	99.6	100.2	100.8	101.4	102.0	102.6	103.1	103.7	104.3	104.9
Pico	42.6	43.2	43.7	44.2	44.7	45.2	45.7	46.3	46.8	47.3
Rancho Mission Viego	14.7	17.0	20.4	23.8	27.2	30.7	34.1	37.5	40.9	41.1
San Mateo	36.2	37.0	37.7	38.5	38.9	39.3	39.7	40.0	40.4	40.8
Trabuco	87.5	87.9	88.3	88.8	89.2	89.6	90.0	90.5	90.9	91.3
Total South Orange County	427.8	433.5	440.1	446.9	453.2	459.5	465.7	471.9	478.1	481.1

B. SDG&E Has Updated its Transmission Assumptions

Since CAISO set the planning assumptions for its 2010-11 Transmission Planning Process cycle, the following relevant changes in transmission system have been implemented or will be implemented, and therefore were included in SDG&E's 2014 review of the need for the Proposed Project:

1) Transmission line TL13812 was opened near Talega Substation and the two ends tied to adjacent transmission lines creating two three terminal transmission lines. The section of TL13812 from San Mateo Substation to the open point was connected to TL13833, creating a three terminal transmission line that ties San Mateo Substation to both Trabuco and Talega substations. The section of TL13812 from Talega Substation to the open point was connected to TL13835. This created a second three terminal transmission line which ties Talega Substation to both San Mateo and Laguna Niguel substations.

2) Transmission line TL13833 described above in (1) was comprised of three transmission line sections tied to a common point (tap). The section of TL13833 from the tap to Trabuco Substation was opened at Pico Substation and each end tied into the substation. This created two transmission lines; Pico to Trabuco substation and Pico Substation to the tap point. The transmission line from Pico Substation to Trabuco Substation retained the designation TL13833 and the three terminal transmission line which now ties San Mateo, Talega and Pico substations together is designated TL13846.

3) A portion of the transmission lines emanating from Laguna Niguel Substation (TL13835A and TL13837) have been converted from overhead conductors to underground cables.

4) A Special Protection System installed at Laguna Niguel Substation senses the flow of power on TL13835A. The protection system is designed to open

TL13837 when the flow of power on TL13835A rises above the transmission line's rating (571 Amps) for more than 5 seconds.

5) Capacitor banks at Talega Substation 230 kV switchyard are being replaced with synchronous condensers.

C. SDG&E Has Updated its Generation Assumptions

At the time of the CAISO's 2011 decision and to the present time, there is no significant generation of electric energy in South Orange County service area.

Since 2011, the SONGS nuclear units were retired early, as announced on July 6, 2012. This removed a significant source of both real and reactive power from a critical location in the Southern California transmission system. However, because South Orange County is supplied through Talega Substation, the removal of SONGS has a limited effect on the manner in which real power flows through the South Orange County 138 kV network. Both San Onofre Nuclear Generating Station generators were removed from the model and a 7 MVA load was placed at the San Onofre 230 kV bus to represent the plant load which will remain as part of the decommissioning process.

Section 4. A Category D Event Causing Outage of the 230 kV or 138 kV Service at Talega Substation Will Result in a Loss of Service to All of SDG&E's South Orange County Customers (Witness: Cory Smith)

As discussed in Chapter 3, NERC Standard TPL-004-0a requires that each Transmission Owner assess the risks and consequences of the loss of a substation. SDG&E and the CAISO have evaluated the risks and consequences of the loss of the Talega Substation.

SDG&E evaluated the risks and consequences of losing 230 kV service or 138 kV service at Talega Substation. Examples of Category D events include fire, explosion, seismic events, vandalism and terrorism. As discussed in Chapter 6, space constraints at the Talega Substation have resulted in the transformers being in relatively close proximity, and no separation wall between adjacent transformers. South Orange County, like most of Southern California, is considered to have a significant seismic risk, at least from strong seismic shaking.[21] The recent attack on PG&E's Metcalf Substation has demonstrated that vandalism or terrorism events can happen.

The evaluation of the consequences of such an event was done by inspection of the one-line diagram shown on Figure [2-2] of chapter 2 and Figure [2-1] of the PEA. The one-line diagram shows the interconnection of South Orange County's ten 138 kV transmission lines and seven 138/12 kV substations. Four of the 138 kV transmission lines terminate at the Talega Substation 138 kV bus and the Talega Substation 138 kV bus connects to the Talega Substation 230 kV bus. This is the only 230 kV bus in South Orange County and the only substation in South Orange County with a connection to the CAISO controlled grid. Consequently, the loss of either the Talega 138 kV bus or Talega 230 kV bus will result in South Orange County being cut off from the CAISO 230 kV transmission system. Without this connection, there is no path for power to flow from generation sources located outside South Orange County to customers located within South Orange County.

For example, on July 18, 2013 at 11:40 pm an insulation failure on a 69 kV transmission line caused a fault which spread to an adjacent 138 kV transmission line which is connected to the Talega Substation 138 kV bus. The protection system operated and removed the Talega Substation 138 kV east and west buses from the CAISO controlled grid. All South Orange County customer load was interrupted. This outage lasted several hours.

A momentary outage may cause sensitive electronic equipment to reset. An outage lasting an hour or more may cause economic impacts (food spoilage, equipment damage, loss of

[21] See SDG&E's Proponent's Environmental Assessment § 4.6.3.4.

business for retail establishments, etc.). A prolonged outage (days or weeks) would leave all customers without power for an extended period of time and cause extensive and serious economic impacts. Although some sensitive loads (such as hospitals, emergency services, data centers, etc.) might have customer owned emergency backup systems, such systems can only operate for a limited duration and are not designed as a primary source of power.

The time to restore a system component to service depends on, among other things, the nature of the event causing failure, the type of equipment that has been damaged or failed, the extent of damage, and the availability of skilled labor, specialized construction equipment, spare materials and equipment, and access to the site and damaged equipment. An outage duration could range from hours to weeks. For example, following the 2011 Mexicali earthquake, it took 24 days to complete repairs at Imperial Valley Substation.

To reduce the risks associated with the loss of Talega Substation, the Proposed Project would introduce a second 230 kV source into South Orange County at the new San Juan Capistrano Substation. Both San Juan Capistrano and Talega Substations would supply the area load during normal operation, maintenance operations at either substation and in the event that one of the substations is removed from service, the remaining substation would supply power to the area.

Section 5. Necessary Maintenance Outages at Talega Substation Place Some or All of SDG&E's South Orange County Customers at Risk of Interrupted Service In the Event of a Forced Outage of a Single Transmission Element (Witness: Cory Smith)

In addition to Category D events that would result in the loss of all South Orange County load, the existing Talega Substation non-standard bus configuration restricts the conditions under which maintenance can be performed, and creates risk of service interruption to some or all of South Orange County from a single forced outage during each planned maintenance outage.

Table 4-2 shows combinations of maintenance and forced outages at Talega Substation that will result in an uncontrolled interruption of service to all South Orange County customers. Maintenance outages listed in the left column of the table will expose South Orange County to a complete loss of load for equipment failures listed on the same row, to the right. Any combination, (ex. 230 West Bus maintenance outage in combination with a 230 East Bus forced outage), will disconnect South Orange County from the CAISO controlled grid.

Table 4-2: Talega Substation Outages and Equipment Failures which Drop South Orange County

Talega Bus Out of Service for Maintenance	NERC Category Contingency								
	C1: Bus Fault	C2: Circuit Breaker Fault or Failure							B: Transformers Fault
230 West Bus	230 East Bus	BK60	1E	2E	3E	4E	-	-	Bank 60
230 East Bus	230 West Bus	BK63	1W	2W	3W	4W	-	-	Bank 63
138 West Bus	138 East Bus	BK60	5E	6T	7T	8E	11E	-	-
138 East Bus	138 West Bus	BK63	5W	6W	7W	8W	11W	BK50	-

In addition to the uncontrolled loss of customers under the outages identified in Table 4-2, because Talega Substation is the sole power source for all of SDG&E's distribution substations in South Orange County, when a planned maintenance outage is taken at Talega, a forced outage could result in an overload requiring SDG&E to "shed load" (i.e., intentionally drop customers) to keep its facilities within applicable ratings. Table 4-3 lists six different maintenance outages of equipment which would put South Orange County load at risk. In all, planned maintenance outages create twenty-eight different scenarios which could require load to be shed in South Orange County.

Maintenance outages of the 230 kV Bus and the 4E circuit breaker are especially troublesome. Requirement R1.3.12 of NERC Standard TPL-002-0b requires SDG&E to assess its transmission system and determine if overloads exist following the forced outage of a single transformer (Category B contingency) during the planned maintenance outage of equipment. It is a violation of the standard to shed load following a Category B contingency. To prevent a violation, the 230 West Bus and the 4E circuit breaker can only be taken out for maintenance when South Orange County load is below the Bank 60 transformer rating (168 MVA). This limits the number of hours that the 230 West Bus or the 4E circuit breaker can be taken out of service.

Table 4-3 - Equipment Maintenance Outages Requiring Load to be Shed Following a Contingency

Talega Equipment out of service for maintenance	NERC Category Contingency								
	C1: Bus Fault	C2: Circuit Breaker Fault or Failure							B: Transformer Fault
230 West Bus	-	BK61	4T	5T	5E	-	-	-	Bank 61
138 West Bus	-	BK61	4T	5T	-	-	-	-	-
Bank 61	-	4W	5W	-	-	-	-	-	-
Bank 63	-	4T	4E	5T	-	-	-	-	-
4E	230 West Bus	BK63	1W	2W	3W	4W	-	-	Bank 63
5E	138 West Bus	BK63	BK50	5W	6W	7W	8W	11W	-

Because of these risks, CAISO restricts when SDG&E may take maintenance outages at Talega Substation. However, because Talega's equipment and infrastructure are aging, maintenance is necessary and will increase. Note that the NERC criteria do not make any distinction as to whether an N-1 contingency is forced or planned. A planned maintenance outage that results in involuntary load shedding in preparation for the next N-1 may be interpreted as a violation of the Cat. B reliability standard. SDG&E, as a matter of operational procedure, would not schedule planned maintenance during system conditions that would result in involuntary load shedding to prepare for the next N-1; however, as the load in South Orange County continues to increase, the allowable window for planned maintenance will continue to shrink.

The Proposed Project will address this by adding a second 230 kV bulk power connection at Capistrano Substation, so that in the event of a maintenance outage of a bus, transformer, or transmission line, service to South Orange County customers would continue uninterrupted for any subsequent contingencies at Talega.

Section 6. The Existing South Orange County Transmission System Is Not Expected to Meet NERC Standard TPL-003-0b Beginning in 2020 (Witness: Cory Smith)

As discussed in Chapter 3, SDG&E must design its system to comply with NERC Standard TPL-003-0b. TPL-003-0b requires that before, during and after the failure of two or more transmission elements (a Category C event), the electric system must remain "System Stable and both Thermal and Voltage Limits within Applicable Rating." TPL-003-0b at 4, Table I (Column 1 under System Limits or Impacts).[22] Footnote a to TPL-003-0b explains: "Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control." Attachment 5 (CAISO Procedure 3100, "System Operating Limit Establishment Procedure for the Operations Horizon") and Attachment 6 (CAISO Procedure 3100A, Examples on Acceptable Thermal Performance) explain this requirement in detail.

The impact of this Category C requirement can be summarized as follows:

(1) To avoid the System Operator shedding South Orange County load (i.e., taking lines out of service, which stops electric service to customers served off such lines) in a Category C event, SDG&E must design its system to: (1) avoid an N-1-

[22] The NERC Glossary of Terms defines a System Operating Limit ("SOL") as the most limiting value that ensures operation within acceptable reliability criteria. A facility thermal rating is a SOL. SDG&E is required by NERC Transmission Operating Standards to operate within SOLs. TOP-004-2_R1 ("Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).").

1 situation where a single outage of a transmission element would leave the system vulnerable, in the event of a second outage, to any line exceeding its Applicable Rating, as CAISO's Operating Procedure 3100 would require preparing for such a second outage by shedding load after the first outage alone; and (2) avoid a situation where any Category C outage would result in any line exceeding its Applicable Rating. Where a line has both a normal and emergency rating and the thermal loading of the line can be brought back to its normal rating within the time limit allowed by the emergency rating, then a line will not exceed its Applicable Rating. However, in South Orange County, some lines have no emergency rating or very short-term emergency ratings (15 minutes to 30 minutes), and therefore load shedding must occur immediately upon the thermal loading of the line exceeding its normal rating.

(2) In South Orange County, because lines have no emergency rating or very short-term emergency ratings (15 minutes to 30 minutes), SDG&E's system must be designed for immediate load shedding under the circumstances described above to remain within Applicable Ratings. Because there is insufficient time for manual load shedding, the only method for such immediate load shedding is a Special Protection System (SPS), which implements automatically within seconds. However, while CAISO considers SPS an appropriate mitigation tool in certain circumstances, its planning standards state: "There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS. The SPS should not be monitoring more than 4 system elements or variables." There are too many Category C contingencies in South

Orange County where the Applicable Ratings would not allow time for manual adjustment of the system for SDG&E to utilize SPSs in compliance with CAISO planning standards. As SDG&E is bound to follow CAISO planning standards, SDG&E cannot employ SPS to mitigate all of the Category C contingency events in South Orange County. As a result, the Proposed Project is needed to comply with TPL-003-0b.

Below, SDG&E explains these issues in more detail.

Under TPL-003-0b, SDG&E must assess system performance under a number of contingency events (Category C1 through C9). Of particular note, Category C3 provides that the assessed contingency is as follows: "Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency." This "N-1-1" scenario means that, after a single outage, SDG&E must be able to make manual system adjustments that will allow the system to perform within applicable ratings (the SOL) in the event of another outage.

During normal operations, SDG&E operators monitor system conditions and make adjustments as necessary to maintain reliability. Following a single element outage (N-1), the Transmission Security Management (TSM) software will assess the system to determine if a second element outage, referred to as (N-1)-1, will create a system condition which results in an overload. If the TSM finds a potential overload exists, then operators must take action to prevent the overload prior to the second outage. In laymen's term, "operators are securing the system for the next outage."

In South Orange County, because there is no significant generation to turn on to reduce overloads, the only option is to shed load (i.e., stop serving customers). This will result in lowering the flow of power through the overloaded element and removing the overload. Therefore, in South Orange County, following the loss of a single element system ("N-1"), operators must make adjustments to prepare for the loss of the next element ("N-1-1"), and the only option is to shed load. Note that, if such a single outage (an "N-1") directly caused operators to shed load, a loss of customer service, it would violate NERC TPL-002-0b (Category B), which does not permit load shedding.

The time within which SDG&E must make such adjustments, i.e., shed load, is determined by the line ratings. When a transmission line has a thermal overload, the temperature of the metal conductor increases. For overhead lines, as the conductor heats up, the transmission line will sag. Under CPUC General Order 95, SDG&E's transmission lines must maintain certain clearances from the ground and structures. Whether there is tolerance for sag depends on the circumstances of each transmission line. If the temperature continues to increase, at some point the conductor will be damaged, requiring replacement of the line and a long duration outage.

In setting Normal and Emergency Ratings, a utility must take into account the physical limitations of the conductor itself, the construction of the line and tolerance for any sag, the normal demand on the line and, if any emergency rating is set, how long the line can be above the normal rating before the physical limits are exceeded.

In South Orange County, SDG&E's transmission lines were designed for maximum loading without margin for emergency ratings. This was an acceptable practice when these transmission lines were constructed. The Normal Rating of the South Orange County transmission lines have been set at the maximum load that SDG&E believes can be safely accommodated by these lines. There is no tolerance for sag on many of these transmission lines.

Although some lines have short emergency ratings (15 to 30 minutes), other lines have no Emergency Ratings.

Because there are no Emergency Ratings on some lines in South Orange County, and because TPL-003-0b requires that all other lines in SDG&E's South Orange County system remain within Applicable Ratings even after specified outages of two other transmission elements, SDG&E's measures to reduce overloads on other lines must be essentially instantaneous or SDG&E will be in violation of TPL-003-0b.

To keep the system within Applicable Ratings during a Category C contingency, on lines with no emergency rating (or a short emergency rating), there is no time for operators to manually determine which load to shed. Instead, an automatic protection system must be utilized to disconnect customers within seconds after the other elements fail. These automatic protection systems are known as Special Protection Schemes ("SPS").

SDG&E will employ SPS in accordance with CAISO planning standards. Under its Transmission Control Agreement with CAISO, Section 6.1.3: "In operating and maintaining its transmission facilities, each Participating TO shall take proper care to ensure the safety of personnel and the general public. It shall act in accordance with Good Utility Practice, applicable law, the CAISO Tariff, CAISO Protocols, the Operating Procedures, and the Applicable Reliability Criteria." CAISO has adopted Planning Standards as authorized by the CAISO Tariff. The CAISO Planning Standards currently in effect are effective from September 18, 2014 to March 30, 2015. *See* Attachment4 (CAISO Planning Standards).

CAISO has considered the advantages and disadvantages of SPS. See Attachment 4 (CAISO Planning Standards at 9). Given concerns about over-use of SPS, CAISO set specific guidelines for the use of SPSs that are binding on SDG&E. SPS6 provides: "A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS. B) The SPS should not be monitoring more than 4 system elements or variables." Attachment 4 (CAISO Planning Standards at 10).

SDG&E's modeling of its South Orange County system for the years 2016 to 2035 with the Capistrano capacitor bank ON has identified 22 Category C contingencies requiring instantaneous load shedding. SDG&E cannot address all of these contingencies using SPSs and stay within CAISO Planning Standard guidelines. As a result, SDG&E expects that its South Orange County system will be in violation of TPL-003-0b by 2020 without the Proposed Project.

Using the 2014 load forecast, SDG&E has identified Category C contingencies that are predicted to lead to a violation of NERC TPL-003-0b and/or TPL-002-0b. The violations were confirmed using SDG&E's 2015 load forecast and are listed here:

1. NERC Category C1: Pico Substation East Bus Fault

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that without an SPS in place by 2024, power flowing on TL13831 will exceed the emergency rating of the transmission line following a fault on the Pico East Bus. This would be a violation of TPL-003-0b. Analysis done using the 2015 load forecast with the Capistrano generator OFF confirmed the violation but shows it occurring in 2022. Turning the Capistrano generator ON moves the violation to 2023.

2. NERC Category C2: TL13836 Circuit Breaker Fault at Pico Substation

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that without an SPS in place by 2024, power flowing on TL13831 will exceed the emergency rating of the transmission line following a fault at Pico Substation on the TL13836 circuit breaker. This would be a violation of TPL-003-0b. Analysis done using the 2015 load forecast with the

Capistrano generator OFF confirmed the violation but shows it occurring in 2022. Turning the Capistrano generator ON moves the violation to 2023.

3. NERC Category C2: TL13846 Circuit Breaker Fault at Pico Substation

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that without an SPS in place by 2024, power flowing on TL13831 will exceed the emergency rating of the transmission line following a fault at Pico Substation on the TL13846 circuit breaker. This would be a violation of TPL-003-0b. Analysis done using the 2015 load forecast with the Capistrano generator OFF confirmed the violation but shows it occurring in 2022. Turning the Capistrano generator ON moves the violation to 2023.

4. NERC Category C1: Pico Substation West Bus Fault

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that by 2029 without an SPS in place power flowing on TL13831 will exceed the emergency rating of the transmission line following a fault at Pico Substation on the TL13833 circuit breaker. This would be a violation of TPL-003-0b. Analysis done using the 2015 load forecast with the Capistrano generator OFF confirmed the violation but shows it occurring in 2027. Turning the Capistrano generator ON moves the violation to 2028.

5. NERC Category C2: TL13833 Circuit Breaker Fault at Pico Substation

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that by 2029 without an SPS in place power flowing on TL13831 will exceed the emergency rating of the transmission line following a fault at Pico Substation on the TL13833 circuit breaker. This would be a violation of TPL-003-0b. Analysis done using the 2015 load forecast with the Capistrano generator OFF confirmed the violation but shows it occurring in 2027. Turning the Capistrano generator ON moves the violation to 2028.

6. NERC Category C2: TL13816 Circuit Breaker Fault at Pico Substation

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that by 2029 without an SPS in place power flowing on TL13831 will exceed the emergency rating of the transmission line following a fault at Pico Substation on the TL13816 circuit breaker. This would be a violation of TPL-003-0b. Analysis done using the 2015 load forecast with the Capistrano generator OFF confirmed the violation but shows it occurring in 2027. Turning the Capistrano generator ON moves the violation to 2028.

7. NERC Category C2: Pico Substation Bus Tie Circuit Breaker

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that by2029 without an SPS in place power flowing on TL13831 will exceed the emergency rating of the transmission line following a fault on the Pico Substation bus tie circuit breaker. This would be a violation of TPL-003-0b. Analysis done using the 2015 load forecast with the Capistrano generator OFF confirmed the violation but shows it occurring in 2027. Turning the Capistrano generator ON moves the violation to 2028.

8. NERC Category C2: Talega Substation 8T Circuit Breaker Fault

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that by 2021, without an SPS in place, power flowing on TL13846A and TL13846C will exceed the emergency rating of the transmission lines following a fault on the 8T circuit breaker at Talega Substation. This would be a violation of TPL-003-0b. Analysis done using the 2015 load forecast with the Capistrano generator OFF confirmed the violation but shows it occurring in 2019. Turning the Capistrano generator ON moves the violation to 2020.

9. NERC Category C3: Talega Bank 61 + Talega Bank 63

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that by

2018, power flowing on Talega Bank 62 will exceed the emergency rating of the transformer bank following the overlapping outage of Talega Bank 61 and Talega Bank 63. This would be a violation of TPL-003-0b. Analysis done using the 2015 forecast with the Capistrano generator OFF confirmed the violation but shows it occurring in 2017. Turning the Capistrano generator ON does not move the violation to a later year. It continues to occur in 2017.

Without an SPS in place, operators will be forced to shed load following the outage of the first transformer bank (Bank 61 or Bank 63) to prevent an overload of Talega Bank 62.. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transformer.

10. NERC Category C3: TL13831 + Capistrano Bank 41

Using the 2014 forecast with the Capistrano generator OFF showed that by 2033, power flowing on TL13833 will equal the emergency rating of the transmission line following the overlapping outage of TL13831 and Capistrano Bank 41. As load growth increases, this may become be a violation of TPL-003-0b. Analysis done using the 2015 forecast with the Capistrano generator OFF confirmed the violation but showed it occurring in 2032. Turning the Capistrano generator ON moves the violation to 2033.

Without an SPS in place, operators will be forced to shed load following the first outage (TL13831 or Capistrano Bank 41) to prevent an overload of TL13833. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line or transformer.

11. NERC Category C3: TL13835 + TL13846

Using the 2014 forecast with the Capistrano generator OFF showed that by 2021, power flowing on TL13836 will exceed the emergency rating of the transmission line following the overlapping outage of TL13835 and TL13846. This would be a violation of TPL-003-0b. The 2015 forecast with the Capistrano generator OFF confirms the violation but shows it occurring in 2018. Turning the Capistrano generator ON moves the violation to 2019.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13835 or TL13846) to prevent an overload of TL13836. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

12. NERC Category C3: TL13836 + TL13846

Using the 2014 forecast with the Capistrano generator OFF showed that by 2019, power flowing on TL13831 will exceed the emergency rating of the transmission line following the overlapping outage of TL13836 and TL13846. This would be a violation of TPL-003-0b. Analysis done using the 2015 forecast with the Capistrano generator OFF confirmed the violation but shows it occurring in 2018. Turning the Capistrano generator ON moves the violation to 2019.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13836 or TL13846) to prevent an overload of TL13831. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

13. NERC Category C3: TL13831 + TL13846

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that by 2016, power flowing on TL13836 will exceed the emergency rating of the transmission line following the overlapping outage of TL13831 and TL13846. This would be a violation of TPL-003-0b. Analysis done using the 2015 forecast with the Capistrano generator OFF confirmed the violation and showed it occurring in 2016. Turning the Capistrano generator ON does not change the year the violation occurs.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13831 or TL13846) to prevent an overload of TL13836. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

14. NERC Category C3: TL13838 + TL13846

Using the 2014 forecast with Capistrano generator OFF, analysis showed that by2017, power flowing on TL13836 will exceed the emergency rating of the transmission line following the overlapping outage of TL13838 and TL13846. This would be a violation of TPL-003-0b. Analysis done using the 2015 forecast with Capistrano generator OFF confirmed the violation but shows it occurring in 2016. Turning the Capistrano generator ON does not change the year the violation occurs.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13838 or TL13846) to prevent an overload of TL13836. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

15. NERC Category C3: TL13835 + TL13836

Using the 2014 forecast with Capistrano generator OFF, analysis shows that by 2024, power flowing on TL13846C will exceed the emergency rating of the transmission line following the overlapping outage of TL13835 and TL13836. This would be a violation of TPL-003-0b. Analysis done using the 2015 forecast with Capistrano generator OFF confirmed the violation but shows it occurring in 2022 Turning the Capistrano generator ON moves the violation to 2023.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13835 or TL13836) to prevent an overload of TL13846C. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

16. NERC Category C3: TL13835 + TL13831

Using the 2014 forecast with Capistrano generator OFF, analysis shows that by 2016, power flowing on TL13816 will exceed the emergency rating of the transmission line following the overlapping outage of TL13835 and TL13831. This would be a violation of TPL-003-0b. Analysis done using the 2015 forecast with Capistrano generation OFF confirmed the violation and shows it occurring in 2016. Turning the Capistrano generation ON does not change the year the violation occurs.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13835 or TL13831) to prevent an overload of TL13816. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

17. NERC Category C3: TL13835 + TL13833

Using the 2014 forecast with the Capistrano generation OFF, analysis showed that by 2022, power flowing on TL13816 will exceed the emergency rating of the transmission line following the overlapping outage of TL13835 and TL13833. This would be a violation of TPL-003-0b. Analysis done using the 2015 forecast with Capistrano generator OFF confirmed the violation but shows it occurring in 2018 Turning the Capistrano generator ON moves the violation to 2019.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13835 or TL13833) to prevent an overload of TL13816. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

18. NERC Category C3: TL13835 + TL13816

Using the 2014 forecast with the Capistrano generation OFF, analysis showed that by 2027, power flowing on TL13834 will exceed the emergency rating of the transmission line equipment located at Capistrano following the overlapping outage of TL13835 and TL13816. The equipment at Capistrano limits TL13834 to 157 MVA, but the TL13834 conductor is rated 273 MVA. Exceeding the emergency rating of the equipment at Capistrano would be a violation of TPL-003-0b. Analysis done using the 2015 load forecast confirms the violation and shows it occurring in 2025.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13835 or TL13816) to prevent an overload of TL13834. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

19. NERC Category C3: TL13835 + TL13838

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that by 2022, power flowing on TL13816 will exceed the emergency rating of the transmission line following the overlapping outage of TL13835 and TL13838. This would be a violation of TPL-003-0b. Analysis done using the 2015 load forecast with the Capistrano generator OFF confirmed the violation but shows it occurring in 2016. Turning the Capistrano generator ON does not change the year the violation occurs.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13835 or TL13838) to prevent an overload of TL13816. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

20. NERC Category C3: TL13831 + TL13833

Using the 2014 load forecast with the Capistrano generator OFF, analysis showed that by 2016, power flowing on TL13816 and TL13834 will exceed the emergency ratings of the transmission lines following the overlapping outage of TL13831 and TL13833. This would be a violation of TPL-003-0b. Analysis done using the 2015 forecast with the Capistrano generator OFF confirmed that the violation will occur by 2016. Turning the Capistrano generator ON does not change the year the violation occurs.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13831 or TL13833) to prevent an overload of TL13816 and TL13834. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

21. NERC Category C3: TL13831 + TL13816

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that by 2028, power flowing on TL13833 will exceed the emergency rating of the transmission line following the overlapping outage of TL13831 and TL13816. This would be a violation of TPL-003-0b. Analysis done using the 2015 forecast with the Capistrano generator OFF confirmed the violation but showed it occurring in 2027. Turning the Capistrano generator ON moves the violation to 2028.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13831 or TL13816) to prevent an overload of TL13833. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transformer.

22. NERC Category C3: TL13833 + TL13838

Using the 2014 forecast with the Capistrano generator OFF, analysis showed that by 2016, power flowing on TL13816 and TL13834 will exceed emergency ratings following the overlapping outage of TL13833 and TL13838. This would be a violation of TPL-003-0b. Analysis done using the 2015 forecast with the Capistrano generator OFF confirmed the violation and shows it occurring in 2016. Turning the Capistrano generator ON does not change the year the violation occurs.

Without an SPS in place, operators will be forced to shed load following the first transmission line outage (TL13833 or TL13838) to prevent an overload of TL13816 and TL13834. This may be interpreted as a violation of TPL-002-0b which does not allow load shedding following the outage of a single transmission line.

Section 7. Numerous Additional Category C Events Will Force SDG&E to Interrupt Service to Customers (Witness: Cory Smith)

In addition to Category C events that will result in violation of TPL-003-0b, using SDG&E's 2014 load forecast modeling for the year 2020 has identified many other Category C events that will force SDG&E to shed load (i.e., interrupt customer service) to remain within Applicable Ratings. Under TPL-003-0b, so long as SDG&E can drop customers quickly enough to keep its facilities within Applicable Ratings, SDG&E is in compliance with the NERC standard. From the standpoint of SDG&E and its customers, however, electric service is still lost.

The following Category C3 events will result in a loss of customer service after a forced outage of a single transmission line or transformer followed by another transmission line or transformer outage:

1) C3_TL13831 + Capistrano Bank 40

A fault removes TL13831 (Cat-B) from service. There are no-system adjustments available in South Orange County and a Capistrano Bank 40 failure (Cat-B) will cause the power flowing on TL13833 to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 15 minutes.

2) C3_TL13831 + Capistrano Bank 41

A fault removes TL13831 (Cat-B) from service. There are no-system adjustments available in South Orange County and a Capistrano Bank 41 failure (Cat-B) will cause the power flowing on TL13833 to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 15 minutes.

3) C3_TL13838 + Capistrano Bank 41

A fault removes TL13838 (Cat-B) from service. There are no-system adjustments available in South Orange County and a Capistrano Bank 41 failure (Cat-B) will cause the power flowing on TL13833 to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 15 minutes.

4) C3 TL13816+ TL13831

A fault removes TL13831 (Cat-B) from service. There are no-system adjustments available in South Orange County and a TL13816 failure (Cat-B) will cause the power flowing on TL13833 to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 30 minutes.

5) C3_TL13836 + TL13838

A fault removes TL13836 (Cat-B) from service. There are no-system adjustments available in South Orange County and a TL13838 failure (Cat-B) will cause the power flowing on TL13846A and TL13846C to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 15 minutes.

6) C3_TL13831 + TL13834

A fault removes TL13831 (Cat-B) from service. There are no-system adjustments available in South Orange County and a TL13834 failure (Cat-B) will cause the power flowing on TL13833 to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 15 minutes.

7) C3_TL13833 + TL13816

A fault removes TL13833 (Cat-B) from service. There are no-system adjustments available in South Orange County and a TL13816 failure (Cat-B) will cause the power flowing on TL13831 to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 30 minutes.

8) C3_TL13838 + TL13816

A fault removes TL13838 (Cat-B) from service. There are no-system adjustments available in South Orange County and a TL13816 failure (Cat-B) will cause the power flowing on TL13831 to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 15 minutes.

9) C3 TL13831 + TL13836

A fault removes TL13831 (Cat-B) from service. There are no-system adjustments available in South Orange County and a TL13836 failure (Cat-B) will cause the power flowing on

TL13846A and TL13846C to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 15 minutes.

10) C3 TL13835 + TL13836

A fault removes TL13836 (Cat-B) from service. There are no-system adjustments available in South Orange County and a TL13835 failure (Cat-B) will cause the power flowing on TL13846A and TL13846C to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 15 minutes.

11) C3 TL13835 + TL13846

A fault removes TL13846 (Cat-B) from service. There are no-system adjustments available in South Orange County and a TL13835 failure (Cat-B) will cause the power flowing on TL13836 to exceed the transmission lines normal rating. To bring flows below the normal rating, load will need to be shed within 30 minutes.

The following Category C events will result in a loss of customer service after a forced outage of multiple transmission elements:

12) NERC Category C1: Pico East Bus Fault.

a) Two transmission lines (TL13836 and TL13846), a transformer (Pico bank 41) and Pico west bus are all connected to the Pico east bus by circuit breakers. In order to remove the fault, and isolated the faulted bus, the protection system will automatically open the circuit breakers connected to the Pico east bus. Consequently, the connection between the Pico 138kV east and west buses will be opened and the two transmission lines will be disconnected from the Pico east bus.

b) Prior to the fault, power flowing to substations located north of Pico substation will flow into the Pico east bus on TL13836 and TL13846, flow to the Pico west bus through the bus tie circuit breaker and flow north out of the Pico west bus on TL13816 and TL13833. After the circuit breakers open, power flowing through Pico Substation will be cutoff and forced to flow on two parallel transmission lines; TL13831 and TL13835A. The flow increase on TL13835A will cause the TL13835A Special Protection System to operate and remove TL13837 from service.

c) After all protection systems have operated three transmission lines will be out of service (TL13836, TL13846, TL13837) and power flowing through TL13831 will exceed the normal continuous rating of the transmission line, but be within the emergency rating of the line.

d) To prevent a violation of NERC standards, operators must reduce the amount of power flowing on TL13831 by shedding 6.5% of the South Orange County load within 15 minutes.

e) As discussed in Section 6 (1), this contingency will result in a violation by 2024.

13) NERC Category C1: Pico West Bus Fault

a) Two transmission lines (TL13833 and TL13816), a transformer (Pico bank 42) and Pico east bus are all connected to the Pico west bus by circuit breakers. In order to remove the fault, and isolate the faulted bus, the protection system will automatically open the circuit breakers connected to the Pico west. Consequently, the connection between the Pico east and west buses will be opened and the two transmission lines will be disconnected from Pico west bus.

b) Prior to the fault, power flowing to substations located north of Pico substation will come into the Pico east bus on TL13836 and TL13846, move to the Pico west bus through the bus tie circuit breaker and go north out of the Pico west bus on TL13816 and TL13833. After the circuit breakers open, power flowing through Pico Substation will be cutoff and forced to flow on two parallel transmission lines; TL13831 and TL13835A. The flow increase on TL13835A will cause the TL13835A Special Protection System to operate and remove TL13837 from service.

c) After all protection systems have operated, three transmission lines will be out of service (TL13833, TL13816, TL13837) and power flowing on TL13831 will exceed its normal continuous rating, but be within its emergency rating.

d) To prevent a violation of NERC standards, operators must reduce the amount of power flowing on TL13831 by shedding approximately 24% of the South Orange County load within 30 minutes.

As discussed in Section 6 (4), this contingency will lead to a violation by 2029.

14) NERC Category C2: Pico Bus Tie Circuit Breaker Fault

a) The Pico bus tie circuit breaker connects Pico east and west 138 kV buses together. In order to remove the fault, and isolate the faulted circuit breaker, the protection system will automatically open all circuit breakers connected to Pico east and west buses. Consequently, all customers served from Pico Substation will be disconnected from the system and four transmission lines will be removed from service; TL13836, TL13846, TL13816 and TL13833.

b) Prior to the fault, power flowing to substations located north of Pico substation will come into the Pico east bus on TL13836 and TL13846, move to the Pico west bus through the bus tie circuit breaker and go north out of the Pico west bus on TL13816 and TL13833. After the circuit breakers open, power flowing through Pico Substation will be cutoff and forced to flow on two parallel transmission lines; TL13831 and TL13835A. The flow increase on TL13835A will cause the TL13835A Special Protection System to operate and remove TL13837 from service.

c) After all protection systems have operated, five transmission lines will be out of service (TL13836, TL13846A, TL13816, TL13833, TL13837) and power flowing through TL13831 will exceed its normal continuous rating, but be within its emergency rating.

d) To prevent a violation of NERC standards, operators must reduce the amount of power flowing on TL13831 by shedding approximately 42% of the South Orange County load within 30 minutes.

15) NERC Category C2: Pico TL13836 Circuit Breaker Fault

a) The TL13836 Circuit Breaker connects the Pico 138 kV east bus to TL13836. In order to remove the fault, and isolate the faulted circuit breaker, the protection system will automatically open all circuit breakers connected to the Pico east bus and the circuit breakers at Talega Substation protecting TL13836. Consequently, the connection between the Pico east and west buses will be opened and the connection of TL13846 to the Pico east bus will be opened.

b) Prior to the fault, power flowing to substations located north of Pico substation will come into the Pico east bus on TL13836 and TL13846, move to the Pico west bus through the bus tie circuit breaker and go north out of the Pico west bus on TL13816 and TL13833. After the protection system opens the circuit breakers, power flowing through Pico Substation will be cutoff and forced to flow on two parallel transmission lines; TL13831 and TL13835A. The flow increase on TL13835A will cause the TL13835A Special Protection System to operate and remove TL13837 from service.

c) After all protection systems have operated, three transmission lines will be out of service (TL13836, TL13846 and TL13837) and over 65% of South Orange County load will be served through a single transmission line. Power flowing on TL13831 will exceed the transmission lines normal continuous rating, but will be within its emergency rating.

d) To prevent a violation of NERC standards, operators must take action to reduce the amount of power flowing on TL13831 by shedding approximately 46.5% of the South Orange County load within 15 minutes.

e) As discussed in Section 6 (2), this contingency will result in a violation by 2023.

16) NERC Category C2: Pico TL13846 Circuit Breaker Fault

a) The TL13846 Circuit Breaker connects the Pico 138 kV east bus to

TL13846. In order to remove the fault, and isolate the faulted circuit breaker, the protection system will automatically open all circuit breakers connected to the Pico east bus and the circuit breakers at Talega Substation and San Mateo Substation protecting TL13846. Consequently, the connection between the Pico east and west buses will be opened and the connection of TL13836 to the Pico east bus will be opened.

b) Prior to the fault, power flowing to substations located north of Pico substation will come into the Pico east bus on TL13836 and TL13846, move to the Pico west bus through the bus tie circuit breaker and go north out of the Pico west bus on TL13816 and TL13833. After the protection system opens the circuit breakers, power flowing through Pico Substation will be cutoff and forced to flow on two parallel transmission lines; TL13831 and TL13835A. The flow increase on TL13835A will cause the TL13835A Special Protection System to operate and remove TL13837 from service.

c) After all automatic protection systems have operated and power redistributes over the remaining transmission lines, power flowing on TL13831 will exceed each transmission lines normal continuous rating, but be within its emergency rating.

d) To prevent a violation of NERC standards, operators must reduce the amount of power flowing on TL13831 by shedding approximately 46.5% of the South Orange County load within 15 minutes.

e) As discussed in Section 6 (3), this contingency will result in a violation by

2024.

17) NERC Category C2: Pico TL13816 Circuit Breaker Fault

a) The TL13816 Circuit Breaker connects the Pico 138kV west bus to TL13816. In order to remove the fault, and isolate the faulted circuit breaker, the protection system will automatically open all circuit breakers connected to the Pico west bus and the circuit breakers at San Juan Capistrano Substation protecting TL13816. Consequently, the connection between the Pico east and west buses will be opened and the connection of TL13833 to the Pico west bus will be opened.

b) Prior to the fault, power flowing to substations located north of Pico substation will come into the Pico east bus on TL13836 and TL13846, move to the Pico west bus through the bus tie circuit breaker and go north out of the Pico west bus on TL13816 and TL13833. After the protection system opens the circuit breakers, power flowing through Pico Substation will be cutoff and forced to flow on two parallel transmission lines; TL13831 and TL13835A. The flow increase on TL13835A will cause the TL13835A Special Protection System to operate and remove TL13837 from service.

c) After all automatic protection systems have operated and power redistributes over the remaining transmission lines, power flowing on TL13831 will exceed its normal continuous rating, but be within the emergency rating.

d) To prevent a violation of NERC standards, operators must reduce the amount of power flowing on TL13831 by shedding approximately 4% of the South Orange County load within 30 minutes.

e) As discussed in Section 6(6), this contingency will result in a violation by 2029.

18) NERC Category C2: Pico TL13833 Circuit Breaker Fault

a) The TL13833 Circuit Breaker connects the Pico west bus to TL13833. In order to remove the fault, and isolate the faulted circuit breaker, the protection system will automatically open all circuit breakers connected to the Pico west bus and the circuit breakers at Trabuco Substation protecting TL13833. Consequently, the connection between the Pico east and west buses will be opened and the connection of TL13816 to the Pico west bus will be opened.

b) Prior to the fault, power flowing to substations located north of Pico substation will come into the Pico east bus on TL13836 and TL13846, move to the Pico west bus through the bus tie circuit breaker and go north out of the Pico west bus on TL13816 and TL13833. After the protection system opens the circuit breakers, power flowing through Pico Substation will be cutoff and forced to flow on two parallel transmission lines; TL13831 and TL13835A. The flow increase on TL13835A will cause the TL13835A Special Protection System to operate and remove TL13837 from service.

c) After all automatic protection systems have operated and power redistributes over the remaining transmission lines, power flowing on

TL13831 will exceed its normal continuous rating, but be within the emergency rating.

d) To prevent a violation of NERC standards, operators must reduce the amount of power flowing on TL13831 by shedding approximately 42% of the South Orange County load within 30 minutes.

e) As discussed in Section 6(5), this contingency will result in a violation by 2029.

19) NERC Category C2: Talega 8T Circuit Breaker Fault

a) The 8T circuit breaker located at Talega Substation connects TL13831 and TL13836. In order to remove the fault, and isolate the faulted circuit breaker, the protection system will automatically open circuit breakers 8E and 8W at Talega and the transmission line circuit breakers TL13836 and TL13831 at Pico and Ranch Mission Viejo substations, respectively.

b) After the protection system operates, two of the four 138 kV transmission lines which serve South Orange County will be out of service and the power flowing on TL13846A and TL13846C will exceed the transmission lines normal rating.

c) To prevent a violation of NERC standards, operators must reduce the amount of power flowing on TL13846A and TL13846C by shedding approximately 12% of the South Orange County Load within 30 minutes.

Section 8. Numerous Substation Maintenance Outages Expose South Orange County Customers to Service Interruptions (Witness: Cory Smith)

Power flowing out of Talega Substation to substations located in the north must flow through the four 138kV transmission lines tied to the Talega 138 kV bus. Substation maintenance outages open the path for power to flow weakening the transmission system and creating situations that would result in large portion of South Orange County load being dropped following a single fault. Tables [4-4], [4-5] and [4-6] below list the amount of South Orange County load, in percent, that will be dropped if the contingency listed on the left side of the column occurs during the maintenance outage listed in the column header. Each column represents a single maintenance outage with all other equipment in service in South Orange County. For example, referring to Table [4-4], under the column titled, "Pico East Bus Out of Service on Maintenance", the contingency event listed to the left of the column, "B_13831", would result in approximately 71% of the South Orange County customer load being dropped from the system (no longer served).

Table 4-4 – Percent of South Orange County at Risk of being Dropped During Pico Substation Maintenance Outage

Contingency Event	Pico East Bus Out of Service on Maintenance	Pico West Bus Out of Service on Maintenance	Pico Bus Tie CB Out of Service on Maintenance	Pico TL13846 CB Out of Service on Maintenance
B_13831	71%	71%	66%	
B_13838	63%	53%	58%	
C1_Maragarita East	52%	53%	47%	
C1_Rancho Mission Viejo East	67%	57%	62%	
C1_Rancho Mission Viejo West	63%	53%	58%	
C2_RMV TL13838 CB	63%	53%	58%	
C2_RMV TL13831 CB	67%	57%	62%	
C2_RMV BT CB	63%	53%	62%	
C2_Talega 8T CB	71%	61%	66%	71%
C2_Talega 8E CB	71%	61%	66%	

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Table 4-5 – Percent of South Orange County at Risk of being Dropped During Margarita Substation Maintenance Outage

Contingency Event	Margarita East Bus Out of Service on Maintenance	Margarita TL13838 CB Out of Service on Maintenance
C1_Pico East	58%	58%
C1_Pico West	53%	53%
C2_Pico BT	53%	53%
C2_Pico 13836	58%	58%
C2_Pico 13846	58%	58%
C2_Pico 13833	53%	53%
C2_Pico 13816	31%	53%

Table 4-6 – Percent of South Orange County at Risk of being Dropped During Rancho Mission Viejo Substation Maintenance Outage

Contingency Event	Rancho Mission Viejo West Bus Out of Service on Maintenance	Rancho Mission Viejo East Bus Out of Service on Maintenance	Rancho Mission Viejo TL13838 CB Out of Service on Maintenance	Rancho Mission Viejo TL13831 CB Out of Service on Maintenance	Rancho Mission Viejo BT CB Out of Service on Maintenance
C1_Pico East	58%	66%	58%	66%	62%
C1_Pico West	53%	61%	53%	61%	57%
C2_Pico BT	53%	61%	53%	61%	57%
C2_Pico 13836	58%	66%	58%	66%	62%
C2_Pico 13846	58%	66%	58%	66%	62%
C2_Pico 13833	53%	61%	53%	61%	57%
C2_Pico 13816	53%	61%	53%	61%	57%

CHAPTER 5: TO PROVIDE RELIABLE ELECTRIC SERVICE, SDG&E'S CAPISTRANO SUBSTATION NEEDS TO BE REBUILT (WITNESS: KARL ILIEV)

To provide reliable electric service to SDG&E's South Orange County customers, SDG&E's existing Capistrano Substation, built over 60 years ago, needs to be rebuilt to, among other things, upgrade its current bus configuration to a more reliable configuration, replace deteriorating infrastructure and equipment near the end of its useful life, meet current seismic, safety and security standards, and allow 12 kV ties with neighboring substations that increase the reliability of the overall system. SDG&E sets forth below its process for assessing aging substations, including whether to rebuild such substations or simply replace equipment, and then the results of assessment of the Capistrano Substation.

In addition, SDG&E's Proposed Project provides for Capistrano Substation to be a second 230 kV source for SDG&E's South Orange County system. The need for a second 230 kV source for SDG&E's South Orange County system is set forth in Chapter 4. Capistrano Substation can be rebuilt to accommodate a 230 kV transmission connection, and it is efficient and cost-effective to plan the rebuild to do so.

Section 1. SDG&E Assessment Process for Aging Substations

SDG&E's Substation Equipment Assessment team reviews SDG&E's aging substations to identify infrastructure and equipment that has little or no remaining useful life. Useful life is determined by considering numerous factors, including age of equipment, maintenance history trends, and/or signs of degradation based on observations and analytical testing. SDG&E has had a proactive program for over 10 years specifically to analyze and ensure that equipment that is likely to fail, based on these factors and SDG&E's experience, is replaced before it fails and impacts customers.

SDG&E tracks the age of the equipment used in its substations. Equipment age, the manufacturer's estimated useful life, and SDG&E's experience with such equipment are factors in assessing remaining useful life. SDG&E also considers the trending of the preventative and corrective maintenance labor hours on equipment. Rising preventive and corrective maintenance issues are a strong indication of decreased equipment reliability and increased probability of failure. SDG&E may also conduct analytical tests on equipment, including oil analysis (gas and moisture content), insulation measurements, and/or electrical tests (including megger, power factor, and Doble tests).

In addition to increased maintenance trends, another factor which indicates aging infrastructure is equipment showing signs of degradation including rusting steel structures and equipment housings, control cable deterioration, and failing seals and gaskets on equipment. SDG&E also considers any lack of available equipment parts due to age (as many of the equipment parts are no longer supported by manufacturers). Additionally, replaced equipment due to failure is another metric that indicates that remaining equipment on a site has reached the end of its useful life.

SDG&E does not consider it prudent to wait to replace equipment only after it has failed and interrupted customer service. Therefore, SDG&E analyzes the useful life of substation equipment as discussed above and determines whether the risk of failure is sufficient to warrant its replacement.

Once SDG&E has determined that a substation has poor performance through the analysis discussed above, then SDG&E conducts an overall substation and equipment assessment to determine if SDG&E's customers would benefit more from a complete rebuild of the substation or in kind equipment replacement. SDG&E proposes substation rebuilds based on assessment of the following issues:

- Non-standard configuration,
- Potential safety issues,
- Poor performing equipment due to age, type, and condition,
- Substation customer load size and customer exposure to outages,
- Exceeded loading limits,
- Increasing or excessive maintenance issues,
- History of outages/failures,
- Lack of adjacent 12 kV circuit ties or tie capacity,
- Available property for rebuild, and
- Poor existing security.

Section 2. The Capistrano Substation's Equipment and Infrastructure is At or Close to the End of its Useful Life

Capistrano Substation was originally built in approximately 1954. SDG&E's Substation Equipment Assessment team has identified its aging equipment and infrastructure as beyond its useful life. Since 1997, Capistrano Substation has been on SDG&E's priority list, identifying substations that are in need of upgrades or replacement due to poor performance. This list was developed utilizing safety, condition of the equipment, probability of outages, and cost to maintain as key metrics. Based on the prioritized list, in the early 2000s, studies and cost estimates were started to develop a plan and design for the rebuild of Capistrano Substation. In the mid-2000s, SDG&E determined that it would be most cost effective and create the most construction synergies if the rebuilt Capistrano Substation included a second 230 kV source for South Orange County. Therefore, the rebuild became part of what is now the Proposed Project.

Trending of the preventative and corrective maintenance labor hours on the Capistrano Substation equipment shows both types of maintenance trending upward, which is expected for aging equipment. Preventive maintenance at Capistrano Substation has been increasing since 1997 at a rate of approximately 15% per year. This indicates an increase in equipment that is not operating within performance specifications when crews maintain it. Additionally, corrective maintenance (maintenance required due to failure of equipment between time based preventive maintenance intervals) has slowly increased. Rising preventive and corrective maintenance issues are a strong indication of decreased equipment reliability and increased probability of failure. It also is a direct indication of rising costs to maintain the equipment.

In addition to maintenance increases, the equipment at Capistrano Substation is showing signs of degradation, including rusting steel structures and equipment housings, control cable deterioration, and failing seals and gaskets on equipment. SDG&E has experienced a lack of available equipment parts for Capistrano Substation equipment due to age (as many of the equipment parts are no longer supported by manufacturers). Additionally, SDG&E has had to replace equipment at Capistrano Substation due to failure. In 2014 alone, both 12 kV and 138 kV capacitors at Capistrano Substation have failed. Because repair parts were not available, SDG&E was required to completely or partially replace the equipment. Over the past 12 years at Capistrano Substation, one transformer has failed requiring replacement, and several 12 kV circuit breakers on the site were replaced because rising customer load caused conditions to exceed the design specification of that equipment.

All of these factors indicate that it is time to rebuild or replace the Capistrano Substation equipment and infrastructure.

Section 3. The Capistrano Substation Needs to be Rebuilt to Provide Reliable Electric Service to SDG&E's South Orange County Customers

Following SDG&E's usual substation assessment protocol, Capistrano Substation was analyzed for issues that determine whether a rebuild would better serve SDG&E's customers than in-kind equipment replacement. Each factor weighed in favor of rebuilding the substation.

(1) Non-Standard Configuration

Capistrano Substation has a non-standard configuration that does not meet current operating criteria or reliability requirements. Capistrano Substation currently is fed by three 138 kV transmission lines: TL13816 (CP-PI), TL13834 (CP-TB), and TL13837 (CP-LNL). These three transmission lines feed the transmission bus, which is constructed as a single bus, single breaker configuration, consisting of four elements: the three TLs, and one 138 kV capacitor. It also includes a 138 kV bus tie for sectionalizing capability (which separates the 138 kV bus into a north and south bus).

Currently at Capistrano Substation, two 138/12 kV transformers are connected directly to the 138 kV north and south bus (respectively). The two 138/12 kV transformers (identified by SDG&E's nomenclature as Bank 41 and Bank 40) feed the 12 kV bus. The 12 kV bus consists of a main bus (divided by a bus tie breaker) and a transfer bus. The 12 kV bus is divided into a west and east bus, and has six 12 kV circuits fed through circuit breakers and three 12 kV capacitors connected directly to the 12 kV bus. These six 12 kV circuits support the San Juan Capistrano community, which has approximately 35,000 people.

The existing configuration at Capistrano Substation does not meet SDG&E's current operating and reliability criteria for either the transmission system or the distribution system.

When the substation was originally constructed in approximately 1954, the transmission and distribution bus configuration was the standard design of that era. However, this design no longer meets SDG&E's current operating and reliability criteria due to the transmission system impacts of a transformer outage.

SDG&E's standard for a substation of this size requires a breaker and half configuration to meet operating and reliability criteria. This configuration means each transmission bay has two elements (lines, capacitors, transmission class transformers, etc.) connected to separate busses with a tie breaker between each element, allowing each element to be fed by either bus. This allows continuity of service to each element in the event of a bus outage. SDG&E's design criteria for a smaller transmission bus is a single breaker-single bus, in which each element is fed by only one breaker and one bus. Both of these SDG&E designs require a breaker protecting each transformer feeding a distribution bus. This prevents a transmission bus outage from occurring if a transformer has a problem because the additional sectionalizing breaker will decrease the infrastructure impacted. A breaker and a half configuration is more reliable and therefore preferred by SDG&E since it limits any single point of failure to a maximum of two elements, minimizing transmission outage impacts.

SDG&E is prevented from installing the current standard of 138 kV bank breakers and/or a breaker and a half configuration due to space limitations at this location.

In addition to the transmission bus issues, the 12 kV capacitors are all connected directly to the 12 kV bus through fuses instead of circuit breakers. Without a circuit breaker installed between the equipment and its service bus, a failure may require customer load shed on the 12 kV bus in order to isolate the problem for repair. This design of not having a protective circuit breaker creates a reliability risk to the system and customers. SDG&E's current operating and reliability criteria require a circuit breaker between each 12 kV capacitor and the 12 kV bus. There is currently insufficient room on the distribution bus to install these capacitor breakers.

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As a result of the Capistrano Substation's non-standard configuration, SDG&E's customers face the following reliability risks:

- If Bank 41 trips, isolation also occurs to the 138 kV north bus, TL13816 and the 138 kV capacitor. Tripping the 138 kV capacitor could result in transmission loading and voltage issues depending upon system characteristics at the time of the loss.
- If Bank 40 trips, isolation also occurs to the 138 kV south bus, including TL13834 and TL13837. The loss of these two transmission lines radializes Capistrano Substation on TL13816. Tripping TL13837 also radializes Laguna Niguel Substation. As a result, both of these substations are at risk to load shed as they would be served with only one transmission line until restoration efforts succeed at Capistrano.
- The failure of a 12 kV capacitor oil or vacuum switch may require isolation of the 12 kV bus, resulting in temporary load shed off either the 12 kV west or east bus (and thus loss of service to customers) to safely isolate the equipment at issue for repairs.

Because of space constraints, the non-standard configuration at Capistrano Substation cannot be corrected to meet SDG&E's current design criteria without rebuilding the substation.

(2) Potential Safety Issues

The aging infrastructure at the existing Capistrano Substation includes oil circuit breaker and oil switch technology. This technology has since been replaced with newer gas and vacuum technologies at other substations. These newer technologies are less volatile during equipment failure, mitigating fire and explosion risk during these events. In addition, the current configuration of Capistrano Substation, due to the site constraints, has the 138 kV capacitor in a less than optimal location. Typically SDG&E prefers that this equipment is located further from the property line.

Rebuilding Capistrano Substation as described in the Proposed Project allows for installation of the newer technologies and also placement of volatile equipment farther from the property line. Installing the GIS equipment inside a building also offers additional protection in both security of the facility and equipment failure protection.

As noted above, rebuilding Capistrano Substation will also provide room for the addition of 138 kV breakers to protect the distribution transformers and 12 kV breakers to protect the 12 kV capacitors. Replacing equipment in kind will not allow positions for these breakers. As described above, the current configuration results in a greater risk to customer electric service, which can be a safety issue for customers.

(3) Age, Type, Condition and Quantity of Equipment

Capistrano Substation is approximately 60 years old and its aging equipment has been identified by SDG&E's Substation Equipment Assessment team as beyond its useful life. Much of the significant equipment at Capistrano Substation ranks high on the replacements lists. The Bank 41 transformer ranks #1 to be replaced, with a current approximation of two years of expected life left. The 138 kV breakers have been identified for replacement. Instrument transformers (used to provide control voltage and current to relays and metering) are also identified for replacement. The control shelter also needs to be replaced due to limited size, age, and security issues. Upgrading some of the electromechanical relays to current solid-state models within the control shelter would also allow further automation and event recording capabilities at the site.

The 138 kV and 12 kV buses are both undersized and their insulators and disconnects can create operational risks due to their age and risk of failure. The current bus design is pieced together with different sizes of bus, which limits available ampacity. The insulators, because of their age and type, will likely start failing because of deterioration of the bonding material. When a bus insulator fails, it will trip out the bus and may damage nearby equipment and pose a risk to personnel due to falling debris. The disconnect switches need replacement because their mechanical mechanisms and arcing blades wear out over repeated use, causing failure to operate properly. If a disconnect switch fails during operation, it may also cause an arc, tripping the bus relaying and leading to customer outages.

Further, Capistrano Substation is located in a high seismic area and it is SDG&E's standard practice to design substations and equipment to have a high probability of withstanding seismic events to predefined ground acceleration levels. The primary industry standards that SDG&E follows are the IEEE 693 Recommended Practice for Seismic Design of Substations, ASCE 96 Guide to Improved Earthquake Performance of Electric Power Systems and ASCE 113 Substation Structure Design Guide. The existing Capistrano Substation was designed and constructed long before these standard practices and guidelines were established. Due to their age and type of construction, the existing structures, foundations, and equipment do not conform to the current recommended practices for seismic design of substations as provided in IEEE 693 and ASCE 113. The older existing electrical equipment does not meet the seismic withstand capability and has not been seismically qualified as provided in IEEE 693.

Replacing equipment only does not allow for replacement of the existing structures and their foundations. Aging circuit breakers and transformers can be replaced along with their foundations, but they will still be connected to aging structures and bus that are not seismically

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qualified. Disconnect switches, bus, and insulators can be replaced but not to required size due to strength and space limitations of the existing structures and foundations. Also, the larger equipment cannot be installed on existing structures as they do not meet current seismic requirements. Newer electrical safety clearances cannot be incorporated because the structures cannot be expanded.

The Capistrano Substation rebuild as described in the Proposed Project will allow for the new substation to meet these recommended practices for seismic design because all new structures can be built in a new yard and the new structures, foundations, and equipment will meet these seismic requirements.

(4) Number of Customers

Capistrano Substation currently serves approximately 14,000 meters in the San Juan Capistrano area, including 13,400 residential and 1,784 commercial and industrial meters. The U.S. Census reports that San Juan Capistrano alone had an estimated 2013 population of 35,852 people. http://quickfacts.census.gov/qfd/states/06/0668028.html. This does not include the employees of businesses located in San Juan Capistrano, visitors to the City, or patrons of its businesses.

(5) Loading Limits

Capistrano Substation transformer loading is currently at 85% capacity at peak. When customer load exceeds the current capacity, the existing substation site cannot be expanded to accommodate the required amount of additional transformers. High transformer loading at Capistrano also limits its ability to support neighboring substations via 12 kV circuit ties thereby limiting flexibility in distribution line equipment and substation transformer outages.

(6) Maintenance Issues

As previously noted, preventive maintenance hours have been increasing at 15% annually, mainly due to the aging infrastructure. Increasing maintenance hours are being spent on breaker, transformer, and disconnect switch repairs due to the age and wear of the existing equipment. The breakers and transformers can be replaced individually to reduce their maintenance requirements, but disconnect switches will not be able to be replaced with SDG&E's larger seismically qualified disconnects because of the age of the steel and the substation configuration.

Rebuilding the entire substation will enable all equipment to be replaced on appropriately sized and seismic qualified structures and foundations. Rebuilding the entire substation will also allow for all new equipment and associated hardware to be installed which will eliminate the issues outlined above. An entire substation rebuild will also allow for the substation to be configured per SDG&E's current operating and reliability criteria. This will create operational flexibility, allowing equipment to be easily taken out of service for planned maintenance.

(7) History of outages/failures

The outage history and corrective (non-programmed) maintenance history over the last 15 years shows increasing trends caused by 138 kV and 12 kV disconnect switches not operating properly, 12 kV and 138 kV capacitor issues, 138 kV and 12 kV potential transformer issues, and various hot spots from connections on both 138 kV and 12 kV busses. Rebuilding the substation will allow for all new equipment and associated hardware to be installed which will eliminate these issues.

(8) Adjacent 12 kV Circuit Ties

Capistrano Substation currently has distribution circuit ties with its neighboring substations: Laguna Niguel and Trabuco. However, these ties cannot be utilized during certain system conditions because of Capistrano Substation's high loading and lack of available capacity. The circuits and transformers at Capistrano Substation are highly loaded during peak conditions, limiting operational flexibility between circuits and other substations. As a result:

- In the advent of a transformer problem at Capistrano, up to 10,000 meters could lose power for over 14 hours or longer until the time a portable transformer is set and energized. In the event of a bus failure, this time frame can be longer because a portable transformer cannot be used in place of a bus failure. Both of these problems would result in load loss because of the limited tie capacity to other substations. These 10,000 meters represent customers that cannot be offloaded from Capistrano Substation during peak load.
- In the event of a major substation failure at the neighboring Laguna Niguel substation, Capistrano Substation could not be used to pick up all customer load, resulting in the loss of service in up to approximately 20,000 meters. The City of Laguna Niguel had a 2013 population of 64,652 people, according to the U.S. Census.[23]

Rebuilding the entire Capistrano substation will allow for expansion from the existing 60 MVA substation to an ultimate 120 MVA substation. This additional capacity will allow for load transfers from neighboring substations into the new Capistrano Substation when needed. Replacing equipment in kind will not allow room for expansion and will not allow for additional transformers to be installed without deviating from acceptable SDG&E reliability criteria. Without the Capistrano Substation being fully rebuilt, the capacity of the existing substation cannot be increased and therefore will not allow load transfers to Capistrano Substation.

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[23] http://quickfacts.census.gov/qfd/states/06/0639248.html.

(9) Size of existing property

The existing Capistrano Substation is located on only a portion of the existing SDG&E-owned substation property, and there is room to rebuild the substation elsewhere on the property. This makes the existing Capistrano Substation an ideal rebuild candidate because:

- A new substation can be built without compromising the reliability of the existing substation during construction or placing construction personnel at risk;
- The new substation will facilitate SDG&E's long range transmission and distribution needs to serve its customers; and
- The new substation would comply with SDG&E's current operating and reliability criteria and seismic and safety design requirements.

(10) Security Issues

The current control shelter configuration does not meet SDG&E's new security guidelines due to its unprotected windows and size restrictions. The empty yard and deteriorating buildings on the same parcel as the existing substation create security issues as vagrants have broken into the building and made camp.

Rebuilding the substation will allow space for a new control shelter in each of the 230 kV and 138 kV yards. Each control shelter will be of masonry block design without windows and a secured door. Additionally, all sides of the entire SDG&E property will be secured with security block wall or fence.

In the existing substation yard, a new control shelter cannot be built without blocking drive access to other equipment due to the limited size of the existing site. The existing control shelter cannot have its windows removed due to proximity of the protection and control equipment inside the shelter.

For all of these reasons, SDG&E determined that the Capistrano Substation needs to be rebuilt.

Section 4. Simply Replacing Equipment at Capistrano Substation Will Not Provide Reliable Electric Service to SDG&E's South Orange County Customers

In contrast to the factors favoring rebuilding Capistrano Substation, analysis of the same factors indicates that simply replacing equipment at the existing substation will not provide the desired level of reliability.

Replacing equipment in kind will not change the existing layout configuration and therefore will not eliminate the risks of forced outages to SDG&E's customers arising from the non-standard configuration of the transmission bus and the distribution bus. The existing substation site is not large enough to rebuild the 138 kV switchyard in a breaker and a half configuration. If SDG&E were to rebuild inside the existing yard, the configuration of the transmission rebuild would be limited to a single breaker – single bus configuration. Rebuilding in-place would also create physical limitations on the number of additional element positions that can be added to only two (transmission lines and distribution transformers). This limitation would not meet the needs for a reliable transmission configuration as mentioned above or any future customer load growth. Additionally, when more transmission lines are added to the substation, more space would be required to build a new and larger control shelter. The enlarged control shelter would contain all the necessary control, protection equipment, and battery systems required to monitor the substation.

Current seismic requirements also require more robust designs in equipment, foundations, and structures than aging substations can meet. Capistrano, like other aging substations in SDG&E's service territory, must be rebuilt to meet these current requirements. Simply replacing equipment does not bring the existing structures and foundations up to the latest seismic standards. Placing IEEE 693-qualified equipment in and on the existing structures and foundations still leave the equipment at risk. SDG&E does not consider that prudent or that it will adequately ensure reliable electric service for its South Orange County customers.

Simply replacing equipment does not allow for greater use of distribution ties between Capistrano Substation and Laguna Niguel and Trabuco Substations. These ties allow each substation to support service to other substations' customers if a substation experiences an outage. Additional capacity that meets SDG&E reliability criteria at Capistrano Substation can only be accomplished by adding additional transformers.

Simply replacing equipment does not address the security concerns regarding the existing substation. The recent attack at PG&E's Metcalf Station and other electric facilities around the United States has raised the general threat level within the energy/electric sector. Various federal agencies (including the Federal Energy Regulatory Commission, the Department of Energy, and the Department of Homeland Security), as well as the North American Reliability Corporation, have issued security alerts specific to physical attacks against the electric utilities and have suggested mitigation measures. SDG&E is currently upgrading its security standards for substations and the new standards will be implemented in the Proposed Project.

Rebuilding a substation in its existing yard also increases reliability risks to customers and safety risks to workers because of the proximity of the energized equipment. It generally takes twice as long to perform construction in an energized substation because of outage restrictions required for worker safety along with delays due to requirements for working around energized equipment. Outages to customers may be required to perform certain construction activities. Temporary configurations of the transmission bus would be required during this type of rebuild as existing elements are transferred from the old configuration to the new configuration. Portable transformers, breakers, and cable may be required for continuity of service to customers while existing elements are taken out of service to make room for the new equipment. While use of portable equipment is a normal construction technique when required, it is much less reliable than permanent equipment, creates less reliable system configurations, and affects voltage regulation while in-service.

For these reasons, among others, simply replacing equipment at the Capistrano Substation does not provide adequate reliability for SDG&E's South Orange County customers or meet SDG&E's transmission objectives set forth in Chapter 4.

CHAPTER 6: WITHOUT SDG&E'S PROPOSED PROJECT, SDG&E'S TALEGA SUBSTATION NEEDS TO BE MODIFIED TO PROVIDE RELIABLE ELECTRIC SERVICE (Witness Karl Iliev)

Without SDG&E's Proposed Project, significant work at Talega Substation will be required to improve the reliability of electric service. However, upgrading Talega Substation alone cannot provide the reliability benefits of a second source of power to SDG&E's South Orange County system. SDG&E's Proposed Project not only provides a second source, it avoids the need to perform an estimated $95 to $120 million of work at Talega Substation. Without a second source of power to South Orange County, SDG&E not only would need to perform such work, but also would have to evaluate the feasibility of acquiring additional property to rebuild the Talega Substation in a more reliable configuration.

Section 1. Reliability Issues at Talega Substation

As discussed in Chapter 2, Talega Substation is the sole source of power to SDG&E's South Orange County system. Talega's source of power is at 230 kV which is then stepped down from 230 kV to 138 kV through four 230/138 kV transformers at Talega Substation. Currently, these are the only 230/138 kV transformers serving the SDG&E's South Orange

County system. Talega then transmits the power at 138 kV to SDG&E's South Orange County distribution substations.

Two of the existing 230/138 kV transformers at Talega Substation, Banks 60 and 62, which were purchased in the 1960s, are beyond their useful life. Moreover, Banks 60 and 62 are rated 162 MVA and 150 MVA, respectively, and are not adequately sized to operate in support of Banks 61 and 63, each rated 392 MVA.

There are a number of problems that arise from having all four transformers at Talega Substation. Because of space constraints within the substation footprint, the transformers are in close proximity to each other, which increases the equipment damage and outage impact if an adjacent transformer or other equipment catches fire or fails. Currently, Banks 61 and 62 are immediately adjacent to the control shelter without enough separation to install a fire wall. If one of these transformers catches on fire, it will create difficulty in entering the control shelter to perform operations necessary to de-energize the equipment to allow workers to safely extinguish the fire.

Also because of space constraints, transformer Banks 60 and 63 are currently fed directly off the 230 kV bus without bank breakers. This is a non-ideal configuration because any bus outage will force a transformer outage and vice versa. There is not sufficient space in the current substation footprint to reconfigure Bank 63 to be fed from a more reliable breaker and a half configuration (where the transformer may stay in-service during a bus outage and vice versa). Banks 61 and 62 are currently fed from a breaker and a half configuration, but are in the same bay, which does not meet current SDG&E's reliability criteria as they are exposed to single point of failure from their shared tie breaker.

Overall, Talega Substation is an aging substation, constructed in 1978. Talega has had numerous equipment replacements in the last 10 years due to its age and poor reliability of the equipment. As Talega Substation gets older, increased frequency and duration of equipment maintenance (both proactive and reactive) will be required to maintain reliability.

These issues pose reliability risks. Because Talega Substation currently is the source of all power to South Orange County, Category D events at Talega Substation (loss of the 230 kV service or the loss of 138 kV service) would drop service to all SDG&E customers in South Orange County—approximately 300,000 people. The space constraints at Talega Substation result in the transformers being in close proximity without a separation wall between two of them, which increases the risk of a catastrophic failure. Even if risks arising from space constraints could be addressed by rebuilding the substation, it would not address all risks arising from having Talega Substation be the sole source of power to South Orange County. That risk can only be addressed by having a second source, as proposed by SDG&E's Proposed Project.

Further, because Talega Substation's equipment (including two transformers) is aging, more maintenance is needed. However, because Talega Substation has a non-standard configuration due to space constraints and is the sole source of power to South Orange County, a single forced outage (such as Category B events) that occurs during a planned maintenance outage at Talega will drop service to all or some SDG&E customers in South Orange County. *See* Chapter 4, Section 5 above; CAISO 2010-2011 Transmission Plan at 207 ("Failure of certain components in this area under maintenance conditions can result in loss of entire South Orange County load which is expected to be about 523 MW by 2020.") This risk makes it difficult to perform maintenance at Talega Substation.

Section 2. Work Avoided at Talega Substation If the Proposed Project is Implemented

SDG&E's Proposed Project resolves a number of reliability issues at Talega Substation by rebuilding Capistrano Substation to serve as a second source of power to SDG&E's South Orange County system. In addition to eliminating the failure modes that could damage all four transformers in one location (Talega Substation), SDG&E's Proposed Project avoids work at Talega Substation that otherwise would be necessary.

First, by installing two 230/138 kV transformers at the new San Juan Capistrano Substation, SDG&E would not need to replace the two aging and undersized transformers at Talega Substation (Banks 60 and 62). Replacement of those transformers at Talega Substation is estimated to cost between $15 and $20 million. Having 230/138 kV transformers serving South Orange County customers from two different substations located several miles apart is a key component to preventing a blackout of South Orange County.

Second, by removing these two transformers from Talega Substation, there would be room within the existing Talega Substation to reconfigure Bank 63 to be fed from a more reliable breaker and a half configuration (where the transformer may stay in-service during a bus outage and vice versa). Because there would be a second source at San Juan Capistrano Substation, the work to perform this reconfiguration would not place SDG&E's South Orange County customers at risk from a single forced outage during the construction work. Once performed, maintenance work at Talega Substation could be performed without placing SDG&E's customers at risk from a single forced outage during a planned maintenance outage.

Third, SDG&E's Proposed Project avoids the need to replace the STATCOM at Talega Substation when it reaches the end of its life. If the Proposed Project does not proceed, the existing STATCOM device would have to be replaced with a similar voltage control device once the technology becomes obsolete and unrepairable. The STATCOM provides fast acting voltage support to prevent a South Orange County voltage collapse. With a new 230 kV source located at San Juan Capistrano, the local system's voltage strength is vastly improved and the STATCOM would not need to be replaced in the future as much less expensive options would be available. Replacing the STATCOM at Talega Substation is estimated to cost between $80 and $100 million.

Section 3. Work Needed at Talega Substation if the Proposed Project is Not Implemented

If SDG&E's Proposed Project is not implemented, SDG&E will perform, or where necessary seek authorization to perform, work at Talega Substation. As noted above, SDG&E will need to replace two transformers at Talega and eventually the STATCOM. These steps alone, however, do not address the reliability risks of Talega Substation's non-standard configuration or having Talega serve as the sole source of power for SDG&E's South Orange County system.

The reliability impact during planned maintenance and from some forced outages could be reduced if Talega Substation could be rebuilt with a new bay in a breaker and a half configuration. This configuration would allow more flexibility in taking maintenance outages and responding to forced outages. However, because Talega Substation is the sole source of power to South Orange County, it cannot be taken out of service to reconfigure equipment on the existing substation site, assuming it would be feasible to do so within the existing space. Assuming it would be feasible to phase and safely perform reconfiguration work by de-energizing certain equipment in the substation, such an approach would place all of SDG&E's South Orange County customers at risk of a long-term outage in the event of a single forced outage of other elements during the construction work (temporary substation configurations would be required to facilitate the removal and addition of equipment). Depending upon the status of the construction work and the nature of the forced outage, it could be a significant period of time before service could be restored.

For these reasons, SDG&E considered rebuilding the Talega Substation on adjacent property. As discussed in SDG&E's Proponent's Environmental Assessment (PEA) starting a 5-13, this alternative to the Proposed Project was rejected for a number of reasons. Among others, doing so would not address the risk posed by having Talega Substation as the sole source of power to SDG&E's South Orange County system. Further, it would require acquiring new property from Camp Pendleton, which SDG&E's PEA found raised environmental concerns.[24] Moreover, SDG&E estimated that it would cost $782 million and require incremental construction of system improvements and ultimately result in SDG&E having to include the costs associated with the No Project Alternative (regarding the rebuilding of Capistrano Substation and upgrading the 138 kV system) in with this rebuild, significantly increasing the cost of this alternative in excess of the Proposed Project cost.

Rebuilding the Talega Substation would also require removal and replacement of the Synchronous Condensers devices already on-site.

Replacing the two transformers and the STATCOM at Talega Substation, and even the purchase of additional property and re-configuration to a breaker and a half scheme, would not eliminate the risk of a Category D event at Talega Substation. Because Talega Substation currently is the source of all power to South Orange County, Category D events at Talega

[24] SDG&E's PEA at 5-16 ("Short- and long-term impacts would increase at Talega Substation due to the required expansion of the substation into undisturbed land which has several environmental constraints. These long-term impacts include sensitive and/or occupied habitat for arroyo toad and California gnatcatcher, recent land slide area which would require significant remedial grading requiring a large impact footprint and 25 percent or greater slopes which would be subject to erosion during construction.").

Substation (loss of the 230 kV service or the loss of 138 kV service) would drop service to all SDG&E customers in South Orange County—roughly around 300,000 people. Therefore, SDG&E does not consider rebuilding Talega Substation to be a prudent or cost-effective solution to the South Orange County reliability issues.

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CHAPTER 7: PURPOSE AND NEED FOR SOUTH ORANGE COUNTY RELIABILITY PROJECT

Section 1. The Purpose of the Project Is To Increase the Reliability of SDG&E's South Orange County Electric System (Witness John Jontry)

The Proposed Project meets the SDG&E's goal to provide safe and reliable electric power to the cities and communities of South Orange County served by SDG&E's system. The Proposed Project will improve the reliability by:

1. Protecting all South Orange County customers against a potentially lengthy loss of electric service in the event that fire, explosion, earthquake, vandalism, terrorism or other cause results in the loss of 230 kV or 138 kV service at Talega Substation.
2. Protecting South Orange County customers against a complete loss of electric service under 29 scenarios, and a partial loss of electric service under 28 scenarios, involving a forced outage during a planned maintenance event at Talega Substation.
3. Protects South Orange County customers against loss of electric service caused by Category C load shedding in the event of numerous single outage or multiple element outages.
4. Permitting SDG&E to design its South Orange County system to comply with mandatory requirements under NERC TPL-003-0b and TPL-002-0b.
5. Rebuilding Capistrano Substation to replace equipment and infrastructure at or close to the end of its useful life, implement a more reliable configuration meeting SDG&E's operating and reliability criteria, meet current seismic, security and safety standards, and provide more capacity to aid neighboring substations in the event of an outage, and.

6. Improve transmission and distribution operating flexibility to, among other things, perform maintenance and respond to outages.

Section 2. The Project Mitigates the Reliability Risks Found in the South Orange County Transmission System (Witness John Jontry)

A. The Project Mitigates the Risk of All Customers Losing Service After Loss of 230 kV or 138 kV Service at Talega Substation

SDG&E's South Orange County customers are dependent on single power source, the 230 kV supply to Talega Substation, which then supplies power via 138 kV transmission lines to the distribution substations within South Orange County. Any event that interrupted the 230 kV or 138 kV service at Talega Substation, such as equipment failure, fire/explosion, earthquake, or vandalism/terrorism, would leave over 300,000 people in South Orange County without electricity until the damage was repaired. An extended outage of the 230 kV or 138 kV service at Talega Substation would threaten public safety and cause severe economic impacts to South Orange County. The Proposed Project addresses this problem by providing a second 230 kV connection at a rebuilt Capistrano Substation (re-named San Juan Capistrano Substation).

B. The Project Mitigates the Risk of Customers Losing Service During Maintenance Events at Talega Substation

Because Talega Substation is the sole power source for SDG&E's South Orange County system, and has a non-standard configuration that cannot be corrected within the existing footprint, planned outages for maintenance at Talega leave some or all South Orange County customers at risk that single forced outage of another element could interrupt their electric service. As discussed in Chapter 4, Section 5, there are 29 scenarios under which a forced outage during a maintenance event at Talega Substation would immediately drop all customer load in South Orange County. There also are 28 scenarios where a forced outage during a maintenance event at Talega Substation would require SDG&E to shed load, thus interrupting electric service to a significant number of South Orange County customers. The need for maintenance at Talega Substation, which is over 35 years old, is increasing. A second 230 kV source at the new San Juan Capistrano Substation will allow maintenance at Talega without this risk.

C. The Project Mitigates the Risk of Customers Losing Service After an Outage of One or More Transmission Elements

As discussed in Chapter 4, Sections 6 and 7, as of 2020, SDG&E expects that a number of potential events, falling under Category C of the North American Electric Reliability Corporation (NERC) reliability standards, involving outages of one or more transmission lines, transformers, or other equipment, will directly result in interruption of service to customers. SDG&E has identified 18 Category C scenarios where SDG&E would not be able to keep the system within its Applicable Ratings before SDG&E could shed load, and 12 Category C scenarios where SDG&E would shed load to keep the system within Applicable Ratings. Under all scenarios, customer service would be interrupted.

SDG&E notes that, although NERC TPL-003-0b permits “controlled/planned” load shedding to remain within Applicable Ratings, that NERC standard requires SDG&E to engage in “controlled/planned” load shedding under the same circumstances that NERC TPL-002-0b forbids any loss of customer load. This may be interpreted as a violation of NERC TPL-002-0b. In any event, the effect on SDG&E’s customers is exactly the same—a single outage results in a loss of electrical service.

The Proposed Project resolves most of these Category C issues by providing a second bulk power source for the South Orange County load pocket.

D. The Project Provides the Same Level of Service to South Orange County as Provided to the Rest of the SDG&E Service Territory

The South Orange County portion of the SDG&E service territory is unique, in that it is served by a single connection to the 230 kV bulk power system. The remainder of the SDG&E system (metropolitan San Diego and the rural portions of East San Diego County) is supplied through multiple 230 kV gateways. The Proposed Project resolves this issue by providing a second bulk power source for the South Orange County load pocket, and providing the same level of reliability to customers there as provided to SDG&E customers elsewhere.

Section 3. The Project Allows SDG&E to Comply with NERC Reliability Standards (Witness John Jontry)

As discussed in Chapter 4, Section 6, as of 2020 there are 18 events, falling under Category C of the NERC reliability standards, under which it is expected that outages of one or more elements will cause overloads on SDG&E's South Orange County transmission system that result in SDG&E's transmission lines exceeding "Applicable Ratings." These events cannot be mitigated using a Special Protection Systems because CAISO’s Planning Standards forbid use of the number of SPSs that would be necessary to address all of these events. These events would be a violation of the mandatory requirements of NERC TPL-003-0b. In addition, there are many events where SDG&E would be required to shed load after a single Category B event in order to prepare for a subsequent outage. These events may be interpreted to be violations of NERC TPL-002-0b. The Proposed Project will allow SDG&E to comply with NERC TPL-003-0b, as well as avoid SDG&E having to interrupt customer service in these events.

Section 4. The Project Mitigates Reliability Risks at the Capistrano Substation By Rebuilding It As the New San Juan Capistrano Substation (Witness Karl Iliev)

As discussed in Chapter 5, Capistrano Substation, built over 60 years ago, long has been on SDG&E’s priority list of substations that are in need of upgrades or replacement due to poor performance. To provide reliable electric service to SDG&E's South Orange County customers, the existing Capistrano Substation needs to be rebuilt to, among other things, upgrade its current bus configuration to a more reliable configuration, replace deteriorating infrastructure and equipment near the end of its useful life, meet current seismic, safety and security standards, and allow 12 kV ties with neighboring substations that increase the reliability of the overall system.

The aging Capistrano Substation has the following issues, which threaten the reliability of electric service to SDG&E's customers served by the substation:

- Capistrano Substation has a non-standard configuration that does not meet current operating criteria or reliability requirements.
- Capistrano Substation uses older technology that is more volatile than current technology, and site constraints has the 138 kV capacitor in a less than optimal location.
- Capistrano Substation has poorly performing equipment due to age, type, and condition. The existing structures, foundations, and equipment do not conform to the current recommended practices for seismic design of substations as provided in IEEE 693 and ASCE 113, and older existing electrical equipment does not meet the seismic withstand capability and has not been seismically qualified as provided in IEEE 693.
- Capistrano Substation currently serves 13,400 residential and 1,784 commercial and industrial meters, and San Juan Capistrano alone had an estimated 2013 population of 35,852 people. These customers are at risk due to the lack of reliability.
- Capistrano Substation's transformer loading is currently at 85% capacity at peak,

and has little capacity for load growth or supporting neighboring substations.,

- Preventive maintenance hours have been increasing at 15% annually, mainly due to the aging infrastructure. SDG&E has had to replace equipment that has failed or is obsolete such that no spare parts are available. ,
- The outage history and corrective (non-programmed) maintenance history over the last 15 years shows increasing trends caused by 138 kV and 12 kV disconnect switches not operating properly, 12 kV and 138 kV capacitor issues, 138 kV and 12 kV potential transformer issues, and various hot spots from connections on both 138 kV and 12 kV busses.,
- Capistrano Substation currently has distribution circuit ties with its neighboring substations, Laguna Niguel and Trabuco, but these ties cannot be utilized during certain system conditions because of Capistrano Substation's high loading and lack of available capacity.
- The current control shelter configuration does not meet SDG&E's new security guidelines due to its unprotected windows and size restrictions.

By completely replacing equipment, upgrading and rebuilding the substation to SDG&E's current design standards, all of the above reliability concerns are addressed. The reliability gains from the Proposed Project, which are not achieved by only replacing equipment, include:

- A new substation configuration which will improve reliability by creating more opportunities to isolate substation buses, transmission lines and transformers during equipment failures and maintenance outages. Additional capacity will improve operating conditions during maintenance and after an equipment failure resulting in a forced outage.

- Additional distribution tie capacity between Capistrano Substation and its two neighboring substations, Trabuco and Laguna Niguel substations, which provide additional reliability for customers fed by each of those substations.
- Equipment, structures, and foundations constructed to current seismic qualifications.
- New control shelter (in each 230 kV and 138 kV yard) built to current security design.
- New and updated security systems.
- Updated relaying and improved SCADA.
- Reduced maintenance.
- Improved aesthetics.
- Increased safety.
- Rebuilding in an adjacent part of SDG&E's parcel instead of the existing yard will also avoid the reliability and safety issues of performing rebuild/replacement construction in an existing yard.

Adequate reliability can only be gained by a complete rebuild and expansion of the existing substation. The Proposed Project does so.

SDG&E also determined that it would be most cost effective and create the most construction synergies if the rebuild of Capistrano Substation included a second 230 kV source for South Orange County. As discussed above, a second 230 kV source is necessary to address reliability concerns created by having Talega Substation serve as the only source of power to SDG&E's South Orange County system. Rebuilding Capistrano Substation as the new San Juan

Capistrano Substation allows it to serve as the second source.

Section 5. Talega Substation (Witness Karl Iliev)

Talega Substation currently is the sole source of power to SDG&E's South Orange County system. A non-standard bus configuration and aging equipment increase the risk of both forced outages to customer service in South Orange County. As discussed in more detail in Chapter 6, SDG&E's Proposed Project addresses these reliability concerns by creating a second 230 kV power source at the rebuilt Capistrano Substation, which also creates space at Talega Substation to re-configure the transmission bus to a more reliable configuration. The Proposed Project will also reduce the loading at Talega Substation, which will allow SDG&E to not replace two existing 230/69 kV transformers and the existing STATCOM voltage regulating device when it reaches the end of its useful life.

Without the Proposed Project, SDG&E will need to perform, or seek to perform, significant work at Talega Substation to improve reliability. SDG&E would need to replace the two existing transformers and eventually the STATCOM noted above, at an estimated $95 to $120 million cost. That alone would not address the reliability concerns arising from the non-standard configuration. SDG&E also would have to evaluate the feasibility of acquiring additional property to rebuild the Talega Substation in a more reliable configuration. However, even rebuilding Talega Substation cannot provide the reliability benefits of a second source of power to SDG&E's South Orange County system.

The Proposed Project addresses all of the reliability concerns at Talega Substation directly and will allow SDG&E to reconfigure Talega Substation within the existing substation property.

Section 6. The Project Improves Transmission and Distribution Operating Flexibility (Witness John Jontry)

The Proposed Project meets this objective of improving transmission and distribution operating flexibility by providing additional bulk power sources, and modernizing and expanding the outdated 138 kV and 12 kV busses at Capistrano Substation.

The new 230 kV source provided by the Proposed Project will significantly improve the ability of the Electric Transmission (Grid) Operations to schedule outages for maintenance purposes not only at Talega Substation but also for neighboring substations at San Mateo, Rancho Mission Viejo, Pico, and Trabuco. This improved transmission operational flexibility is the result of two 230 kV transmission lines serving San Juan Capistrano and Talega Substations and two 230/138 kV sources serving the South Orange County 138 kV network as proposed by SDG&E.

The modernized 138 kV bus at the new San Juan Capistrano Substation will improve operational flexibility with its breaker and a half design and increased positions to allow for the feed of the new 230 kV source and three additional 138 kV transmission lines. This increased operational flexibility will also allow SDG&E's Grid Operations to utilize the 138 kV system more efficiently and reliably in normal operations and in programming routine maintenance. The additional distribution capacity of the San Juan Capistrano Substation will improve distribution reliability by providing tie capacity to neighboring substations. This improved reliability and operational flexibility comes from allowing existing cicuits to be more fully utilized and allow for new 12 kV circuits to be added at San Juan Capistrano Substation.

Section 7. The Project Increases the Load Serving Capability of the South Orange County System to Meet Customer Load Growth (Witness John Jontry)

The South Orange County is an area in SDG&E's service territory experiencing continuing load growth – it is expected to increase 13% over the next ten years. To provide efficient and effective service in the South Orange County area, SDG&E must locate the proposed facilities (a new 230/138 kV substation and associated 230 kV transmission lines) within the transmission load center. Capistrano Substation is in very close in proximity to the electrical center of South Orange County's transmission load. Approximately 81 percent of the load served by South Orange County 138 kV transmission network is within four miles of the Capistrano Substation. By utilizing the Capistrano Substation location and its proximity to the transmission load center, efficiencies will be obtained by reducing transmission line losses and allow for more effective service. The rebuilding of Capistrano Substation will also allow for increased capacity to more effectively serve the customer load surrounding Capistrano Substation and support neighboring substations.

Section 8. A Transmission Project Is The Best Alternative To Address The Reliability Deficit In South Orange County (Witness: John Jontry)

Public Utilities Code Section 1002.3 provides: "In considering an application for a certificate for an electric transmission facility pursuant to Section 1001, the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation, as defined in Section 353.2, and other demand reduction resources."

SDG&E's Proposed Project addresses the potential loss of all power to SDG&E's South Orange County system and the over 300,000 people it serves as the result of a Category D event, or a forced outage during a maintenance event, at Talega Substation. Energy efficiency, demand response programs, and distributed generation cannot solve these reliability concerns and thus are not feasible alternatives to the Proposed Project. Energy efficiency and demand response programs can slow demand growth and can reduce local load levels in emergencies, but these programs cannot mitigate the potential loss of all power to SDG&E's South Orange County customers if either the 230 kV service or 138 kV service at Talega Substation are out of service.

Similarly, distributed generation is not a feasible alternative to the Proposed Project. First, even homes and businesses with solar panels are unlikely to have power during an outage on SDG&E's South Orange County system. Absent a specially customized system, inverters that serve solar and battery systems are designed to disconnect when they detect loss of service from the utility, and do not reconnect until they detect 60 seconds or more of stable electric service on the utility side of the inverter. This is a safety requirement. Second, even if some residents or businesses have such customized systems, they must disconnect from the grid to draw power from their batteries and thus cannot supply electricity to any other customers in the area. Higher levels of energy efficiency and distributed generation can, at times, reduce load on SDG&E's system, thus potentially making Category C outages less likely to trigger load shedding. However, as discussed in Chapter 4, Section 3, SDG&E's local area forecasts already account for anticipated levels of energy efficiency and distributed generation. Further, distributed solar generation does not provide electricity to the grid when the sun is not shining on the solar panels.

The need to rebuild Capistrano Substation exists regardless of any energy efficiency, demand response programs or distributed generation.

STATEMENT OF QUALIFICATIONS

- KARL ILIEV, PE

My name is Karl Iliev and my business address is 8316 Century Park Court, San Diego, California 92123. I am the System Protection & Control Engineering Manager in the Electric Transmission & Distribution Engineering Department of San Diego Gas & Electric (SDG&E). My section's primary responsibities are to provide protective relay and control schemes, settings, and communication systems for a safe and reliable grid, including providing technical support, scoping advice, and review of substation electrical designs.

I began work at SDG&E in June 1999 as an Engineering Intern and have held positions around the company on both transmission and distribution sides ranging from planning to engineering to construction and operations. Since 2003, I've held positions of increasing responsibility related to substation design and construction including work in System Protection Engineering & Maintenance, Substation Construction & Maintenance, and Substation Engineering & Design. I was the Substation Engineering & Design Manager for over 4 years from 2009 into 2014 where my responsibities included cost estimatation, design specifications and scoping, material procurement, apparatus assessment, engineering review, substation drawing management, construction support, and real-time operational involvement for all of SDG&E's substations and substation related capital projects.

Immediately prior to obtaining full time employment with SDG&E in 2001, I graduated California State University of Sacramento with a Bachelor of Science in Electrical and Electronic Engineering with a concentration in Power Systems and a minor in Physics. In 2004, I earned my license as a Professional Engineer in the State of California.

I have previously testified before this Commission.

- **JOHN M. JONTRY**

My name is John M. Jontry. My business address is 8330 Century Park Court, San Diego, California, 92123. I am employed by San Diego Gas & Electric Company (SDG&E) as Transmission Planning Manager. I have been employed by SDG&E since 2005. For the past five years I have managed the Grid Planning group within the Transmission Planning department, with the primary responsibility of overseeing the annual grid reliability studies and the planning studies for major special projects such as the South Orange Country Reliability Enhancement project (SOCRE). Prior to working for SDG&E, I worked for electric utilities in Texas and Illinois and for the Midwest Independent System Operator (MISO) in Indiana in various engineering and operational roles for approximately fifteen years. I hold a bachelor's degree in Electrical Engineering from the University of Illinois and a master's degree in Industrial Technology from Eastern Illinois University. I am a Registered Professional Engineer in the states of Illinois and Texas.

I have previously testified before this Commission.

- **CORY SMITH**

My name is Cory Smith and my business address is 8330 Century Park Court, San Diego, California 92123. I am employed as a Principal Engineer in the Transmission Planning Department of San Diego Gas & Electric where I have worked since 2008. My duties include assessing SDG&E's transmission system for compliance with NERC Transmission Planning Standards and creating technical models of SDG&E's high voltage transmission system to assess transmission system performance.

Prior to joining SDG&E, I was employed by Northeast Utilities in Berlin, Connecticut as a Senior Engineer. My duties included the creation of technical models and the application of specialized software to assess the reliability performance of the high voltage transmission system owned by Northeast Utilities. Before my employment with Northeast Utilities I was employed as an Engineer by the New York Independent System Operator in Schenectady, New York. My duties included reliability assessments of the high voltage transmission system serving the State of New York.

I received my Bachelor of Science degree in Electrical Engineering from Arizona State University in 1989, my Master of Engineering degree in Electric Power Engineering from Rensselaer Polytechnic Institute in 1994 and my Master of Business Administration degree from The College of Saint Rose in 2003. In addition, I am a Registered Professional Engineer in the states of California and New York.

Attachment 1

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-0b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

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 (non-recallable 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.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

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 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).

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.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

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.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

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.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

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:

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 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.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0a	July 30, 2008	Adopted by NERC Board of Trustees	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Interpretation
0b	September 15, 2011	FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)	Interpretation

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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 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).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

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.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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 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).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

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.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
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 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). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TPL-002-0b — System Performance Following Loss of a Single Bulk Electric System Element (Category B)

United States

Standard	Requirement	Enforcement Date	Inactive Date
TPL-002-0b	All	10/24/2011	12/31/2014

Attachment 2

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 23, 2010

B. Requirements

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 (non-recallable 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.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

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 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).

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.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

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.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

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.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

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:

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.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation
0b	February 7, 2013	Interpretation adopted by NERC Board of Trustees	
0b	June 20, 2013	FERC order issued approving Interpretation	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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 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).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

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.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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 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).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

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.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee	
Date submitted:	December 12, 2011
The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.37 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).	
Standard	Requirement (and text)
TPL-003-0a	**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.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**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.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.
Please explain the clarification needed (as submitted).	
This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning	

clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system

[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)
[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.
[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."

response.

Question 2: For the phrase "Delayed Clearing[5]" used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase "Delayed Clearing" used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term "Delayed Fault Clearing." While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to "stuck breaker" or "protection system failure" contingency assessments.

Question 1

For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[9] of either "stuck breaker" or "protection system failure" contingency[10], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

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[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[8] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"
[9] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.
[10] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3ø) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase "(stuck breaker or protection system failure)." Footnote (e) explains that "Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay." The parenthetical further emphasizes that the failure may be a "stuck breaker or protection system failure" that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions "(stuck breaker or protection system failure)" must be considered.

Question 2

For the phrase "Delayed Clearing[11]" used in Category C[12] contingencies 6-9 and Category D[13] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[14] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term "Delayed Clearing" that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system's normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full

[11] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[12] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[13] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[14] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example "…any protection system component such as, relay, circuit breaker, or current transformer..." because the component "circuit breaker" is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of "protection system" inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team's further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, "Protection System," the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TPL-003-0b — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)

United States

Standard	Requirement	Enforcement Date	Inactive Date
TPL-003-0b	All	06/20/2013	12/31/2014

Attachment 3

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number:** TPL-004-0a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

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.

R1.2. Be conducted for near-term (years one through five).

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).

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.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

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.

R1.4. Consider all contingencies applicable to Category D.

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.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	February 7, 2013	Interpretation adopted by NERC Board of Trustees	

0a	June 20, 2013	Interpretation approved in FERC order	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee	
Date submitted:	December 12, 2011
The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.37 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).	
Standard	Requirement (and text)
TPL-003-0a	**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.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**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.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.
Please explain the clarification needed (as submitted).	
This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.	

More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

Question 2: For the phrase "Delayed Clearing[5]" used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to

[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)
[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.
[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."
[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase "Delayed Clearing" used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term "Delayed Fault Clearing." While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to "stuck breaker" or "protection system failure" contingency assessments.

Question 1

For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[9] of either "stuck breaker" or "protection system failure" contingency[10], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted

[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[8] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"
[9] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.
[10] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3ø) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase "(stuck breaker or protection system failure)." Footnote (e) explains that "Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay." The parenthetical further emphasizes that the failure may be a "stuck breaker or protection system failure" that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions "(stuck breaker or protection system failure)" must be considered.

Question 2

For the phrase "Delayed Clearing[11]" used in Category C[12] contingencies 6-9 and Category D[13] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[14] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term "Delayed Clearing" that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system's normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example "…any protection system component such as, relay, circuit breaker, or current transformer..." because the component "circuit breaker" is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of "protection system" inferred the

[11] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[12] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[13] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[14] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

NERC glossary term and the components described therein; however, based on the interpretation drafting team's further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, "Protection System," the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TPL-004-0a — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

United States

Standard	Requirement	Enforcement Date	Inactive Date
TPL-004-0a	All	06/20/2013	12/31/2015

Attachment 4

California ISO
Planning Standards

Effective September 18, 2014 to March 30, 2015

Table of Contents

I. Introduction

The California ISO (ISO) tariff provides for the establishment of planning guidelines and standards above those established by NERC and WECC to ensure the secure and reliable operation of the ISO controlled grid. The primary guiding principle of these Planning Standards is to develop consistent reliability standards for the ISO grid that will maintain or improve transmission system reliability to a level appropriate for the California system.

These ISO Planning Standards are not intended to duplicate the NERC and WECC reliability standards, but to complement them where it is in the best interests of the security and reliability of the ISO controlled grid. The ISO planning standards will be revised from time to time to ensure they are consistent with the current state of the electrical industry and in conformance with NERC Reliability Standards and WECC Regional Criteria. In particular, the ISO planning standards:

- Address specifics not covered in the NERC Reliability Standards and WECC Regional Criteria;
- Provide interpretations of the NERC Reliability Standards and WECC Regional Criteria specific to the ISO Grid;
- Identify whether specific criteria should be adopted that are more stringent than the NERC Reliability Standards and WECC Regional Criteria where it is in the best interest of ensuring the ISO controlled grid remains secure and reliable.

NERC Reliability Standards and WECC Regional Criteria:

The following links provide the minimum standards that ISO needs to follow in its planning process unless NERC or WECC formally grants an exemption or deference to the ISO. They are the NERC Transmission Planning (TPL) standards, other applicable NERC standards (i.e., NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant), and the WECC Regional Criteria:

http://www.nerc.com/page.php?cid=2|20

http://www.wecc.biz/library/Documentation%20Categorization%20Files/Forms/AllItems.aspx?RootFolder=%2flibrary%2fDocumentation%20Categorization%20Files%2fRegional%20Criteria&FolderCTID=&View=%7bAD6002B2%2d0E39%2d48DD%2dB4B5%2d9AFC9F8A8DB3%7d

Section II of this document provides additional details about the ISO Planning Standards. Guidelines are provided in subsequent sections to address certain ISO planning standards, such as the use of new Special Protection Systems, which are not specifically addressed at the regional level of NERC and WECC. Where appropriate, background information behind the development of these standards and references (web links) to subjects associated with reliable transmission planning and operation are provided.

II. ISO Planning Standards

The ISO Planning Standards are:

1. Applicability of NERC Reliability Standards to Low Voltage Facilities under ISO Operational Control

The ISO will apply NERC Transmission Planning (TPL) standards, the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant, and the approved WECC Regional Criteria to facilities with voltages levels less than 100 kV or otherwise not covered under the NERC Bulk Electric System definition that have been turned over to the ISO operational control.

2. Combined Line and Generator Outage Standard

A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002). Supporting information is located within Section IV of this document.

3. Voltage Standard

Standardization of low and high voltage levels as well as voltage deviations across the TPL-001, TPL-002, and TPL-003 standards is required across all transmission elements in the ISO controlled grid. The low voltage and voltage deviation guideline applies only to load and generating buses within the ISO controlled grid (including generator auxiliary load) since they are impacted by the magnitude of low voltage and voltage deviations. The high voltage standard applies to all buses since unacceptable high voltages can damage station and transmission equipment. These voltage standards are shown in Table 1.

All buses within the ISO controlled grid that cannot meet the requirements specified in Table 1 will require further investigation. Exceptions to this voltage standard may be granted by the ISO based on documented evidence vetted through an open stakeholder process. The ISO will make public all exceptions through its website.

Table 1
(Voltages are relative to the nominal voltage of the system studied)

Voltage level	Normal Conditions (TPL-001)		Contingency Conditions (TPL-002 & TPL-003)		Voltage Deviation	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	TPL-002	TPL-003
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05	0.90	1.1	≤5%	≤10%

Voltage and system performance must also meet WECC Regional Criteria TPL-001-WECC-CRT-2.1: http://www.wecc.biz/library/Documentation%20Categorization%20Files/Regional%20Criteria/TPL-001-WECC-CRT-2.1.pdf

The bus voltage at the San Onofre Switchyard must be maintained within established limits as determined by transmission entities (Southern California Edison and San Diego Gas & Electric) through grid operations procedures.

4. Specific Nuclear Unit Standards

The criteria pertaining to the Diablo Canyon Power Plant (DCPP), as specified in the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for DCPP, and Appendix E of the Transmission Control Agreement located on the ISO web site at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=3972DF1A-2A18-4104-825C-E24350BA838F

5. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

A single module of a combined cycle power plant is considered a single contingency (G-1) and shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002). Supporting information is located in Section V of this document. Furthermore a single transmission circuit outage with one combined cycle module already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002) as established in item 1 above.

A re-categorization of any combined cycle facility that falls under this standard to a less stringent requirement is allowed if the operating performance of the combined cycle facility demonstrates a re-categorization is warranted. The ISO will assess re-categorization on a case by case based on the following:

a) Due to high historical outage rates in the first few years of operation no exceptions will be given for the first two years of operation of a new combined cycle module.

b) After two years, an exception can be given upon request if historical data proves that no outage of the combined cycle module was encountered since start-up.

c) After three years, an exception can be given upon request if historical data proves that outage frequency is less than once in three years.

The ISO may withdraw the re-categorization if the operating performance of the combined cycle facility demonstrates that the combined cycle module exceeds a failure rate of once in three year. The ISO will make public all exceptions through its website.

6. Planning for New Transmission versus Involuntary Load Interruption Standard

This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements. It does not address all circumstances under which load dropping is permitted under NERC and WECC planning standards.

1. No single contingency (TPL002 and ISO standard [G-1] [L-1]) should result in loss of more than 250 MW of load. This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to position the electric system for reliable operation in anticipation of the next worst contingency.
2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines “closed in” during normal operation.
3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more constraining.
4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure, through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

7. Planning for High Density Urban Load Area Standard

7.1 Local Area Planning

A local area is characterized by relatively small geographical size, with limited transmission import capability and most often with scarce resources that usually can be procured at somewhat higher prices than system resources.[1] The local areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local generation and transmission capacity. Increased reliance on load shedding to meet these needs would run counter to historical and current practices, resulting in general deterioration of service levels.

For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL002 and TPL003 standards and impacts on the 115 kV or higher voltage systems.

- In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.
- In considering if load shedding, where allowed by NERC standards, is a viable mitigation in either the near-term, or the long-term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, number of customers impacted by the outage, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

7.2 System Wide Planning

System planning is characterized by much broader geographical size, with greater transmission import capability and most often with plentiful resources that usually can be procured at somewhat lower prices than local area resources. Due to this fact more resources are available and are easier to find, procure and dispatch. Provided it is allowed under NERC reliability standards, the ISO will allow non-consequential load dropping system-wide SPS schemes that include some non-consequential load dropping to mitigate NERC TPL002 and TPL003 standards and impacts on the 115 kV or higher voltage systems.

[1] A "local area" for purposes of this Planning Standard is not necessarily the same as a Local Capacity Area as defined in the CAISO Tariff.

8. Extreme Event Reliability Standard

The requirements of NERC TPL004 require Extreme Event contingencies to be assessed; however the standard does not require mitigation plans to be developed for these Extreme Events. The ISO has identified in Section 7.1 below that the San Francisco Peninsula area has unique characteristics requiring consideration of corrective action plans to mitigate the risk of extreme events. Other areas of the system may also be considered on a case-by-case basis as a part of the transmission planning assessments.

8.1 San Francisco-Peninsula - Extreme Event Reliability Standard

The ISO has determined through its Extreme Event assessments, conducted as a part of the annual transmission planning process, that there are unique characteristics of the San Francisco Peninsula area requiring consideration for mitigation as follows.

- high density urban load area,
- geographic and system configuration,
- potential risks of outages including seismic, third party action and collocating facilities; and
- challenging restoration times.

The unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages that are beyond the application of mitigation of extreme events in the reliability standards to the rest of the ISO controlled grid. The ISO will consider the overall impact of the mitigation on the identified risk and the associated benefits that the mitigation provides to the San Francisco Peninsula area.

III. ISO Planning Guidelines

The ISO Planning Guidelines include the following:

1. Special Protection Systems

As stated in the NERC glossary, a Special Protection System (SPS) is “an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition of faulted components to maintain system reliability.” In the context of new projects, the possible action of an SPS would be to detect a transmission outage (either a single contingency or credible multiple contingencies) or an overloaded transmission facility and then curtail generation output and/or load in order to avoid potentially overloading facilities or prevent the situation of not meeting other system performance criteria. A SPS can also have different functions such as executing plant generation reduction requested by other SPS; detecting unit outages and transmitting commands to other locations for specific action to be taken; forced excitation pulsing; capacitor and reactor switching; out-of-step tripping; and load dropping among other things.

The primary reasons why SPS might be selected over building new transmission facilities are that SPS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, SPS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, SPS is a commonly considered alternative to building new infrastructure in an effort to keep costs down when integrating new generation into the grid and/or addressing reliability concerns under multiple contingency conditions. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability. These reliability concerns necessarily dictate that guidelines be established to ensure that performance of all SPSs are consistent across the ISO controlled grid. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of existing transmission facilities while maintaining system reliability and optimizing operability of the ISO controlled grid. Needless to say, with the large number of generator interconnections that are occurring on the ISO controlled grid, the need for these guidelines has become more critical.

It needs to be emphasized that these are guidelines rather than standards and should be used in the development of any new SPS. In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies). This is to emphasize that best engineering practice and judgment will need to be exercised by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of SPS in all potential applications.

ISO SPS1

The overall reliability of the system should not be degraded after the combined addition of the SPS.

ISO SPS2

The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. In situations where the design of the SPS requires WECC approval, the WECC Remedial Action Scheme Design Guide will be followed.

ISO SPS3

The total net amount of generation tripped by a SPS for a single contingency cannot exceed the ISO's largest single generation contingency (currently one Diablo Canyon unit at 1150 MW). The total net amount of generation tripped by a SPS for a double contingency cannot exceed 1400 MW. This amount is related to the minimum amount of spinning reserves that the ISO has historically been required to carry. The quantities of generation specified in this standard represent the current upper limits for generation tripping. These quantities will be reviewed periodically and revised as needed. In addition, the actual amount of generation that can be tripped is project specific and may depend on specific system performance issues to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts provided in this guide. The net amount of generation is the gross plant output less the plant's and other auxiliary load tripped by the same SPS.

ISO SPS4

For SPSs, the following consequences are unacceptable should the SPS fail to operate correctly:

A) Cascading outages beyond the outage of the facility that the SPS is intended to protect: For example, if a SPS were to fail to operate as designed for a single contingency and the transmission line that the SPS was intended to protect were to trip on overload protection, then the subsequent loss of additional facilities due to overloads or system stability would not be an acceptable consequence.

B) Voltage instability, transient instability, or small signal instability: While these are rare concerns associated with the addition of new generation, the consequences can be so severe that they are deemed to be unacceptable results following SPS failure.

ISO SPS5

Close coordination of SPS is required to eliminate cascading events. All SPS in a local area (such as SDG&E, Fresno, etc.) and grid-wide need to be evaluated as a whole and studied as such.

ISO SPS6

The SPS must be simple and manageable. As a general guideline:

A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS.

B) The SPS should not be monitoring more than 4 system elements or variables. A variable can be a combination of related elements, such as a path flow, if it is used as a single variable in the logic equation. Exceptions include:

   i. The number of elements or variables being monitored may be increased if it results in the elimination of unnecessary actions, for example: generation tripping, line sectionalizing or load shedding.

ii. If the new SPS is part of an existing SPS that is triggered by more than 4 local contingencies or that monitors more than 4 system elements or variables, then the new generation cannot materially increase the complexity of the existing SPS scheme. However, additions to an existing SPS using a modular design should be considered as preferable to the addition of a new SPS that deals with the same contingencies covered by an existing SPS.

C) Generally, the SPS should only monitor facilities that are connected to the plant or to the first point of interconnection with the grid. Monitoring remote facilities may add substantial complexity to system operation and should be avoided.

D) An SPS should not require real-time operator actions to arm or disarm the SPS or change its set points.

ISO SPS7

If the SPS is designed for new generation interconnection, the SPS may not include the involuntary interruption of load. Voluntary interruption of load paid for by the generator is acceptable. The exception is that the new generator can be added to an existing SPS that includes involuntary load tripping. However, the amount of involuntary load tripped by the combined SPS may not be increased as a result of the addition of the generator.

ISO SPS8

Action of the SPS shall limit the post-disturbance loadings and voltages on the system to be within all applicable ratings and shall ultimately bring the system to within the long-term (4 hour or longer) emergency ratings of the transmission equipment. For example, the operation of SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back additional generation (or trip load if not already addressed under ISO SPS7 above) to bring the line loading within the line's four-hour or longer rating. This is intended to minimize real-time operator intervention.

ISO SPS9

The SPS needs to be agreed upon by the ISO and may need to be approved by the WECC Remedial Action Scheme Reliability Task Force.

ISO SPS10

The ISO, in coordination with affected parties, may relax SPS requirements as a temporary "bridge" to system reinforcements. Normally this "bridging" period would be limited to the time it takes to implement a specified alternative solution. An example of a relaxation of SPS requirement would be to allow 8 initiating events rather than limiting the SPS to 6 initiating events until the identified system reinforcements are placed into service.

ISO SPS11

The ISO will consider the expected frequency of operation in its review of SPS proposals.

ISO SPS12
The actual performance of existing and new SPS schemes will be documented by the transmission owners and periodically reviewed by the ISO and other interested parties so that poorly performing schemes may be identified and revised.

ISO SPS13
All SPS schemes will be documented by the owner of the transmission system where the SPS exists. The generation owner, the transmission owner, and the ISO shall retain copies of this documentation.

ISO SPS14
To ensure that the ISO's transmission planning process consistently reflects the utilization of SPS in its annual plan, the ISO will maintain documentation of all SPS utilized to meet its reliability obligations under the NERC reliability standards, WECC regional criteria, and ISO planning standards.

ISO SPS15
The transmission owner in whose territory the SPS is installed will, in coordination with affected parties, be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO SPS16 Generally, the SPS should trip load and/or resources that have the highest effectiveness factors to the constraints that need mitigation such that the magnitude of load and/or resources to be tripped is minimized. As a matter of principle, voluntary load tripping and other pre-determined mitigations should be implemented before involuntary load tripping is utilized.

ISO SPS17
Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO is required unless otherwise deemed unnecessary by the ISO. Specific telemetry requirements will be determined by the Transmission Owner and the ISO on a project specific basis.

IV. Combined Line and Generator Unit Outage Standards Supporting Information

Combined Line and Generator Outage Standard - A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002).

The ISO Planning Standards require that system performance for an over-lapping outage of a generator unit (G-1) and transmission line (L-1) must meet the same system performance level defined for the NERC standard TPL-002. The ISO recognizes that this planning standard is more stringent than allowed by NERC, but it is considered appropriate for assessing the reliability of the ISO's controlled grid as it remains consistent with the standard utilized by the PTOs prior to creation of the ISO.

V. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard Supporting Information

Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard - A single module of a combined cycle power plant is considered a single (G-1) contingency and shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002).

The purpose of this standard is to require that an outage of any turbine element of a combustion turbine be considered as a single outage of the entire plant and therefore must meet the same performance level as the NERC TPL standard TPL-002.

The ISO has determined that, a combined cycle module should be treated as a single contingency. In making this determination, the ISO reviewed the actual operating experience to date with similar (but not identical) combined cycle units currently in operation in California. The ISO's determination is based in large part on the performance history of new combined cycle units and experience to date with these units. The number of combined cycle facility forced outages that have taken place does not support a double contingency categorization for combined cycle module units in general. It should be noted that all of the combined cycle units that are online today are treated as single contingencies.

Immediately after the first few combined cycle modules became operational, the ISO undertook a review of their performance. In defining the appropriate categorization for combined cycle modules, the ISO reviewed the forced outage history for the following three combined cycle facilities in California: Los Medanos Energy Center (Los Medanos), Delta Energy Center (Delta), and Sutter Energy Center (Sutter)[2]. Los Medanos and Sutter have been in service since the summer of 2001, Delta has only been operational since early summer 2002.

Table 2 below sets forth the facility forced outages for each of these facilities after they went into operation (i.e. forced outages [3]that resulted in an output of zero MWs.) The table demonstrates that facility forced outages have significantly exceeded once every 3 to 30 years. Moreover**,** the ISO considers that the level of facility forced outages is

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[2] Los Medanos and Sutter have two combustion turbines (CT's) and one steam turbine (ST) each in a 2x1 configuration. Delta has three combustion turbines (CT's) and one steam turbine (ST) in a 3x1 configuration. All three are owned by the Calpine Corporation.

[3] Only forced outages due to failure at the power plant itself are reported, forced outages due to failure on the transmission system/switchyard are excluded. The fact that a facility experienced a forced outage on a particular day is public information. In fact, information on unavailable generating units has been posted daily on the ISO website since January 1, 2001. However, the ISO treats information regarding the cause of an outage as confidential information.

significantly above the once every 3 to 30 years even accounting for the fact that new combined cycle facilities tend to be less reliable during start-up periods and during the initial weeks of operation. For example, four of the forced outages that caused all the three units at Los Medanos to go off-line took place more than nine months after the facility went into operation.

Facility	Date	# units lost
Sutter[4]	08/17/01	No visibility
Sutter	10/08/01	1 CT
Sutter	12/29/01	All 3
Sutter	04/15/02	1 CT + ST
Sutter	05/28/02	1 CT
Sutter	09/06/02	All 3
Los Medanos[5]	10/04/01	All 3
Los Medanos	06/05/02	All 3
Los Medanos	06/17/02	All 3
Los Medanos	06/23/02	1CT+ST
Los Medanos	07/19/02	All 3
Los Medanos	07/23/02	1CT+ST
Los Medanos	09/12/02	All 3
Delta[6]	06/23/02	All 4
Delta	06/29/02	2 CT's + ST
Delta	08/07/02	2 CT's + ST

Table 2: Forced outages that have resulted in 0 MW output from Sutter, Los Medanos and Delta after they became operational

The ISO realizes that this data is very limited. Nevertheless, the data adequately justifies the current classification of each module of these three power plants as a single contingency.

VI. Background behind Planning for New Transmission versus Involuntary Load Interruption Standard

For practical and economic reasons, all electric transmission systems are planned to allow for some involuntary loss of firm load under certain contingency conditions. For some systems, such a loss of load may require several contingencies to occur while for other systems, loss of load may occur in the event of a specific single contingency. Historically, a wide variation among the PTOs has existed predominantly due to slightly differing planning and design philosophies. This standard is intended to provide a

[4] Data for Sutter is recorded from 07/03/01 to 08/10/02
[5] Data for Los Medanos is recorded from 08/23/01 to 08/10/02
[6] Data for Delta is recorded from 06/17/02 to 08/10/02

consistent framework upon which involuntary load interruption decisions can be made by the ISO when planning infrastructure needs for the ISO controlled grid.

The overarching requirement is that implementation of these standards should not result in lower levels of reliability to end-use customers than existed prior to restructuring. As such, the following is required:

1. No single contingency (TPL002 and ISO standard [G-1] [L-1]) may result in loss of more than 250 MW of load. This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to protect for the next worst single contingency.

   This standard is intended to coordinate ISO planning standards with the WECC requirement that all transmission outages with at least 300 MW or more be directly reported to WECC. It is the ISO's intent that no single contingency (TPL002 and ISO standard [G-1] [L-1]) should trigger loss of 300 MW or more of load. The 250 MW level is chosen in order to allow for differences between the load forecast and actual real time load that can be higher in some instances than the forecast and to also allow time for transmission projects to become operational since some require 5-6 years of planning and permitting with inherent delays. It is also ISO's intent to put a cap on the footnote to the NERC TPL-002 that may allow radial and/or non-consequential loss of load for single contingencies.

2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines "closed in" during normal operation.

   This standard is intended to bring consistency between the PTOs' substation designs. It is not the ISO's intention to disallow substations with load below 100 MW from having looped connections; however it is ISO's intention that all substations with peak load above 100 MW must be connected through a looped configuration to the grid.

3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more stringent.

   This standard is intended to insure that the system is maintained at the level that existed prior to restructuring. It is obvious that as load grows, existing back-ties for radial loads (or remaining feed after a single contingency for looped substations) may not be able to pick up the entire load; therefore the reliability to customers connected to this system may deteriorate over time. It is the ISO's intention to establish a minimum level of back-up tie capability that needs to be maintained.

4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure through a benefit

to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

It is ISO's intention to allow the build-up of transmission projects that are proven to have a positive benefit to ratepayers by reducing load drop exposure.

Information Required for BCR calculation: For each of the outages that required involuntary interruption of load, the following should be estimated:

- The maximum amount of load that would need to be interrupted.
- The duration of the interruption.
- The annual energy that would not be served or delivered.
- The number of interruptions per year.
- The time of occurrence of the interruption (e.g., week day summer afternoon).
- The number of customers that would be interrupted.
- The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural).
- Value of service or performance-based ratemaking assumptions concerning the dollar impact of a load interruption.

The above information will be documented in the ISO Transmission Plan for areas where additional transmission reinforcement is needed or justified through benefit to cost ratio determination.

VII. Background behind Planning for High Density Urban Load Area Standard for Local Areas

A local area is characterized by relatively small geographical size, with limited transmission import capability and most often with scarce resources that usually can be procured at somewhat higher prices than system resources. These areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local resource and transmission capacity. The need for system reinforcement in a number of local areas is expected to climb due to projected resource retirements, with single and double contingency conditions playing a material role in driving the need for reinforcement. Relying on load shedding on a broad basis to meet these emerging needs would run counter to historical and current practices, resulting in general deterioration of service levels. One of the fundamental ISO Tariff requirements is to maintain service reliability at pre-ISO levels, and it drives the need to codify the circumstances in which load shedding is not an acceptable long-term solution:

1. For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local

resource capability to mitigate NERC TPL002 and TPL003 standards and impacts on the 115 kV or higher voltage systems.

This standard is intended to continue avoiding the need to drop load in high density urban load areas due to, among other reasons, high impacts to the community from hospitals and elevators to traffic lights and potential crime.

The following is a link to the 2010 Census Urban Area Reference Maps:

http://www.census.gov/geo/maps-data/maps/2010ua.html

This site has diagrams of the following urbanized areas which contain over one million persons.

Los Angeles--Long Beach--Anaheim, CA
San Francisco--Oakland, CA
San Diego, CA
Riverside--San Bernardino, CA
San Jose, CA

2. In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.

   This standard is intended to insure that a reliable transition exists between the time when problems could arise until long-term transmission upgrades are placed in service.

3. In considering if load shedding, where allowed by NERC standards, is a viable mitigation in either the near-term, or the long-term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

   It is ISO’s intention to thoroughly evaluate the risk of outages and their consequences any time a load shedding SPS is proposed regardless of population density.

VIII. Interpretations of terms from NERC Reliability Standard and WECC Regional Criteria

Listed below are several ISO interpretations of the terms that are used in the NERC standards that are not already addressed by NERC.

Combined Cycle Power Plant Module: A **combined cycle** is an assembly of heat engines that work in tandem off the same source of heat, converting it into mechanical energy, which in turn usually drives electrical generators. In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, one or more gas turbine generator(s) generates electricity and heat in the exhaust is used to make steam, which in turn drives a steam turbine to generate additional electricity.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTO and the ISO subject to appropriate coordination and review with the relevant local, state, regional and federal regulatory authorities.

Entity Required to Develop Load Models: The PTOs, in coordination with the utility distribution companies (UDCs) and others, develop load models.

Entity Required to Develop Load Forecast: The California Energy Commission (CEC) has the main responsibility for providing load forecast. If load forecast is not provided by the CEC or is not detailed and/or specific enough for a certain study then the ISO, at its sole discretion, may use load forecasts developed by the PTOs in coordination with the UDCs and others.

High Density Urban Load Area: Is an Urbanized Area, as defined by the US Census Bureau[7] with a population over one million persons.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. For studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level. The more stringent requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. Having a more stringent standard for local areas will help minimize the potential for interruption of end-use customers.

[7] Urbanized Area (UA): A statistical geographic entity consisting of a densely settled core created from census tracts or blocks and contiguous qualifying territory that together have a minimum population of at least 50,000 persons.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified and corresponding operating procedures are in place when required.

Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

Attachment 5

Table of Contents

Purpose

The NERC FAC-011-2 Standard requires that the Reliability Coordinator have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator area. This document provides implementation details on how the California ISO applies the Peak[1] Reliability SOL Methodology to the California ISO-Controlled Grid to meet NERC FAC-014-2 R2 in establishing SOLs for the Operations Horizon. The Operations Horizon is defined as a rolling 12-month period starting at Real-time (now) through the last hour of the twelfth month into the future, including the following Sub-horizons: Seasonal, Outage Planning, Next-day, Same-day, and Real-time.

1. Responsibilities

ISO System Operators	Hold authority, as delegated by the executive officers of the ISO, to take or direct timely and appropriate Real-Time actions necessary to ensure reliable operation of the ISO Controlled Grid, up to and including shedding Firm Load to prevent or alleviate System Operating Limit or Interconnection Reliability Operating Limit exceedance and comply with NERC and WECC Standards and follow the reliability criteria and guidelines in this procedure.
ISO Operations Engineers	Follow the reliability criteria and guidelines in this procedure when performing engineering studies and establishing System Operating Limits (SOLs) during all Operations Horizons, including Seasonal, Outage Planning, Next-day, Same-day, and Real-time.

[1] Peak Reliability is an independent corporation, separated from Western Electricity Coordinating Council – WECC, designated as the Reliability Coordinator of the Western Interconnection, starting from January 1st, 2014.

2. Scope/Applicability

2.1 Background

Applicable Reliability Standards

This implementation document is based on the North American Electric Reliability Corporation (NERC) Reliability Standards FAC-014 R2 and is in accordance with the Peak Reliability Coordinator's System Operating Limits (SOL) Methodology for the Operations Horizon.

2.2 Scope/Applicability

Applicability to California ISO

This SOL implementation document is applicable to the ISO-Controlled Grid in establishing System Operating Limits for the Operations Horizon.

SOLs and IROLs

All operating limits, including Facility Ratings[1] and WECC Path SOLs, are designated SOLs to the California ISO in the Operations Horizon. A subset of the SOLs which, if exceeded, could cause severe impacts on neighboring Balancing Authorities (BAs) and/or Transmission Operators (TOPs), will be coordinated with the RC to be considered as Interconnection Reliability Operating Limits (IROLs). These severe impacts include instability, uncontrolled separation, and cascading outages.

[1] As specified by the associated Participating Transmission Owners facility rating methodology.

3. Procedure Detail

3.1 Acceptable System Performance and Response

An SOL represents the value (such as MW, MVAr, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable operating criteria. These criteria include, but are not limited to, the following:

- Thermal limits are provided to the California ISO by the Participating Transmission Owners (PTOs)[1] and are documented in the ISO Transmission Register[2] or in PTO Operating Procedures provided to the ISO
  - In pre-contingency analysis, the California ISO utilizes continuous/normal ratings of the monitored elements in establishing SOLs
  - In post-contingency analysis, the California ISO utilizes short-term ratings of the monitored elements in establishing SOLs. If a short-term rating[3] is not available, the California ISO will utilize the normal/continuous rating.
- Transient stability limits are established as pre-contingency flow limits on paths, cut planes or interfaces to facilitate monitoring in both operational planning studies and real time operations. Paths, cut planes or interfaces should be clearly defined and the metering point should be identified.
- Voltage stability limits are established as pre-contingent flow limits on paths, cut planes or interfaces to facilitate monitoring in both operational planning studies and real time operations
- System voltage limits are provided to the California ISO by Participating Transmission Owners (PTOs) as listed in Appendix 3100B.

An Interconnection Reliability Operating Limit (IROL) is a System Operating Limit (SOL) that, if exceeded, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System (BES).

In accordance to the Reliability Standards Agreement, the Participating Transmission Owners, in coordination with the California ISO, calculates and establishes SOLs based on the most restrictive of the above four criteria as determined by pre-contingency analysis, single-contingency analysis, and credible multiple contingency analysis.

[1] Normal/Continuous and short-term rating provided by PTO may reflect limitation on the protection system in the equipment which could be more limiting than the actual thermal capability of the transmission line/transformer.
[2] The ISO Transmission Register (TR) is the official rating source for the ISO. Any modifications to existing ratings used for real time operations must be documented in the TR or a written PTO procedure.
[3] Including an associated duration applicable to the short-term rating.

3.1.1 Acceptable System Performance for Pre-Contingency State

In the pre-contingency state under conditions that reflect current or expected system conditions and system topology, all Facilities shall be within their continuous Facility Rating, thermal limits, pre-contingency voltage limits, transient stability limits, and voltage stability limits.

3.1.2 Acceptable System Performance and Response for Single Contingency

Following a single contingency, all Facilities shall be operating within their short term Facility Rating, thermal limits, post-contingency voltage limits, transient stability limits, and voltage stability limits. In addition, cascading outages or uncontrolled separation shall not occur.
A single contingency is defined as any of following:

- Single-line-to-ground or 3-phase fault (whichever is more severe), with normal clearing, on any faulted generator, line, transformer, or shunt device.
- Loss of any generator, line, transformer, or shunt device without a fault.
- Single pole block, with normal clearing, in a monopolar or bipolar high voltage direct current system.

Please note that a single contingency may impact one or more facilities due to system configuration or protection settings.

In determining the system's response to a single contingency, the following shall be acceptable:

- Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the faulted facility or by the affected area.
- Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies (e.g., load greater than studied).
- System reconfiguration through manual or automatic control or protection actions.

To prepare for the next single contingency, system adjustments may be made, including but not limited to changes to generation, uses of the transmission system, and the transmission system topology, as required.

3.1.3 Acceptable System Performance and Response for Credible Multiple Contingency

As required by the RC SOL Methodology for Operations Horizon, the California ISO, as the TOP, must determine which Multiple Contingencies, if any, in its TOP area are credible for operations horizon by working with the Planning Coordinator, TOs, Generator Owners (GOs), and Transmission Planner (TP), and referencing the applicable NERC/WECC standards (TPL-

003-0a, FAC-011-2, and TPL-001-WECC-RBP-2, etc.). The comprehensive list of credible multiple contingencies applicable to the California ISO are included in Appendix 3100B.

During the different Operations Sub-horizons (Seasonal, Outage Planning, Next-day, Same-day, and Real-time), the credibility of a Multiple Contingency could change. If the credibility of the Multiple Contingency is determined to be changing, such change shall be communicated in time with the RC and impacted TOPs to coordinate the required studies.

Following any of the credible multiple contingencies, the following may not occur: voltage instability, cascading outages or uncontrolled separation, and all Facilities shall be within their applicable short-term Facility Ratings and thermal limits, post-contingency voltage limits, and stability limits. Due to equipment outages, topology changes and other conditions for which the system was not designed, when studies indicate that the requirement that all facilities shall be within their applicable short-term Facility Ratings, and thermal limits and post-contingency voltage limits may not be met in the Outage Planning, Next-day, Same-day, or Real-time Sub-horizons, the California ISO shall coordinate with impacted TOPs and establish adequate plans, processes, and procedures to contain and mitigate the impacts.

In addition, the following system responses are acceptable:

- Depending on system design and expected system impacts, the following may be necessary to maintain the overall security of the interconnected transmission systems:
  - controlled interruption of electric supply to customers (load shedding)
  - planned removal from service of certain generators
  - curtailment of contracted firm (non-recallable reserved) electric power transfers
- Interruption of firm transfer, load or system reconfiguration is permitted through manual or automatic control or protection actions, including RAS/SPS.
- To prepare for the next contingency, system adjustments are permitted, including changes to generation, load and the transmission system topology when determining limits.

3.2 Study Model

The California ISO utilizes both the EMS model (which includes the WECC area's full loop model) and the approved WECC Regional Entity Operating Base Cases for establishing, calculating and monitoring SOLs/IROLs in the operations horizon. These cases are updated periodically to reflect expected system topology based on known and reported facility outages and upgrades.

The California ISO's EMS model contains detailed representations of all the California ISO controlled facilities, including sub-100 kV facilities, (with proper equivalence, e.g., some loads fed by radial lines are lumped at the delivery bus) and the representations of the WECC area's full loop model.

3.3 Reliability Criteria and Guidelines for Determining SOLs and IROLs

The following criteria and guidelines will be applied in determining SOLs and IROLs to ensure the acceptable system performance is maintained following single and credible multiple contingencies.

3.3.1 Determining Post-Contingency Steady State Limits

Following a single contingency, the flow on all facilities must be within their short-term facility ratings and thermal ratings, and post-contingency voltage limits. In addition, voltage instability, cascading outages, or uncontrolled separation must not occur. The thermal rating for post-contingency operation is defined as the short-term thermal rating (if a short-term rating is not available, the California ISO will utilize the normal/continuous rating).
For single and multiple credible contingencies, the following post-contingency voltage deviation guideline should be applied to identify contingencies for potential further evaluation:

- Voltage deviation threshold is 5% for a single contingency, and 10% for a credible multiple contingency.

The ISO engineers will work with PTO engineers to discuss further actions, if needed, about the contingencies causing voltage deviation beyond the above guideline.

In addition to the above voltage deviation guideline, post-contingency steady state voltage limits and guidelines in Appendix 3100B are applied.

In the post-contingency steady-state assessment, system reconfiguration through manual or automatic control or special protection scheme actions are allowed if it has been proven that these adjustments can be done in timely manner and will be sufficient to prevent the system from equipment damage, voltage collapse, cascading outages or uncontrolled separation. This includes automatic voltage regulators, automatic fast-switched shunt capacitors, and special protection scheme actions.

3.3.2 Determining Post-Transient and Voltage Stability Limits

The California ISO performs post-transient and voltage stability simulations for the areas and paths that have been known to have potential post-transient or voltage stability issues.

Following single or credible multiple contingencies, voltage instability, cascading outages and uncontrolled separation must not occur.

The following margins should be applied when setting voltage stability limited SOLs that are in proximity of power flow solution divergence:

- For the worst single contingency, a 5% MW margin from the last good power flow solution
- For the worst credible multiple contingency, a 2.5% MW margin from the last good power flow solution

If this voltage stability SOL qualifies as an IROL, the ISO will coordinate with the RC and impacted TOPs.

3.3.3 Determining Transient Stability Limits

The California ISO performs transient stability simulations for the areas and paths that have been known to have potential transient stability issue. Following single or credible multiple contingencies, transient instability, cascading outages and uncontrolled separation must not occur.

If transient instability, un-damped oscillation (if the transient oscillation cannot be positively damped within 30 seconds, it is deemed as un-damped oscillation[1]), cascading outages or uncontrolled separation is observed following a single or credible multiple contingency, a transient stability limited SOL should be established by using the following margin from the last acceptable transient simulation (meaning stable, damped oscillation, and no cascading and uncontrolled separation).

- For the worst single contingency, a 5% MW margin from the last acceptable transient simulation
- For the worst credible multiple contingency, a 2.5% MW margin from the last acceptable transient simulation
- The maximum margin is 200 MW

If this transient stability SOL qualifies as an IROL, the ISO will coordinate with the RC and impacted TOPs.

[1] This stipulation is not intended to require that transient stability simulations be run out to 30 seconds all the time in order to ensure the system is stable and positively damped. Shorter runs are permissible as long as the system can be demonstrated to be stable and positively damped in the simulation.

If the studies show that the instability is contained in a pre-defined local area, the ISO will coordinate with the impacted PTOs to determine if a transient stability SOL is needed, and to determine the SOL values and develop mitigation plans if a transient stability SOL is needed.

In addition, the following guidelines may be applied to identify contingencies for potential further evaluation:

- Transient voltage dip should not exceed 25% at load buses (including pump load) or 30% at non-load buses after fault clearing for a single contingency.
- Transient voltage dip should not exceed 20% for more than 20 cycles at load buses (including pump load) for a single contingency.
- Transient frequency should not fall below 59.6 Hz for more than 6 cycles at a load bus for a single contingency.
- Transient voltage dip should not exceed 30% at any buses after fault clearing for a credible multiple contingency.
- Transient voltage dip should not exceed 20% for more than 40 cycles at load buses (including pump load) for a credible multiple contingency.
- Transient frequency should not fall below 59.0 Hz for more than 6 cycles at a load bus following a credible multiple contingency.

In the transient stability assessment, only system reconfigurations through automatic, fast-switched shunt capacitors and special protection scheme actions are allowed. Other automatic actions may be included if the Transmission Owner provides documentation of the capability of the device to automatically react within the transient/dynamic window.

3.3.4 Determining SOLs Affecting Other TOPs

When an SOL is identified that would affect other and adjacent TOPs, the ISO will notify and coordinate with the impacted TOPs to determine SOL value and develop mitigation plans, processes, and procedures. If there is disagreement between the ISO and the impacted TOPs on the value of the SOL, the most conservative value shall be used until the issue is resolved.

3.3.5 Determining SOLs That Qualify as IROLs

When studies in the Operations Horizon indicate pre- or post-contingency instances of instability, uncontrolled separation, or cascading, a potential IROL condition is present. Any of the SOLs qualifies as an IROL if

(1) The impact of instability, uncontrolled separation or cascading cannot be demonstrated to be contained in the pre-defined area, or

(2) The impacted load level is equal to or greater than 1000 MW regardless of demonstrated containment. The load loss due to the intended RAS/SPS actions can be excluded.

Please note that the 1000 MW load impact level threshold is only an upper bound. Depending on the real time operating conditions, an SOL with load impact level less than 1000 MW can be identified and determined as an IROL by working with the RC and impacted TOPs.

When an SOL is identified as a potential IROL, the ISO will communicate the study results to the RC and other impacted TOPs. The RC shall make the final determination whether the identified SOL shall be deemed an actual IROL. Once an IROL is determined, the RC shall work with all impacted TOPs to develop plans, processes, and procedures to prevent IROL exceedance and to mitigate the magnitude and duration of IROL exceedance.

3.3.6 Determining Thermally Limited IROLs

Cascading outages potentially occurs when studies indicate that a contingency results in severe overloading on one or a few facilities, triggering a chain reaction of facility disconnections by relay actions (including UVLS and UFLS), equipment failures, or forced immediate manual disconnections of the facilities. When the cascading outages cannot be contained within a pre-defined area or the load impact level exceeds 1000 MW regardless of demonstrated containment, a thermally limited IROL shall be established to prevent cascading outages from happening. The California ISO employs the following general steps in identifying potential cascading outages and thermally limited IROLs:

(1) Run contingency analysis and flag contingencies that result in post-contingency loading in excess of the lower of the facility relay trip setting or 125% of the highest facility rating.
(2) For each flagged contingencies, disconnect both the contingent element(s) and all the facilities whose post-contingency loading in excess of the lower of the facility relay trip setting or 125% of the highest facility rating, then re-run power flow analysis.
(3) Identify whether or not there is any facility whose loading exceeds the lower of the facility relay trip setting or 125% of the highest facility rating.
(4) Repeat the above steps (2) and (3) until cascading outages stops within a pre-defined area or the power solution fails.
(5) Determine if the impacted load level exceeds 1000 MW (excluding load impacted by RAS/SPS).
(6) Evaluate the results to identify thermally limited SOLs that qualify as IROLs.

3.3.7 Criteria for Nuclear Power Interface Requirement

With the retirement of the San Onofre Nuclear Generating Station (SONGS), there is only one Nuclear Power Plant – Diablo Canyon Power Plant (DCPP), within the CAISO TOP area. The voltage requirements (both steady state and transient) for DCPP are considered as SOLs.

The specific voltage requirements for DCPP are specified under the corresponding Nuclear Plant Interface Requirements (NPIRs) and listed in Appendix 3100B.

3.3.8 Exception to these Criteria

Exception to the above criteria should only be allowed with permission of the owner of the impacted facilities. In addition, exception should only be allowed if there is no wide-spread impact and does not conflict with the RC SOL Methodology for the Operations Horizon and applicable NERC Reliability Standards.

3.3.9 Re-assessing and Updating SOLs

Although SOLs are established based on the anticipated transmission system configuration, generation dispatch, and load level, the system condition may still be different than the anticipated conditions as time approaches to Real-time, including in Real-time. The ISO may re-assess the anticipated system conditions and perform new studies at any time, including in Real-time, to establish new SOLs or revise the existing SOLs if the anticipated system conditions are significantly different with that in the previous studies. The revised SOLs can be higher or lower than those established in the previous studies (including seasonal studies, outage studies, or procedure studies), even for the same contingency and limiting element.

3.4 SOL Documentation in ISO Operating Procedure

SOLs that are established during seasonal assessment are documented in ISO Operating Procedure. Each operating procedure would contain tables in the specified format as illustrated in Table 1 or Table 2 below.

Table 1: Operating Limits (Option 1)

SOL #	Transmission Facilities	Operating Limit (MW)		Stability, Thermal, or Voltage Limit	a) Contingency b) Limiting Factors	a) Contingency Name / Flowgate Name b) Nomogram Name c) Flowgate Name (for single line flow monitoring)
		Summer	Winter			

Table 2: Operating Limits (Option 2)

SOL #	Transmission Facilities	Operating Limit (MW)	Stability, Thermal or Voltage	a) Contingency b) Limiting Factors	Contingency/ Nomogram Name
				a) b)	

The column "Transmission Facilities" contains the list of facilities, flow limit, path, cut plane, or interface that will be monitored

The column "Operating Limit" contains the System Operating Limits and indicates if the limit is an SOL or an IROL and the applicable season.

The Column "Stability, Thermal or Voltage" contains limit type as follows:

- Stability limit can be due to transient stability or voltage stability
- Thermal limit is due to thermal equipment of the facilities
- Voltage limit is due to stead state voltage limit or voltage deviation criteria

The column "Contingency and Limiting Factor" contains the information on the contingent element and the limiting elements that are to be protected by the SOL established.

The column "Contingency/Nomogram/Flowgate Name" contains the information on how the potential congestion, SOLs and IROLs are being managed and respected in the ISO Security Constrained Economic Dispatch tool.

In addition to Table 1 and 2, each procedure contains facility rating as illustrated in Table 3 or Table 4. These tables include the Facility/thermal capability of the lines and will include the time duration on which those ratings are derived for.

Table 3: Ratings Tables (Option 1)

Transmission Facilities	Short Term Rating (MVA or Amps)	Short Term Rating Duration	Normal Rating (MVA or Amps)	Short Term Rating (MVA or Amps)	Short Term Rating Duration	Normal Rating (MVA or Amps)
	Summer			Winter		
230/115 Transformers						
60kV Lines						
115kV Lines						
230kV Lines						

Table 4: Ratings Tables (Option 2)

Transmission Facility	Normal Rating	Short Term Rating - 4 Hour (MVA or Amps)	Short Term Rating - 1 Hour (MVA or Amps)	Short Term Rating – 0.5 Hour (MVA or Amps)	Short Term Rating – 0.25 Hour (MVA or Amps)

Communication and sharing of the Operating Procedure containing SOL and IROLs will be sent to the Operationally Affected Parties including, but not limited to, the Participating Transmission Owner, Affected Neighboring BA/TOP, and the Reliability Coordinator

3.5 SOL and Constraint Management in ISO Market Application

SOLs and IROLs that are established can be modeled as transmission constraint within the ISO Market System. This would allow the ISO Market system to economically dispatch the resources within ISO market while respecting SOLs that are established. Information on modeling of transmission constraint within the ISO Market system can be found in the Technical Bulletin posted on April 1, 2012. (http://www.caiso.com/Documents/TechnicalBulletin-Information-Modeling_TransmissionConstraints.pdf)

3.6 Criteria and Guidelines for Mitigating SOL/IROL Exceedance

California ISO System Operators shall monitor established SOLs and IROLs in the Real-time and utilize the following criteria and guidelines to mitigate SOL/IROL exceedance.

3.6.1 Mitigating SOLs in Pre-contingency State

When an SOL is exceeded in pre-contingency state, it means that the system either is experiencing unacceptable pre-contingency performance or will experience unacceptable post-contingency performance if the corresponding contingency occurs. The system must be adjusted as soon as practicable to mitigate the SOL exceedance by taking pre-contingency actions, which include, at a minimum, the following:

- Commit and re-dispatch generation
- Make adjustments to the uses of the transmission system (e.g., schedule curtailments/adjustments)
- Make changes to system topology

For any transient or voltage stability SOL, which has impacts on other TOPs but is not an SOL that qualifies as an IROL, the ISO will coordinate with the impacted TOPs in developing plans, processes, and procedures to mitigate the SOL exceedance within a pre-defined time duration. If an agreement for the pre-defined time duration cannot be reached, a default 30-minute time duration will be utilized.

3.6.2 Mitigating SOLs in Post-contingency State

After a contingency occurs, the system may be in the following states:

(1) Post-contingency Acceptable System Performance is not met. The System Operators shall take immediate actions to adjust the system to meet the Post-contingency Acceptable System Performance.
(2) All Post-contingency Acceptable System Performance is met. However, Pre-contingency Acceptable System Performance is not met. The System Operators shall take immediate actions to adjust system to meet the Pre-contingency Acceptable System Performance within applicable time duration.
(3) All Post-contingency Acceptable System Performance and Pre-contingency Acceptable System Performance are met. However, studies indicate that the system will experience unacceptable post-contingency performance if another contingency is to occur. The system needs to be adjusted as soon as practicable to prepare for the next contingency.

3.6.3 Mitigating Thermal Limited SOLs

While there are stability or voltage limited SOLs within the ISO system, the majority of the SOLs are established based on thermal limitations[1]. Since no facility should be operated above its applicable thermal limits, an SOL may be established as a pre-contingency flow limit to

[1] Most Facilities are rated based on thermal limitations; however some facilities may be rated based on relay settings. In these cases the same philosophy that is applied to thermal ratings applies.

ensure that following a contingency, all facilities remain within their applicable Facility Ratings. For these flow limits, System Operators must be aware what facilities are being protected under their applicable facility ratings, so that if the contingency occurs, they can take appropriate actions.

Facility ratings are generally defined as normal or short-term with the distinction being that normal ratings may be used continuously whereas use of short-term ratings is time limited. In addition, there may be multiple short-term ratings with different time limits applicable for their use. In all cases, ratings must have a time duration (whether continuous or other) specified for that rating.

When a pre-contingency flow limit is established, it is important to understand that if the actual pre-contingency flow is at or near the flow limit, three scenarios exist for post-contingency flow (as illustrated in 3100A, WECC Examples on Acceptable Thermal Performance):

1. Post-contingency facility loading may be within normal ratings[1] in which case no further action is necessary.
2. Post-contingency facility loading may be above normal ratings, but within a defined short-term rating. In that case the System Operator must take whatever action is necessary to return facility loading to an applicable continuous rating within the time frame allowed by the short-term rating. For example, consider a line with the following ratings:

Description	Limit	Duration
Normal	800 MVA	Continuous
Short-term 4-hour	900 MVA	4 hour
Short-term 15-min	950 MVA	15 min

And assume that the post-contingency loading of the line is 910 MVA. In this case the line loading is within its 15 minute short-term rating and the System Operator has 15 minutes to return line loading to an appropriate lower level. In most cases this will be to the 800 MVA normal rating; however, each Participating Transmission Owner defines short-term ratings based on its facility rating methodology and the conditions under which they may be applied. It is possible, for example, for the 15 minute rating to be based on returning the line loading to be within the 4 hour rating in 15 minutes and to be within the normal rating in an additional 4 hours.

For PG&E facilities, the facility rating methodology is to return the facility loading below the normal rating within the associated short-term rating duration. In the absence of specific instructions to the contrary as provided by PG&E, it is assumed that following a

[1] Meaning a rating with no time limit specified for its use, i.e. a rating that can be used continuously.

contingency which loads some facility above its normal rating, but within a defined short-term rating, the facility loading must be returned below its normal rating within the time duration specified for the short-term rating in use[1].

However, for facilities in SCE, SDG&E, and VEA, the facility rating methodology is to return the facility loading below the next available lower short-term rating within the associated time duration, then to return the facility loading below the normal rating within additional time duration associated with the lower short-term rating. In the absence of specific instructions to the contrary as provided by SCE, SDG&E, or VEA, it is assumed that following a contingency which loads some facility above its normal rating, but within a defined short-term rating, the facility loading can be returned below the next available lower short-term rating within the associated time duration and then be returned below the normal rating within the additional time duration as specified for the lower short-term rating in use[2].

3. Post-contingency facility loading may be above all defined ratings. If pre-contingency loading was within the defined pre-contingency SOL, this should not be the case; however, if at any time any facility is loaded above its highest defined short-term rating, the System Operator shall take immediate actions to get the facility loading within its defined rating.

   A clear distinction needs to be made between exceeding a pre-contingency flow limit and exceeding all defined Facility Ratings. If a pre-contingency flow limit is being exceeded, actions must be taken to either reduce loading or mitigate the concern, (such as checking with the facility owner to determine if higher short-term ratings can be applied based on current conditions). If some facility is loaded above all defined ratings for that facility, the System Operator must act immediately to reduce loading to within a defined rating.

If system conditions are such that the contingency is imminent and that there are no available resources to mitigate the flows, the System Operator should ensure that an adequate and timely plan exists to prevent cascading outages. The System Operator needs to ensure, if utilized, that any post-contingency mitigation plans respect the time necessary to take mitigating actions, including control actions, to return the system to a secure state as soon as possible. If post-contingency mitigation cannot be implemented within the required time frame and the contingency could cause cascading outages and wide spread impact, the System Operator should consider shedding load to return to the acceptable operating range.

[1] The rating in use is always the rating above the last rating exceeded.
[2] The rating in use is always the rating above the last rating exceeded.

3.6.4 IROL TV

The IROL T_V is the maximum time that an IROL can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Within the California ISO BA, the default IROL T_V is 30 minutes. The shorter IROL T_V can be established according to the real time operating conditions in coordination with other impacted TOPs based on relay/protection settings and other considerations.

In the real time operations, after an IROL is confirmed being exceeded by working with the RC and other impacted TOPs, the System Operators must take any appropriate actions, up to and including load shedding pre-contingency, to bring the system below the IROL within the IROL T_V. IROL exceedence shall be mitigated in the pre-contingency state to prevent cascading, voltage collapse, or instability in the post contingency state.

3.6.5 Mitigating SOL Exceedance for Major WECC Paths

NERC Standard TOP-007-WECC-1 defines 40 major WECC transfer paths in the BES which are significant components for reliable delivery of power in the Western Interconnection. The following WECC major paths are within the ISO TOP area:

- Path 15 – Midway-Los Banos
- Path 24 – PG&E-SPP
- Path 26 – Northern-Southern California
- Path 45 – SDGE-CFE
- Path 46 – West of Colorado River (WOR)
- Path 61 – Lugo-Victorville 500 kV
- Path 66 – California Oregon Intertie (COI)
- Southern California Import Transmission (SCIT)

When the actual flow exceeds an SOL for these WECC major paths, the System Operators shall take immediate action to reduce the actual flow on these paths to be below the SOL within 30 minutes.

3.7 Study Guidelines for Non-Credible Multiple Contingencies

Under certain conditions, the ISO may choose to study some non-credible multiple contingencies as described below. Based on the study results, the ISO will coordinate with the impacted PTOs to determine if any actions are applicable to mitigate the impacts of the multiple contingencies.

The following guidelines are applied for non-credible multiple contingencies.

1. Bus Section Contingencies
   1.1 Under system intact condition, bus section contingency will not be studied and no SOLs will be established. Sometimes, bus section contingencies may be studied for situational awareness only.

   1.2 Only when one of the bus sections in a substation is out of service and all equipments are rolled to another bus section, the bus section contingency will be treated as credible multiple contingency and the corresponding SOLs will be established, if needed.

2. Stuck Breaker Contingencies
   2.1 Stuck breaker contingencies will not studied and no SOLs will be established. Sometimes, stuck breaker contingency may be studied for situational awareness only.

3. Common Tower Circuit Contingencies (230 kV and Below)
   3.1 Only the common tower circuit contingencies (230 kV and below) which are known to cause potential reliability issues to the studied area will be studied in the Operations Horizon to identify potential instability, uncontrolled separation, voltage collapse, or cascading issues.
   3.2 The ISO will coordinate with the impacted PTOs to determine if any actions are agreed upon to mitigate the impacts of instability, uncontrolled separation, voltage collapse, or cascading outages.

4. Under certain conditions, such as fire threat or extreme weather threat, a non-credible multiple contingency may become credible in the shorter sub-horizons, the ISO will coordinate with the impacted PTOs and communicate such information in a timely manner to the RC. The ISO will coordinate with the impacted PTOs to develop SOLs and mitigation plans, if needed.

4. Supporting Information

Operationally Affected Parties

Shared on the Internet

References

Resources studied in the development of this procedure and that may have an effect upon some steps taken herein include but are not limited to:

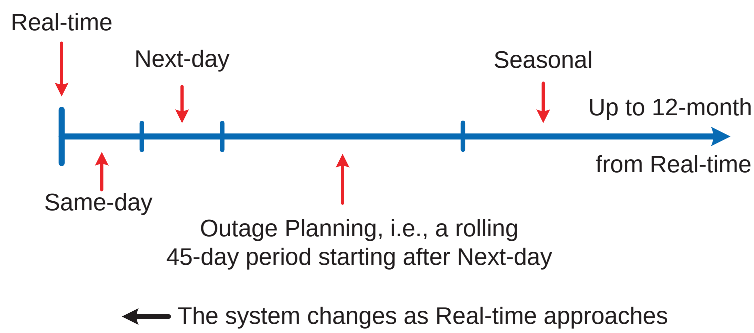
NERC Standards	**FAC-011-2** System Operating Limit Methodology for the Operations Horizon
NERC Standards	**FAC-014-2** Establish and Communicate System Operating Limits
NERC Standards	**TPL-003-0** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
NERC Standards	**TOP-007-WECC-1** Major WECC Transfer Paths in the Bulk Electric System
Peak Reliability	Establish and Communicate System Operating Limits v. 4.0.
Peak Reliability	Reliability Coordinator System Operating Limit Methodology for the Operations Horizon Rev 7.0 – Effective Date 3-3-2014

Definitions

Unless the context otherwise indicates, any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have that meaning when capitalized in this Operating Procedure. The following additional terms are capitalized in this Operating Procedure when used as defined below:

Credible	Meaning plausible (i.e., believable) with a sufficiently high degree of likelihood of occurrence.
Multiple Contingency	The simultaneous failure of multiple system facilities that are wither physically or electrically linked in response to a single initiating event or common mode failure, e.g., common transmission tower failure, common right-of-way or breaker failure.
Operations Horizon	A rolling 12-month period starting at Real-time (now) through the last hour of the twelfth month into the future. The Operations Horizon is subdivided into sub-horizons that

	include Seasonal, Outage Planning, Next-day, Same-day, and Real-time, as shown in the figure below.



Regionally Critical Multiple contingency	The contingency that is determined by the RC to have interconnection-wide impact (including but not limited to cascading, voltage collapse, and instability) and special circumstances which, considered together, supersede the determination of credibility by the TOPs. The special circumstances include historical performances and practices, system disturbances, system analysis, etc.
Single Contingency	The failure of any single element of facility that impacts one or more facilities as determined by prevailing zones of protection.
Transmission Path	Any defined grouping of BES facilities that are treated as a monitored power system element. Transmission Paths may include for example, paths internal to a TOP Area, paths spanning multiple TOP Areas, and paths defined by the list of “Major WECC Transfer Paths in the Bulk Electric System” referenced in NERC Reliability Standard TOP-007-WECC-1.

Version History

Version	Change	By	Date
1.0	Plan-09 converted to Procedure 3100 and revised.		6/6/12
1.1	Sect 3.1, 3.1.3, 3.2.1: updated cross referenced sections Sect 3.2.4: new subsection for "Criteria for Nuclear Power Interface Requirement" Sect 3.2.4: corrected a sentence		4/5/13
2.0	Annual Review. Section 3.6: Updated List of Credible Multiple Contingency Outage for Operations Horizon		9/19/13
3.0	Major revision (no yellow highlights) based on the newly published RC SOL Methodology for the Operations Horizon Rev 7.0 with effective date of 3/3/2014		3/3/14
4.0	1. Revised procedure title. 2. Removed bus voltage requirements for SONGS. 3. Added notes to SDG&E 30-minutes Post-Contingency High Limits. 4. Extracted and created Appendix 3100B.		6/01/14
4.1	Section 3.1: Added language regarding the ISO Transmission Register as the official rating source for the ISO. Added footnote that all ratings utilized for real-time operations must be documented in TR or a PTO Operating Procedure.		8/27/14

5. Periodic Review Procedure

Review Criteria	This procedure shall be reviewed annually. In addition, follow instructions in Procedures 5510 and 5520.
Frequency	Review as recommended in Procedures 5510 and 5520.
Incorporation of Changes	There are no specific criteria for changing this document, follow instructions in Procedures 5510 and 5520.

Technical Reviewer

Reviewed By Content Expert	Signature	Date
Operating Procedures		8/7/14
Operations Planning		8/7/14
Real-Time Operations		7/24/14

Director Approval

Approved By	Signature	Date
Director, Real Time Operations		8/18/14
Director, Operations Engineering Services		8/13/14

Appendix

3100A, Examples on Acceptable Thermal Performance 3100B, System Voltage Limits and Guidelines and Multiple Contingencies List

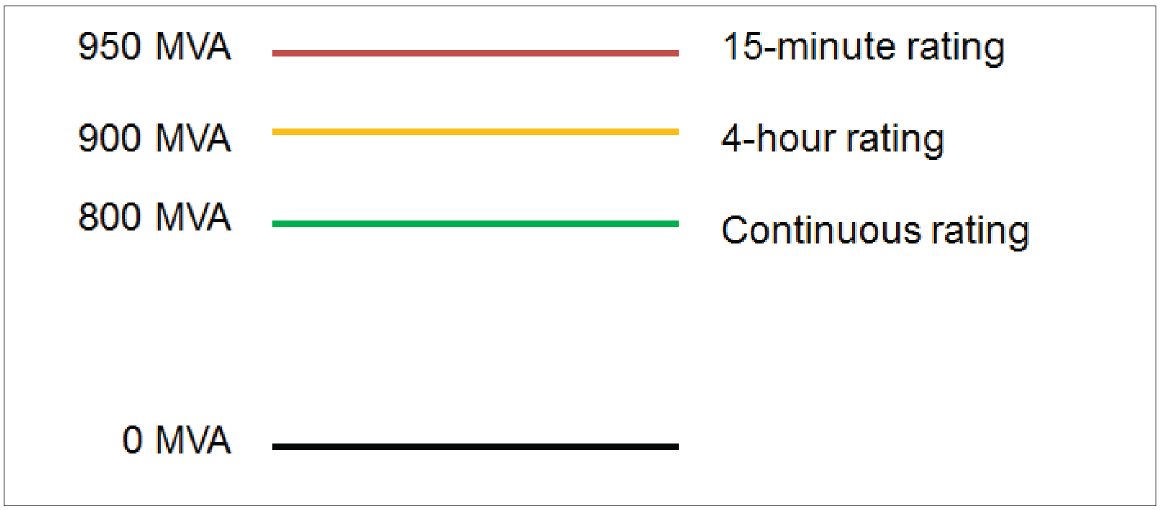
Attachment 6

3100A,
Examples on
Acceptable Thermal Performance

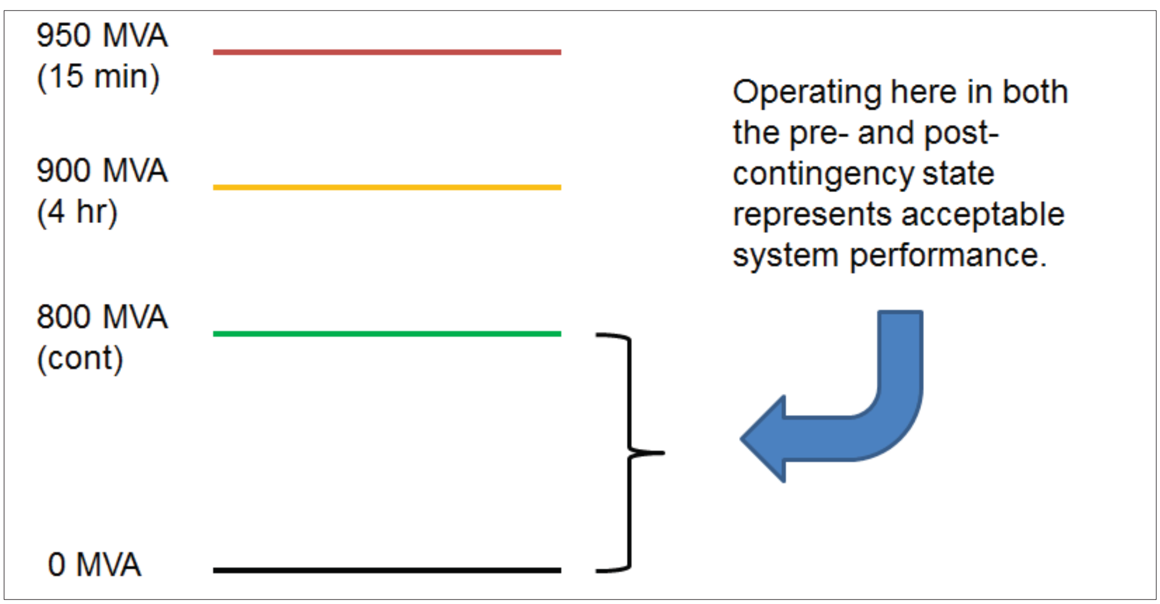
Appendix 'II': Acceptable Thermal Performance Example

1. Transmission line Facility Rating/Thermal example

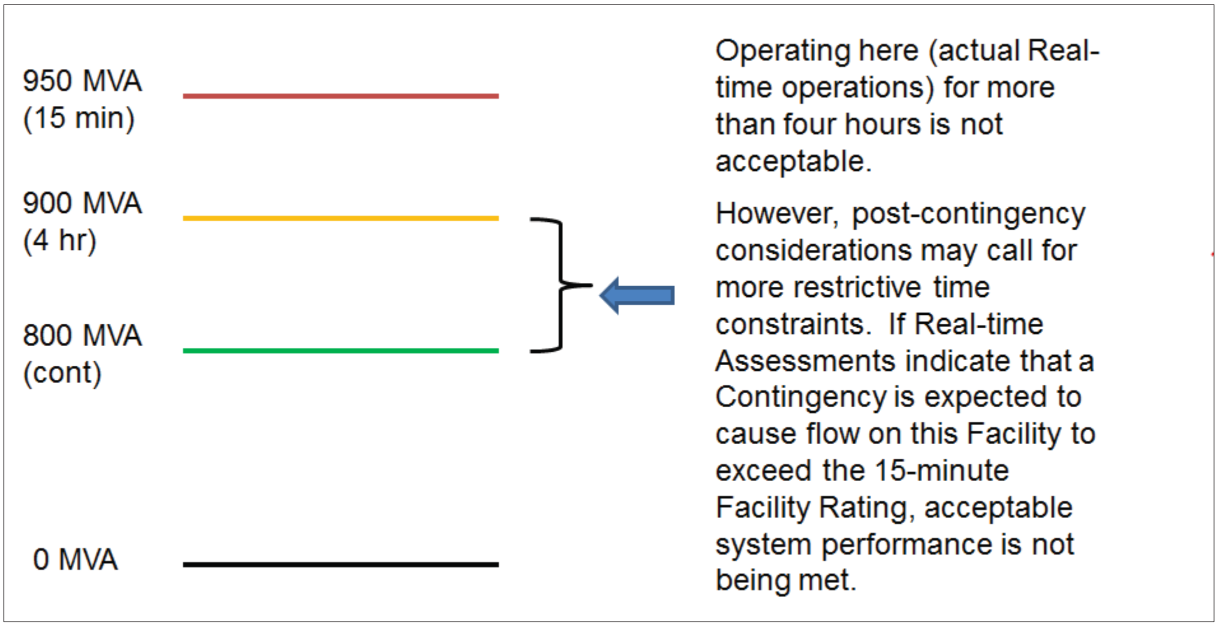
A sample Facility has the following set of Facility Ratings or thermal limits and corresponding time durations as provided by the Transmission Owner consistent with their Facility Rating Methodology.



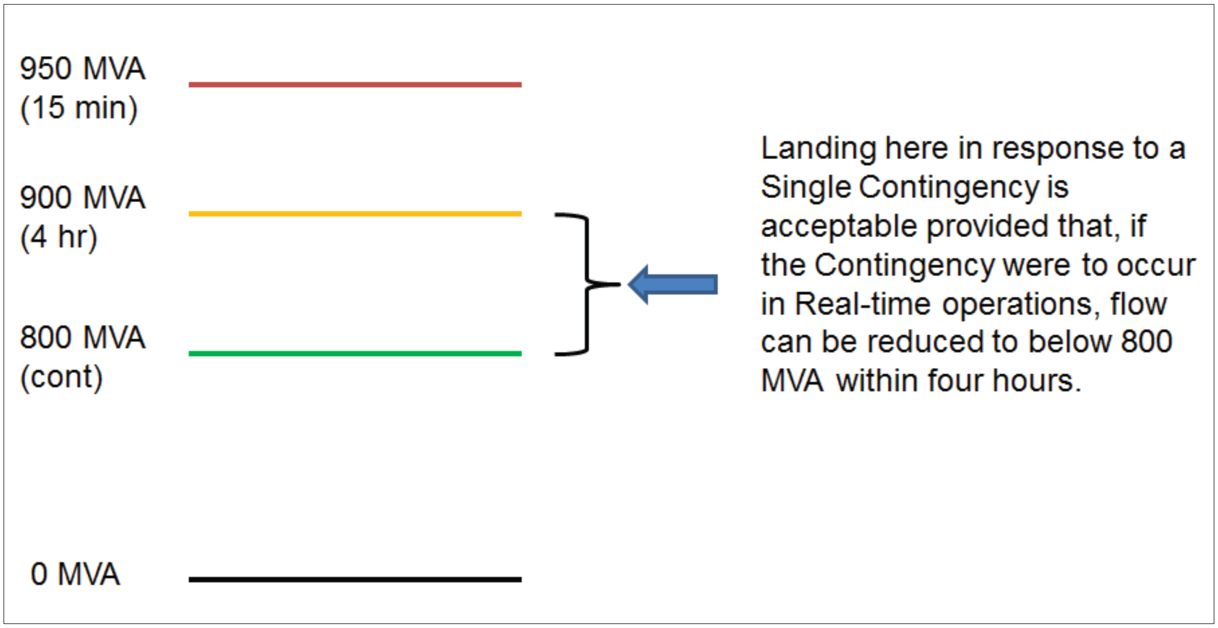
2. Pre-and Post-Contingency State



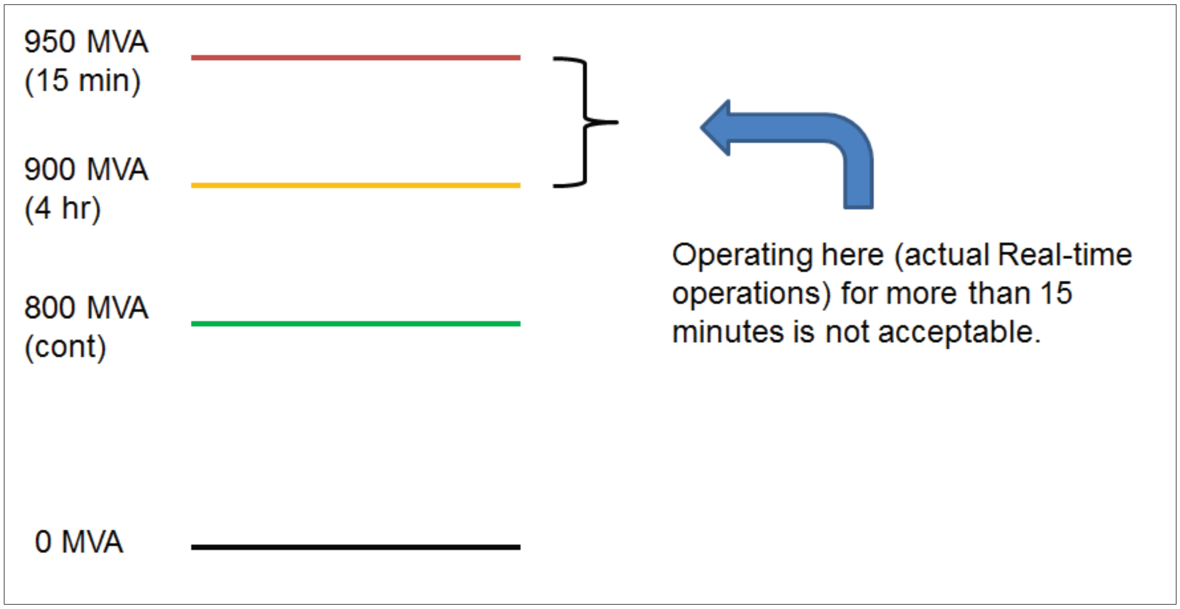
3. **Pre-Contingency State (i.e., actual Real-time operations)**



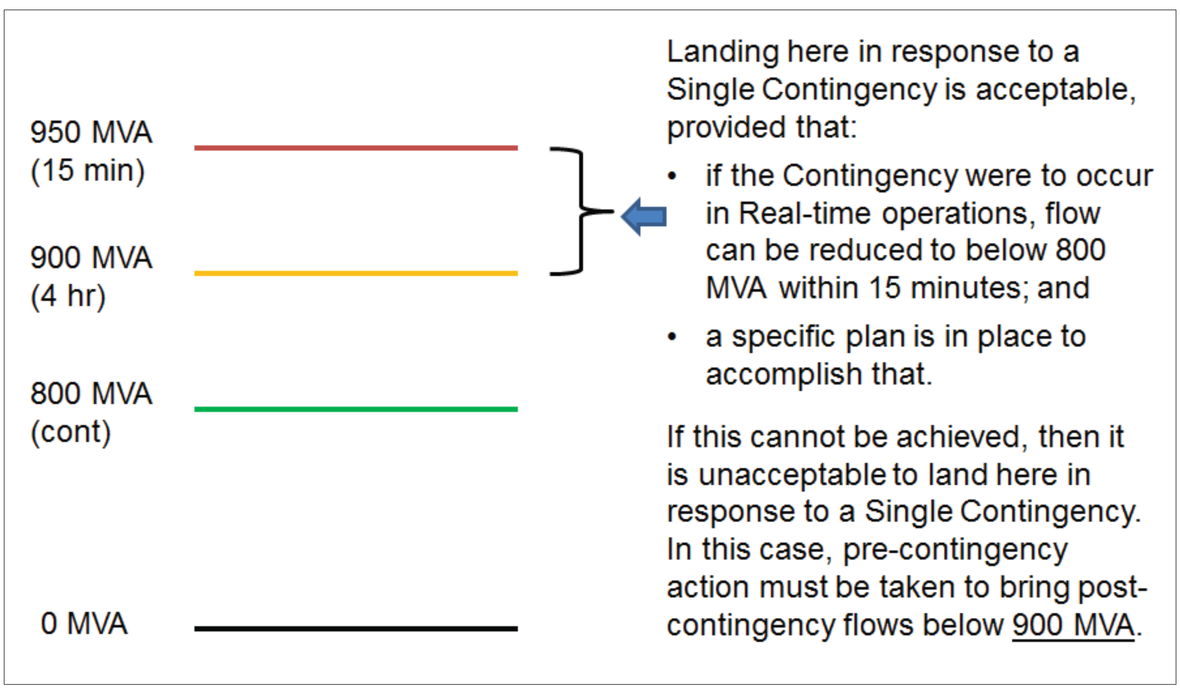
4. **Post-Contingency State (i.e., where the system is expected to land in response to a Single Contingency)**



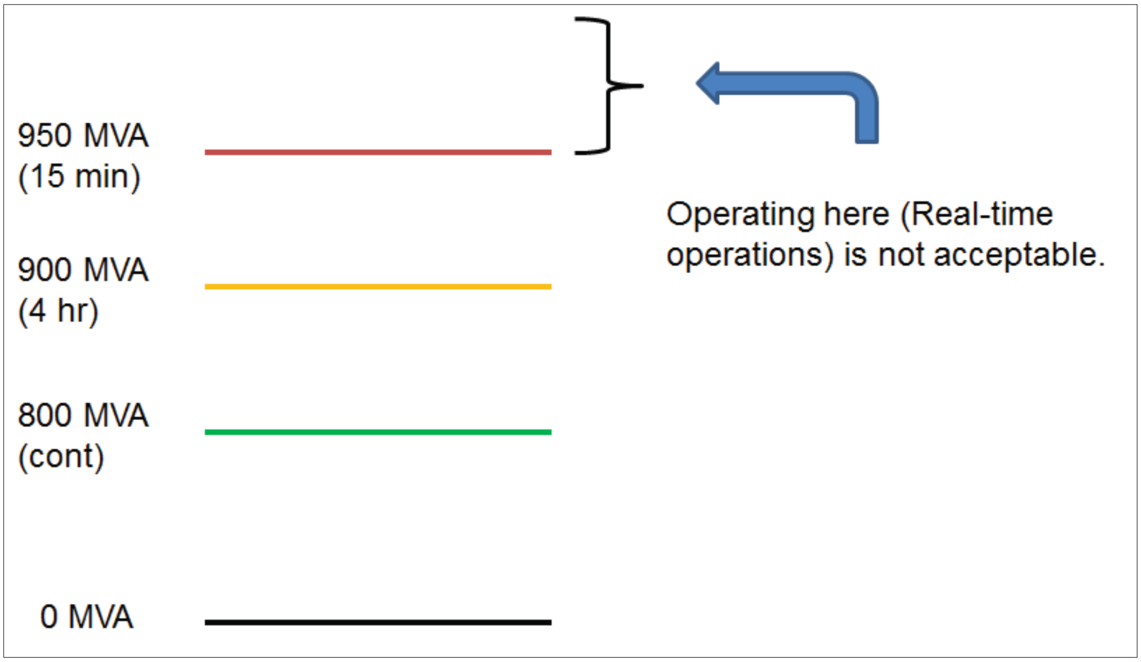
5. **Pre-Contingency State (i.e., actual Real-time operations)**



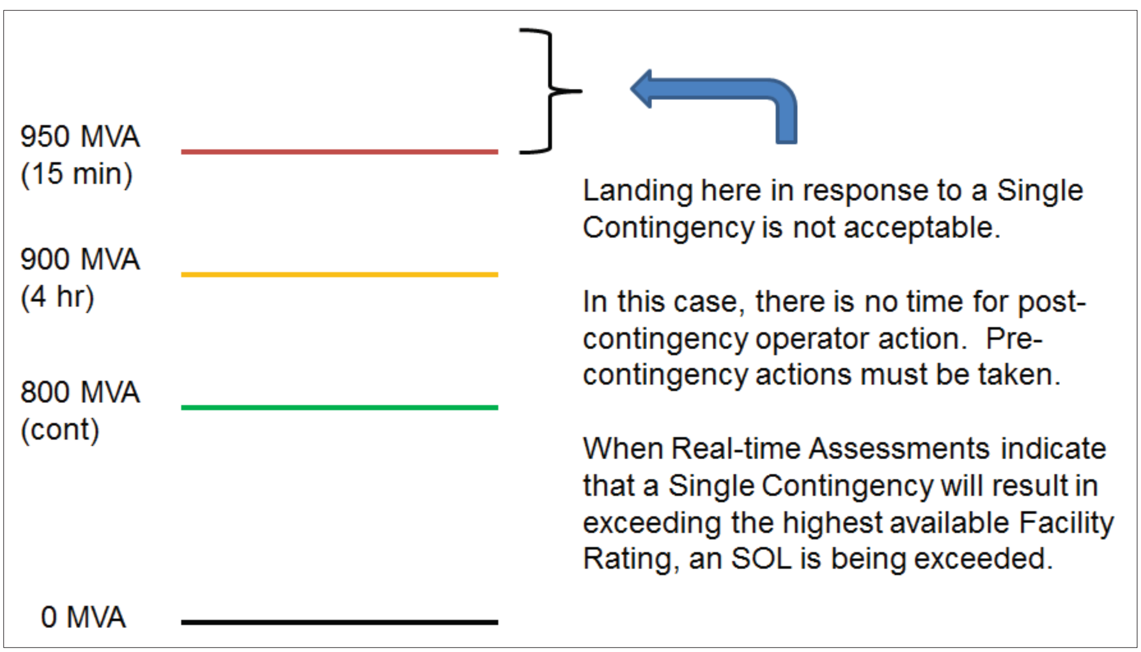
6. **Post-Contingency State (i.e., where the system is expected to land in response to a Single Contingency)**



7. **Pre-Contingency State (i.e., actual Real-time operations)**



8. **Post-Contingency State (i.e., where the system is expected to land in response to a Single Contingency)**



Attachment 7

California ISO
Shaping a Renewed Future

2010-2011
Transmission Plan

May 18, 2011
Approved by ISO Board of Governors

For these overloads that are listed in Appendix A, the NERC reliability standards allow for controlled load curtailment. The ISO recommends developing operating procedures or SPSs to drop load or generation for these contingencies.

The list of overloaded facilities and proposed mitigations is shown in Appendix A.

Mission-Old Town Area

SDG&E proposed the *Reconfigure TL23013 and TL23028 Project* for this area. The scope of this project includes converting TL23013 from a bundled line into two single conductor 230 kV lines and reconfiguration between Silvergate, Penasquitos, Old Town and Mission 230 kV substations. This project would eliminate the need to shed load under an extreme contingency which includes the loss of Otay Mesa power plant and TL50001 and TL23013 which is a (G-1/N-1 + N-1) contingency. After the *Sunrise Powerlink Project* comes into service, this scenario will be even more unlikely as it will have to be a (G-1/N-2 + N-1) contingency, hence this project is not needed.

Orange County Area

The southern Orange County area in SDG&E's service territory demonstrates multiple Category C-driven issues by 2020. More than 40 combinations of contingencies can result in load shed in the southern Orange County area. Some of these problems are existing ones and there are SPSs to address these issues. Detailed contingency analysis results are presented in Appendix A. There are more than 40 contingencies that result in overloads in 2020 and the number is more than 70 beyond 2025. The ISO standards do not recommend using SPS that looks at more than six contingencies causing more than four elements to get overloaded. This highlights the need for a reliability upgrade in the area. Southern Orange County is fed by a single 230 kV source at Talega. Failure of certain components in this area under maintenance conditions can result in loss of entire South Orange County load which is expected to be about 523 MW by 2020. There are 16 combinations of credible contingencies just at Talega substation which result in loss of partial or complete Orange County load under maintenance condition. Historical planned outage data reveals that 'load at risk' notifications have been part of several planned outages in recent past. These notifications are issued when more than 100 MW of load is at risk during planned outage conditions. In 2009-2010, 'load at risk' notifications were issued on 50 days. This indicates that any maintenance work at Talega substation or at several other 138kV facilities frequently results in an increased risk of loss of load on the southern Orange County system. Loss of this load is also an existing concern due to the topology in this area. The proposed solution and alternatives have proposed in-service date of June 2015.

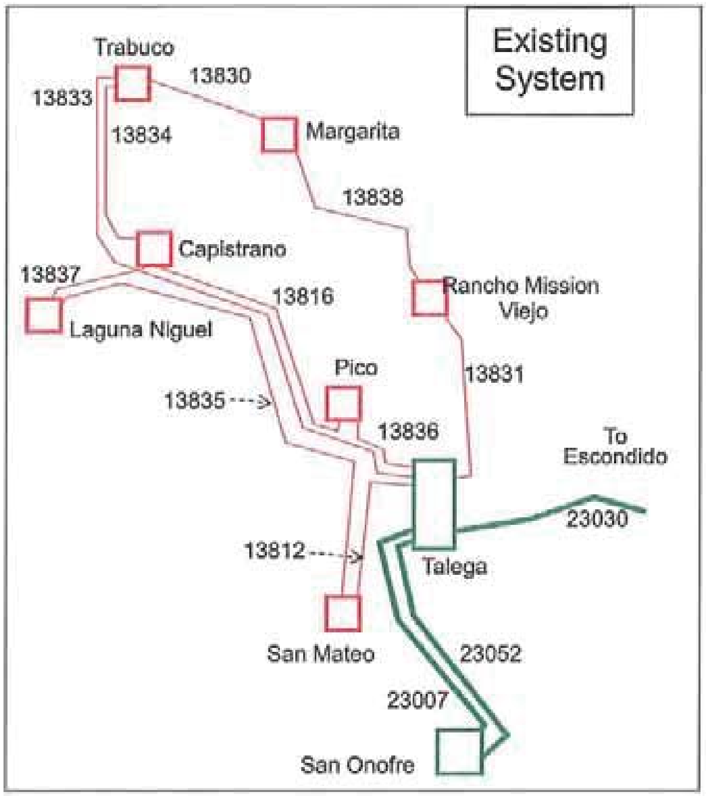


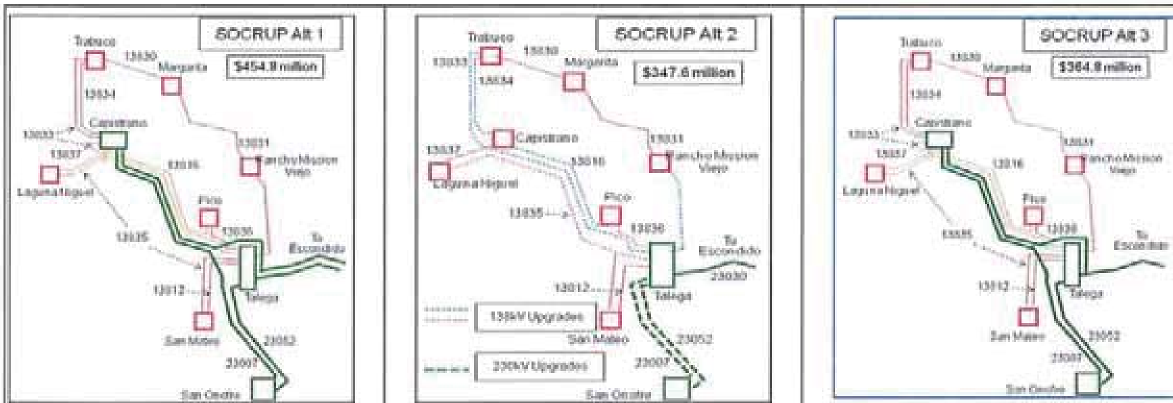
Figure 2.19-5: Existing Southern Orange County System

SDG&E submitted the *Modified – South Orange County Reliability Upgrade Project* to build new 230 kV lines and bring an additional source into southern Orange County in the 2008 request window and the ISO has been evaluating this project over several transmission planning cycles. The *Southern Orange County Reliability Upgrade Project (SOCRUP)* studies performed by SDG&E and the ISO provide substantial evidence that reliability need for upgrades exists in this area and the most effective method for achieving this is to add another source into this system. Most of the reliability concerns stem from the fact that only one 230 kV source feeds entire southern Orange County load. While it is important to develop a plan and ensure that the reliability concerns are addressed appropriately, it is also important to recognize that the upgrades should be optimal and cost effective. The southern Orange County area is susceptible to multiple Category C overloads by 2020, each requiring load shedding in this area. Under maintenance conditions, these load shed requirements are greater than 100 MW and can be as high as the entire southern Orange County load. Given these issues, the ISO performed an in-depth southern Orange County area transmission assessment to identify the necessary transmission upgrades in order to serve the area load reliably. After determining that alternative 2, the lowest cost alternative, required $347.6 million in investment, the ISO wanted to ensure that this investment would be a cost effective long-term plan. Therefore, all of the alternatives were designed to last beyond 2025 and compared on that basis. The purpose of this analysis was to identify the minimum upgrades needed during this timeframe to address NERC compliance and then to explore possibilities for alleviating concerns caused by a single source supplying the entire southern Orange County load. In addition to mitigating Category C issues, upgrades were identified to resolve issues faced under maintenance scenarios which can put significant load at risk. This effort led to creation of alternatives described below.

The project submitted by SDG&E was referred to as *SOCRUP Alternative 1*. The ISO worked with SDG&E to come up with two additional alternatives (*SOCRUP Alternative 2 and Alternative 3*). *SOCRUP Alternative 2* aims at upgrading 138kV system to solve potential overload issues, but it does not solve the problems created due to lack of a second source into this area. *SOCRUP Alternative 3* is a trimmed down version of alternative 1 (proposed by SDG&E) and provides similar reliability benefits as Alternative 1 while saving considerable amount of money.

Here is a brief summary of scope of each of these alternatives:

1. **SOCRUP Alternative 1:** Rebuild Capistrano 230 kV substation, build a new SONGS – Capistrano 230 kV line using existing right-of-way, and build a new Escondido to Capistrano 230 kV line using existing right-of-way. Estimated cost for this alternative is $454.8 million.
2. **SOCRUP Alternative 2:** Rebuild Capistrano 138kV substation (aging infrastructure maintenance project), reconductor 138kV lines – Talega – Pico, Talega – Laguna Niguel, Talega – Trabuco, Capistrano – Trabuco, Talega – Rancho Mission Viejo, and upgrade SONGS – Talega 230 kV lines. Upgrade two 230/138 kV transformer banks at Talega. Estimated cost for this alternative is $347.6 million.
3. **SOCRUP Alternative 3:** Rebuild Capistrano 230 kV substation, build a new SONGS – Capistrano 230 kV line using existing right-of-way, and tap off a 230 kV line to Capistrano from existing Escondido – Talega 230 kV line. Estimated cost for this alternative is $364.8 million.



SOCRUP Alt 1	SOCRUP Alt 2	SOCRUP Alt 3
-Reliable but most expensive -Cheaper alternative provides similar reliability benefits	-No additional source into Orange County -Only marginally cheaper than Alt 3 which brings another source into Orange County - Mitigates cat-C overloads but Orange County load will still be at risk under planned outage conditions -Does not mitigate issues with Talega substation configuration	-Provides similar reliability benefits as Alt-1, yet considerably cheaper -Marginally more expensive than the cheapest alternative -Additional source into Orange County -Provides infrastructure for a possible future interconnection with SCE in Orange County. -Flexibility to easily expand this into Alt-1 if required in future.

Figure 2.19-6: Southern Orange County Reliability Upgrade Project (Alternatives 1, 2 and 3)

Power flow study results of the peak load scenarios identified numerous facility loadings that exceeded their rated capabilities under Category C contingencies beyond 2015. All three alternatives considered here can mitigate the loading issues for Category C contingencies. In order to determine the most effective alternative, aspects beyond just the NERC compliance were taken into consideration. Historical data for bus outages at Talega and planned outages that put load at risk was accumulated and examined. It was quite evident that the lack of second source into southern Orange County puts more load at risk than the Category C issues noticed in the reliability assessment of the system. Hence, in order to improve the overall reliability of this system, it is important to bring another source into this area. The project submitted by SDG&E (Alternative 1) aims to achieve this, but Alternative 3 achieves similar reliability performance at a considerably lower cost. Alternative 2 mitigates the Category C issues through 2021, but fails to deliver another source into this area and hence fails to address the risk of load shedding due to contingencies at Talega. Alternative 3 provides another source into southern Orange County system at very little extra cost compared to Alternative 2. It also offers a potential for future upgrades in case of further load growth. After a comprehensive analysis, the ISO staff concluded that *SOCRUP Alternative 3* as the most effective, feasible solution to meet the reliability needs of southern Orange County area. Therefore, the ISO has found that the *SOCRUP Alternative 3* project is needed to address the reliability concerns in the southern Orange County area.

Other Projects

EXHIBIT 4

SDG&E Corrected Supplemental Testimony with Public Attachments 13-16, 18-25 and without Confidential Attachment 17

(PUBLIC/REDACTED VERSION)

Exhibit No.: __________

In The Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) for a Certificate of Public Convenience and Necessity for the South Orange County Reliability Enhancement Project	Application 12-05-020

SAN DIEGO GAS & ELECTRIC COMPANY

SUPPLEMENTAL PREPARED TESTIMONY

OF

SCOTT BOCKIEWICZ, DON HOUSTON, JOHN JONTRY,

KARL ILIEV, HAL MORTIER, HENRY NEMBACH,

CORY SMITH, MICHAEL SULLIVAN, AND WILLIE THOMAS

*****redacted, public version*****

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

APRIL 7, 2015

CORRECTED SEPTEMBER 10, 2015

(PUBLIC/REDACTED VERSION)

TABLE OF CONTENTS

SDG&E'S SOCRE PROJECT

CHAPTER 1. INTRODUCTION AND OVERVIEW (Witness John Jontry)

San Diego Gas & Electric Company ("SDG&E") submits the following testimony to supplement its January 15, 2015 Prepared Testimony of John Jontry, Karl Iliev, and Cory Smith, as corrected ("SDG&E January 15 Testimony").

SDG&E's Supplemental Opening Testimony is organized as follows:

- Chapter 2: SDG&E's supplemental testimony on the need for the Proposed Project directed to the specific issues identified in the Scoping Memo.
- Chapter 3: The infeasibility of the "No Project" alternative as set forth in Energy Division's Draft Environmental Impact Report for the South Orange County Reliability Enhancement Project ("DEIR").
- Chapter 4: The infeasibility of the DEIR's "Alternative B1, Reconductor Laguna Niguel–Talega 138-kV Line" alternative (the "Reconductoring Alternative").
- Chapter 5: The infeasibility of the DEIR's "Alternative D, SCE 230-kV Loop In to Reduced-Footprint Substation at Landfill" alternative (the "SCE Alternative").
- Chapter 6: The infeasibility of certain of the DEIR's proposed mitigation measures.
- Chapter 7: The estimated cost of the Proposed Project.
- Chapter 8: The Proposed Project design comports with Commission rules and regulations and other applicable standards governing safe and reliable operations.
- Chapter 9: Economic and social impacts of an outage of the Talega Substation.

CHAPTER 2 THE PROPOSED PROJECT IS NEEDED TO PROVIDE RELIABLE ELECTRIC SERVICE TO SDG&E'S SOUTH ORANGE COUNTY CUSTOMERS.

Section 1. Introduction (Witness John Jontry)

SDG&E testified in detail regarding the need for SDG&E's Proposed Project in SDG&E's January 15 Testimony. The February 23, 2015 Scoping Memo, in addition to identifying as an issue whether the benefits of the Proposed Project are needed generally, specifically identified the following need-related issues to be addressed:

> a. Is there a genuine risk of uncontrolled outages for the entire South Orange County load, and if so, is the Project necessary to reduce this risk in an appreciable way or are there alternative ways to reduce this risk?
>
> b. Is there a genuine risk of a controlled interruption of a portion of the South Orange County load, as SDG&E asserts, and if so, is the Project necessary to reduce this risk in an appreciable way or are there alternative ways to reduce this risk?
>
> c. Is the Project necessary to comply with mandatory North America Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and California Independent System Operator (CAISO) transmission and operations standards or are there other ways to comply with the standards above?
>
> d. What is the projected load growth over the next 10 years in the Project area?
>
> e. Is the Project necessary to accommodate the projected load growth in the Project area over the next ten years, or are there alternative ways to accommodate this load growth?

Scoping Memo at 8. SDG&E addresses each of these issues below, seeking to limit repeating its January 15 Prepared Testimony.

Section 2. The Public Safety Risk of Uncontrolled Outages For The Entire South Orange County Load (Witness John Jontry)

The purpose of the South Orange County Reliability Enhancement Project (SOCRE) is to provide a second, independent bulk power source to SDG&E's customers in South Orange County. As currently configured, SDG&E's 230/138 kV Talega substation is the sole source of electricity for all 300,000 residents of South Orange County, including all commercial, industrial, and other major customers. A catastrophic loss of either the 230 kV or 138 kV service at Talega Substation will result in loss of service to all South Orange County customers; service will not be restored until Talega substation is returned to service. If major pieces of equipment at Talega are damaged or otherwise inoperable, service will not be restored until such equipment is either repaired or replaced.

It cannot be emphasized enough that, without the SOCRE project, there will be no way to provide service to South Orange County in the event of the catastrophic loss of Talega substation – there are no alternate, temporary, or emergency sources of electricity capable of providing service to the 120,000 meters served by SDG&E in that region. If this event were to occur, South Orange County would be without electric service; if the damage were severe or restoration efforts hindered, this loss of service could extend for multiple days, potentially for up to several weeks. In other words, South Orange County will go dark, and stay dark, until Talega Substation is placed back into service.

To say that catastrophic loss of Talega substation and an extended outage of electric service would negatively impact the physical and economic well-being of the 300,000 residents of South Orange County would be a considerable understatement. As discussed in further detail in Chapter 9, a widespread long-term outage would negatively impact nearly every facet of life from public safety issues such as health care, police and fire response, and traffic signals, to access to telecommunications and the supply of fresh water and treatment of wastewater. Public school, hospitals, and other community resources would be severely impacted. Finally, widespread loss of electric service coupled with the landlocked nature of the topology of South Orange County would make any attempt at a mass evacuation of the area in the event of a major natural disaster extremely problematic.

As discussed in SDG&E's January 15 Prepared Testimony at pp. 40-42, a forced outage at Talega Substation could occur as a result of equipment failure, fire, explosion, wildfire, seismic events, vandalism or terrorism. In addition, as discussed in SDG&E's January 15 Testimony, Chapter 4, Section 5, there are 29 scenarios under which a forced outage during Talega Substation maintenance would directly interrupt all South Orange County customer electric service. Because Talega's equipment and infrastructure are aging, maintenance is necessary and will increase. Forced outages during such maintenance would interrupt service until the equipment undergoing maintenance could be returned to service or the failed equipment could be returned to service.

The SOCRE project will mitigate these risks by providing a second, independent source of electricity to South Orange County. When the SOCRE project is complete, SDG&E will be able to provide uninterrupted electric service to all of the customer load in South Orange County even after the complete, catastrophic loss of Talega Substation. The SOCRE project brings other reliability and operational benefits to the system as well, but from a public safety standpoint, this is the most significant benefit the project offers.

Each of these issues is addressed in more detail below.

A. Equipment Failure, Fire or Explosion Risk (Witness Karl Iliev)

SDG&E takes measures consistent with Good Utility Practice to minimize the risk of equipment failure, fire or explosion, but risk remains. SDG&E has experienced forced outages caused by such events. Recent events include:

- 230 kV Potential Transformers violently failed at San Luis Rey (2013) and Escondido (2007) substations, each resulting in an oil fire and shrapnel that damaged surrounding insulators in these substations. Initial restoration of damaged line positions took three days and it was months before all damage was repaired. Because of transmission redundancy, no customer load was lost, but the initial loss of transmission lines impacted SDG&E system power import capabilities until restoration was made.

- 12kV Shunt Capacitors at Montgomery (2010) and Imperial Beach (2011) substations violently failed resulting in chemical fires at both locations. A similar failure occurred on the 12kV shunt reactor at Margarita substation in early 2014. No customer load was lost during these incidents as upstream protection isolated the devices. Shunt capacitors and reactors make the electric system more efficient and allow finer voltage control. These failures impacted ability to control power quality to customers fed from these stations, but did not interrupt their service.

- 69kV Shunt capacitor bank current limiting reactor caught fire at Los Coches substation (2007) due to insulation failure and arcing, which electrically ignited the device. The damage was isolated to the capacitor unit, which was out of service for several weeks. This resulting outage to the shunt capacitor resulted in loss of grid voltage optimization in the region until its repair was completed.

- 500/230kV single-phase autotransformer experienced a bushing failure that caused a tank rupture and subsequent transformer fire at SDG&E's Miguel (2013) substation. Firewalls on-site prevented the failure from damaging an adjacent transformer unit. No customer outage resulted from this loss of equipment due to additional transformer capacity and redundant transmission lines to feed the San Diego region. The incident did cause significant impacts to SDG&E's power import capability for the duration of the outage. News video from the incident can be seen at the following link: https://www.youtube.com/watch?v=UCQMKCixawI

- The Palomar Energy Center generator step-up transformer (GSU) violently failed in 2010, leading to a transformer fire. Firewalls contained the damage and prevented it from spreading to an adjacent transformer unit. The power plant was off-line for approximately 3 months, while a replacement unit was procured and installed. Amateur video from the event can be seen at: https://www.youtube.com/watch?v=iEHvpo9i4fU

- In 2014, an oil switch used to turn on and off a 12kV capacitor at Capistrano violently failed due to mechanical wear, resulting in an oil fire. The smoke from this fire caused a secondary arc on the 138 kV bus, resulting in a transmission outage to half of the Capistrano substation transmission lines. Restoration of service took an hour as damage was limited to the failed device, which is non-essential and could be isolated. The device was replaced within 2 weeks.

- In 2008, a 500kV Series Capacitor violently failed at Imperial Valley Substation, causing a major 500kV Transmission Line outage and triggering customer load shed in a neighboring utility. The fire caused extensive damage to the series capacitor, which was bypassed to restore load flow on the line in roughly 3 hours.

> The capacitor outage lasted several months, which caused limited generation power import capability on the SDG&E grid during that time.

In general, the Commission is aware of the risk of substation fires, and initiated a rulemaking for substation inspections following a 2003 fire at PG&E's Mission Substation.[1]

Based on the history of catastrophic transformer failures in the last 10 years that resulted in fire inside an SDG&E substation (taking into account the given population of transformers) the failure rate per year is 0.238% per transformer per year. Given that Talega Substation has four critical transformers on-site and extrapolating the previous statistic, the chance of one of them failing catastrophically is near 1% per year (0.95%).

Because Talega Substation, constructed in the late 1970s, has had equipment added over the years to meet load growth, it has greater risk from fire or explosion than newer substations meeting SDG&E's current standards. As shown in Confidential Attachment 8[2], photographs of Talega Substation, because of space constraints within the substation footprint, the transformers are in close proximity to each other, which increases the equipment damage and outage impact if an adjacent transformer or other equipment catches fire, explodes or otherwise fails.

There are four 230/138 kV transformers at Talega Substation (Bank 60 = 168 MVA; Bank 61 = 392 MVA; Bank 62 = 150 MVA; Bank 63 = 392 MVA). So long as one of the two 392 MVA transformers, plus one other transformer, is in service, Talega Substation has sufficient transformer capability to serve all of the expected South Orange County load through 2030. However, loss of more than two transformers will result in a loss of electric service to some or all of SDG&E's customers in South Orange County.

[1] *See* Order Instituting Rulemaking to Implement Commission Regulations Relating to the Safety of Electric Utility Substations, R.10-09-001.

[2] SDG&E is seeking confidential treatment for photographs that identify specific structures inside Talega Substation.

Currently, Banks 61 and 62 are immediately adjacent to the control shelter without enough separation to install a fire wall. If one of these transformers catches on fire, it will create difficulty in entering the control shelter to perform operations necessary to de-energize the equipment to allow workers to safely extinguish the fire. It could also cause direct damage to the control shelter and the control/protection equipment housed within, which would further and significantly hinder any power restoration as installation of this critical equipment is labor intense, and therefore would take a long time to replace.

Additionally, a fire on Bank 61 may spread to Bank 60 and/or Bank 62 because space and access constraints prevent construction of a firewall or a 50 foot intervening distance. The control shelter is not tall enough to act as a firewall. Likewise, a fire on Bank 62 may spread to Bank 63 and/or Bank 61 because space and access constraints prevent construction of a firewall or a 50 foot intervening distance as well. This would result in more collateral damage than the initial failure of Bank 62.

Moreover, the outage risk is not solely from the threat of transformer outages. A maintenance outage of one 138 kV or 230 kV bus at Talega, followed by loss of the remaining bus, will result in loss of all South Orange County load. Certain overlapping outages of multiple 138 kV or 230 kV transmission lines (N-1-1 or N-2) will also result in at least a partial loss of customer load. A physical attack that causes failure of mechanical structures and supports inside the substation or the surrounding transmission lines would also cause long-term significant outages.

Other types of equipment failures, such as relays, instrument transformers, insulators, and circuit breakers would also cause outages. Direct explosion of these devices could damage surrounding equipment including the transformers, insulators, structures, and any burning resulting from a failure could cause arcing on surrounding infrastructure. These types of equipment usually have shorter duration outages than power transformers because replacement parts and units are easier to procure and install.

In general, Good Utility Practice calls for reducing system vulnerabilities using accepted industry practices. While some system vulnerabilities seem small, a single point of failure can cause widespread outage on the electric system, the risk typically is larger than anticipated. In addition to the risks discussed above, the potential for adverse events is higher than anticipated due to the potential for human error. Safe work practices and careful system design can help mitigate this threat, but will not provide the security provided by removing the vulnerability.

For example, as noted in SDG&E's January 15 Testimony at p. 41, on July 18, 2013, an insulation failure on a 69 kV transmission line caused a fault which spread to an adjacent 138 kV transmission line which is connected to the Talega Substation 138 kV bus. The protection system operated and removed the Talega Substation 138 kV east and west buses from the CAISO controlled grid. All South Orange County customer load was interrupted for three hours while the system was restored. This event was caused by a system fault coupled with intermittent protection communication, coupled with the single 230kV source to the Southern Orange County load center, and also coupled with a control and protection design vulnerability at Talega Substation.

A seemingly improbable event resulted in a complete loss of load to SDG&E's South Orange County customers because the Talega-supplied 138kV system was and is the sole source to SDG&E's Southern Orange County system. A second 230kV source into the South Orange County system would have prevented this 3 hour outage. Fortunately, the event occurred in the middle of the night and did minimal damage and thus had minimal impact. Although this event represents a "best case" scenario, where a system vulnerability could be corrected with minimal system impact due to the small duration and timeframe, it serves as an important lesson to point out the vulnerability of the configuration of Southern Orange County. A similar but longer event, occurring during business hours, would be a much more significant impact to the communities within Southern Orange County.

Another example of a system vulnerability is the Southwest Power Outage of 2011. This event was the result of a technician error in a neighboring utility that accidentally caused isolation of a 500kV transmission line. The outage of that line cascaded through the San Diego/Imperial Valley/Baja California grid due to generation and protection vulnerabilities identified in the FERC incident investigation report. This resulted in a 14 hour outage to most of SDG&E's load. This illustrates how a system vulnerability can be exposed by human error, leaving a higher probability of damaging impacts to the electric power system and the customers served by this system.

These examples serve as a warning that careful system planning, along with early identification and mitigation of potential system vulnerabilities, are appropriate to avoid both high probability-medium impact events and high impact-lower probability events, because both may create significant risk and cost to SDG&E's customer base. Having Talega Substation serve as the only 230kV source for SDG&E's South Orange County system poses a risk that only a second 230kV source to the system can mitigate. The Proposed Project provides such a second source at the rebuilt Capistrano Substation.

B. Wildfire Risk (Witness Hal Mortier)

Talega Substation is located on the Camp Pendleton Marine Corps base. As recognized in the DEIR: "The California Department of Forestry and Fire Protection (CAL FIRE) is the state agency responsible for fire protection in State Responsibility Areas (SRAs) of California and also identifies and maps fire risks in SRA's, Federal Responsibility Areas (FRAs), and Local Responsibility Areas (LRAs). CAL FIRE designates areas as having very high, high, or moderate fire hazards. Fire Hazard Severity Zone designations are based on fuels, terrain, fire history, and weather of the area (CAL FIRE 2009)."[3] Talega Substation is located within a zone identified by CAL FIRE as having a "very high" fire hazard risk.[4]

The CAL FIRE rankings aggregate a number of risk components including the condition of available fuel, fire return interval, and relative slope. A close look at the surrounding vegetation as it exists today validates these rankings as still very accurate today. Fire occurrence in the area is very high due primarily to the fire activity associated with Camp Pendleton Marine Base. Camp Pendleton keeps very little records on fire occurrence on the base, but fire return intervals are frequent with many fires occurring in each decade in much of their wildland area. This is evidenced by visible fuel type conversion from moderate chaparral to a mix of grasses and light brush which present a much flashier fuel component.

CALFIRE fire occurrence records reveal about 10 fires (9.6 to be exact) a decade within a 10 mile radius around Talega Substation over the last 50+ years. This only includes fires large enough to be mapped and recorded, generally 10 acres or larger. This again would not include all of the Camp Pendleton fires that did not have CALFIRE/Orange County Fire Authority involvement. Fire professionals and fire ecologists alike agree that even 3 fires per decade is a much too frequent return interval for fire occurrence in chaparral species. So the 10 per decade fires reported in CALFIRE records, combined with an equal number or more on the base, easily represent a very high fire occurrence for this area.

[3] DEIR at 4.8-5.
[4] DEIR at Figure 4.8-1.

Recent fires on Camp Pendleton near Talega Substation include:[5]

- Basilone Complex Fire, May 17, 2014 (21,420 acres) near Basilone Road was the combination of three fires;
  - Pulgas Fire: May 15, 2014, near Las Pulgas.
  - San Mateo Fire: May 16, 2014, near Talega.
  - Tomahawk Fire: May 13, 2014, near Naval Weapons Station Fallbrook.
- Ammo Fire, October 23, 2007 (21,004 acres).

Basically, Talega Substation and the transmission lines to and from it lie in the western edge of the SDG&E Fire Threat Zone. As a result, these components of SDG&E's system are at risk to wildfire and the consequences thereof. The potential consequences include:

- Heavy smoke from wildfires can be dense enough to cause phase to phase and/or phase to ground arcing, which can take the lines and/or substation completely out of service. For example, smoke took a 500 kV line out of service during the Harris Fire in October 2007, and a 69 kV line out of service during the Old Fire in June 2012. In the May 2014 wild fires this phenomenon was caught by local Channel 10 news at a fire in San Marcos. (see video "230kV Flashover San Marcos Fire 5-15-2014" https://www.youtube.com/watch?v=Te_1WTXi2YE)

- All but one of the transmission structures supporting the 138 kV lines leaving Talega Substation to serve SDG&E substations in South Orange County are made of wood. Where wooden structures still exist, they are at risk to catch fire, burn down, and potentially cause system failure. Examples of transmission structure failures include the 2003 and 2007 San Diego County Wildfires. In the 2007 fires, which started on October 21st, approximately 1,880 wood poles were replaced with service restorations to all customers being completed by November 12th.[6] In May of 2014, approximately a dozen wildfires burned across the county and approximately 135 pole wood poles had to be replaced. As seen from the 2007 fires, the restoration efforts could take days or weeks depending on the severity of the fire damage, access restrictions by fire agencies due to safety and/or fire investigation, and material availability and construction resources.

- Much of the electric system in this area parallels high valued structures and other assets at the immediate edge of the wildland community. During a fire, fire personnel may be more apt to request shut-down of the system for firefighter safety due to proximity of at risk values. Both the Cocos Fire and Poinsettia Fire

[5] http://cdfdata.fire.ca.gov/incidents/incidents_current.

[6] http://www.sdge.com/newsroom/press-releases/2007-11-13/sdge-completes-service-restoration-all-fire-impacted-customers

in May of 2015 had formal firefighter request for de-energization (138 kV and 230 kV) and SDG&E complied. This is a very frequent occurrence.

- Air tactical firefighting operations can put the system at risk as well. Fire retardant can cause problems to the electric system during firefighting operations. For example, airtanker drops took a 500 kV line out of service during the Jacumba Fire in June 2011.

SDG&E's Proposed Project will bring a second 230 kV source into South Orange County at a rebuilt Capistrano Substation. This system redundancy will increase the electric reliability for Southern Orange County by reducing the likelihood and magnitude of effect from wildfire and/or adverse weather conditions, such as high speed winds from Santa Ana Wind conditions or severe wind weather storms. The new 230kV source will be designed to a higher wind pressure than what is dictated in General Order 95, Rule 43.2 (18 psf versus 8 psf) and will be on self supporting steel poles that do not require guys and anchors. Because the new structures will be of man-made steel, the variability of strength will be much less than that of a naturally grown wood structure and thus yield a lower probability of failure.

A recent gathering at Talega Substation was attended by SDG&E, Orange County Sheriff, Orange County Fire Authority, Camp Pendleton F.D., FBI, DHS, and Camp Pendleton Military Police to discuss the unique nature and specific vulnerabilities of the Southern Orange County electric system, and how loss of the Talega substation would have extremely disruptive effects on the general public in Southern Orange County. Discussions took place regarding wildfire, terrorism, vandalism, and other outside influences that could potentially affect all of Southern Orange County. The fire and law enforcement agencies in attendance strongly support and encourage all efforts to improve system reliability in this area as currently it poses a vulnerability with which they are not comfortable.

C. Seismic Risk (Witness Karl Iliev)

South Orange County, like most of Southern California, is considered to have a significant seismic risk, at least from strong seismic shaking.[7] As recognized in the DEIR:

> The proposed project would be located in a seismically active region and would likely experience moderate to severe ground shaking if a large magnitude earthquake occurs on one of the region's active faults during the lifespan of the proposed project. Seismic hazards in a region are estimated using statistics of earthquake occurrence to estimate the level of potential ground motion. A common parameter used for estimating ground motion at a particular location is the peak ground acceleration (PGA). PGA is a measure of earthquake intensity; it is a measure of how hard the earth shakes at a given geographic location during the course of an earthquake (USGS 2007). The higher the PGA value, the more intense the ground shaking.
>
> The U.S. Geological Survey (USGS) National Seismic Hazards Mapping Program performed a probabilistic seismic hazard assessment for the continental United States. Using an interactive web mapping tool, PGA values were assessed for a location near the center of the project site in Transmission Line Segment 3. Based on the interactive map, there is a 10 percent chance in 50 years (a recurrence interval of 475-years) that areas within and in the vicinity of the proposed project area would experience ground shaking with a PGA exceeding 0.25g (very strong perceived shaking and moderate property damage). There is a 2 percent chance in 50 years (a recurrence interval of 2,475 years) that areas within and in the vicinity of the proposed project area would experience ground shaking with a PGA exceeding 0.46g (severe perceived shaking and moderate to heavy property damage).[8]

SDG&E asked URS to calculate the PGA values for Talega Substation, which are set forth in Table 4-7 below:

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[7] See SDG&E's Proponent's Environmental Assessment § 4.6.3.4.
[8] DEIR at 4.6-6 (footnotes omitted).

Table 4-7

Estimated Ground Motions at Talega Substation (33.4533, -117.5714)		
Annual Frequency of Exceedance	**Ground Motion**	**Source**
10% in 50 years	0.315g	USGS Uniform Hazard Values
2% in 50 years	0.517g	USGS Uniform Hazard Values
Risk-Targeted MCE PGA_M	0.467g	ASCE 7-10

URS calculated the PGA values using the USGS Seismic Design Maps (Site Class D, which represents the presence of stiff soil at the site) and the ASCE 7-10[9] risk-targeted peak ground acceleration adjusted for site class effects (PGA_M) values. The values from the DEIR are lower than those estimated by URS from USGS Seismic Design Maps. URS suspects this difference is probably due to the DEIR using the USGS National Hazard Mapping Program (USGS 2008, Java Program), which calculates ground motions only for Site Class B. Site Class B is only appropriate for sites where the average shear wave velocity in the upper 100 feet of the site is between 2,500 and 5,000 feet per second (a "rock" site). Either predicted PGA will produce "severe" perceived shaking with "moderate/heavy" potential damage based on a USGS scale.

The ASCE 7-10 ground motions are slightly lower than the 2% in 50 yr year hazard level ground motion from the USGS Seismic Design Maps. This is because the ASCE 7-10 ground motions (design values) are geometric mean, risk-targeted values and are not derived from a

[9] American Society of Civil Engineers, Standards: Minimum Design Loads for Buildings and Other Structures (ASCE/SEI 7-10).

uniform-hazard spectra. These design values are the lesser of the probabilistic and deterministic values.

Seismic shaking can damage equipment at substations. For example, a 7.2 Mw on the Moment Magnitude Scale earthquake that struck near Mexicali caused damage to transformers at SDG&E's Imperial Valley Substation in 2010. Earthquake ground movement, with an estimated PGA of 0.29 to 0.35 g, caused oil to move inside the transformers, which caused a pressure increase, setting off pressure relaying systems designed to detect an internal faults in the units. Normal protocol requires physical inspection and electronic testing of the transformer to ensure that no permanent damage is present. Upon physical inspection, crews noticed that bushing gaskets had been damaged from the ground motion and were protruding outside of the bushing wells, breaking the oil to air seals on the bushing tank, and requiring repairs prior to re-energizing the transformers. Between procurement of custom replacement bushing, which were luckily available, around the clock shipping from utilities across the United States, removal and installation time, re-sealing and processing of exposed oil, and final electrical testing, it was roughly a month before all transformer repairs could be made.

In the 2010 Imperial Valley event, system capacity and redundancy avoided losing customer service during the transmission equipment outage. A seismic event at Talega Substation that damages all of the transformers on-site would create an outage to near all customer load in the Southern Orange County area for the duration of the transformer inspection and repairs. An event which damages two or more transformers could lead to long duration outages for a significant portion of SDG&E's South Orange County customers.

The Talega Substation was designed and constructed in the early 1980's and similar to the Capistrano Substation, this was before the establishment of the primary industry standards that SDG&E uses, which include the IEEE 693 Recommended Practice for Seismic Design of Substations, ASCE 96 Guide to Improved Earthquake Performance of Electric Power Systems and ASCE 113 Substation Structure Design Guide. Similar to the Capistrano Substation, the majority of the existing structures, foundations, and equipment do not conform to the current recommended practices for seismic design of substations as provided in the latest IEEE 693 and ASCE 113 and the existing electrical equipment has not been seismically qualified as provided in IEEE 693.

The primary seismic hazard at the Talega Substation will be from the Rose Canyon-Newport Inglewood fault zone located about 7 miles west-southwest (offshore). Seismic induced damage within the substation potentially would include:

- Some damage to the 230kV power transformers, primarily to the 230 kV surge arrestors and the 230 kV bushings.
- Swinging motions of the 230 kV line drops, especially those with hanging CCVTs, could potentially damage adjacent disconnect switches.

There is also concern about earthquake triggered landslides occurring in the vicinity of the Talega Substation. Regional and local hazard mapping efforts have identified numerous landslides and possible landslides in the vicinity of the Talega Substation with several extensive ancient landslides shown in the general area. A landslide occurred within and adjacent to the substation in July 1997.[10] This landslide was located within the cut slopes on the southwestern portion of the substation. The landslide was determined to be a reactivation of an existing ancient landslide.

Access to the Talega Substation is limited to a single access road from E Avenida Pico. This access road is on top of a flood water retention basin fill embankment. Any failures of this

[10] See Confidential Attachment 8.

fill embankment from a seismic or other event would severely restrict access to the Talega Substation.

D. Vandalism or Terrorism Risk (Witness Henry Nembach)

Utilities have experienced damage from third party action, including acts of terrorism, vandalism, and theft. Third party action that targets electric infrastructure can cause substantial damage to a substation. The third party action can occur from inside the substation or from outside the substation. Most recently, PG&E's Metcalf Substation was targeted by one or more shooters on April 16, 2013, who damaged multiple transformers banks and multiple circuit breakers with numerous gunshots.

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E. Potential Outage Duration (Witness Karl Iliev)

The duration of any forced outage at Talega Substation would depend upon the nature and extent of damage. Certain outages might be resolved within a few hours; other possible outages could last weeks or several months.

The longest total outage would be caused by transformer damage to all four 230/138 kV transformers at Talega. Damage to three of the four Talega transformers would cause a lengthy partial outage to SDG&E's customers. The normal time to install a transmission transformer is approximately 60 days or more depending on the complexity of the design and the size of the transformer. In the event that all four transformers were catastrophically damaged, full electric service to South Orange County would be lost until replacement of at least two the transformers could be made. SDG&E would work around the clock to install two new transformers, but it likely would take at least three to four weeks to do so.

Catastrophic events that damage transformers beyond repair usually include an electric arc that creates and ignites combustible gasses inside the transformer oil. This results in an explosion and oil fire that may spread up to a radius of 50 feet. Transformer oil fires may get so hot that they cannot be easily extinguished. In the event of the Palomar Energy GSU transformer fire, the transformer burned oil for 48 hours before it cooled enough to be extinguished by fire-fighting crews. In some cases, depending upon the scope of the fire and prevailing wind, it may be necessary to de-energize other equipment at the substation until the fire is contained or out. Resulting damage, burn time, and forensic analysis, may hamper removal of the transformer from the site for up to a week.

[redacted]

In a parallel fashion, when a transformer fails, Substation Engineering & Design begins work to assess if the system spare transformer will fit on the existing pad (if undamaged—a damaged pad would cause further delays) and within the space vacated by the failed unit. Design work must also be completed to structurally anchor the transformer, look at electrically connecting it given new dimensions, look at the pad integrity and size for any modifications necessary, look at existing conduit for control and auxiliary power connections, and perform electrical design. Crews begin disassembling the spare for transport. This process includes pumping down the oil level and replacing it with dry pressurized nitrogen to make it lighter. Also, radiators and other accessories are removed to ready the transformer for transport. A heavy hauler transportation company is called-in to relocate the transformer to the new location. This process may take up to 2 weeks.

Once design is completed, modifications to the existing foundation and conduit must be made before the transformer is placed. Setup of the transformer then proceeds, including re-installation of the radiators and/or bushings (if necessary), vacuum processing of the transformer tank to remove moisture (to maintain electrical integrity of the transformer and prevent degradation of the paper insulation), filling the tank with hot oil and circulating it using an oil processing rig to remove moisture from the oil, and finally electrical testing to ensure the transformer is ready for service. SDG&E likely would need to retain outside transformer technicians to assist in this work. This process may take another 2 weeks or more.

SDG&E keeps two spare transmission 230/138 kV class transformers to provide emergency replacement if a failure of this classification were to occur. It is possible that SDG&E could have only one spare transformer at the time of a Talega Substation event as these transformers are installed when an opportunity arises to ensure that the spare transformers are energized before their 5-year warranty expires. This practice ensures a higher level of reliability and manufacturer support for the SDG&E spare fleet. An example of not having one of these spares available is shown as SDG&E is installing one of its spare transformers in June 2015 and will receive its replacement spare in early 2016 due to long lead times for a transformer purchase and manufacturing. The typical manufacturing time for a transformer of this size is 45 weeks.

If SDG&E lost all four of the Talega transformers with only one spare available, it would need to procure another transformer to meet the Southern Orange County loading requirements. If the cause of the damage was a terrorist attack, it would seek a federal emergency declaration. Such a declaration would allow SDG&E to utilize the Edison Electric Institute (EEI) program spares (a program under which SDG&E and other utilities pool nationwide spares). With or without such a declaration, SDG&E would ask other utility members to sell or lend SDG&E a spare or two. If the EEI protocols are not put in place, SDG&E would be at the mercy of the market availability for a transformer, which (if none are suitable for SDG&E use) would subject it to the 45 week manufacturer timeframe. If SDG&E were able to find a spare meeting its specifications, the outage under that scenario might be limited to around 6-8 weeks. The extra time beyond a normal spare installation would be used for communication with other utilities, engineering review of the sufficiency of the available transformer, and transport of the transformer to SDG&E's facility from the location in North America where it resides.

The next most critical outage would be a complete loss of the control and protection system located inside the control shelter. As previously mentioned, this could be caused by a catastrophic loss of Bank 61 or Bank 62, which are in close proximity to the shelter and do not have firewalls installed between the shelter and the transformers. Typical installation time for a control shelter the size of that needed at Talega would be 4 months. Under an emergency situation, creation of a temporary shelter to perform minimal control and protection could be accomplished within 3-5 weeks.

There are other examples of shorter, but still significant outage risks at the Talega site. A common failure is a potential transformer or circuit breaker bushing failure. If this failure is catastrophic, the failure usually causes an explosion, resulting in shrapnel being expelled by the fragmenting of the porcelain bushing. This shrapnel can damage insulation on-site and injure any workers in proximity (100 feet or less) of the device failure. The shrapnel damage or resulting equipment fire could result in outages of multiple transmission lines or transformers. Repairs could take 1 to 3 days if damage is limited to insulation. It may take much more time, depending on the location of the damage and the severity of the damage to other equipment within the substation. The time to replace a damaged transformer is discussed above.

Other outages may be less than a day. When infrastructure is taken out for maintenance, this further increases the probability of a concurrent event causing a forced customer outage at Talega. A maintenance outage on Bank 61 or one of the 138/230 kV busses, coupled with the resulting failure of Bank 63 or the other bus would result in an outage to the Southern Orange County system. The other bank or bus outage may be caused by multiple types of failures including a stuck breaker during a fault, a failure of any infrastructure on the Bank or bus position, or human error as crews are working in close proximity to energized equipment. Restoration for this type of event would be determined by restoration time (or "recall" time) of the maintenance outage, and would likely range from 1-4 hours, depending on how much disassembly has occurred of the infrastructure that maintenance is being performed on.

Section 3. The Risk Of A Controlled Interruption of a Portion Of The South Orange County Load (Witness Cory Smith)

A "controlled outage," also known as load shed, is the deliberate interruption of service to customers by operating personnel to prevent damage to equipment, prevent violation of NERC/WECC/CAISO requirements or prevent a violation of a regulatory requirement (e.g., CPUC G.O. 95). As noted in SDG&E's January 15 Testimony, Chapter 4, Sections 5-8, SDG&E has identified failures in South Orange County that would require customer load to be shed, some as early as 2016:

- 22 Category C events that would result in system elements exceeding Applicable Ratings and thus violate NERC TPL reliability standards, thus requiring SDG&E to take pre-contingency action to interrupt customer service after a single outage. (pages 50-59)

- 19 Category C events that would require SDG&E to interrupt customer service to stay within Applicable Ratings and thus comply with NERC TPL-003-0b. (pages 59-70)

- 28 scenarios under which a forced outage during Talega Substation maintenance would require SDG&E to interrupt customer electric service to stay within Applicable Ratings. (Table 4-3 on page 44)

- 80 scenarios under which a forced outage during maintenance at a substation would directly interrupt electric service to over half of South Orange County customers (this would be an uncontrolled loss of service). (tables 4-4, 4-5 and 4-6 on pages 71-72)

Under the Federal Power Act, Section 215, the FERC-adopted NERC standards are mandatory for SDG&E. There is no provision in the NERC transmission planning standards to consider the "risk" of an event. NERC transmission planning criteria requires SDG&E to develop plans for the future not based on the mathematical probability of an event (risk), but based on the results of required simulations. Requirement R1 of TPL-003-0a states;

"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 (non-recallable reserved) Transmission Services, at all demand levels over the range of forecasted system demands, under the contingency conditions as defined in Category C of Table I. 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."

The "contingency conditions" for Category C (and Categories A and B) in Table I include the system remaining within Applicable Ratings.

CAISO is the registered Planning Authority and SDG&E is the registered Transmission Planner for South Orange County. As required, both CAISO and SDG&E simulated the response of South Orange County's 138 kV transmission system to Category C contingencies and found overloads. Requirement R2 of NERC standard TPL-003-0b requires the CAISO and SDG&E to create a Corrective Action Plan to remove the overloads. The standard allows the use of planned and controlled load shedding as a Corrective Action Plan to remove overloads following a Category C contingency (but not following the first outage of a Category C3 contingency, as discussed below). Throughout, all equipment ratings must be respected. When simulations show that an equipment rating will be exceeded, the Corrective Action Plan must prevent such a result.

SDG&E also is required to comply with CAISO Planning Standards. In addition to limiting the use of Special Protection Systems ("SPS"), CAISO has adopted Planning Standards for its control area that require transmission planning "to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements."[68] In Planning Standard 5, "Planning for New Transmission versus Involuntary Load Interruption Standard," CAISO identifies three specific circumstances where new transmission is required over load shedding, and includes a fourth where "Upgrades to the

[68] Attachment 13 (CAISO Planning Standards, effective April 1, 2015, at 6).

system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure, through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances."[69] This standard was in place when CAISO approved SDG&E's Proposed Project.

Since CAISO's approval of the Proposed Project, CAISO has adopted Planning Standard 6, "Planning for High Density Urban Load Area Standard." CAISO notes: "Increased reliance on load shedding to meet these needs would run counter to historical and current practices, resulting in general deterioration of service levels."[70] Therefore, CAISO provides: "For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems."[71]

South Orange County does not qualify as a "high density urban load area," which CAISO defines as a population of one million people or more. However, South Orange County is surrounded by "high density urban load areas". Specifically, Los Angeles-Long Beach-Anaheim in the north, Riverside-San Bernardino in the northeast and San Diego in the south. CAISO Planning Standards also state:

> In considering if load shedding, where allowed by NERC standards, is a viable mitigation in either the near-term, or the long-term for <u>local areas that would not call upon high density urban load</u>, <u>case-by-case assessments need to be considered</u>. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the

[69] Attachment 13 (CAISO Planning Standards, effective April 1, 2015, at 6).
[70] Attachment 13 (CAISO Planning Standards, effective April 1, 2015, at 6).
[71] Attachment 13 (CAISO Planning Standards, effective April 1, 2015, at 6).

area, number of customers impacted by the outage, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.[72]

Although this specific portion of the CAISO Planning Standard did not exist when CAISO approved the Proposed Project, CAISO could chose to apply it in considering whether the risk of certain events that would cause load shedding in South Orange County should be mitigated.

To the extent that NERC reliability standards and CAISO Planning Standards allow load shedding as a planned response to potential outages, the "risk" of a failure occurring that would require operators to shed load is relatively low, but real. Since the NERC requirements took effect in 2007, systems have been planned with load shedding as an accepted corrective action following multi-element outages. Because of the long term planning required for transmission systems, the corrective actions in transmission plans are not fully realized until years after decisions are made and the systems either upgraded or not. At this time, there is not enough data to quantify the risk. That said, SDG&E expects load shedding to occur more often because systems in the future will be operated using transmission plans created today and load shedding is used as acceptable mitigation in recent CAISO transmission plans.

The Proposed Project removes the need to shed load or replace other transmission equipment in South Orange County for the foreseeable future.

Section 4. The Proposed Project Is Necessary to Comply with Mandatory Reliability Standards (Witness John Jontry)

The Proposed Project is necessary for SDG&E to comply with the mandatory NERC reliability standard TPL-003-0b and TPL-002-0b, as interpreted by the Federal Energy Regulatory Commission ("FERC").

[72] Attachment 13 (CAISO Planning Standards, effective April 1, 2015, at 7).

A. Load Shedding under NERC Transmission Planning Standards

Under the Federal Power Act § 215, FERC has adopted the NERC reliability standards, including its Transmission Planning and Transmission Operations standards, as mandatory for all "users, owners, and operators of the bulk power system."[73] As discussed in SDG&E's January 15 Testimony at 16-22, among other things, NERC TPL-002-0b requires that the "Transmission Planner" (here, SDG&E) plan its system to stay within Applicable Ratings and not interrupt any firm customer service following the loss of any one transmission system element reflected in Category B of Table I (a "Category B" or "N-1 event).[74] NERC TPL-003-0b requires that SDG&E plan its system to stay within Applicable Ratings following the loss of any two transmission system elements reflected in Category C of Table I (a "Category C" or "N-2 event), but some planned and controlled interruption of customer service is permitted to do so.[75]

NERC TPL-003-0b also requires that SDG&E plan its system to stay within Applicable Ratings following the consecutive loss of two transmission system elements as reflected in Category C3 of Table I (a "Category C3" or "N-1-1" event). Category C3 describes the contingency to be planned for as "Category B (B1, B2, B3 or B4) contingency, manual system adjustments, followed by another Category B ((B1, B2, B3 or B4) contingency."[76]

In adopting the relevant NERC TPL reliability standards, FERC stated: "Based on the record before us, we believe that the transmission planning Reliability Standard should not allow

[73] 16 U.S.C. § 215: "(b) Jurisdiction and applicability. (1) The Commission shall have jurisdiction, within the United States, over the ERO certified by the Commission under subsection (c) of this section, any regional entities, and all users, owners and operators of the bulk-power system, including but not limited to the entities described in section 824 (f) of this title, for purposes of approving reliability standards established under this section and enforcing compliance with this section. All users, owners and operators of the bulk-power system shall comply with reliability standards that take effect under this section."
[74] TPL-002-0b, R1 & Table I (SDG&E January 15 Testimony, Attachment 1).
[75] TPL-003-0b, R1 & Table I (SDG&E January 15 Testimony, Attachment 2).
[76] TPL-003-0b, Table I (SDG&E January 15 Testimony, Attachment 2).

an entity to plan for the loss of non-consequential load in the event of a single contingency."[77] Referring to "footnote b" of Table I, FERC stated it "allows for the interruption of firm load for consequential load loss,"[78] which FERC defined as "the load that is directly served by the elements that are removed from service as a result of the contingency."[79] FERC further stated: "The Commission agrees that footnote (b) should permit manual adjustments including generation redispatch and transmission reconfiguration, <u>but not load shedding</u>, to return the system to a normal operating state within the time period permitted by the emergency or short term ratings."[80] FERC repeated this admonition in later Order 762: "In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency."[81]

Citing these FERC directives, CAISO also has stated that it "ISO does not plan for load loss for category B contingencies other than on: radial supplied load within the allowable load levels identified in the ISO Planning Standards; and interim basis prior to the completion of needed transmission upgrades."[82] SDG&E's South Orange County system is considered network load and not radial supplied load.

NERC TPL-003-0b, Table I describes allowable "Impacts" permitted following a Category C contingency. The Standard allows the Transmission Planner to plan to use "load shedding" to keep the system within Applicable Ratings when overloads and/or voltage

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[77] Attachment 14 (FERC Order 693, Paragraph 1795, 72 Federal Register 16416, 16583 (April 4, 2007)).
[78] Attachment 14 (FERC Order 693, Paragraph 1772 fn. 453, 72 Federal Register at 16580).
[79] Attachment 14 (FERC Order 693, Paragraph 1795 fn. 461, 72 Federal Register at 16583).
[80] Attachment 14 (FERC Order 693, Paragraph 1797, 72 Federal Register at 16583) (emphasis added).
[81] Attachment 15 (FERC Order 762, Paragraph 4, 77 Federal Register 26686, 26687 (May 7, 2012)).
[82] Attachment 16 (R. Sparks' 4/25/12 Email to SDG&E and W. Stephenson).

violations occur as a result of one of the Category C contingencies listed in Table I. Category C contingencies are defined as "Events resulting in the loss of two or more (multiple) elements."

Based on FERC's direction that a system should not be planned to shed load after a single Category B contingency and that allowable manual system adjustments do not include load shedding, and the definition of Category C contingencies as an outage of two or more elements, SDG&E believes that it may not plan to shed load following the first Category B outage of a Category C3 contingency (the N-1) to stay within Applicable Ratings following the second Category B outage of a Category C3 contingency (the N-1-1). Otherwise, SDG&E would be shedding load after a single element contingency.

B. Staying within Applicable Ratings May Require Pre-Contingency Action

Under the NERC TPL Standards, "Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner."[83] As described in SDG&E's January 15 Testimony at 47-48, exceeding applicable thermal ratings can cause physical damage to transmission lines. In addition to the risk of physical damage to transmission facilities, transmission lines operated at temperatures in excess of their design limits may exceed their designed sag limits, resulting in clearance violations and increased risk to utility personnel and the general public.

As noted above, the mandatory NERC Transmission Planning Standards require SDG&E to plan its system not to exceed Applicable Ratings. The system must remain within Applicable Ratings after each of an N-1 event, an N-1-1 event, or an N-2 event. No facility can exceed its highest emergency rating at any point. If a facility has an emergency rating, then a facility can exceed its normal (or continuous) rating so long as it never exceeds its emergency rating and is

[83] *E.g.*, TPL-003-0b, Table I footnote a (SDG&E January 15 Testimony, Attachment 2).

brought back down to its normal rating within the time limits of the emergency rating.[84] If a facility does not have an emergency rating, then its highest Applicable Rating is its normal or continuous rating, and it cannot be exceeded.

This is consistent with the mandatory NERC Transmission Operations Standards. In particular, NERC TOP-004-02 R1 provides: "Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs)."[85] The NERC Glossary of Terms defines a SOL as the most limiting value that ensures operation within acceptable reliability criteria. A facility thermal rating is a SOL.

CAISO's Operating Procedure 3100 and 3100A, Attachments 5 and 6 to SDG&E's January 15 Testimony provide a detailed discussion of this requirement. Operating Procedure 3100A, Paragraph 8, labeled "Post-Contingency State (i.e., where the system is expected to land in response to a Single Contingency)," clearly presents the operating requirements. Showing a post-contingency state that exceeds the highest emergency rating, CAISO states: "Landing here in response to a Single Contingency is not acceptable. In this case, there is no time for post-contingency operator action. <u>Pre-contingency actions must be taken</u>. When Real Time Assessments indicate that a Single Contingency will result in exceeding the highest available Facility Rating, an SOL is being exceeded."[86]

SDG&E must plan its system to take pre-contingency action if necessary to stay within Applicable Ratings. Under Category C3, that includes taking action after the first Category B

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[84] Attachment 14 (FERC Order 693, Paragraph 1789, 72 Federal Register at 16582: "The N–1 condition is a Category B event under TPL–002–0, and, following the N–1 contingency, the system must be stable and thermal loading and voltages be within applicable limits. Some adjustment of generation or other controls is permitted to return loadings to within continuous ratings, provided the loadings before adjustments are within the emergency or short-term ratings.")

[85] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TOP-004-2&title=Transmission%20Operations&jurisdiction=United%20States.

[86] CAISO Operating Procedure 3100A at 34 (SDG&E January 15 Testimony, Attachment 6) (emphasis added).

outage so that the second Category B outage will not result in facilities exceeding their Applicable Ratings.

C. Load Flow Analyses Indicate that SDG&E Will Have to Shed Load To Stay within Applicable Ratings, Including Pre-Contingency Action

As discussed in SDG&E's January 15 Testimony at 50-59, SDG&E's load flow analyses, based upon SDG&E's 2014 load forecast, predicted 22 Category C1, C2 and C3 events that will result in SDG&E's facilities exceeding their Applicable Ratings absent use of a Special Protection System ("SPS"). As required by NERC TPL-003-0b,[87] South Orange County was reassessed using the 2015 load forecast. The reassessment confirmed the findings of the power flow analysis done using the 2014 load forecast. The 2015 load forecast is approximately 2% higher than the 2015 load forecast. This increase does not change the need for the project, but moves the date needed forward. Because many of SDG&E's South Orange County transmission lines highest Applicable Rating is the normal rating, without an SPS the identified Category C contingencies would result in the identified elements exceeding their highest Applicable Rating, and thus violating NERC TPL-003-0b.[88]

An SPS can take automatic and instantaneous action to shed load and thus prevent facilities from exceeding Applicable Ratings. However, SDG&E is bound to use SPSs in accordance with good utility practice and the CAISO Planning Standards. CAISO has provided guidance that limits the number of SPSs in use, recognizing that use of SPS has both benefits and

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[87] SDG&E Attachment 2 (TPL-003-0b, R2.2 requires the continuing need be reassessed on an annual basis).

[88] See SDG&E January 15 Testimony at 50-59.

risks.[89] SPS 6 provides: "A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS. B) The SPS should not be monitoring more than 4 system elements or variables."[90]

SDG&E agrees that use of multiple SPSs to address 18 different Category C contingencies in South Orange County is not prudent because:

- SPSs are complex electronic systems that depend on multiple inputs applied to a control system to perform properly and as such have numerous points of failure. Transformers and transmission lines with adequate capacity to handle the forecast demand have none these complexities.

- Assessing the interaction of 18 different load shedding SPSs will be difficult, if not impossible. Without this assessment, unknown interactions leading to mis-operation could be present. When called upon to operate, the mis-operation of a load shedding SPS may result in shedding more load than is necessary, or not shedding any load at all.

- An SPS can operate and drop customer load under normal conditions. The inadvertent operation of an SPS may shed load when it is not necessary to do so, or for no reason at all.

Because CAISO Planning Standards and Good Utility Practice indicate that SDG&E cannot use SPSs to address all of these Category C events, the system would not remain within Applicable Ratings. This is a violation of NERC TPL-003-0b.

As described in SDG&E's January 15 Testimony, Chapter 4, Section 6, SDG&E must take pre-contingency action to ensure that its system will remain within Applicable Ratings. For the two C1 and six C2 overloads described in numbers 1-8 on page 50-52, SDG&E would have

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[89] CAISO Planning Standards at 9 (SDG&E January 15 Testimony, Attachment 4): "While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability."

[90] CAISO Planning Standards at 10 (SDG&E January 15 Testimony, Attachment 4):

no choice but to shed load pre-contingency to avoid violating Applicable Ratings. For the remaining fourteen C3 overloads described in numbers 9-22 on pages 52 through 59, SDG&E would have to shed load after the first Category B outage to ensure that the system would not exceed Applicable Ratings after the second Category B outage. As discussed above, shedding load after a single Category B contingency violates FERC's interpretation of NERC TPL-002-0b and is not an allowable manual adjustment after the first Category B contingency under Category C3.

In the case of the 19 predicted Category C overloads described in SDG&E's January 15 Testimony, Chapter 4, Section 7 that do not exceed the Applicable Rating, SDG&E would resort to load shedding to remove the overloads.

Section 5. SDG&E's Proposed Project is the Best Available Means to Mitigate the Risk of Load Dropping or Load Shedding in South Orange County (Witness John Jontry)

With respect to the risk of dropping some or all South Orange County customers discussed above, the Scoping Memo asks "are there alternative ways to reduce this risk." Similarly, with respect to the NERC violations, the Scoping Memo asks "are there other ways to comply with the standards." SDG&E interprets these questions as asking if there are any other cost-effective, reasonably feasible alternative ways of solving the identified reliability needs.

As discussed in SDG&E's January 15 Testimony at 104-05, a transmission project is the best solution to address the reliability concerns for South Orange County. Energy efficiency, demand response programs, and distributed generation cannot address the risk of dropping all or some of the South Orange County load as a result of an event at Talega Substation or a forced outage during a maintenance event. These programs are meant to reduce the amount of load being served from the 138 kV transmission system, but as described in the January 15 Testimony at 43, the contingency events in Table 4-2 will result in all South Orange County load being dropped regardless of the load level.

SDG&E does not consider construction of a natural gas-fired electric generation facility in South Orange County to be a cost-effective or reasonably feasible solution.

Although individual overloads caused by specific contingencies in South Orange County could be addressed by reconductoring a number of transmission lines and replacing the smaller transformers at Talega, implementing such projects would not address the risk of a total loss of service to SDG&E's South Orange County customers arising from a significant event at Talega Substation, which currently is the sole source of power to the South Orange County system. Moreover, as discussed in Chapter 3, Sections 5 and 6 with respect to the DEIR's No Project Alternative, the multitude of projects required to provide most of the reliability benefits of the Proposed Project likely would cost significantly more than the Proposed Project and could well have greater environmental impacts.

The aging Capistrano Substation must be rebuilt to provide reliable electric service. As discussed in SDG&E's January 15 Testimony at 103-04, Capistrano is near the electrical center of South Orange County's transmission load. The SDG&E-owned Capistrano Substation property also is large enough to accommodate a rebuild of the substation including a 230 kV yard. Therefore, SDG&E determined that it would be most cost effective and create the most construction synergies if the rebuild of Capistrano Substation included a second 230 kV source for South Orange County.

Section 6. Forecasted Load Growth By 2025 and Load Serving Capacity Assuming All Transmission Elements In Service (Witness John Jontry)

As discussed in SDG&E's January 15 Testimony at 38, the aggregate summer adverse weather load forecast for SDG&E's South Orange County service territory was forecasted to reach approximately 481 MW by 2023. This 2014 forecast has since been updated by SDG&E's Distribution Planning Department, based on load and weather data inclusive of the 2014 calendar year and reflecting the new peak load for the SDG&E service territory set in September 2014. The 2015 load forecast for the South Orange County service area is shown in Table 2-1, below:

Table 2-1: South Orange County's 2015 Load Forecast

Substation	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Capistrano	53.6	54.1	54.7	55.2	55.7	56.3	56.8	57.3	57.9	58.4
Laguna Niguel	102.6	103.1	103.6	104.1	104.6	105.0	105.4	105.8	106.2	106.6
Margarita	106.4	107.0	107.5	108.1	108.7	109.3	109.8	110.4	111.0	111.6
Pico	42.6	43.1	43.6	44.1	44.6	45.1	45.5	46.0	46.5	47.0
Rancho Mission Viejo	14.4	17.6	20.9	24.1	27.3	30.8	34.2	37.6	41.0	44.4
San Mateo	33.4	34.3	35.1	35.6	36.1	36.5	36.9	37.3	37.7	38.2
Trabuco	90.3	90.7	91.2	91.6	92.0	92.4	92.8	93.2	93.6	94.0
Total South Orange County	443.3	449.9	456.6	462.8	469.0	475.4	481.4	487.6	493.9	500.2

For comparison purposes, Table 2-2 below reproduces the 2014 load forecast from Table 4-1 of SDG&E's January 15 Testimony.

Table 2-2: South Orange County's Previous 2014 Load Forecast

Substation	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capistrano	52.0	52.5	53.1	53.6	54.1	54.6	55.2	55.7	56.2	56.7
Laguna Niguel	95.2	95.7	96.1	96.6	97.1	97.5	97.9	98.2	98.6	99.0
Margarita	99.6	100.2	100.8	101.4	102.0	102.6	103.1	103.7	104.3	104.9
Pico	42.6	43.2	43.7	44.2	44.7	45.2	45.7	46.3	46.8	47.3
Rancho Mission Viejo	14.7	17.0	20.4	23.8	27.2	30.7	34.1	37.5	40.9	41.1
San Mateo	36.2	37.0	37.7	38.5	38.9	39.3	39.7	40.0	40.4	40.8
Trabuco	87.5	87.9	88.3	88.8	89.2	89.6	90.0	90.5	90.9	91.3
Total South Orange County	427.8	433.5	440.1	446.9	453.2	459.5	465.7	471.9	478.1	481.1

The latest forecast represents an approximately 2% increase over the previous forecast. SDG&E's September 10, 2015 corrections to its Opening Testimony reflect use of the 2014 load forecast and the 2015 load forecast. Results found using 2014 load forecast were confirmed using the 2015 load forecast.

Note that any load forecast estimates future load growth using a set of assumptions – past load levels, estimated population and economic growth, changes in load composition, effects of energy efficiency programs, etc. No forecast can be perfect. However, it is important to point out that there are several important factors that may push the load growth in South Orange County beyond what is currently forecast. Current uncertainties that could place additional demands on the transmission system include:

- More rapid than expected adoption of electric vehicle technology and a concomitant growth in electric vehicle charging demand
- Changing customers behavior might reduce cooperation with and effectiveness of demand response and energy efficiency programs
- New energy storage technology may change energy consumption patterns
- Reduction of subsidies or rate incentives may slow the growth of distributed generation (i.e. rooftop solar)
- Regulatory risk associated with the repowering and/or replacement of OTC units in Southern California
- The possibility of a robust economic recovery following the long and lingering effects of the 2009 recession leading to faster than expected load growth in South Orange County, especially with regard to a rebounding of the residential housing market.

Based on the current load forecast, and with the caveats as described above, following is an analysis of the load-service capacity of the South Orange County transmission system as currently configured.

A. Load Serving Capacity

South Orange County is a non-radial, networked transmission system. Load serving capacity is the maximum amount of load which can be served following a failure which removes a single or multiple elements from service without violating the Applicable Rating of the remaining elements. Failures may result in load being dropped or shed.

The most optimistic pre-contingency setting for South Orange County under normal conditions with all transmission lines and transformers in-service will have the TL13835A Special Protection System in-service, the Prima Deshecha Landfill Generator in-service, the Capistrano 138 kV capacitor in-service and the Talega transformer taps set to increase the Talega 138 kV bus voltage 5% above nominal. Under these conditions, SDG&E's transmission system in South Orange County can support 410 MW of load without violating the Applicable Rating of a transmission element in the event of a NERC Category B or C contingency. South Orange County peak load already exceeds 410 MW.

At this load level, for example, the overlapping outage of two 138 kV transmission lines will result in a third line being loaded to its maximum rating. The outage of the transmission line connecting Talega and Rancho Mission Viejo substations [TL13831] and the outage of the transmission line connecting Pico and Trabuco substations [TL13833] will cause the power flowing on the transmission line connecting Pico and Capistrano substations [TL13816] to increase to the transmission line's maximum allowable power flow (Applicable Rating). As described in Section 5(B), when South Orange County load exceeds 410 MW and an outage of either TL13831 (or TL13833) occurs, system operators will be forced to shed load to prepare the transmission system for the outage of TL13833 (or TL13831) to prevent a violation of the Applicable Rating of TL13816.

Another example, continuing with the same optimal conditions described above, when the load reaches 490 MW, a fault on the 8T circuit breaker at Talega (a single event), will remove two transmission lines; TL13836 which connects Talega to Pico and TL13831 which connects Talega to Rancho Mission Viejo. The outage of these two transmission lines will cause the flow of power on sections A and C of the transmission line connecting three substations, Talega to Pico to San Mateo substations [TL13846], to reach its maximum loading. Above 490 MW, SDG&E will be forced to shed load either pre-contingency or install an SPS which will automatically shed load following the event.

The 2014 forecast showed South Orange County reaching 490 MW beyond 2023, but the most recent 2015 load forecast now shows South Orange County reaching 490 MW in 2023.

B. Forecasted Load Growth by 2025

As discussed above, the forecast shown on Table 4-1 of the January 15 Testimony on 38 was created in 2014. It shows load growing to 481 MW by 2023. Using this data, the 2025 load is found to be 496 MW. The 2015 forecast is complete, and the 2015 forecasted load is higher than the 2014 forecast (see Table 2-1 above).

Past and present forecasts have shown growth in South Orange County and the rate of growth is accelerating. The 2015 forecast is higher than the previous 2014 forecast. Also, the all-time South Orange County peak load occurred in 2007 and SDG&E has added customers to its customer base since then. The accelerating load forecasts and the expanding customer base are indications that South Orange County is growing. This combined with the recorded 2007 peak event set conditions for an extreme peak day which may exceed the forecast. The Proposed Project will provide the transmission infrastructure necessary to meet load needs well into the future. It will prevent a prolonged outage caused by a failure at Talega Substation. It will remove the need to interrupt customer load (shed load). It will ensure that SDG&E and CAISO meet regulatory compliance requirements.

CHAPTER 3 THE DEIR'S "NO PROJECT" ALTERNATIVE IS NOT FEASIBLE

Section 1. Introduction (Witness Scott Boczkiewicz)

The CPUC's DEIR states: "The purpose of describing and analyzing a No Project Alternative is to allow decision-makers to compare the effects of approving versus not approving the proposed project."[91]

In Section 3.0 "Description of Alternatives," the DEIR makes various statements about what it is reasonable to expect will happen if SDG&E's Proposed Project is not approved. These include:

- "Regardless of whether the proposed project is constructed, it is reasonably foreseeable that the following would occur prior to 2018 (SDG&E 2012; CAISO 2014): "Talega Substation's STATCOM would be replaced …"[92]

- "In addition, if equipment at Capistrano Substation or existing distribution or 138-kV lines within the South Orange County Service Area fail or would be inadequate to serve customer demand, it is anticipated that the applicant would replace the equipment or facilities pursuant to CPUC General Order 131-D and CEQA Guidelines Section 15260 et seq. and 15300 et seq. (statutory and categorical exemptions)."[93]

- "Given the applicant's ability to replace failed or inadequate equipment at Capistrano Substation to meet conditions that may occur under the No Project Alternative pursuant to General Order 131-D and CEQA (see above), it is clear that the No Project Alternative would meet Objective 2 as defined by the CPUC (Section 1.2.1, 'Objectives of the Proposed Project')."[94]

- Referring to two expected NERC Category C (N-1-1) overloads, the DEIR states: "In accordance with CPUC General Order 131-D, it is anticipated that the applicant would implement system adjustments (e.g., reconductor 138-kV line segments) prior to this date to ensure that some or all of these overload scenarios do not occur. Examples of system

[91] DEIR at 3-3.
[92] DEIR at 3-4 (footnotes omitted).
[93] DEIR at 3-4 (footnotes omitted).
[94] DEIR at 3-5.

adjustments that could be implemented may be similar to the installations discussed under Alternatives B1 through B4."[95]

- "In addition, under the No Project Alternative, it is assumed that energy efficiency improvements and distributed generation facilities (including rooftop solar generation) will continue to be implemented throughout the 10-year planning horizon that will incrementally reduce load on SDG&E's 138-kV South 12 Orange County System."[96]

- "Given the anticipated rooftop solar facility installations and the applicant's ability to replace both distribution line facilities and 138-kV line facilities to meet conditions that may occur under the No Project Alternative, this alternative would fully meet Objective 1 as defined by the CPUC (Section 1.2.1, 'Objectives of the Proposed Project')."[97]

Notwithstanding the above description of the No Project Alternative, in DEIR Section 5.0 "Comparison of Alternatives," which compares the environmental impacts of the No Project Alternative to the Proposed Project, the DEIR states:

> Under the No Project Alternative, it is assumed that <u>none of the components of the proposed project would be constructed</u>. All of the significant impacts from construction and operation of the proposed project would be avoided. It is anticipated that <u>minor maintenance work</u> would occur as needed to repair or replace failed or inadequate substation equipment and transmission line facilities as described in Chapter 3, "Description of Alternatives." Such <u>maintenance activities are not expected to cause a significant impact</u> as they would be constructed without obtaining a Certificate of Public Convenience and Necessity or Permit to Construct from the CPUC pursuant to CPUC General Order 131-D and CEQA Guidelines Section 15260 et seq. and 15300 et seq. (statutory and categorical exemptions). Work that may require review pursuant to CEQA is not considered part of the No Project Alternative.[98]

In the sections below, SDG&E addresses the infeasibility of the No Project Alternative as described in DEIR Section 5.0, including the projects that are reasonably expected to occur in the near future if the Commission were to select the No Project Alternative and their estimated cost.

[95] DEIR at 3-6 (footnotes omitted).
[96] DEIR at 3-6.
[97] DEIR at 3-6.
[98] DEIR at 5-4 (emphasis added).

Section 2. The No Project Alternative Does Not Comply with Mandatory NERC Reliability Standards (Witness John Jontry)

As set forth in SDG&E's January 15 Testimony and in Chapter 2 above, SDG&E's Proposed Project will mitigate expected violations of mandatory NERC Reliability Standards TPL-003-0b and TPL-002-0b as interpreted by FERC. The No Project Alternative does not mitigate these violations of the NERC reliability standards.

SDG&E's Project Objectives include providing transmission system reliability to South Orange County. A critical and express part of that objective is: "Comply with mandatory North American Electric Reliability Corporation (NERC), Western Electric Coordinating Council (WECC) and California Independent System Operator (CAISO) transmission planning and operations standards."[99]

The CPUC recognizes: "Components of the applicant's South Orange County transmission system that connect to the regional electrical grid managed by the CAISO must be constructed and maintained in compliance with mandatory NERC, WECC, and CAISO standards."[100]

The CPUC's DEIR, however, provides "objectives of the proposed project defined by the CPUC for CEQA review."[101] Notwithstanding SDG&E's obligation to comply with FERC approved NERC Reliability Standards under the Federal Power Act Section 215,[102] the CPUC re-wrote SDG&E's project objective to <u>exclude</u> compliance with the mandatory NERC Reliability Standards. Instead of providing the transmission reliability required by FERC through the NERC Reliability Standards, the CPUC's DEIR identifies the project objective as: "Reduce the

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[99] Proponent's Environmental Assessment at 1-3.
[100] DEIR at 1-8.
[101] DEIR at 1-8
[102] 16 USC § 215.

risk of instances that could result in the loss of power to customers served by the South Orange County 138-kV System through the 10-year planning horizon."[103]

The No Project Alternative fails to meet a basic objective of the Proposed Project, prevents SDG&E from complying with the FERC-approved NERC Reliability Standards, and is infeasible.

Section 3. The No Project Alternative Is Infeasible Unless it Includes Rebuilding Capistrano Substation

A. To Provide Reliable Electric Service, Capistrano Substation Must be Rebuilt (Witness Karl Iliev)

SDG&E's January 15 Testimony, Chapter 5, discusses the need to rebuild the Capistrano Substation in detail. As summarized:

The aging Capistrano Substation has the following issues, which threaten the reliability of electric service to SDG&E's customers served by the substation:

- Capistrano Substation has a non-standard configuration that does not meet current operating criteria or reliability requirements.
- Capistrano Substation uses older technology that is more volatile than current technology, and site constraints have the 138 kV capacitor in a less than optimal location.
- Capistrano Substation has poorly performing equipment due to age, type, and condition.
- The existing structures, foundations, and equipment do not conform to the current recommended practices for seismic design of substations as provided in IEEE 693 and ASCE 113, and older existing electrical equipment does not meet the seismic withstand capability and has not been seismically qualified as provided in IEEE 693.
- Capistrano Substation currently serves 13,400 residential and 1,784 commercial and industrial meters, and San Juan Capistrano alone had an estimated 2013 population of 35,852 people. These customers are at risk due to the lack of reliability.

[103] DEIR at 1-8.

- Capistrano Substation's transformer loading is currently at 85% capacity at peak, and has little capacity for load growth or supporting neighboring substations.

- Preventive maintenance hours have been increasing at 15% annually, mainly due to the aging infrastructure. SDG&E has had to replace equipment that has failed or is obsolete such that no spare parts are available.

- The outage history and corrective (non-programmed) maintenance history over the last 15 years shows increasing trends caused by 138 kV and 12 kV disconnect switches not operating properly, 12 kV and 138 kV capacitor issues, 138 kV and 12 kV potential transformer issues, and various hot spots from connections on both 138 kV and 12 kV busses.

- Capistrano Substation currently has distribution circuit ties with its neighboring substations, Laguna Niguel and Trabuco, but these ties cannot be utilized during certain system conditions because of Capistrano Substation's high loading and lack of available capacity.

- The current control shelter configuration does not meet SDG&E's new security guidelines due to its unprotected windows and size restrictions.

By completely replacing equipment, upgrading and rebuilding the substation to SDG&E's current design standards, all of the above reliability concerns are addressed.[104]

Capistrano Substation needs to be rebuilt to address these issues even if Capistrano remains a 138/12 kV substation and does not include a 230/138 kV substation yard. Attached as Confidential Attachment 17 are recent photographs of Capistrano Substation and some of its equipment. These photographs show its non-standard configuration, aging and outdated equipment, and structures not meeting current seismic standards.

Rebuilding the Capistrano Substation as a 138/12 kV substation is estimated to cost between $135 million - $165 million (includes AFUDC). If the No Project Alternative does not permit the rebuilding of Capistrano Substation, at least as a 138/12 kV substation, then it does not permit SDG&E to provide reliable electric service to its customers served by the Capistrano Substation.

[104] SDG&E January 15 Testimony at 98-102.

B. Simply Replacing Equipment As It Fails Is Not Prudent and Does Not Provide Reliable Electric Service (Witness Karl Iliev)

SDG&E's January 15 Testimony explains that simply replacing failing equipment at the existing Capistrano Substation is not adequate to provide reliable electric service. For example: "Replacing equipment in kind will not change the existing layout configuration and therefore will not eliminate the risks of forced outages to SDG&E's customers arising from the non-standard configuration of the transmission bus and the distribution bus."[105] "Simply replacing equipment does not bring the existing structures and foundations up to the latest seismic standards. Placing IEEE 693-qualified equipment in and on the existing structures and foundations still leave the equipment at risk."[106] "Simply replacing equipment does not address the security concerns regarding the existing substation."[107]

More fundamentally, SDG&E does not consider replacing equipment only as it fails, and thus disrupts electric service, to be prudent or consistent with its obligation to provide reliable electric service.

Capistrano Substation is over 60 years old. SDG&E's Substation Equipment Assessment team has identified its aging equipment and infrastructure as beyond its useful life. SDG&E analyzes the useful life of substation equipment as discussed in its January 15 Testimony and determines whether the risk of failure is sufficient to warrant its replacement. Under that standard, SDG&E has determined that much of the significant equipment at Capistrano Substation needs to be replaced.

[105] SDG&E January 15 Testimony at 86.
[106] SDG&E January 15 Testimony at 86-87.
[107] SDG&E January 15 Testimony at 87.

As discussed in SDG&E's January 15 Testimony,[108] rebuilding Capistrano Substation within its existing footprint would pose a safety risk to workers, would take longer—thus costing more, and would create a greater reliability risks to customer electric service. Moreover, as stated in SDG&E's January 15 Testimony, the "existing substation site is not large enough to rebuild the 138 kV switchyard in a breaker and a half configuration. If SDG&E were to rebuild inside the existing yard, the configuration of the transmission rebuild would be limited to a single breaker – single bus configuration. Rebuilding in-place would also create physical limitations on the number of additional element positions that can be added to only two (transmission lines and distribution transformers). This limitation would not meet the needs for a reliable transmission configuration as mentioned above or any future customer load growth."[109]

To achieve reliability, even if 230 kV service were not added at Capistrano Substation, the rebuild of Capistrano Substation would occur in the same locations on the SDG&E-owned substation property as the Proposed Project.

C. Simply Replacing Equipment Does Not Allow Additional Transmission Lines to Be Connected to Capistrano Substation (Witness Karl Iliev)

The CPUC's DEIR asserts that the No Project Alternative meets the CPUC's "Objective 2," which is stated to be "Replace inadequate equipment at Capistrano Substation."[110] The CPUC asserts that, "[g]iven the applicant's ability to replace failed or inadequate equipment at Capistrano Substation to meet conditions that may occur under the No Project Alternative,"[111] the No Project Alternative meets the CPUC's Objective 2.

Referring to Objective 2 and Capistrano Substation, the DEIR states: "The replacement of equipment (e.g., transformers) is expected to increase the electrical distribution capacity of

[108] SDG&E January 15 Testimony at 87.
[109] SDG&E January 15 Testimony at 86.
[110] DEIR at 1-8, 3-5.
[111] DEIR at 3-5.

Capistrano Substation as well as help ensure the substation's reliability. It would also allow for the connection of three additional 138-kV transmission lines to the substation."[112]

To the contrary, no new lines or transformers can be added to Capistrano Substation without rebuilding the current station, either as proposed by SDG&E's Proposed Project or in-place, to add positions. Simply replacing equipment at Capistrano Substation also would not increase capacity as increasing equipment ratings is not feasible for reasons outlined in previous testimony.

A rebuild in place at the existing substation would limit the number of new elements to only two (either a TL or transformer) due to the space limitations of the existing substation site. Additional capacity at Capistrano Substation can only be accomplished by adding additional transformers, for which there is limited connection capability if additional transmission lines are to be added.

In addition, if multiple transmission lines are added, then it is SDG&E's standard to build a breaker and half configuration to ensure that any single point of failure is limited to a maximum of two elements, thereby minimizing transmission outage impacts, which is a reliability requirement for a transmission bus of this size.

In order for the substation to accommodate future transformers and transmission lines that may be required under the extended life of the station beyond the current planning horizon and to allow for a safe, more reliable, and faster construction schedule, a complete rebuild of the 138/12kV station would be proposed in the lower yard, similar to the 138/12kV elements of the Proposed Project.

[112] DEIR at 1-9.

D. The DEIR's Comparison of Alternatives Assumes Capistrano Substation Will Not Be Rebuilt (Witness Scott Boczkiewicz)

The CPUC's DEIR suggests that the No Project Alternative addresses SDG&E's need to address the reliability issues at Capistrano Substation, stating: "Given the applicant's ability to replace failed or inadequate equipment at Capistrano Substation to meet conditions that may occur under the No Project Alternative pursuant to General Order 131-D and CEQA (see above), it is clear that the No Project Alternative would meet Objective 2, as defined by the CPUC (Section 1.2.1, 'Objectives of the Proposed Project')."[113]

In comparing the No Project Alternative to the Proposed Project, however, the CPUC's DEIR asserts: "Under the No Project Alternative, it is assumed that none of the components of the proposed project would be constructed. All of the significant impacts from construction and operation of the proposed project would be avoided. It is anticipated that minor maintenance work would occur as needed to repair or replace failed or inadequate substation equipment and transmission line facilities as described in Chapter 3, 'Description of Alternatives.'"[114]

Rebuilding the 138/12kV Capistrano Substation is not "minor maintenance work." Because the DEIR's comparison of environmental impacts assumes no significant work at Capistrano Substation, SDG&E interprets the No Project Alternative to exclude rebuilding Capistrano Substation. For the reasons set forth above, that is not feasible.

As noted above, if the Proposed Project is not approved, the required work would still include rebuilding the Capistrano Substation as a 138/12 kV Substation in the same location as the Proposed Project locates the 138/12 kV yard. Therefore, the DEIR overstates the reduction

[113] DEIR at 3-5.
[114] DEIR at 5-4.

in temporary impacts that the No Project Alternative will have because it entirely omits those impacts associated with the required rebuild of the Capistrano Substation.

The DEIR identifies the significant and unavoidable environmental impacts of the Proposed Project as (1) temporary impacts to air quality, largely from the rebuild of Capistrano Substation, (2) temporary traffic impacts from partial closure (one of three lane) on Camino Capistrano to allow undergrounding of existing power and distribution lines,[115] and from any full closure of Camino Capistrano, Via Pamplona and Calle San Diego during undergrounding of existing power and distribution lines. (3) cumulative impacts on traffic, which arise specifically from the Camino Capistrano lane closure identified as having a significant traffic impact.

The DEIR's asserted reductions of these temporary adverse effects under the No Project Alternative are largely related to omission of the impacts associated with rebuilding the Capistrano Substation. Because Capistrano Substation must be rebuilt even if it remains a 138/12 kV substation, many of these impacts will occur under the No Project Alternative as well.[116]

Unless the CPUC precludes SDG&E from rebuilding Capistrano Substation, at least as a 138/12 kV substation, then rebuilding Capistrano Substation is work that should reasonably be expected to occur in the near future if the CPUC selects the No Project Alternative.

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[115] DEIR at 4.15-19. *Id.* SDG&E's construction and engineering contractors do not expect a full closure of any of these roads during underground construction and SDG&E did not state any full road closures in its Proponents Environmental Assessment (PEA).

[116] Only the 230/138 kV yard of the rebuilt Capistrano Substation under the Proposed Project would be avoided by the No Project Alternative. The emissions from that work constitute less than half of the total anticipated Localized Significance Thresholds (LST) exceedances for all Capistrano Substation emissions estimated for the Proposed Project (DEIR Table 4.3-8a). Per the DEIR, the total emissions of the Proposed Project constitute "less than one percent of the total SCAQMD's daily emissions inventory." DEIR at 6-15.

Section 4. The No Project Alternative Does Not Provide Reliable Transmission

A. The No Project Alternative Fails to Address Transmission Reliability Concerns (Witness Cory Smith)

The No Project Alternative does not include a 2nd 230kV source independent of Talega Substation and therefore does not meet SDG&E's reliability Objectives 1(a) or 3, or even CPUC's Objective 3. The approximately 300,000 people who rely on SDG&E electricity in South Orange County would remain exposed to the risk of service interruption arising from catastrophic events at Talega Substation or a forced outage during Talega maintenance events, as discussed in SDG&E's January 15 Testimony, Chapter 4, Sections 4-5, and in Chapter 2 above.

The No Project Alternative would require replacement of two transformers at Talega Substation estimated to cost between $15 million - $20 million and future replacement of the STATCOM currently located at Talega Substation or addition of a new dynamic voltage control device at a rebuilt Capistrano Substation to maintain voltage support at an estimated cost of $81 million - $99 million. This cost estimate does not include the potential purchase of additional easements on Camp Pendleton to accommodate the replacement equipment. None of these replacements is needed if the Proposed Project is constructed.

The No Project Alternative does not address the risk of losing service to some or all South Orange County customers during or after Category C events, forced outages during a Talega Substation maintenance outage, or forced outages during maintenance at other substations. This alternative does not address Category C contingencies under which SDG&E would not be able to shed load quickly enough to remain within Applicable Ratings, and thus would not permit SDG&E to remain compliant with FERC-approved NERC Reliability Standards as required by Section 215 of the Federal Power Act.

In the DEIR, the CPUC recognizes that Category C3 (N-1-1) overloads will occur, and states: "In accordance with CPUC General Order 131-D, it is anticipated that the applicant would implement system adjustments (e.g., reconductor 138-kV line segments) prior to this date to ensure that some or all of these overload scenarios do not occur."[117] But in comparing the No Project Alternative to the Proposed Project, the DEIR states that only "minor maintenance work would occur as needed to repair or replace failed or inadequate substation equipment and transmission line facilities."[118] Because the DEIR Alternative B1 proposes the same reconductoring that the CPUC identifies as "anticipated" under the No Project Alternative,[119] it seems clear that the CPUC's No Project Alternative only includes "minor maintenance work" and not reconductoring of any 138 kV lines.

SDG&E's practice is to provide reliable service to its customers and the No Project Alternative fails to meet SDG&E's operating and reliability criteria.

As the CPUC agrees, demand side management and energy conservation programs would not offset current transmission overload issues in the south Orange County System as the expected impact of such programs is already included in SDG&E's load forecasts for the area.[120]

B. Solar Rooftop Systems Will Not Provide Reliable Electric Service to SDG&E's South Orange County Customers (Witness Cory Smith)

The CPUC's DEIR asserts:

> In addition, under the No Project Alternative, it is assumed that energy efficiency improvements and distributed generation facilities (including rooftop solar generation) will continue to be implemented throughout the 10-year planning horizon that will incrementally reduce load on SDG&E's 138-kV South Orange County System. The installation of new rooftop solar generation facilities is expected to continue during the 10-year planning horizon for the proposed project. Nationwide, the cost of new solar

[117] DEIR at 3-6.
[118] DEIR at 5-4.
[119] Compare DEIR at 3-5 to 3-6 with DEIR at 3-7.
[120] DEIR, Appendix B, CEQA Alternatives Screening Report at 3-4.

> installations is anticipated to continue to decrease, and the amount of solar power generation is expected to increase through 2024. …
> The applicant's data indicate that by the end of 2014, more than 12.6 megawatts (MW) of demand within the south Orange County service area will be provided by rooftop solar generation, which is approximately 3 percent of the approximately 450 MW South Orange County 138-kV System (see Appendix B). Should the installation of new rooftop solar generation continue to increase within southern Orange County, the additional generation would substantially offset the increase in electrical demand anticipated by the applicant, which is estimated at 5.7 MW per year (1.1 percent per year) through 2024; Table 1-1. In 2013, 3.1 MW of new solar generation [nameplate] was installed within the applicant's South Orange County service area (see Appendix B). Additionally, peak demand typically occurs during daylight hours in the summer, when rooftop solar facilities are capable of generating power.[121]

The DEIR's analysis is mistaken in several respects and rooftop solar (PV) will not ensure reliable electric service for SDG&E's South Orange County customers.

While PV produces energy when the sun shines, the majority of PV systems are oriented due south to maximize energy production with a resultant production peak occurring at approximately 1 pm. However, as shown in Figure 3-1 below, residential customer load will peak at 6 pm or later when PV system output is de-minimus. This is confirmed in Figure 3-2, which is a plot showing actual load consumed in South Orange County with an estimate of possible solar production. Hourly solar production data was created using the known installed capacity of solar installations in South Orange County (12.5 MW) and data available from NREL.[122] The plot shows load supplied to each substation and the sum of all the substation loads for a 24 hour period starting at 12 am. At the bottom of the plot is an estimate of PV

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[121] DEIR at 3-6 (footnote omitted). As recognized in footnote 6, DEIR at 3-6: "The rooftop solar generation capacity data provided by the applicant refer to the nameplate capacity of installed rooftop solar equipment. The applicant is not able to report the specific amount of power provided by Net Energy Metering program participants with rooftop solar installations." SDG&E does not know how much energy is produced by a customer's PV system as that energy is consumed by the customer. As the CPUC's footnote recognizes: "Net Energy Metering program generation, however, is accounted for in the South Orange County 138-kV System's recorded (historical) peak loads (Figure 1-1) and is reflected in the applicant's system-wide load forecasts, which are based in part, on historical peak loads."

[122] NREL National Renewable Energy Laboratory. http://gisatnrel.nrel.gov/PVWatts_Viewer/index.html

production for each hour. Note, actual PV production is netted with load (it is included with substation load data). As Figure 3-2 shows, South Orange County load is reaching its peak as the PV production is waning.

<u>Figure 3-1: Typical Residential PV Customer Load Profile</u>

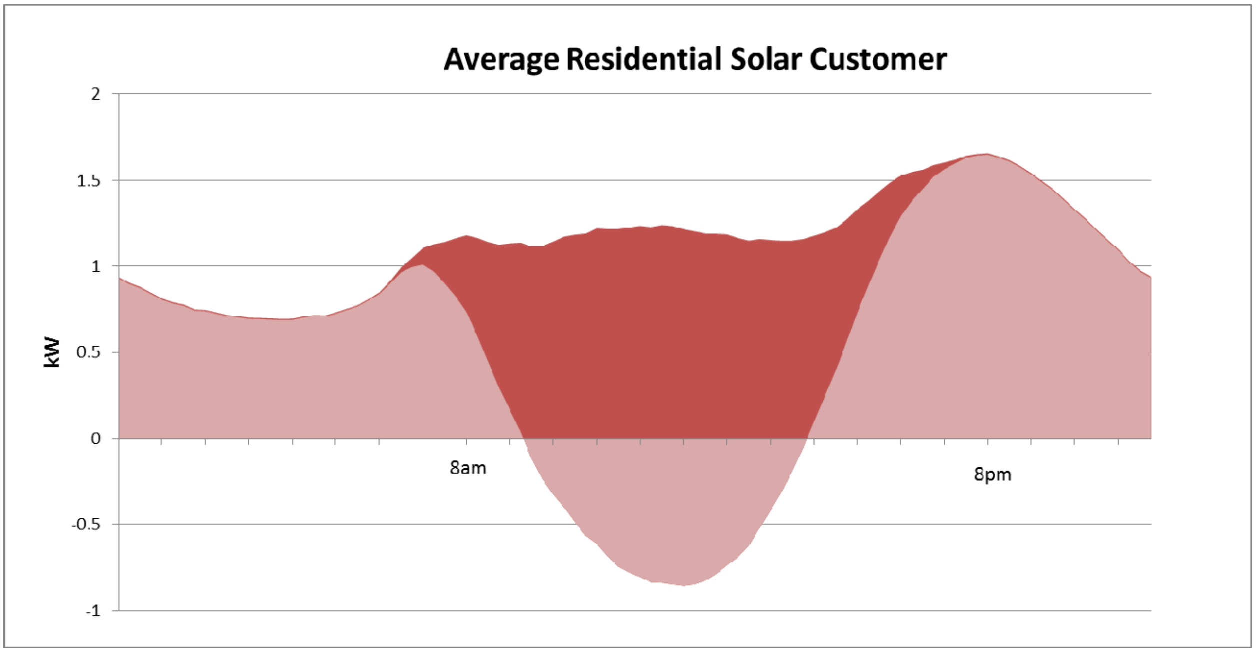
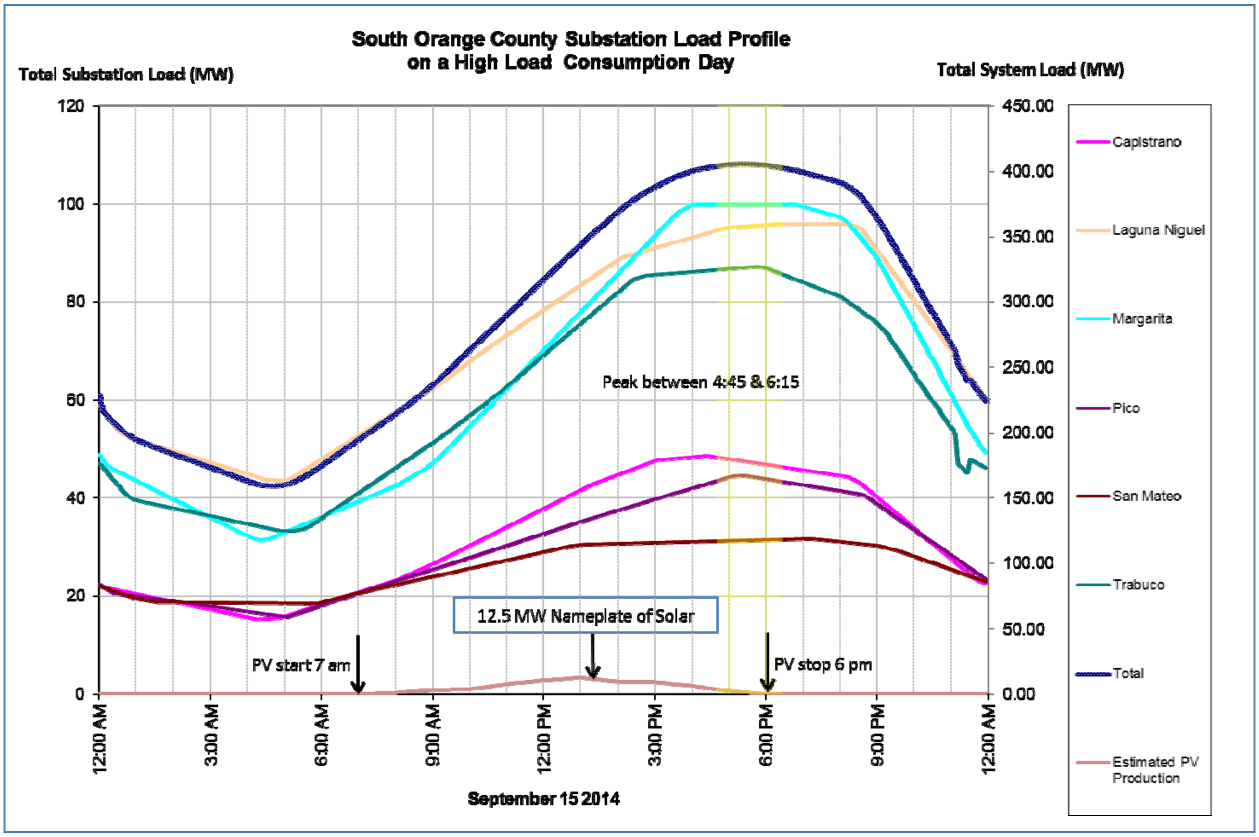


Figure 3-2: South Orange County Load Profile with Installed PV MW Nameplate Profile.

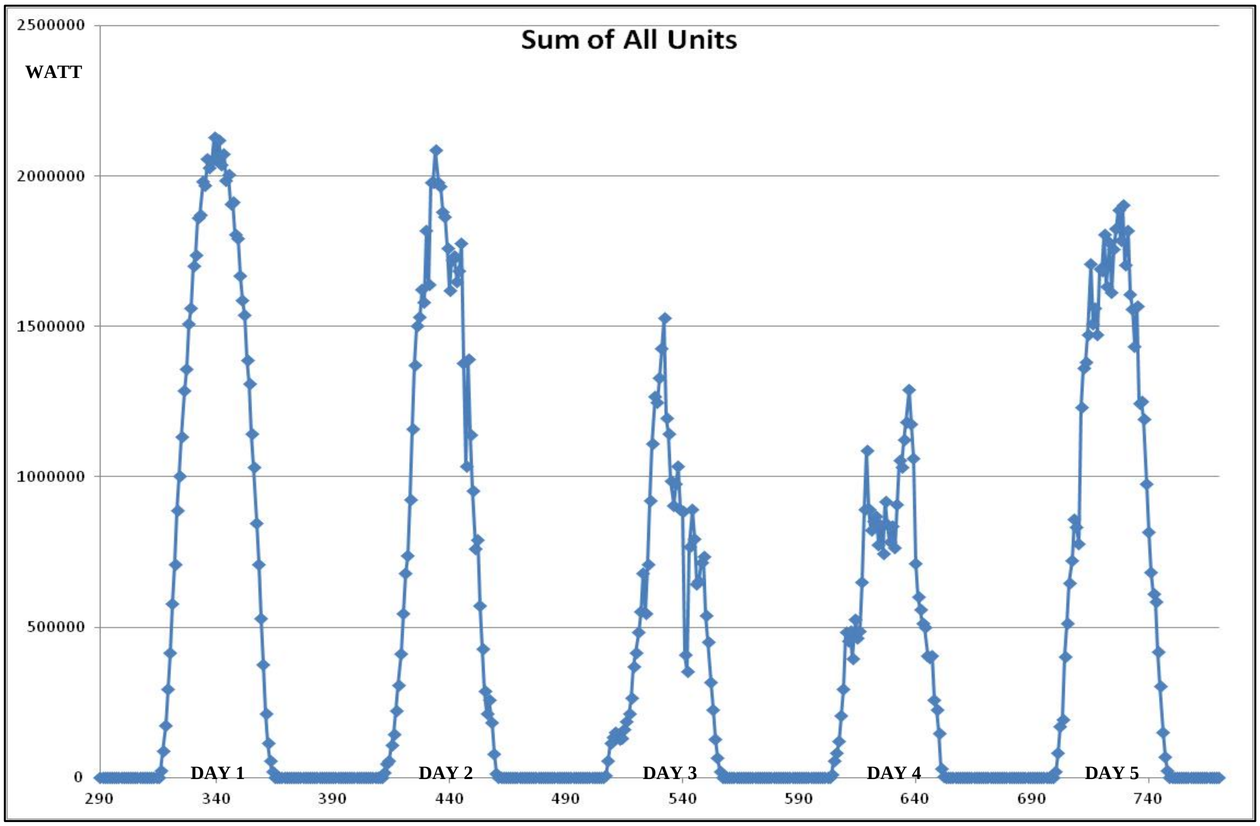


In order to shift the PV production to the evening, some form of energy storage needs to be utilized. Existing PV systems do not have energy storage and it is unlikely that future PV installations will install energy storage given the additional costs. Additionally, an energy management system is required to accomplish this time shifting action at another additional cost.

Additionally, as the amount of South Orange County PV increases, the marine layer will impact all PV systems uniformly and create an aggregate transmission issue that must be mitigated at the transmission level. Figure 3-3 is a plot showing the aggregate solar production of a group of PV customers over a five day period. Day 1, production smoothly rises to a peak of a little over 2 MW (2,000,000 Watts) and falls off smoothly. Day 2 is roughly the same, but by Day 3 a marine layer interferes causing spotty production. Day 4 is a little worse than Day 3 and on Day 5 production begins to improve. This example is only 2 MWs. As suggested by the

DEIR, this could grow to 20 MW and beyond. Large power swings combined with intermittency will require addition control measures which may require costly equipment ($81 million - $99 million for a dynamic voltage control device) which is not included in the DEIR No Project Alternative. The Proposed Project provides a connection to the larger 230 kV system, which will mitigate these impacts.

Figure 3-3: Five Days of Aggregated Residential Solar Production



Because South Orange County receives all of its power through Talega Substation, loss of the 230 kV or 138 kV service at or from Talega will result in the loss of power to the entire South Orange County area. Contrary to popular belief, customers' PV systems will also go dark as the inverters, in response to Rule 21 and IEEE 1547 standards, disconnect upon loss of a grid voltage reference. While there is a great deal of discussion regarding microgrids, there are no generation resources and control systems in place to allow an islanded South Orange County to operate as an island away from the main grid. The generator located at Prima Deshecha landfill which is connected to the 12 kV distribution network is not designed for islanded operation.

The Proposed Project creates a second connection to the main grid at a rebuilt Capistrano Substation. This will ensure that PV systems continue to operate during an outage of Talega Substation. Furthermore, the second connection at Capistrano will stabilize power fluctuations caused by PV generation. South Orange County will be able to accept a large penetration of residential PV without costly transmission upgrades.

The DEIR assumptions about PV growth also may be overly optimistic. There is uncertainty regarding the pace of future PV installations. Potential changes in rate design, NEM 2.0 and investment tax credits likely will have some impact on PV adoption in South Orange County.[123] Rate design changes can have a significant impact, as shown in the attached article regarding a lawsuit in Arizona.[124] Regulatory actions are currently active in California on rate design.[125] The federal investment tax credit is set to expire on December 31, 2016. In sum, there is no guarantee that the predicted amount of PV penetration in South Orange County (which would not impact the peak loads there in any event), will even materialize.

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[123] *See, e.g.*, Attachment 18 ("Rooftop solar finds out utilities can disrupt, too")
[124] *See, e.g.*, Attachment 19 ("SolarCity sues Salt River Project over 'anti-competitive' solar customer rates").
[125] *See* Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations, R.12-06-013.

Section 5. To Provide Reliable Electric Service Without the Proposed Project, SDG&E Would Pursue Numerous Other Reliability Projects. (Witness Cory Smith)

SDG&E has an obligation to meet NERC reliability standards and CAISO planning standards. If the Commission were to select the No Project Alternative, SDG&E would have an obligation to implement, or where necessary seek authorization to implement, other projects in an attempt to ensure compliance with NERC reliability standards as well as more stringent CAISO standards.

To comply with the mandatory NERC Reliability Standards and provide reliable electric service, but not addressing the vulnerability created by having Talega Substation as the sole source of power to SDG&E's South Orange County system, SDG&E would seek to implement the following projects:

- SDG&E has identified upgrades needed to meet NERC standards under the CPUC's No Project Alternative. SDG&E would need to implement projects to upgrade transmission lines; TL13835A, TL13816, TL13836, TL13846A and TL13846C.

- As described in Section 3 above (and to add any transmission lines to Capistrano Substation), SDG&E also would need to proceed with rebuilding Capistrano Substation with space to add a voltage control device at Capistrano Substation.

- Without the Proposed Project, SDG&E will need to replace the two transformers at Talega Substation and replace the Talega STATCOM with a new dynamic voltage control device to be installed at either Capistrano or Talega substation.

In addition, to address the vulnerabilities arising from Talega Substation serving as the sole source of power to SDG&E's South Orange County system, SDG&E would seek authorization to construct a 138 kV transmission line from its San Luis Rey Substation located south of Camp Pendleton to San Mateo Substation located on the northern border of Camp Pendleton. Connection of a 138kV transmission line at San Luis Rey Substation, located in the city of Oceanside, County of San Diego, would require the addition of two new 230/138kV transformers. Since the PEA was filed, the generation at San Onofre was unexpectedly retired. This event prompted the CAISO to approve local voltage support equipment to be installed at San Onofre, Talega and San Luis Rey substations. To make room for the new equipment at San Luis Rey, the 138 kV yard is being retired and removed. The addition of new 138/230 kV transformers would require building of a 138 kV yard within the San Luis Rey Substation.

Section 6. The Reliability Projects That Would Be Necessary under the No Project Alternative Are More Costly Than the Proposed Project. (Witness Willie Thomas)

The projects that SDG&E would need to pursue if the Commission selected the No Project Alternative can be broken into several groups: (a) the work necessary to comply with NERC Reliability Standards; (b) the additional work necessary to mitigate the risk of a Talega Substation outage and other events that would cause load shedding; and (c) the additional work that would not be avoided if the Proposed Project is not approved.

Based on conceptual engineering and comparisons to other projects, SDG&E's preliminary estimate of the costs of the projects that SDG&E would reasonably expect to implement, and where necessary seek authorization to implement, to comply with NERC Reliability Standards if the CPUC selects the No Project Alternative are as follows:

- At an estimated cost from $97 million - $118 million (including AFUDC), upgrade or replace the several 138kV transmission lines identified in Section 5. The scope of work would include the following:
    - (1) TL13835A (Laguna Niguel to Talega Hub)
        - (a) Reconductor approximately 9.5 miles of overhead conductor and replace all structures.
        - (b) Reconductor of approximately 1,800 feet of underground cable in Vista Montana with and associated cable splices and termination.
        - (c) Reconductor of approximately 10,000 feet of underground cable segment from Laguna Niguel Substation to cable pole structure and associated cable

splices and terminations, includes new spices and terminations. The route generally goes south from Laguna Niguel Substation, on to Park Rd, east on Del Avion, and north on Golden Lantern Street, to a cable riser structure across the street from Laguna Niguel Dog Park. Traffic control will be required for cable pulling and splicing at six different vaults along the route.

(d) By reconductoring the line a SPS (special protection scheme) would be eliminated.

(e) Distribution facilities would need to be transferred (approximately 3.0 miles) to the new 138kV poles from Capistrano to Prima Deshecha Landfill.

(2) TL13816 (Capistrano to Pico)

(a) Reconductor approximately 1,800 feet of underground cable in Vista Montana and associated cable splices and terminations. To install the cable, extended outages would be required on TL13816 and TL13833 because they share the same trench and vaults, and crews would need the facilities de-energized to safely perform their work. Also, getting outages on the lines at the same time are likely not feasible due to system outage constraints. To facilitate the reconductor in this section of the line, a third trench, conduit and vault package would likely be necessary in Vista Montana, and would be similar to the Proposed Project.

(b) Reconductor approximately 24,000 feet of overhead conductor from approximately San Juan Creek road to San Juan Hills High School, and from the intersection of Vista Montana and La Pata avenue to Pico substation.

(3) TL13836 (Pico to Talega Sub)

(a) Reconductor approximately 2,200 feet from Talega to Talega Hub and replace six wood poles from Talega Sub to Talega Hub to improve reliability and fire resistance as they are within fire prone areas.

(4) TL13846A (Pico to Talega Hub)

(a) Reconductor approximately 4,000 feet of overhead conductor with bundled conductor, and replace approximately 3 poles with steel poles.

(5) TL13846C (Talega Hub to Talega Sub)

(a) Reconductor approximately 1,900 feet of overhead conductor and replace approximately 7 wood poles with steel poles.

(6) Move TL13846A From Pico East Bus to Pico West Bus

(a) To facilitate TL13846 crossing TL13833, replace steel pole adjacent to Pico with cable riser pole and install approximately 500ft of trench, conduit, cable to route to west bus.

(7) Move TL13833 From Pico West Bus to Pico East Bus

(a) To facilitate TL13833 crossing TL13846, replace steel pole adjacent to Pico with cable riser pole and install approximately 500ft of trench, conduit, cable to route to east bus.

- As stated in Chapter 3, Section 3, rebuilding Capistrano Substation as a 138/12 kV substation at an estimated cost between $135 million - $165 million (includes AFUDC).
- As described in Section 5 above, construct a new dynamic voltage control device (SVC, STATCOM or Synchronous Condenser) at the new rebuilt 138/12 kV Capistrano Substation or replace the existing STATCOM at Talega Substation at an estimated cost of $81 million - $99 million (with AFUDC, $89 million to $109 million).

Based on conceptual engineering and comparisons to other projects, SDG&E's preliminary estimate of the costs of the projects that SDG&E would not avoid without construction of the Proposed Project is as follows:

- As stated in Section 4 above, replacement of the two transformers at Talega Substation is estimated to cost between $15 million - $20 million (with AFUDC, $17 million to $21 million).

Based on conceptual engineering and comparisons to other projects, SDG&E's preliminary estimate of the costs of the projects that SDG&E would reasonably expect to implement, and where necessary seek authorization to implement, to provide a second source of power to South Orange County if the CPUC selects the No Project Alternative are as follows: At an estimated cost of $242 million - $296 million (includes AFUDC), add a second source from San Luis Rey Substation to San Mateo Substation by:

  - Addition of a new 138 kV substation at San Luis Rey, by adding two new 230/138kV transformers and expanding the existing San Luis Rey Substation,
  - 138kV Underground getaway from San Luis Rey into TL23006 Overhead structure (approximately 1,500 feet),
  - Reconductor of both sides of TL23006 with bundled conductor from San Luis Rey to SONGS Tap (approximately 18 miles),
  - Reconductor TL99904 (de-energized TL13832) from SONGS Tap to San Mateo Tap with bundled conductor (approximately 6.5 miles) on existing steel lattice towers,

- Replacement of TL13835 from San Mateo Tap to San Mateo with double circuit steel pole structures (approximately 12 structures), transfer of TL13835 conductor, and add new bundled wire for new 138kV (approximately 3,500 feet),
- Addition of a new transmission line terminal at San Mateo Substation (created by rebuilding the existing substation) and additional dynamic voltage support in South Orange County.

The total estimated cost of these projects would range from $580 million to $708 million, well in excess of the Proposed Project's estimated cost. This estimated cost would not be used for actual project budget costs, which could not be obtained until a higher level of engineering is done on the proposed design, but is provided for a comparison of the Proposed Project's cost to the No Project Alternative's reasonably anticipated costs.

Section 7. The Reasonably Expected Actions If the No Project Alternative Is Selected May Have Greater Environmental Impacts Than the Proposed Project (Witness Scott Boczkiewicz)

The CPUC's DEIR states: "The purpose of describing and analyzing a No Project Alternative is to allow decision-makers to compare the effects of approving versus not approving the proposed project."[126] The reasonably anticipated actions that would arise if the Commission were to select the No Project Alternative may have greater environmental impacts than the Proposed Project.

First, the CPUC's DEIR recognizes that at least one 138 kV line segment would need to be reconductored, but does not consider its environmental impacts. The CPUC asserts that the No Project Alternative would meet Objective 1 because of "the anticipated rooftop solar facility installations and the applicant's ability to replace both distribution line facilities and 138-kV line facilities to meet conditions that may occur under the No Project Alternative."[127]

Referring to two expected NERC Category C (N-1-1) overloads on a section of the Talega–Laguna Niguel–San Mateo 138-kV Line (TL13835) by 2020, the DEIR states: "In

[126] DEIR at 3-3.
[127] DEIR at 3-6.

accordance with CPUC General Order 131-D, it is anticipated that the applicant would implement system adjustments (e.g., reconductor 138-kV line segments) prior to this date to ensure that some or all of these overload scenarios do not occur. Examples of system adjustments that could be implemented may be similar to the installations discussed under Alternatives B1 through B4."[128]

In other words, the work reasonably expected under the No Project Alternative includes numerous potential smaller projects, including reconductoring of the same segment of the Laguna Niguel–Talega 138-3 kV Line (TL13835) that is contemplated under DEIR Alternative B-1. Thus, the environmental impacts of the No Project Alternative should be at least as great as the environmental impacts of Alternative B-1.[129]

The DEIR, however, when comparing environmental impacts of the Project and its alternatives, does not include any environmental impacts of the reconductoring project that it agrees would occur under the No Project Alternative. Specifically, reconductoring of TL13835 by itself, even without rebuilding Capistrano Substation, could still result in temporary exceedance of SCAQMD LST thresholds, which would be significant and unavoidable under CEQA.[130]

Second, as discussed above, to provide reliable electric service, SDG&E would seek to construct additional projects, including the reconductoring of other 138kV power lines in the south Orange County service territory and the construction of a new 138kV power line between the San Luis Rey Substation (located in the City of Oceanside, San Diego County) and the San Mateo Substation located in San Clemente, Orange County. These additional projects would

[128] DEIR at 3-6 (footnotes omitted).
[129] SDG&E discusses the infeasibility of Alternative B-1 in Chapter 4 infra.
[130] DEIR at 5-5.

result in increases in emissions of criteria pollutants, and could also include potential impacts to aquatic, biological and cultural resources during construction of the new 138kV power line from the San Luis Rey Substation. The environmental impacts of these projects may exceed those of the Proposed Project.

Section 8. The Talega STATCOM Would Not Be Replaced If the Proposed Project is Approved (Witness Cory Smith).

The CPUC's DEIR states: "Regardless of whether the proposed project is constructed, it is reasonably foreseeable that the following would occur prior to 2018 …: Talega Substation's STATCOM would be replaced …"[131]

This is not correct. As SDG&E expressly informed Energy Division: "The SOCRE Project removes the need to upgrade and replace 138 kV transmission in South Orange County and the need to replace the STATCOM when it reaches the end of its useful life. The STATCOM will only be replaced if the Project is not constructed and there is no 2nd 230 kV source."[132]

As stated in SDG&E's January 15 Testimony at 91-92, the STATCOM will be replaced, at an approximate cost of $81 million - $99 million (without AFUDC), only if the Proposed Project is not approved. Therefore, the environmental impacts of replacing the STATCOM should have been, but were not, considered for the No Project Alternative, but not for the Proposed Project.

[131] DEIR at 3-4 (footnotes omitted).
[132] SDGE 2/11/2015 Response to Energy Division Data Informal Data Request Dated February 6, 2015.

CHAPTER 4 THE DEIR'S RECONDUCTORING ALTERNTATIVE IS NOT FEASIBLE

Section 1. Introduction (Witness John Jontry)

The CPUC's DEIR describes "Alternative B1 – Reconductor Laguna Niguel–Talega 138-kV Line" (the "Reconductoring Alternative") as follows:

> Under Alternative B1, which was identified by the CPUC, a segment of the Laguna Niguel–Talega 138-kV Line (TL13835) would be reconductored with conductor of a comparable size but higher capacity, such as aluminum conductor steel supported (ACSS) or similar. ACSS has a higher operating temperature and greater resistance to overload than other types of comparably sized conductor, such as aluminum conductor steel reinforced (ACSR) (Southwire 2014). The use of ACSS or similar high-capacity conductor would allow for high power transfer (e.g., 273 megavolt amperes [MVA]) in comparison to the existing 138-kV line's 136 MVA rating.
>
> Under this alternative, a 138-kV segment (approximately 7. 8 miles long) from Capistrano Substation to Talega Substation would be reconductored (Figure 3-1). Reconductoring would occur along the same transmission line route (Segments 1b to 4) as the proposed project (Figures 2-1 and 3-1). In addition, an approximately 2.5-mile-long segment of transmission line (TL13835) from Laguna Niguel Substation would be tied into Capistrano Substation (but would not require reconductoring) at a location adjacent to the substation to create a new Laguna Niguel–Capistrano 138-kV Line under this alternative. Some structures may need to be replaced during reconductoring. Equipment at Capistrano Substation found to be inadequate would also be replaced.[133]

The Reconductoring Alternative is not feasible for the reasons discussed below. In brief, the Reconductoring Alternative does not achieve compliance with NERC Reliability Standards, does not rebuild Capistrano Substation as necessary to provide reliable electric service to its customers and to accommodate the proposed interconnection, and does not mitigate the vulnerability of Talega Substation serving as the sole source of power to SDG&E's South Orange County system. If the Commission were to select the Reconductoring Alternative, SDG&E reasonably expects to implement, or where necessary seek authorization to implement, numerous other reliability projects that likely will cost more than the Proposed Project and which may have much greater environmental impacts.

[133] DEIR at 3-7.

Section 2. The Reconductoring Alternative Does Not Comply with Mandatory NERC Reliability Standards (Witness Cory Smith)

Compliance with NERC transmission planning standards require that all transmission equipment must be within Applicable Ratings at all times. The category or type of contingency does not change this. NERC standards allow load shedding to be used following an event which removes multiple elements from service as long as all transmission elements remain within the Applicable Rating. If any element falls outside the Applicable Rating, a System Operating Limit has been violated which is a violation of NERC operating standards.

NERC transmission planning standards are designed to identify elements which may load above the Applicable Rating in the future. In compliance with NERC transmission planning standards, SDG&E assessed DEIR Alternative B1 (Reconductor section of TL13835A & loop into Capistrano).

The description in the DEIR of Alternative B1 lacks detail about the termination points of the new Capistrano transmission line interconnections. This is important. The location of circuit breakers with respect to transmission equipment will define how the system reacts to a contingency event (fault) which forces the protection system to isolate failed equipment (*e.g.*, a single circuit breaker may protect two pieces of equipment). To create a power flow model, SDG&E had to make assumptions about this CPUC alternative. There are no vacant positions on the existing 138 kV bus at Capistrano and there is not enough space to extend the existing bus. SDG&E would need to build a new 138 kV substation in the location identified by the Proposed Project, which is located on the same property as the existing 138 kV substation, and move all connections to the new substation (the old substation would be razed). The rebuilt Capistrano 138 kV substation would be designed to minimize exposure to bus faults (Category C1) and circuit breaker failures (Category C2). To accomplish this, the new substation would be of "breaker and a half" design and transmission lines would be connected in such a way that no two transmission lines share a common circuit breaker. This reduces the risk of a circuit breaker failure removing two transmission lines from service.

Assuming SDG&E is successful in its design goals, Category C1 and C2 contingencies at a rebuilt Capistrano Substation will only remove a single transmission line or transformer. This leaves the overlapping outage of transmission elements (Category C3).

SDG&E has identified contingencies which would cause transmission equipment to load above the Applicable Rating. Table 4-8 lists four transmission lines that will exceed the maximum Applicable Rating. These are C3 (N-1-1) events, which would require SDG&E to shed load following the first transmission line outage to prevent a violation following the second transmission line outage.

Table 4-8 – Alternative B1: Transmission Lines which will Exceed Emergency Rating.

South Orange County Load Level. (MW)	Based on latest forecast. Year load will be Reached	Transmission Line Outage	Transmission Line Outage	Transmission Line which will meet or exceed its emergency rating
450	2017	TL13831	TL13835	TL13816
475	2020	TL13831	TL13846	TL13836
500	2024	TL13835	TL13836	TL13846C
500	2024	TL13836	TL13846	TL13835C

If the Commission were to select the DEIR Alternative B1, the "Reconductoring Alternative," SDG&E would need to upgrade these four additional transmission lines to remain compliant with mandatory NERC transmission planning standards. In all, under this Alternative, SDG&E would need to implement projects to upgrade transmission lines TL13816, TL13846C, TL13835C, and TL13836 in addition to the transmission line reconductored as part of Alternative B1 "a 138-kV segment (approximately 7.8 miles long) from Capistrano Substation to

Talega Substation").[134] As set forth in Section 7 below, without preliminary engineering of such project and based solely on comparison to similar projects, SDG&E estimates that such projects would cost from $64 million - $79 million.

As discussed below, upgrading these lines alone would not provide reliable electric service to SDG&E's South Orange County customers.

Section 3. The Reconductoring Alternative Is Infeasible Because it Does Not Rebuild Capistrano Substation (Witness Karl Iliev)

For the reasons set forth above with respect to the DEIR's No Project Alternative, the failure of the DEIR's Reconductoring Alternative to include rebuilding the Capistrano Substation—at least as a 138/12 kV substation--means that it will not provide reliable electric service to SDG&E's South Orange County customers. The DEIR's Reconductoring Alternative provides only that "Equipment at Capistrano Substation found to be inadequate would also be replaced."[135]

Adequate reliability can only be gained by a complete rebuild and expansion of the existing substation. Replacing aging equipment after it fails[136] will not achieve the improvements provided by the Proposed Project, and will not achieve SDG&E's goal to provide reliable electric service to its South Orange County customers.

Moreover, the Reconductoring Alternative cannot be implemented without rebuilding Capistrano Substation. The CPUC DEIR's Reconductoring Alternative states: "In addition, an approximately 2.5-mile-long segment of transmission line (TL13835) from Laguna Niguel Substation would be tied into Capistrano Substation (but would not require reconductoring) at a

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[134] DEIR at 3-7.
[135] DEIR at 3-7.
[136] SDG&E already has identified Capistrano Substation equipment as at or near the end of its useful life. By not directly stating that the Reconductoring Alternative includes rebuilding the Capistrano Substation, the DEIR presumably is stating that SDG&E must wait until the equipment fails to replace it.

location adjacent to the substation to create a new Laguna Niguel–Capistrano 138-kV Line under this alternative."[137]

Even if the Capistrano Substation did not otherwise require rebuilding, Capistrano Substation and the transmission lines feeding into it would require a rebuild to facilitate TL13835 entrance into the substation. To loop TL13835 into Capistrano Substation would require the addition of two new positions, which the current configuration cannot accommodate.

Any rebuild of Capistrano Substation should also account for spare positions to meet future needs for additional lines, distribution transformers, or other elements outside of the current planning time horizon, but within the service life of the rebuilt station. It is more efficient to account for these needs at the time of the rebuild, rather than to build the station for the minimum needs identified and require another expensive rebuild for any unforeseen substation expansion. SDG&E would rebuild the station to add an ultimate capacity of a minimum of four new elements, which would necessitate relocation of the switchyard to the lower yard on SDG&E-owned property to obtain these positions. The additional Tie Lines would also require the bus configuration to be a breaker and half to meet SDG&E's reliability standards. These additional positions and new configuration will require Capistrano Substation to be rebuilt similar to that identified in SDG&E's Proposed Project, without the proposed scope of the 230 kV switchyard.

Additionally, the ability to rebuild the substation within its existing footprint (to a maximum of two additional positions) would be limited under the current transmission configuration as CAISO does not allow extended outages on TL13835 that would be needed to

[137] DEIR at 3-7.

implement Alternative B1 because this would result in Laguna Niguel substation being fed by only one transmission line.

Rebuilding Capistrano Substation as a 138/12 kV substation is estimated to cost $135 million - $165 million (includes AFUDC).

Section 4. As Described, the Reconductoring Alternative Lacks Transmission and Distribution Work Necessary to Make It Feasible (Witness Willie Thomas)

As described in the DEIR, the transmission and distribution line work set forth in Alternative B-1 is not feasible because:

a. TL13835A (Talega to Capistrano substations) – cannot simply be reconductored with a similar size ACSS. A larger diameter ACSS compared to what exists today would be required to reach the ampacity rating of 273 MVA. The sag of the ACSS wire may also exceed the minimum ground clearance requirements required in GO 95. It is best to assume that all approximately 45 structures will need to be replaced.

b. Existing UG cables do not meet required rating of 273 MVA. Cables would have to be replaced for TL13835A, requiring an extended outage which may not be feasible as it would leave Laguna being fed by only one transmission line, TL13837, during the extended outage.

c. A distribution circuit shares many of the same structures from Capistrano to the west end of Vista Montana Rd. The new poles would need to be designed to support the 138kV and well as the distribution level, unless the distribution was relocated as in the Proposed Project. To avoid relocating the distribution, it would be reasonable to build the new line as double circuit structures rather than single circuit.

Section 5. The Reconductoring Alternative Does Not Provide Reliable Electric Service (Witness Cory Smith)

The DEIR's Reconductoring Alternative does not include a second 230 kV source independent of Talega Substation. Therefore, it does not address the system vulnerabilities that arise from having Talega Substation serve as the sole source of power to SDG&E's South Orange County system. This vulnerability would remain, despite incurring the cost to reconductor most of the 138 kV transmission lines in South Orange County, which the Proposed Project renders unnecessary.

Moreover, the Reconductoring Alternative, by not providing a second source, would require SDG&E to replace two transformers at Talega Substation at an estimated cost between $15 million - $20 million and future replacement of the STATCOM currently located at Talega Substation or addition of a new dynamic voltage control device at a rebuilt Capistrano Substation to maintain voltage support at an estimated cost of $81 - $99 million. This cost estimate does not include the potential purchase of additional easements to accommodate the replacement equipment. None of these projects at Talega Substation is needed if the Proposed Project is constructed.

Section 6. To Provide Reliable Electric Service, SDG&E Would Pursue Other Reliability Projects (Witness Cory Smith).

If the Commission were to select the Reconductoring Alternative, SDG&E would reasonably expect to implement, and where necessary seek authorization to implement, the following projects in addition to the work stated in this Alternative.

To comply with the mandatory NERC Reliability Standards and provide reliable electric service, but not addressing the vulnerability created by having Talega Substation as the sole source of power to SDG&E's South Orange County system, SDG&E would seek to implement the following projects:

- As described in Section 2 above, SDG&E has identified transmission line upgrades in addition to the upgrade contemplated by DEIR Alternative B1 which are needed to meet NERC standards under this Alternative. SDG&E would need to implement projects to upgrade transmission lines; TL13835A, TL13835C, TL13816, TL13846C, and TL13836. (Not all of these projects require transmission line replacement).

- As described in Section 3 above, SDG&E also would need to proceed with rebuilding Capistrano Substation as a 138/12 kV substation.

- Without the Proposed Project, SDG&E will need to replace the two transformers at Talega Substation and replace the Talega STATCOM with a new dynamic voltage control device to be installed at either Capistrano or Talega substation.

In addition, to address the vulnerabilities arising from Talega Substation serving as the sole source of power to SDG&E's South Orange County system, SDG&E would seek authorization to construct a 138 kV transmission line from its San Luis Rey substation located south of Camp Pendleton to San Mateo Substation located on the northern border of Camp Pendleton. This additional 138kV transmission line at San Luis Rey Substation, located in the city of Oceanside, County of San Diego, would also require the addition of two new 230/138kV transformers. Since the PEA was filed, the generation at San Onofre was unexpectedly retired. This event prompted the CAISO to approve local voltage support equipment to be installed at San Onofre, Talega and San Luis Rey substations. To make room for the new equipment at San Luis Rey, the 138 kV yard is being retired and removed. The addition of new 138/230 kV transformers would require building a new 138 kV yard within the San Luis Rey substation.

Section 7. The Reliability Projects That Would Be Necessary under the Reconductoring Alternative Are More Costly Than the Proposed Project. (Witness Willie Thomas)

The projects that SDG&E would need to pursue if the Commission selected the Reconductoring Alternative can be broken into several groups: (a) the work necessary to simply implement what the DEIR describes as the Reconductoring Alternative; (b) the additional work necessary to comply with NERC Reliability Standards; (c) the additional work necessary to mitigate the risk of a Talega Substation outage and other events that would cause load shedding; and (d) the additional work that would not be avoided if the Proposed Project is not approved.

Based on conceptual engineering and comparisons to other projects, SDG&E's preliminary estimate of the costs simply to implement the CPUC's Reconductoring Alternative is as follows:

- At an estimated cost from $48 million - $58 million (includes AFUDC), upgrade or replace the 138kV transmission lines identified in the DEIR Alternative. The scope of work would include the following:
    - Reconductoring the transmission line identified as part of Alternative B1 (TL13835A & C), "a 138-kV segment (approximately 7.8 miles long) from Capistrano Substation to Talega Substation").[138] Some of the DEIR assumptions under this alternative are flawed. To facilitate the reconductor of this circuit, SDG&E would need to replace the wire with a wire larger in diameter and weight to meet the required rating. This would be true even if we used an "ACSS" wire as they are suggesting in the Draft EIR in section 3.2.2. In doing so the sag and clearances of the wire are likely to cause clearance violations per GO 95, Rule 37 and 38, Tables 1 & 2. Without detailed engineering analysis, it is correctly assumed that replacement of all structures is necessary to accommodate the higher ampacity and larger conductor (both in weight and diameter). Therefore, the work would include:
        - Reconductor approximately 7.5 miles of overhead conductor, removal of approximately 57 structures, and installation of approximately 46 new steel poles, and would be similar in scope to the Proposed Project except for slightly shorter structures and smaller foundations due to the reduced spacing required to build 138 kV structures versus 230 kV structures. The Draft EIR incorrectly assumes "…designed to support a single circuit…"[139]. It fails to address the need to transfer and accommodate the existing 12kV line from Capistrano Substation to the Landfill. In addition, it is common industry practice to design foundational steel structures to accommodate double circuit configurations.
        - Reconductor of approximately 1,800 feet of underground cable in Vista Montana with and associated cable splices and termination.
    - Tie an approximately 2.5-mile-long segment of transmission line (TL13835) from Laguna Niguel Substation into Capistrano Substation, without reconductoring to create a new Laguna Niguel–Capistrano 138-kV Line under this alternative.
    - Transfer Distribution conductor and equipment to new steel poles from Capistrano to Prima Deshecha Landfill. The 66/69kV structures that carry only the distribution facilities would be permanently removed.

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[138] DEIR at 3-7.
[139] Draft EIR 5.2.2

- As stated in Chapter 4, Section 3 above, Capistrano Substation would need to be rebuilt as a 138/12 kV substation to accommodate the tie-in of a new transmission line, and the estimated cost of doing so is between $135 and $165 million (includes AFUDC).

Based on conceptual engineering and comparisons to other projects, SDG&E's preliminary estimate of the costs of the projects that SDG&E would reasonably expect to implement, and where necessary seek authorization to implement, to comply with NERC Reliability Standards if the CPUC selects the Reconductoring Alternative are as follows:

- Upgrading or replacing the 138kV transmission lines identified in Section 2 above is estimated to cost $17 million to $20 million (includes AFUDC). This includes:
    - 13816 (Pico to Capistrano)
        - Reconductor approximately 1,800 feet of underground cable in Vista Montana and associated cable splices and terminations. To install the cable extended outages would be required on TL13816 and TL13833, and because they share the same trench and vaults, crews would need both circuits de-energized to safely perform their work. In the case of TL13816 it would de-energized for weeks. Also, getting outages on the lines at the same time are likely not feasible due to system operating constraints. To facilitate the reconductor in this section of the line a third trench, conduit and vault package would likely be necessary in Vista Montana, and would be similar to the Proposed Project.
        - Reconductor approximately 24,000 feet of overhead conductor from approximately San Juan Creek road to San Juan Hills High school, and from the intersection of Vista Montana and La Pata avenue to Pico substation.
    - 13836 (Pico to Talega)
        - Reconductor approximately 2,200 feet from Talega to Talega Hub. Six wood poles from Talega Sub to Talega Hub should be replaced to improve reliability and fire resistance as they are within fire prone areas.
    - 13846C (Talega Hub to Talega Sub)
        - Reconductor approximately 1,900 feet of overhead conductor and replace approximately 7 wood poles with steel poles

Based on conceptual engineering and comparisons to other projects, SDG&E's preliminary estimate of the costs of the projects that SDG&E would not avoid without construction of the Proposed Project are as follows:

- Replacement of the two transformers at Talega Substation is estimated to cost between $15 million - $20 million (with AFUDC, $17 million to $21 million).
- Replacement of the STATCOM currently located at Talega Substation or addition of a new dynamic voltage control device at Capistrano Substation is estimated to cost $81 million - $99 million (with AFUDC, $89 million to $109 million). This cost estimate does not include the potential purchase of additional easement on Camp Pendleton to accommodate the replacement equipment.

Based on conceptual engineering and comparisons to other projects, SDG&E's preliminary estimate of the costs of the projects that SDG&E would reasonably expect to implement, and where necessary seek authorization to implement, to provide a second source of power to South Orange County if the CPUC selects the Reconductoring Alternative are as follows:

- At an estimated cost of $242 million to $296 million (includes AFUDC), add a second source from San Luis Rey Substation to San Mateo Substation by:
    - Addition of a new 138 kV substation at San Luis Rey, by adding two new 230/138kV transformers and expanding the existing San Luis Rey Substation,
    - 138kV Underground getaway from San Luis Rey into TL23006 Overhead structure (approximately 1,500 feet),
    - Reconductor of both sides of TL23006 with bundled conductor from San Luis Rey to SONGS Tap (approximately 18 miles),
    - Reconductor TL99904 (de-energized TL13832) from SONGS Tap to San Mateo Tap with bundled conductor (approximately 6.5 miles) on existing steel lattice towers,
    - Replacement of TL13835 from San Mateo Tap to San Mateo with double circuit steel pole structures (approximately 12 structures), transfer of

TL13835 conductor, and add new bundled wire for new 138kV (approximately 3,500 feet),

- o Addition of a new transmission line terminal at San Mateo Substation (created by rebuilding the existing substation) and additional dynamic voltage support in South Orange County.

The total estimated cost of these projects would range from $548 million - $669 million (includes AFUDC), well in excess of the Proposed Project's estimated cost. This estimated cost would not be used for actual project budget costs, which could not be obtained until a higher level of engineering is done on the proposed design, but provides a basis for comparison of the Alternative's cost compared to the Proposed Project's cost.

Section 8. The Reasonably Expected Actions If the Reconductoring Alternative Is Selected May Have Greater Environmental Impacts Than the Proposed Project (Witness Scott Boczkiewicz).

The reasonably anticipated actions that would arise if the Commission were to select the Reconductoring Alternative may have greater environmental impacts than the Proposed Project.

First, the DEIR identifies the significant and unavoidable environmental impacts of the Proposed Project as (1) temporary impacts to air quality, largely from the emissions during the rebuild of Capistrano Substation, (2) temporary traffic impacts from partial closure (one lane) on Camino Capistrano to allow undergrounding of existing transmission and distribution lines, and from any full closure of Camino Capistrano, Via Pamplona and Calle San Diego during undergrounding of existing power and distribution lines[140], and (3) cumulative impacts on traffic, which arise specifically from the Camino Capistrano lane closure identified as having a significant traffic impact.

The DEIR's asserted reductions of these temporary adverse effects under the Reconductoring Alternative are largely related to omission of the impacts associated with

[140] DEIR at 4.15-19. SDG&E's construction and engineering contractors do not expect a full closure of any of these roads during underground constructionand SDG&E did not state any full road closures in its Proponents Environmental Assessment (PEA).

rebuilding the Capistrano Substation. Because Capistrano Substation must be rebuilt even if it remains a 138/12 kV substation, as set forth above, essentially all of these impacts will occur under the Reconductoring Alternative as well.[141]

The DEIR's Reconductoring Alternative understates the full extent of the required work at the Capistrano Substation in two respects and therefore understates the impacts that would occur (and overstates the reduction in impacts when compared to the Proposed Project). While the Reconductoring Alternative would remove the 230/138 kV substation yard at the Capistrano Substation site; the Capistrano 138/12 kV substation would still have to be rebuilt to provide reliable electric service to SDG&E's South Orange County customers, as discussed in SDG&E January 15 Testimony, Chapter 5, and above at Section 3). In addition, even if Capistrano Substation did not require being rebuilt to address reliability concerns, it would need to be rebuilt and expanded to accommodate the addition of the two new 138 kV connections (the Capistrano Substation currently does not contain capacity (space) to accommodate any new 138kV connections).

Second, the DEIR states that the Reconductoring Alternative would reduce traffic impacts along Via Pamplona by utilizing an existing 138kV underground duct bank. However, as described in Section 7 above, utilizing the existing duct bank to replace/upgrade the cable

[141] Only the 230/138 kV yard of the rebuilt Capistrano Substation under the Proposed Project would be avoided by the Reconductoring Alternative. The emissions from that work constitute less than half of the total anticipated Localized Significance Thresholds (LST) exceedances for all Capistrano Substation emissions estimated for the Proposed Project (DEIR Table 4.3-8a). Per the DEIR, the total emissions of the Proposed Project constitute "less than one percent of the total SCAQMD's daily emissions inventory." DEIR at 6-15.

would still likely require work (cable pulling and splicing) within Via Pamplona and Vista Montana. Therefore, partial closures of Via Pamplona would still occur.[142]

Third, as outlined in Chapter 4, Sections 2 and 6, SDG&E reasonably expects to implement or propose to implement additional projects to comply with NERC Reliability Standards and provide reliable electric service, including the reconductoring of other 138kV power lines in the south Orange County service territory and the construction of a new 138kV power line between the San Luis Rey Substation (located in the City of Oceanside, San Diego County) and the San Mateo Substation located in San Clemente. These additional projects would result in increases in emissions of criteria pollutants, and could also include potential impacts to aquatic, biological and cultural resources during construction of the new 138kV power line from the San Luis Rey Substation.

The combined environmental impacts of these projects would likely exceed those of the Proposed Project.

[142] Note that work required on Proposed Project Segment 2 (new 230kV underground in Vista Montana and Via Pamplona) would not require full road closures at Via Pamplona, and therefore would not result in significant, unavoidable impacts.

CHAPTER 5 THE DEIR'S SCE ALTERNATIVE IS NOT FEASIBLE

Section 1. Introduction (Witness John Jontry)

The CPUC's DEIR describes "Alternative D – SCE 230-kV Loop In to Reduced-Footprint Substation at Landfill" (the "SCE Alternative") as follows:

> Alternative D includes design details sufficient to ensure that analysis pursuant to CEQA may be conducted. Under this alternative, a new 230/138/12-kV substation would be constructed at PDL [Prima Deshecha Landfill] in proximity to the transmission corridor that crosses the landfill (Figure 3-3). Both SDG&E and SCE transmission lines are located within this corridor. Power would be provided to the new substation from SCE's Serrano–SONGS 230-kV line. A new double-circuit 230-kV line segment (less than 0.25 miles long) would be constructed, possibly within new ROW, which would loop the new substation into SCE's 230-kV line.
>
> Under this alternative, a new, single-circuit 138-kV line segment (approximately 0.75 miles long) would be installed that would use the existing 66-kV/69-kV transmission line route described for Alternative B2. This line segment would extend from the new substation west to the applicant's transmission ROW and then extend north along the 66-kV/69-kV line route to the San Juan Hills High School area, where it would connect to the applicant's existing underground 138-kV line.
>
> Distribution circuit 315 (12 kV) would be relocated as described for the proposed project, which would allow the existing 138-kV line that extends from the San Juan Hills High School area to Capistrano Substation to be energized at 138 kV instead of 12 kV. The new 138-kV segment would be used to create a continuous new 138-kV line between the new substation and Capistrano Substation.
>
> One 230/138-kV transformer would be installed at the new substation with space for a spare if the applicant provides data indicating a spare could be needed. One 138/12-kV transformer would also be installed. Space for additional 138/12-kV transformers and/or additional distribution-level transformers would also be included in the substation design if the applicant provides data indicating that the space could be needed. The substation would be gas insulated and require 3 to 10 acres of land. In addition, equipment at Capistrano Substation found to be inadequate would be replaced.[143]

The SCE Alternative is not a feasible solution to South Orange County's reliability needs for the following reasons:

1) This arrangement would parallel a robust 230 kV path with a relatively weak 138 kV network. This would have the dual negative impacts of restricting the allowable flow

[143] DEIR at 3-12.

on the 230 kV path while subjecting the 138 kV system to network flows for which it was not designed.

2) Restricting allowable flow on the SCE lines in South Orange County could result in limiting the transfer capability between the SDG&E and SCE systems, resulting in reduced import capability for both utilities.

3) This alternative is not as effective at serving the South Orange County load following the catastrophic of Talega substation as the SOCRE project as proposed by SDG&E, and thus does not provide the full benefit of the additional independent bulk power source.

4) Seeking an interconnection with SCE's system under the Transmission Owner's Tariff and the Transmission Control Agreement will delay any project for years.

5) SCE's System Impact Study is likely to identify significant impacts to a number of important import paths and therefore require Reliability Upgrades to SCE's and SDG&E's systems at SDG&E's expense.

6) Capistrano Substation will need to be rebuilt to accommodate the interconnection proposed by this Alternative, and rebuilding a 138/12 kV Capistrano Substation plus a building a new 230/138/12 kV Prima Deshecha Landfill substation will be more costly and have greater environmental impacts than simply rebuilding a 230/138/12 kV Capistrano Substation.

7) The costs imposed on ratepayers may be greater under the SCE Alternative than under the Proposed Project.

In short, while the SCE Alternative provides a second independent source to South Orange County, it also presents numerous drawbacks, delays, and operational complications. It also does not bring any additional reliability benefits beyond what is provided by the SOCRE Project as proposed by SDG&E.

These issues are discussed in greater detail below.

Section 2. Any Interconnection to SCE's System Would Take Years to Accomplish (Witness John Jontry)

Among other steps that would be required for a transmission interconnection to SCE's system, SDG&E would need to comply with SCE's Transmission Owner Tariff,[144] the Transmission Control Agreement among transmission owners and the California Independent System Operator ("CAISO"),[145] and the CAISO Tariff.[146]

The Transmission Owner ("TO") Tariff, Sections 8 and 10, would govern requests to SCE to allow SDG&E to interconnect to SCE's transmission facilities. Section 8.1 provides: "The Participating TO shall, at the request of a third party pursuant to Section 10, interconnect its system to the … wholesale load of such third party, or modify an existing wholesale Interconnection." However, there are a number of requirements that must be met before such interconnection may be approved. Among others:

- Section 8.1.1 "Interconnection must be consistent with Good Utility Practice, in conformance with all Applicable Reliability Criteria, all applicable statutes, regulations, and ISO reliability criteria for the ISO Controlled Grid. The Participating TO will not accommodate the Interconnection if doing so would impair system reliability."

- Section 8.1.2 "Each party requesting Interconnection shall pay the costs of planning, installing, owning, operating, and maintaining any Direct Assignment Facilities and, if applicable, any Reliability Upgrades required to provide the requested Interconnection. In addition, such party shall implement all existing operating procedures necessary to safely and reliably interconnect such party's wholesale load to the facilities of the Participating TO and to ensure the ISO

[144] https://www.sce.com/wps/wcm/connect/ec2671c9-f6ba-4085-a72d-513f9549cb9e/TransmissionOwnerTariffv5.pdf?MOD=AJPERES
[145] http://www.caiso.com/Documents/TCA_Effective_20140601.pdf
[146] http://www.caiso.com/Documents/ConformedTariff_Nov1_2014.pdf

Controlled Grid's conformance with the ISO Grid Planning Criteria, and shall bear all costs of implementing such operating procedures."

- Section 8.1.3 "Pursuant to Section 10.4, 10.7.1, or 10.9.1, a party requesting Interconnection shall request in writing that the Participating TO tender to such party an Interconnection Agreement that will be filed with FERC …. The Interconnection Agreement will include, without limitation, cost responsibilities and payment provisions for any engineering, equipment, construction, ownership, operation and maintenance costs for any Direct Assignment Facilities, any Reliability Upgrades, and for any other mitigation measures."

- Section 10.2 "A party requesting Interconnection shall submit a written Interconnection Application which provides the information required in Section 10.3 to the Participating TO and shall send a copy of the application to the ISO. The Participating TO shall time-stamp the application to establish study priority." The priority of any SDG&E request to connect to SCE's system is unknown, and thus the timing of any study is unknown.

- Section 10.5: "If the Participating TO determines that a System Impact Study is necessary to accommodate the requested Interconnection, the Participating TO shall so inform the applicant, as soon as practicable." Because SCE would need to consider the impact on the SCE system of the NERC mandated outage scenarios studied by SDG&E and CAISO, SDG&E believes that SCE would conclude that a System Impact Study is necessary. The System Impact Study would be performed by SCE at SDG&E's expense.

- Section 10.7 "Upon receipt of an executed System Impact Study Agreement or initiation of the ISO ADR Procedures and receipt of payment for estimated study costs, the Participating TO will use due diligence to complete the required System Impact Study within a sixty (60) calendar day period. The System Impact Study will identify whether any Direct Assignment Facilities or Reliability Upgrades are necessary, as well as whether any transmission additions or upgrades are necessary to serve a wholesale load. … In the event that the Participating TO is unable to complete the required System Impact Study within such time period, it shall so notify the applicant, in writing, and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the applicant and the ISO."

- Section 10.8 "If a System Impact Study indicates that additions or upgrades to the ISO Controlled Grid are needed to satisfy an applicant's request for Interconnection, the Participating TO shall, within fifteen (15) Business Days of the completion date of the System Impact Study tender to the applicant a Facilities Study Agreement that defines the scope, content, assumptions and terms of reference for such study; the estimated time required to complete the required study; and such other provisions as the parties may reasonably require, and pursuant to which the applicant agrees to reimburse the Participating TO for the reasonable actual costs of performing the required Facilities Study."

- Section 10.9 "Upon receipt of an executed Facilities Study Agreement or initiation of the ISO ADR Procedures and receipt of payment for the estimated study costs, the Participating TO will use due diligence to complete the required Facilities Study within a sixty (60) calendar day period. In the event that the Participating TO is unable to complete the required Facilities Study within such time period, it shall so notify the applicant, in writing, and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies."

- Section 3.30: "Facility or Facilities Study. An engineering study conducted to determine required modifications to the Participating TO's transmission system, including the estimated cost and scheduled completion date for such modifications that will be required to provide needed services."

SDG&E estimates that it would take a minimum of twelve months and could take as long as twenty-four months to complete an interconnection application, System Impact Study, and a Facilities Study for an interconnection with SCE as described in the SCE Alternative.

Two recent examples of "seams" projects involving SDG&E and other interconnecting utilities include the synchronous condenser project at the SONGS 230 kV switchyard, and the request from the Imperial Irrigation District (IID) to add a 500/230 kV transformer at the Imperial Valley substation. In the case of IID, the initial negotiations over how and what to study have already consumed six months, for a project that would install an additional transformer at an existing interconnection. For a substantially more complicated project (in this case, establishing a new interconnection point between SCE and SDG&E and converting what is essentially a load pocket to network transmission) developing reasonable assumptions, performing the necessary study work, identifying potential issues, and then reaching agreement on acceptable mitigations, will likely take much longer (potentially several years).

SDG&E estimates that the Application and reports would cost on the order of $150,000-250,000[147], but could go higher depending on the complexity of the required study work. This cost would not include any required system upgrades.

Once these studies are completed, the interconnection request would undergo further review at CAISO. The Transmission Control Agreement, Section 10.3.5 provides: "Each Participating TO and the CAISO shall process requests for interconnection of transmission facilities or load to the CAISO Controlled Grid in accordance with the CAISO Tariff and the TO Tariff as applicable, provided that the terms of the CAISO Tariff shall govern to the extent there is any inconsistency between the CAISO Tariff and the TO Tariff." Section 11 then provides: "The provisions of Sections 24 and 25 of the CAISO Tariff will apply to any expansion or reinforcement of the CAISO Controlled Grid affecting the transmission facilities of the Participating TOs placed under the Operational Control of the CAISO." Both SCE and SDG&E are parties to the Transmission Control Agreement.

Section 24 of the CAISO Tariff outlines the CAISO Transmission Planning process. As the CPUC is aware, the CAISO prepares an annual transmission plan based on CAISO's evaluation of the transmission system. Under Section 24.4.6.2 of its FERC-approved Tariff, CAISO determines the solution to reliability driven system needs "that meets the identified reliability need in the more efficient or cost effective manner." With respect to SDG&E's SOCRE Project, the CAISO considered the needs of SDG&E's South Orange County system and potential solutions since 2008 before approving the SOCRE Project in its 2010-11 Transmission Plan.

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[147] Estimated costs based on similar study work for large generator interconnections.

If the Commission were to deny SDG&E authorization to construct the Proposed Project and instead authorize SDG&E to construct the SCE Alternative, SDG&E would have to return to CAISO to seek CAISO's approval of the SCE Alternative. SDG&E would need to apply to implement the CPUC's solution to the identified South Orange County reliability needs, providing CAISO with SCE's System Impact Study and Facilities Study. CAISO then would conduct its own studies of the SCE Alternative's impact on the CAISO-controlled grid.

Although SDG&E cannot predict the outcome of such an evaluation by CAISO, SDG&E believes that such an application would go through the normal annual transmission planning process. Depending when the CPUC provided such direction, and SCE completed its studies, it could be up to a year before CAISO would decide whether to approve the Commission's preferred solution (and any "Reliability Upgrades" to SCE's or other systems determined to be necessary to permit the interconnection).

SDG&E raised its concerns about the reliability of electric service in South Orange County with CAISO beginning in 2008. CAISO approved the SOCRE project in May 2011. SDG&E filed its Application for Commission authorization to construct the SOCRE project in May 2012. SDG&E is hopeful that the Commission will render a decision in 2015. If the Commission were to select the SCE Alternative, it is likely that SDG&E would not learn whether SCE and CAISO would approve implementation of such a solution until 2017 or 2018.

At that point, assuming an SCE determination that interconnection would not impact the reliability of SCE's system and subsequent CAISO approval, SDG&E could begin construction of the project. However, if SCE or CAISO determined that Reliability Upgrades were necessary to allow the interconnection, SDG&E might need to return to the CPUC to seek permission for

SCE or other affected utilities to perform the necessary Reliability Upgrades at SDG&E's expense per the Transmission Owner's Tariff.

Throughout this period of time, SDG&E's approximately 300,000 South Orange County customers are at risk of losing electric service under a variety of outage scenarios. SDG&E does not believe that the SCE Alternative is capable of being accomplished in a successful manner within a reasonable period of time.

Section 3. An SCE Interconnection Likely Would Have Impacts to Both the SCE and SDG&E Transmission Systems That Would Need to be Mitigated (Witness John Jontry)

Until SCE performs a System Impact Study and any follow-on Facilities Study, the full scope of activities that would be required to implement the SCE Alternative is unknown. The SCE Alternative does not reflect any of the Direct Assignment Facilities[148] or Reliability Upgrades[149] that may be required by SCE and CAISO for SDG&E to implement the SCE Alternative. And until SCE conducts a Facilities Study to determine the modifications to SCE's facilities necessary to permit interconnection, the construction activities, new structures and new lines that may be needed for such modifications is not known.

Although the Transmission Owner Tariff provides that SCE will conduct the System Impact Study for an SDG&E request to interconnect to the SCE system, SDG&E has evaluated

[148] Under the TO Tariff, § 3.18, "Direct Assignment Facilities" are "[f]acilities or portions of facilities that are owned by the Participating TO necessary to physically and electrically interconnect a particular party requesting Interconnection under this TO Tariff to the ISO Controlled Grid at the point of interconnection."

[149] Under the TO Tariff, § 3.88, a "Reliability Upgrade" is "[t]he transmission facilities, other than Direct Assignment Facilities, beyond the first point of Interconnection necessary to interconnect a wholesale load safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the Interconnection of a wholesale load, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a wholesale load to the ISO Controlled Grid. Reliability Upgrades also include, consistent with WECC practice, the facilities necessary to mitigate any adverse impact a wholesale load's interconnection may have on a path's WECC path rating."

the potential CAISO-controlled system impacts of the interconnection proposed in the SCE Alternative.

A. As Described, the SCE Alternative Will Impact SCE's Transfer Capability on the 230 kV Interconnection with SDG&E (Witness John Jontry)

SDG&E submits that this Alternative will impact the ability of SCE to rely on their 230 kV interconnection with SDG&E to serve their load. As currently configured, the four 230 kV lines connecting SCE with SDG&E form a direct connection with the San Onofre switchyard to three of SCE's major 230 kV substations in Southern California:

1) San Onofre-Santiago 230 kV #1 and #2
2) San Onofre-Viejo 230 kV
3) San Onofre-Serrano 230 kV

This series of lines (formerly referred to as Path 43 in the WECC path rating catalog) has served as a major import gateway for the SCE service territory. For the purposes of this discussion, this testimony will refer to this set of four lines as Path 43.

These lines are significantly larger than the 230 kV lines proposed as a part of SDG&E's SOCRE Project. The ratings of each of SCE's lines are as follows:

1) San Onofre-Santiago 230 kV #1 –1195/1315 MVA normal/emergency
2) San Onofre-Santiago 230 kV #2 - 1195/1315 MVA normal/emergency
3) San Onofre-Viejo 230 kV - 1195/1339 MVA normal/emergency
4) San Onofre-Serrano 230 kV - 1195/1315 MVA normal/emergency

By contrast, the 230 kV lines proposed by SDG&E to connect with the rebuilt Capistrano Substation would have normal ratings of 456 MVA – easily sufficient for SG&E's forecasted South Orange County load.

The DEIR's SCE Alternative would insert a new 230/138/12 kV substation at the Prima Deshecha landfill, and by extension the SDG&E 138 kV system in South Orange County into SCE's Path 43 import pathway. Depending on the outcome of the system studies, this could reduce or restrict SCE's ability to import through Path 43. This could occur due to 1) additional demand now being placed on the SCE system, thus reducing the capacity available to serve SCE load, or 2) SCE being forced to restrict flow on their 230 kV system to avoid overloading the underlying 138 kV system in South Orange County following system contingencies. In order to prevent restricting flow on the 230 kV interface between SDG&E and SCE in this scenario, additional system upgrades would likely be required in both systems. The second point will be discussed further in Section 3B, below.

B. As Described, the SCE Alternative Will Induce Undesirable Loop Flows on SDG&E's South Orange County 138 kV System (Witness John Jontry)

As currently configured, the 138 kV system serving South Orange County is effectively a load pocket, and is not subject to significant system loop flow. This is true from an electrical standpoint, although it is technically considered network transmission from a NERC, WECC, and CAISO reliability standpoint. For the future South Orange County transmission system, as planned by SDG&E in the Proposed Project, the 138 kV system would effectively remain a load pocket, and again not be subject to any significant system loop flows. System loop flows (i.e. energy transfers that flow across a transmission interface from a remote generator to a remote load) are not inherently undesirable, if the portion of the system carrying such flows is designed to accommodate them. The 138 kV system serving South Orange County has never been subject to such flows, and is not designed to accommodate them.

SCE had used SONGS generation to support voltage on the four transmission lines owned by SCE. Since the retirement of SONGS, these four transmission lines have taken voltage supported from SDG&E. Reactive power in the form of MVars (megavolt –amperes-reactive) has been flowing north out of San Onofre into these SCE transmission lines. The DEIR

Alternative D creates a connection to one of these 230 kV transmission lines. Preliminary analysis shows that South Orange County 138 kV transmission system would supply MVars to SCE's 230kV transmission system. This would require SDG&E to add voltage support equipment to supply the SCE MVars at the point of interconnection. Additional analysis and study is necessary to fully determine the scope and capability of the additional reactive support equipment; however, the cost of this additional equipment should be considered when evaluating the total cost of this alternative and the estimated cost is in Section 5 below.

The DEIR's SCE Alternative would insert a new 230/138/12 kV substation at the Prima Deshecha landfill, and by extension the SDG&E 138 kV system in South Orange County, into SCE's Path 43 import pathway. The 138 kV system in South Orange County would now effectively be a part of SCE's import path, a function for which it is not designed. Similarly, the 138 kV system in South Orange County would also be a part of SDG&E's import pathway from SCE, particularly during severe system contingencies, and may cause restrictions on energy that could be imported into the San Diego load center under extreme system conditions. If this is the case, it would be necessary to reduce the effective import capability of either SCE, or SDG&E, or both, thus requiring the procurement of additional generation resources to meet customer demand and meet resource adequacy criteria, or it would be necessary to perform additional system upgrades to maintain the present import capability.

Of greater importance is the effect such a change may have on Southern California's import capability. CAISO imports electric power from its neighbors through WECC monitored and controlled Paths (Paths are groups of transmission lines which define the interconnection between neighboring areas). Southern California is bounded by Path 49 on its eastern border with Arizona and Path 45 which separates California from Mexico. Power flowing on Path 49 and Path 45 are sensitive to the flow of power on the 230 kV transmission lines that emanate from San Onofre. When one of the transmission lines in the northern part of Path 49 comes out of service, power flowing from Arizona to SCE will be cut off and will flow to SCE through SDG&E. Additional power will flow into SDG&E's southern transmission lines, then through SDG&E traveling north and on to SCE through the four 230 kV transmission lines owned by SCE which extend from San Onofre into the SCE service territory north of San Onofre. The 230 kV transmission line referenced in DEIR Alternative D is one of these transmission lines. When one of the transmission lines making up the southern part of Path 49 comes out of service, specifically the 500 kV transmission line connecting SDG&E's Imperial Valley Substation to Arizona Public Service's North Gila Substation, the reverse happens. Power flowing from Arizona to San Diego is cut off and must flow through SCE to reach the load in San Diego. This will increase the amount of power flowing from north to south on the four SCE transmission lines connected to San Onofre.

This increased flow, either north to south, or south to north, may be limited by the proposed Alternative D interconnection and as such, this new proposed interconnection to the SCE 230 kV transmission line may limit imports into Southern California. To properly assess the risk to the import limit, a WECC PRG (Path Rating Group) would be formed. The PRG is a committee of engineers who represent path owners and other affected parties. The PRG will assess the SCE loop-in Alternative D and determine what effect, if any, it has on surrounding path ratings. During the assessment, additional projects may be found that will be required before the PRG will accept the DEIR Alternative D project.

The WECC path review process will take several years to complete. Any upgrades that are identified as necessary by the WECC path review process would presumably be borne by CAISO ratepayers.

Section 4. The DEIR's Description of the SCE Alternative Does Not Accurately Reflect the Work That Would be Required Under this Alternative.

A. As Described, the SCE Alternative Lacks Transmission and Distribution Work Necessary to Make It Feasible (Witness Willie Thomas)

The DEIR describes the SCE Alternative as set forth in Section 1 above. The DEIR's description, however, lacks the necessary transmission and distribution work to actually implement the SCE Alternative, even leaving aside projects that may be required to mitigate the interconnection's impacts on SCE's system and the various WECC Paths described in Sections 2 and 3 above. The transmission line work required simply to perform the work called for by the SCE Alternative as described in the DEIR includes:

1. The use of the existing 66-kV/69-kV transmission line is not feasible. The structures are not capable of supporting 138kV construction. To meet GO 95 requirements additional pole height and strength is necessary to accommodate the 138kV reconstruction.
2. All structures on TL13835 would need to be rebuilt from the Prima Deshecha Landfill to Capistrano Substation to accommodate the new 138kV transmission line and existing TL13835. Since the new line needs to have the capacity to carry all South Orange county load, it would require bundled conductor of larger size than the existing lattice and foundational steel poles were designed for. The structures were also not designed for the higher wind pressures being used in the proposed project, 18 psf versus 8 psf as indicated in Chapter 10, Section B. This would result in the construction of a transmission line similar to the Proposed Project.
3. As indicated in the Draft EIR section 3.2.8 the remaining distribution that is attached on existing structures or on adjacent 66/69kV structures from Vista Montana to Capistrano Substation would need to be relocated as described in the proposed project.
4. To accommodate a new 138kV transmission line Capistrano Substation will have to be rebuilt and expanded.

5. Reconductor and replace structures from Laguna Niguel to Talega Hub [TL13835A], and remove SPS on TL13835A to meet NERC Transmission Planning Requirement.
6. In Vista Montana, a new trench and conduit package will be required to accommodate the new 138kV line due to the need for two cables per phase to meet capacity requirements and lack of available conduits in the existing TL13835 trench. The two existing cable riser poles would need to be replaced to accommodate both lines. This underground portion of this alternative would result in work similar to the proposed project.
7. A Connection to SCE would require new structures on both existing SCE lines and the existing SDG&E lines. SDG&E estimates that connection of the 230kV lines into the PDL Substation would require at least 6 new 230kV structures, approximately 7 138kV cable poles structures and approximately 4,500ft of trench. Detailed engineering studies and discussion with the Prima Deshecha Landfill and SCE would be required to refine this estimate of work scope.

The alternative does not include distribution impacts from running lines from the 138/12kV landfill substation to the load areas.

B. The SCE Alternative Requires Further Work to Mitigate NERC Violations and Serve as a Reliable Second Source for South Orange County (Witness Cory Smith)

Furthermore, the connection to SCE at Prima Deshecha Landfill would not remove all NERC violations without additional upgrades. For the overlapping outage of TL13831 and TL13834, TL13833 will load above its Applicable Rating when load rises above 450 MW. The 2015 load forecast shows this happening as early as 2016. For the overlapping outage of TL13834 and TL13838, TL13833 will load above is Applicable Rating when load rises above 482 MW. The 2015 load forecast shows this happening as early as 2021. These scenarios are violations of NERC standard TPL-003-0b. To avoid a violation, the new TL13833 rating needed will exceed 1200 Amps.

Based on analysis done using the 2015 load forecast, the transmission lines listed below will need to be upgraded in order for the new substation at Prima Deshecha Landfill to carry all South Orange County load with Talega Substation out-of-service;

- TL13834 will reach the transmission lines maximum rating of 1145 Amps by 2032 and will need to carry 1221 Amps by 2035.
- TL13837 will reach the transmission lines maximum rating of 569 Amps by 2027 and will need to carry 608 Amps by 2035.
- TL13830 will reach the transmission lines maximum rating of 816 Amps by 2031 and will need to carry 903 Amps by 2035.

Additionally, in order to secure the South Orange County transmission system for the loss of a single element with Talega Substation out of service, more transmission upgrades are needed. When South Orange County load reaches 450 MW (2015 forecasted peak load for 2016 peak load level), the transmission lines listed below will load above emergency ratings;

- The outage of TL13834 will increase flow on TL13816 to 1036 Amps. TL13816 has an emergency rating of 841 Amps. To prevent damage to TL13816, either South Orange County load must be limited to 371 MW or TL13816 must be upgraded. Load would be limited by shedding load before the contingency.
- The outage of TL13834 will increase flow on TL13833 to 985 Amps. TL13833 has an emergency rating of 858 Amps. To prevent damage to TL13833, either South Orange County load must be limited to 388 MW or TL13833 must be upgraded. Load would be limited by shedding load before the contingency.
- The outage of TL13837 will increase flow on TL13846B to 142 MVA (594 Amps). TL13846B has an emergency rating of 569 Amps. To prevent damage to TL13846B, either South Orange County load must be limited to 449 MW or TL13846B must be upgraded. Load would be limited by shedding load before the contingency.

C. As Described, the SCE Alternative Lacks Capistrano Substation Work Necessary to Make It Feasible (Witness Karl Iliev)

The SCE Alternative is infeasible for failure to rebuild Capistrano Substation to address the reliability issues discussed in SDG&E's January 15 Testimony, Chapter 5. Without rebuilding Capistrano Substation, at least as a 138/12 kV substation, SDG&E cannot provide reliable electric service to SDG&E's South Orange County customers.

Moreover, Capistrano Substation will have to be rebuilt to allow for the interconnection of the proposed transmission line between the new Prima Deshecha Landfill Substation and Capistrano Substation. As noted in Chapters 3 and 4, any rebuild of the Capistrano Substation would expand to the lower yard within SDG&E-owned property and add a minimum of two spare 138kV positions for future needs that may arise outside of the planning time horizon, but within the expanded lifetime of the newly rebuilt substation. Additionally, as mentioned in Chapter 3, rebuilding the substation cannot be built in its current location and needs to be built in the lower yard of the existing SDG&E owned site to maintain construction safety and station reliability during the rebuild project.

The estimated cost of rebuilding Capistrano Substation as a 138/12 kV substation, with the same configuration and location as proposed in the Proposed Project, is between $135 million and $165 million (includes AFUDC).

D. The SCE Alternative Does Not Identify a Specific Site Or Design Scope for the New Prima Deshecha Landfill Substation (Witness Karl Iliev)

The SCE Alternative does not include a specific site or design details and assumes SDG&E would construct a new substation at Prima Deshecha Landfill. The CPUC's DEIR does not identify exactly where this substation would be sited other than to provide a small scale map with a conceptual location and to say "in proximity to the transmission corridor that crosses the landfill."[150] SDG&E would need to identify and study a suitable location, and incur the cost to acquire it.

The CPUC asserts that the new Prima Deshecha Landfill (PDL) Substation will be GIS design. It is SDG&E's standard to use an air insulated (AIS) design because of the reduced cost of this design if there is space available. An AIS design (and also a GIS design) requires a larger yard than described in the DEIR because of the increased scope required for this substation.

The DEIR incorrectly assumes that SDG&E would construct a tapped (one that is connected directly to the transmission line with no interrupting protective or sectionalizing devices) single 230/138-kV transformer at the new PDL Substation. Because of outage restrictions required when maintenance is performed, which would impact load flow and system reliability, SDG&E would install circuit breakers and relaying systems. Additionally, SDG&E would also install at a minimum two (392 MVA) 230/138kV transformers and space for a future third transformer to enable enough capacity to feed the South Orange County load center at the system peak demand. This would also increase the size of the site needed for the proposed new substation, increasing grading and below grade impact. Preliminary estimates indicate that a new AIS substation in this area would require approximately 12 acres.

The estimated cost of this new substation is between $221 million and $270 million (includes AFUDC). This cost includes construction of the substation only and does not include permitting, environmental mitigation, or transmission costs. This estimate may also be subject to change, as it is based on SDG&E's past experience, which may not perfectly apply to the scope of the proposed substation. Preliminary engineering would need to be performed to create a more detailed cost estimate.

[150] DEIR at 3-12.

If SDG&E were to install a GIS alternative at this site, it would impose an increased cost of approximately 20-30% of the AIS alternative. SDG&E would not propose GIS as its preferred solution as it increases cost that is passed on to its customers. SDG&E would only implement GIS if instructed by the Commission.

Section 5. The SCE Alternative Will Be More Costly Than the Proposed Project (Witness Willie Thomas)

If the Commission were to select the SCE Alternative, and SCE, CAISO and WECC were to approve the interconnection pursuant to the Transmission Owner Tariff and the Transmission Control Agreement, then SDG&E would have to implement, or where necessary seek authorization to implement, the following actions to implement the SCE Alternative (leaving aside necessary Reliability Upgrades):

- As described in Section 4C above, construct a new 230/138/12 kV Air Insulated Substation at Prima Deshecha Landfill ("PDL"), with two transformers, and acquire the property to do so, at an estimated cost of $221 million - $270 million (includes AFUDC). A Commission directive to construct a GIS substation would increase this cost.
- As described in Section 3 above, construct a new dynamic voltage control device (SVC, STATCOM or Synchronous Condenser) at the PDL Substation at an estimated cost of $81 million - $99 million (with AFUDC, $89 million to $109 million).
- As described in Section 4 above, construct a new double-circuit 230-kV line segment to loop the new PDL Substation into SCE's Serrano–SONGS 230-kV line, potentially including new ROW, at an estimated cost of $28 million - $34 million (includes AFUDC).

- As described in Section 4 above, construct a single circuit 138 kV line between the new PDL Substation and Capistrano Substation, and the additional upgrades to TL13835 at an estimated cost of $85 million - $104 million (includes AFUDC).
- As described in Section 4B above, rebuild the Capistrano Substation as a 138/12 kV substation at an estimated cost of $135 million - $165 million (includes AFUDC).
- As described in Section 3 above, construct a new dynamic voltage control device (SVC, STATCOM or Synchronous Condenser) at the new rebuilt 138/12 kV Capistrano Substation at an estimated cost of $81 million - $99 million (with AFUDC, $89 million to $109 million).

In addition to those costs, as described in Section 4.B above, SDG&E will need to upgrade TL13833 to meet NERC reliability standards and, by 2027, to ensure that this alternative could serve as a reliable second source for South Orange County, SDG&E would also need to upgrade TL13837, TL13830 and TL13846B.

In addition to those costs, as described in Sections 2 and 3 above, SDG&E would have to pay SCE the costs to construct all Reliability Upgrades required on SCE's system that are identified as required to permit the contemplated SCE interconnection, and also incur the cost to construct all Reliability Upgrades to SDG&E's system required by CAISO or WECC to permit the interconnection. SDG&E cannot estimated the costs of performing all of the required Reliability Upgrades because it will take several years to complete the necessary System Impact Study, Facilities Study, CAISO review and WECC Path Rating Study.

At a total estimated cost of $647 million to $791 million (includes AFUDC), not including the necessary Reliability Upgrades, the SCE Alternative imposes greater costs on ratepayers, as well as exposing them to unknown future costs that may be much more costly than the Proposed Project.

Section 6. The Reasonably Expected Actions If the SCE Alternative Is Selected May Have Greater Environmental Impacts Than the Proposed Project (Witness Scott Boczkiewicz).

The reasonably expected actions if the SCE Alternative is selected may have greater environmental impacts than the Proposed Project. Not only does the DEIR description of the SCE Alternative fail to identify the construction necessary simply to implement the SCE interconnection, the DEIR fails to identify the environmental impacts of the likely Reliability Upgrades that will be required to mitigate the interconnection's impacts on SCE's system and the WECC Paths.

The DEIR identifies the significant and unavoidable environmental impacts of the Proposed Project as (1) temporary impacts to air quality, largely from the rebuild of Capistrano Substation, (2) temporary traffic impacts from partial closure (one of three lanes) on Camino Capistrano to allow undergrounding of existing power and distribution lines and from any full closure of Camino Capistrano, Via Pamplona and Calle San Diego during undergrounding of existing power and distribution lines[151], and (3) cumulative impacts on traffic, specifically from the Camino Capistrano lane closure identified as having a traffic impact.

[151] DEIR at 4.15-19SDG&E's construction and engineering contractors do not expect any full closure of these roads and SDG&E did not state any full road closures in its Proponents Environmental Assessment (PEA).

Because Capistrano Substation must be rebuilt even if it remains a 138/12 kV substation, essentially all of these impacts will occur under the SCE Alternative as well.[152]

The DEIR concludes that the SCE Alternative would result in less of a temporary significant and unavoidable impact to air quality than the Proposed Project (although temporary air quality impacts of the SCE Alternative would still be anticipated to exceed local significance thresholds). The DEIR also concludes that the SCE Alternative would result in less of a temporary significant and unavoidable impact to traffic and cumulative impacts than the Proposed Project, with those impacts of the SCE Alternative being less than significant.[153] Finally, the DEIR concluded that the SCE Alternative would reduce impacts relating to noise and visual resources while increasing impacts relating to hazardous materials and land use. Impacts to other resource areas would be similar to those identified for the Proposed Project.[154]

However, the comparison of the SCE Alternative's impacts to those anticipated for the Proposed Project excludes certain scope items that would be required in order to construct the SCE Alternative. The missing construction scope includes:

- As set forth in Section 4B above, rebuilding Capistrano Substation to solve its reliability issues and to create a position to accept the transmission lines needed to implement the SCE Alternative.
- As set forth in Section 4A above, additional transmission and distribution line work necessary to implement the SCE Alternative.
- As set forth in Section 4C above, sufficient design scope for the new PDL substation, which SDG&E would construct as an Air-Insulated Substation due to the potential availability of the required amount of land needed, the need for

[152] Only the 230/138 kV yard of the rebuilt Capistrano Substation under the Proposed Project would be avoided by the SCE Alternative. The emissions from that work constitute less than half of the total anticipated Localized Significance Thresholds (LST) exceedances for all Capistrano Substation emissions estimated for the Proposed Project (DEIR Table 4.3-8a). Per the DEIR, the total emissions of the Proposed Project constitute "less than one percent of the total SCAQMD's daily emissions inventory." DEIR at 6-15.
[153] DEIR at 5-15.
[154] DEIR at 5-14 and 5-15.

> additional transformers, and the additional cost associated with a GIS substation. Key preliminary design analysis has not been conducted for any potential new substation site located at the Landfill, including geotechnical analysis. Without at least some preliminary design analysis of the Landfill substation site, key construction and land requirements cannot be known, such as extent of grading, volume of cut and fill (including required depth of over-excavation), and site access. The results of the design could alter/increase specific impacts, such as air quality (increases in grading and site preparation would increase emissions), biological/cultural/aquatic resources (the extent of site preparation [substation footprint] would be proportional to the extent for potential adverse effects on resources located at the Landfill site).

The immediate construction impacts associated with the SCE Alternative are understated based upon the scope of work known to be necessary to implement it.

The DEIR's assessment of the SCE Alternative's environmental impacts also fails to address any of the Reliability Upgrades that are likely to be required for interconnection to SCE' system. As discussed in Section 1 above, to interconnect with SCE's system, SDG&E must follow the process set forth in the Transmission Owner Tariff, including paying for any necessary Reliability Upgrades to the SCE system. The interconnection with the existing SCE system under the SCE Alternative will require approval at CAISO and WECC. This alternative has not yet been studied and the approval process may take several years. As set forth in Section 2 above, without an analysis of the interconnection, it is impossible to define the full extent of work that may be required. Specifically, it is uncertain how the SCE Alternative interconnection with SCE would affect the SCE or SDG&E systems. The impacts of any work required on the SCE system (or additional work required for the SDG&E system) are not accounted for. Depending upon the scope and location of such system upgrades, impacts could increase for any number of CEQA resource areas.

CHAPTER 6 THE DEIR'S MITIGATION MEASURES ARE NOT ALL FEASIBLE (Witness Don Houston)

CEQA defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social and technological factors." SDG&E believes that the following mitigation measures are infeasible, in whole or in part, and discusses the reasons for that determination.

Mitigation Measure AES-1

> **MM AES-1: Architectural Review of San Juan Capistrano Substation**. To ensure that the design of San Juan Capistrano Substation facilities such as walls, buildings, and landscaping are consistent with the City of San Juan Capistrano's design criteria, the applicant shall submit a revised series of elevations and a landscape plan to the City's Architectural Review Board (ARB) prior to filing for grading and building permits. The ARB shall determine if the applicant's revised plans are consistent with the City's design criteria and if any modifications are needed. The applicant shall not initiate ground disturbing activities until the ARB approves the design and landscaping plan for the proposed San Juan Capistrano Substation.[155]

Mitigation Measure AES-1 is infeasible, and threatens to derail the Proposed Project, by requiring approval of the City of San Juan Capistrano's Architectural Review Board (ARB) of "the design of San Juan Capistrano Substation facilities such as walls, buildings, and landscaping," and barring SDG&E from initiating any "ground disturbing activities" until the ARB has granted such approval.

The City of San Juan Capistrano has opposed the Proposed Project in this proceeding and most recently, on March 17, 2015, authorized hiring a consultant to comment on the DEIR in opposition to the Proposed Project.[156] During that City Council meeting, a Councilmember spoke about his concerns about EMF from the Proposed Project.[157] Even if not motivated by the

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[155] DEIR at 4.1-43.
[156] Attachment 20 (City of San Juan Capistrano Agenda Report (March 17, 2015).
[157] A recording of the City Council meeting is at http://www.sanjuancapistrano.org/Index.aspx?page=1474.

City's opposition to the Proposed Project, the ARB has no demonstrated expertise in the design of appropriate walls, buildings and landscaping for electrical substations.

The Commission asserted its exclusive jurisdiction over public utilities' facilities in General Order 131-D, Section XIV.B, which states that "local jurisdictions action pursuant to local authority are preempted from regulating electric power line projects, distribution lines, substations or electric facilities constructed by public utilities subject to the Commission's jurisdiction." If the Commission authorizes the Proposed Project, ARB should not have the ability to block its commencement through MM AES-1.

While SDG&E appreciates the ARB's substantive input on the landscaping and exterior wall for the Substation location, the CPUC determines the appropriate design and mitigation necessary for electric utility projects. MM-AES-1 should be limited to requiring SDG&E to consult with the ARB, and obtaining CPUC approval of its plans.

<u>Mitigation Measure AQ-1</u>

> **MM AQ-1: Oxides of Nitrogen (NOX) Credits**. The emissions of NOX due to construction of the proposed project will be mitigated through the purchase of Regional Clean Air Incentive Market Trading Credits (RTCs) for every pound of NOx emissions in excess of the SCAQMD regional significance threshold of 100 pounds per day. The total amount of NOX RTCs to be purchased will be calculated when the construction schedule is finalized. The applicant will purchase and submit the required RTCs to the SCAQMD prior to the start of project construction. The applicant will also track actual daily emissions during construction according to a monitoring plan that includes records of equipment and vehicle usage.[158]

Mitigation Measure AQ-1 requires the purchase of Regional Clean Air Incentive Market Trading Credits (RTCs) for every pound of NOx emissions in excess of the regional significance threshold of 100 pounds per day. The total amount of NOx RTCs to be purchased will be calculated once the construction schedule is finalized. SDG&E concurs with the mitigation

[158] DEIR at 4.3-19 to 4.3-20.

proposed to offset NOx emissions from project construction, and concurs that calculation based on the construction schedule is the appropriate approach. However, SDG&E believes that requiring the tracking of daily emissions during construction, according to a monitoring plan that includes records of equipment and vehicle usage, is infeasible, imposes unnecessary costs on ratepayers, and not necessary to achieve the intent of the mitigation measure. Furthermore, because this mitigation measure requires purchasing the credits prior to construction based on construction schedule, it renders the requirement to track daily emissions both redundant and unnecessary.

Mitigation Measure CUL-4

> MM CUL-4: Native American Consultation and Participation Planning. As a supplement to APM CUL-7, prior to construction, the applicant will provide evidence to the CPUC that tribes requesting consultation with the applicant regarding the project design and impacts on cultural resources were consulted. In addition, the applicant will provide evidence to the CPUC that tribes that have expressed interest in the project during any phase (i.e., project application through end of construction and restoration) have been given the opportunity to participate in additional cultural resources surveys (MM CUL-1) and cultural resources monitoring when performed by a CPUC-approved cultural resources consultant (MM CUL-3).
>
> To outline the expected duties and responsibilities of all parties involved, the applicant and a CPUC-approved cultural resources consultant will submit a Native American Participation Plan prior to construction. The final Native American Participation Plan shall be implemented, as specified, throughout construction and restoration. Tribes that have expressed interest in the project prior to construction will be given the opportunity to participate in development of the plan. At a minimum, the plan will specify that: [list of eight requirements including compensation for Native American monitoring][159]

Mitigation Measure CUL-4 requires that SDG&E provide evidence to the CPUC that any tribes that have expressed interest in the project during any phase (application through construction and restoration) have been given the opportunity to participate in additional cultural resources surveys and monitoring when performed by a CPUC-approved cultural resources

[159] DEIR at 4.5-20.

consultant. To be clear, it would be infeasible for tribes that express an interest in the project only during later project phases (e.g. end of construction and restoration) to have had the opportunity to participate in surveys that typically occur during the early phases of a project. Furthermore, it is likely that the majority of cultural surveys will take place in the earlier phases of the project. Therefore, this mitigation measure must make clear that tribes may participate in any surveys that have not yet occurred at any given project phase, but this mitigation measure does not confer an implied right to reconduct any surveys that have already occurred prior to the tribe's expressed interest.

Mitigation Measure BR-4

> **MM BR-4: Limit Removal of Native Vegetation Communities and Trees**. The removal of native vegetation and trees will be limited to the minimum practicable area required for construction of the project. Grading, grubbing, graveling, or paving will only occur for permanent project components. Temporary staging areas will be used in such a way that it facilitates post-construction restoration, per Section 7 of the SDG&E Subregional NCCP/HCP. Drive-and-crush methods will be employed.

Mitigation Measure BR-4 requires, among other items, that "drive and crush methods will be employed." However, drive and crush methods may not be feasible or appropriate in all cases, in particular for some temporary staging areas for safety reasons (e.g. fire, trip hazards) and may not be suitable for use for placement of temporary structures such as construction trailers and drop tanks. Furthermore, Section 7 of the SDG&E NCCP/HCP does not prohibit the use of grading, grubbing, graveling, or paving in a temporary work area as long as the area is returned to pre-construction conditions and the area is rehabilitated per the enhancement program and defined success criteria. The success of the restoration efforts is the responsibility of SDG&E under the NCCP/HCP. Because SDG&E is already required to successfully restore impacted areas, the means and methods need not be dictated, as this mitigation measure does not provide any additional resource protection. Following the NCCP/HCP Operation Protocols and

Enhancement Plan is sufficient to ensure adequate resource protection, and avoids potentially contradictory requirements.

Mitigation Measure BR-6

> **MMBR-6: Migratory Birds and Raptors Impact Reduction Measures**. The applicant will develop a Nesting Bird Management Plan in consultation with the USFWS, CDFW, and CPUC that outlines protective measures and BMPs that will be employed to prevent disturbance to active nests of both special status and Migratory Bird Treaty Act (MBTA)-protected bird species with the potential to occur in the project area. The Nesting Bird Management Plan will include the following components: … The Nesting Bird Management Plan will specify that active bird nests will not be removed during breeding season unless the project is expressly permitted to do so by the USFWS or CDFW. … Buffer reductions for special status species and raptors must be approved by appropriate wildlife agencies and the CPUC. … The Nesting Bird Management Plan will be submitted to the USFWS, CDFW, and CPUC for comment and approval no more than six months prior to the start of construction ….[160]

Mitigation Measure BR-6 outlines the elements the CPUC requires to be included in a Nesting Bird Management Plan, prepared in consultation with USFWS, CDFW and the CPUC. However, based on SDG&E's experience with USFWS and CDFW on its recent East County Substation and South Bay Substation Relocation Projects, two proposed elements of the Plan render it infeasible. First, the measure is inconsistent with current wildlife agency guidance, in that USFWS and CDFW cannot expressly permit removal of an active bird nest. Instead, it is incumbent on SDG&E to make its own determination as to whether the removal of a nest is permitted within the meaning of the State and Federal code. Second, USFWS and CDFW cannot expressly approve a buffer size or reduction. Rather, SDG&E must make its own determination of appropriate nesting bird buffer sizes and/or the implementation of other appropriate avoidance measures to ensure minimization of impacts to nesting birds. When making these determinations, SDG&E may seek and receive guidance from the agencies, but they will not provide approval or concurrence.

[160] DEIR at 4.4-50.

Mitigation Measure TR-3

> **MM TR-3: Notification and Monitoring of Helicopter Use**. SDG&E will notify the Long Beach Flight Standards District Office at least one week in advance of all days during which helicopter operations are planned to occur or as required by the Flight Standards District Office. In addition, SDG&E will notify all residents, businesses, and owners of property within 0.25 miles of planned or emergency helicopter flight paths and landing areas at least one week in advance of all days during which helicopter operations are planned to occur.

Mitigation Measure TR-3 requires that SDG&E "… notify all residents, businesses, and owners of property within 0.25 miles of planned <u>or emergency</u> helicopter flight paths and landing areas at least one week in advance of all days during which helicopter operations are planned to occur." By definition, an emergency is an event or incident that requires an immediate response; therefore advance notification to all residents with 0.25 miles is infeasible. Additionally, the term "flight path" should be clarified to pertain only to low altitude helicopter activities at or near the project site that could affect residents, business owners and owners of property. Otherwise the term "flight path," if broadly interpreted, could apply from the airport of origin to the project location many miles away. If interpreted in this manner, the notification requirement would impose unnecessary costs on ratepayers, be unduly burdensome and infeasible.

CHAPTER 7 COST ESTIMATE FOR SDG&E'S PROPOSED PROJECT (Witnesses -- Willie Thomas and Karl Iliev)

Section 1. Cost Estimate for SDG&E's Proposed Project

A. Proposed Project Cost

The Proposed Project includes the following key elements that have contributed to the assumptions for the cost estimate:

- Complete re-build and expansion of the existing 138/12kV Capistrano Substation to a 230/138/12kV GIS substation (including site grading) on existing SDGE property,
- Relocate three 138kV transmission lines into the new San Juan Capistrano Substation,
- Install new 138 kV underground getaways from the substation Install new underground distribution circuit getaways,
- Minor alterations and 138kV transmission lines reconfiguration at Talega Substation,
- Install approximately 8 miles of new overhead and some underground double-circuit 230 kV transmission lines and remove existing 138kV transmission line and structures,

The construction of the new 230 kV transmission line between Talega and the proposed San Juan Capistrano Substations will utilize approximately 7.5 miles of existing ROW, and approximately 1,900 feet of franchise and ROW in the City of San Juan Capistrano along an existing street (Vista Montana).

Grade new or refresh existing construction maintenance pads and spur roads as-needed.

Table 1, Proposed Project Cost Estimate, presents the estimated total cost for construction of the Proposed Project.

Table 1: Proposed Project Cost Estimate

Proposed Project Cost Component	Approximate Cost
Substation (including site development, below and above grade at the proposed San Juan Capistrano Substation).	$160.8 Million +/-10%
Talega Substation	$0.3 Million +/-10%
Talega Area 138kV Transmission	$9.9 Million +/-10%
San Juan Capistrano Substation 138kV Underground Getaways	$15.1 Million +/-10%
230kV Overheads (includes removal of the 138kV)	$58.6 Million +/-10%
230kV Underground	$33.3 Million +/-10%
Permitting, Environmental and Mitigation	$31.6 Million +/-10%
ROW Acquisitions	$3.1 Million +/-10%
Distribution Circuits	$7.1 Million +/-10%
Allowance for Funds Used During Construction (AFUDC)	$63.7 Million +/-10%
Grand Total Project Cost Estimate	$**383.6** Million +/-10%

Notes:

All costs are approximate and based on preliminary engineering, and include a 15% contingency. Final costs will be determined upon approved final project scope and contracting costs. Costs do not include associated O&M annual expenditures.

Source: *SDG&E*

Project costs have decreased from those presented in 2012. This cost decrease is comprised of savings due to the smaller scope pertaining to the construction of TL13835 and also due to the reconciliation of the estimated construction and equipment costs at Capistrano substation with actual bids to procure the equipment and perform the work by a contractor.

Section 2. Methodology for Preparing Cost Estimates

A. Cost Estimate Development Process

SDG&E utilized the following process to determine the Proposed Project's cost estimate:

During the alternative selection process, each internal SDG&E department and their respective project leads developed their costs based on past estimated costs for similar projects, manufacturer suggested costs on specific equipment, and average cost per mile for transmission and/or distribution circuits for all proposed alternatives.

Once the alternatives were analyzed and the proposed project was determined, each department completed a more detailed cost analysis for their respective section of the Proposed Project. This included the cost for initial design and permitting stages, through construction and into potential post-construction mitigation measures.

Within each SOCRE and non-SOCRE alternative estimate, SDG&E has accounted for costs associated with the various levels of SDG&E project management, engineering, land services, environmental, regulatory, public affairs, and others, including the various consultants who support these departments. The cost estimates include consideration for the expected level of participation from each department for each project.

The Finance and Project Management teams conducted internal meetings with all groups in order to better understand all cost elements, and once each section was agreed upon, the costs were included within the Work Breakdown Structure (WBS).

Contingency level was determined based on the level of detailed engineering and costs able to be done on each portion of the project and the amount of undeterminable factors that could affect the project cost, including weather, outage restrictions, permit issues, environmental unknowns, material issues, etc.

SDG&E has approximated the potential costs associated for both the environmental and construction related mitigation measures based on past project's spend and known costs associated with the Proposed Project.

SDG&E's AFUDC is an estimate of SDG&E's cost of capital invested in the project during construction and is applied to all capital orders or projects that have a construction period of greater than 30 days. AFUDC is applied to a project's total direct cost, applicable taxes, capital A&G, and any escalation. AFUDC is accrued from the first month that costs are first charged to a project and continues until the month a project is declared energized and operational. The percentage used is an internal calculation updated monthly for SDG&E and is based on current costs of short term debt and equity during the actual construction.

B. Cost Estimate Sources and Assumptions

- Utilization of historical spends on past SDG&E projects. This includes but is not limited to costs for labor and engineering, materials, acquisition and condemnation, environmental analysis and monitoring, and regulatory and legal.

- AFUDC is a generally accepted regulatory accounting procedure to capitalize the cost of debt and equity funds used to finance capital additions.

- Initial solicitations of design and construction consultants and contractors.

- Overhead and indirect costs, including Allowance for Funds Used During Construction (AFUDC), have been calculated based on the company wide planning rates provided by SDG&E Financial Planning for the period from 2015 through 2020.

- SDG&E budgeted electric and magnetic field ("EMF") reduction measures at 4% of the estimated cost of SDG&E's transmission project cost consistent with CPUC Decision 06-01-042.

- SDG&E adds escalation to the estimate of any long-term project (i.e., greater than one year in duration) as a provision for increases in costs resulting from inflation. Escalation within these estimates is primarily broken into two categories: (1) SDG&E labor and (2) non-SDG&E labor and non-labor. The percentages used for SDG&E labor is in accordance with SDG&E's Capital Accounting Guidelines which are based upon rates provided by Global Insight.

These guidelines are a tool used by SDG&E to provide guidance when no additional information is available.

Non-SDG&E labor and non-labor for transmission construction projects have been historically higher than those published by Global Insight. With the known volatility of the market over the past few years and the size of the project, additional consideration was required to establish the appropriate escalation rate for these estimates.

The Proposed Project estimate submitted in 2012 involved a review of the status of market conditions with regards to recent past and future material and labor markets. Overall, the feedback from various manufacturers and contractors, as well as market analysis consultants, showed a tendency for basic transmission materials such as resin, copper, aluminum, and steel to be increasing at a rate of 3% to 8% per year. Market analysis further indicated that additional finished good price adjustment over the next few years in excess of projected standard inflationary rates could be due to (a) pricing for finished goods tending to lag raw material increases, (b) cost uncertainty increased by the volatile fuel (hence transportation) cost increases, as well as (c) increasing interest rates. SDG&E made a decision to utilize 6% per year escalation for non-SDG&E labor and non-labor costs. As much as possible, SDG&E has been pro-actively seeking to control these price uncertainties by entering into contractual agreements with major material manufacturers to try to stabilize pricing as well as to maintain manufacturing windows necessary to meet required in-service dates.

With consideration of the above and additional feedback from vendors on price and availability over the next few years and the unknown construction start date, SDG&E has made a decision not to deviate from the 6% escalation rate originally used for the 2012 estimate.

This decision is consistent with typical SDG&E transmission and high voltage substation project estimates.

- Some of the key project assumptions include the following:
  - California Public Utilities Commission (CPUC) approval time (CPCN)
  - Approximately 60 month construction schedule from January 2016 through December 2020.
  - Minimal modifications to the proposed project during the approval process
  - Minimal outage and/or weather delays.
  - Minimal environmental issues.

C. SDG&E's Internal Resources, Alliances and Preferred Contractors

SDG&E is a regulated public utility that since 1887 has had experience owning, operating and constructing electric infrastructure. This long and successful experience coupled with the internal resources and external relationships results in a very knowledgeable understanding of the associated costs of a project like the Proposed Project. This fundamental knowledge results in a reduction of the Proposed Project's risk related to cost and schedule and is therefore an indirect cost containment strategy.

- SDG&E currently has existing and internal departments for every aspect of the Proposed Project which enables known internal labor and engineering costs.

- Utilization of existing SDG&E material alliances including substation equipment, steel poles, cable, hardware, etc. reduces uncertainty about price and availability.

- Preferred design and engineering consultants of which have existing master service agreements.

- Preferred construction contractors of which have existing contracts. These contractors include grading, foundation, electric, substation, construction monitoring and Storm Water Pollution Prevention Plan (SWPPP) implementation.

Section 3. O&M Costs

SDGE has also estimated its future annual operation and maintenance costs for the Proposed Project. Transmission Operations and Maintenance (O&M) costs will include transmission line monitoring, surveying and reporting.

The average annual Transmission & Substation Operations and Maintenance (O&M) costs will include:

- Approximately 8 miles of Transmission Line O&M ($118,500)
- Substation O&M
  - 138 GCB testing and maintenance ($70,800/yr)
  - 230kV GCB testing and maintenance ($32,500/yr)
  - Transformer testing and maintenance ($22,100/yr)
  - Switchgear maintenance ($11,200/yr)
  - 12kV and 230kV capacitor testing and maintenance ($3,700/yr)
  - Control and relay testing ($36,400/yr)
  - Battery testing and maintenance ($2,600/yr)
  - General yard maintenance ($16,400/yr)
  - Corrective maintenance (50% of preventive maintenance ($97,800/yr)

The total Transmission Line and Substation O&M annual costs are approximately $412,000.

Section 4. SUMMARY

The Proposed Project is designed to improve transmission system reliability and safely increase capacity for projected load growth in the South Orange County service area. With the addition of a new 230 kV transmission line between the Talega and Capistrano Substations, the proposed project will meet SDG&E's long term planning and reliability goals and CAISO's Functional Specifications for the Project including all NERC, CAISO, and WECC transmission planning standards. The Proposed Project will mitigate transmission overloads identified by CAISO and SDG&E, by delivering reliable power safely, efficiently and effectively to the South Orange County service area Additional benefits of the Proposed Project will include the reduction of the risk of a service interruption resulting from a transmission and/or substation equipment failure, infrastructure improvement of existing transmission lines and of Capistrano Substation, fire hardening existing wood structures, and the fact that the Proposed Project is located entirely within existing utility corridors and franchise position.

SDG&E's Proposed Project cost estimate of approximately $383.6 Million has been thoroughly analyzed and includes the appropriate amount of contingency given the current design of the Proposed Project. If any aspect of the Proposed Project is modified, revised or altered for any reason, the current cost estimate may not be applicable. Potential reasons for changes to the cost estimate include but are not limited to:

- Route and/or project modification through the CEQA process
- Schedule delays due to permit acquisition timing, unforeseen weather and/or outage constraints
- Post construction mitigation measures above and beyond SDG&E's Applicant Proposed Measures (APMs).

CHAPTER 8 THE PROPOSED PROJECT WILL BE CONSTRUCTED IN ACCORDANCE WITH THE COMMISSION'S RULES AND POLICIES ON SAFE AND RELIABLE OPERATION

Section 1. INTRODUCTION (Witness Willie Thomas)

The Scoping Memo at 9 identifies as one issue: "Does the Project design comport with Commission rules and regulations and other applicable standards governing safe and reliable operations."

SDG&E proposes to construct and operate a new, approximately 8-mile double-circuit 230 kV transmission line between the existing SDG&E Talega Substation and a new San Juan Capistrano Substation to be constructed on the existing Capistrano Substation property (Proposed Project). The Proposed Project will remove the existing 138/12 kV Capistrano substation and replace it with the new 230/138/12 kV San Juan Capistrano Substation (sometimes referred to as the rebuilt Capistrano Substation).

Section 2. SAFETY AND RELIABILITY

A. Transmission Planning (Sponsored by John Jontry)

As described in the SDG&E's January 15, 2015 Prepared Testimony and in Chapter 2 above, the Proposed Project is needed to provide reliable electric service to South Orange County, and to comply with mandatory NERC, WECC, and CAISO reliability standards.

In addition to the NERC Category A and Category B performance categories described in the testimony referenced above, SDG&E is required to study the effects of NERC Category D contingencies. Category D system performance addresses the impact of an extreme event on the bulk power system. Category D contingencies include the loss of a substation.

The Proposed Project, over significant sections of the proposed route, will occupy a common right-of-way with as many as three other transmission or power lines. SDG&E, as the

NERC registered Transmission Planner, is obligated to assess the risks and consequences of such a system contingency. The applicable NERC standard, however, does not necessarily require mitigation for these extreme system contingencies. Note that the WECC has a somewhat stricter requirement for transmission lines in common corridors, but it is only applicable to lines with voltages over 300 kV. The Proposed Project will share common-corridor segments with other 230 kV, 138 kV, and 69 kV lines, so the WECC common-corridor standard does not apply.

As a practical matter, location of multiple transmission lines in a common corridor is a common industry practice. This is due to several factors, primary among them being the expense and difficulty of obtaining new right-of-way in populated areas, and the desire of utilities to minimize impact on communities by fully utilizing existing available right-of-way. It is also more efficient to use existing corridors, since they already tend to connect major load centers and thus already go right where utility planners see the need to go. Utility standards and construction practices allow for the construction and operation of lines on common structures and in common ROW in a safe and reliable manner.

Although SDG&E is required to study the simultaneous loss of all transmission circuits in the corridor occupied by the Proposed Project, as a practical matter the addition of the Proposed Project to the existing corridors cannot degrade system performance. As described in SDG&E's January 15 Testimony and Chapter 2 above, the Proposed Project will significantly improve the performance of the system from a NERC Category B and C perspective. From a NERC Category D perspective, loss of all lines in the common-corridor segments occupied by the Proposed Project will not leave the bulk power system in a worse condition than exists today. Since the scope of the Proposed Project will upgrade portions of the existing transmission lines in the common ROW, as well as add a second connection to the Southern California bulk power system at San Juan Capistrano and provide a second source to serve the South Orange County load, the overall performance of the system even under the most extreme Category D contingencies will improve. Also, as a practical matter, all of the available mitigation options for loss of all lines in the common ROW available before the Proposed Project goes into service will also be available once the Proposed Project is energized.

To summarize, the Proposed Project will significantly improve system performance, and will in no way degrade system performance.

B. Transmission Engineering & Design (Witness Willie Thomas)

- *General Orders 95, General Order 128 & Additional SDG&E Standards*
  - All applicable rules in General Orders 95 and 128 will be met in the design and construction of the Proposed Project, including but not limited to the:
    - Sag and tension limits of the overhead conductor and OPGW/shield wire,
    - Overhead conductor clearances to ground, waterways, bridges, buildings, overhead crossings and many other obstacles,
    - Underground clearances and depths will be maintained,
    - Trench and conduit system will be constructed with adequate provision for safety of the workmen, safety of the general public, and the preservation of property,
    - Loading cases that dictate wind speeds and temperature,
    - Safety factors for all components on a structure (wire, pole, tower, guys, anchors, insulators, etc.),
    - Grounding for equipment and personal safety,
    - Climbing and working space,

  - Proper warning and high voltage marking,
  - Proper guarding of structures, such as fencing and a steel shroud around 230kV cable poles to prevent climbing or vandalism.

  In cases where there is ambiguity in the rules, the most conservative interpretation of the rules will be applied.

- SDG&E Standards
  - In addition to the minimum loading and safety factors required in Section IV of General Order 95, a more stringent loading condition of 18 psf will be used for the design criteria of new structures proposed in the project. This is due to the fact a portion of the line resides in fire prone areas such as in and around Camp Pendleton.
  - Additional clearances above and beyond General Order 95 will be included in the design criteria for the project to the extent feasible. This provides additional margin of safety to account for any variations with materials and/or construction of the project. Land Surveyors will be utilized to ensure the design clearances are achieved during construction.
  - Steel Poles have become the most common structure type used on the SDG&E transmission system. It's important to note there are two types of steel poles used at SDG&E, the direct burial poles (aka wood equivalent) that come in standard heights and dimensions, and the engineered steel poles that sit on top of foundations and are engineered specifically for each site. Since steel poles have standard heights and dimensions, the tools and hardware used to install them can be easily standardized unlike wood

poles whose diameters vary greatly. Since steel poles are man-made there is greater confidence the strength and quality of the material meet design requirements. Wood poles strengths can vary significantly since they are naturally grown product. Engineered steel poles can be designed to meet nearly any loading requirements and eliminate the need for guys and anchors, thus improving the safety and reliability of the system by eliminating additional points of failure and maintenance. Lastly, steel poles are more resistant to fires than are wood poles.

- Seismic loading for transmission lines will be considered and is above and beyond what is required by GO 95, or by the National Electric Safety Code (NESC), or by the American Society of Civil Engineers (ASCE). SDG&E will avoid locations on seismic faults and will design for seismic-induced soil liquefaction if foundations are located in soils prone to liquefaction. Currently GO 95 and NESC focuses on loading requirements based on effects of wind, ice, gravity, and temperature induced loading. The American Society of Civil Engineers (ASCE) No. 74 Manual "Guidelines for Electrical Transmission Line Loading" similarly has no provisions for seismic loading, but do comment in Appendix F that transmission structures are not typically designed for seismic loading, and wind/ice combinations and broken wire generally exceed design earthquake loads.

C. Substation Engineering & Design (Witness Karl Iliev)

- ***General Order 174/NERC Regulation***
  - The new San Juan Capistrano substation will have an inspection program that meets compliance with GO 174 inspection requirements. Additionally, SDG&E will maintain the substation in compliance with all applicable NERC and WECC reliability standards including CIP version 5, pertaining to cyber security and CIP 014, pertaining to substation physical security.
- ***Industry Standards***
  - SDG&E will design substations to meet its own internal standards, which are largely based on IEEE equipment and substation design standards.
  - Seismic requirements will meet the IEEE 693 Recommended Practice for Seismic Design of Substations, ASCE 96 Guide to Improved Earthquake Performance of Electric Power Systems and ASCE 113 Substation Structure Design Guide. These standard serves as an industry guide to seismic design of utility substations and the associated equipment design specifications and testing standards used by manufacturers of substation equipment throughout North America. Manufacturers of a range of utility substation equipment have adopted the testing requirements of IEEE 693-2005 in their equipment design specifications and offer commercially available IEEE 693-2005 compliant products to the utility industry. This includes key products such as transformer bushings (composite design), transformer surge arrestors (composite design), disconnect switches, circuit breakers, capacitive coupling voltage transducers (CCVTs) and other devices that are essential to the operation of electric utility substations. Use of these Standards

such as IEEE 693 and 1527 and proper application of these standards can be expected to provide significant loss avoidance benefits for utilities in seismically active regions and customers served by those utilities. In addition to avoided losses related to the utility's assets, customers enjoy benefits of shortened service interruption following large earthquakes.

- ***Substation Technology***
  - The following equipment and technology enhancements can be seen as an upgrade to the safety and reliability of the substation:
  - **GAS INSULATED SUBSTATION (GIS):** GIS technology enables a flexible and compact design of the new San Juan Capistrano substation. GIS technology uses Sulfur Hexafluoride (SF6) gas as an insulating medium rather than atmospheric air. SF6 is non-toxic, inert and is safely used by SDG&E in circuit breakers and switching gear due to its high dielectric strength. This technology in a GIS application allows conductors to be spaced closer together without an increased risk of arcing and has the potential of significantly reducing a substation size of that required by an air insulated substation (AIS), depending on site specifics and restrictions. Additionally, GIS technology may reduce field assembly time, as most of the equipment is pre-assembled by the manufacturer prior to arriving on-site. This allows reduced construction schedules on this project.
  - **CONDITION BASED MONITORING (CBM):** Substation transformers and circuit breakers are monitored with devices for the purposes of detecting and preventing catastrophic failure and reducing maintenance. Transformer monitors

perform Dissolved Gasses Analysis (DGA) in dielectric oil (DGA), and measure thermal performance, auxiliary device load, and bushing insulation. These analytics allow SDG&E's field operations group to detect and repair manufacturer defects that could lead to early failure of transformers on this project. It also allows field crews to quickly repair auxiliary devices that have failed on these transformers, allowing for more operability and increased reliability. Gas circuit breaker monitoring measures SF6 density, operating mechanism timing, and cumulative fault interruption. This technology helps crews identify and mitigate SF6 leaks, which pose an environmental risk for their greenhouse gas contribution. It also reduces maintenance on circuit breakers, while increasing reliability for these devices. Circuit breaker monitoring tells crews when maintenance needs to be performed, rather than them performing it on time-based intervals.

- **ADVANCED SECURITY:** Advanced physical and cyber security systems at San Juan Capistrano substation will use state-of-the-art security technologies for electronic access control, monitoring, intrusion detection, intruder tracking, motion & thermal video capture, centralized monitoring and intelligent analytics. Additionally, these systems will be used to create a physical security perimeter to protect cyber assets enabling SDG&E to maintain compliance with NERC standards. These systems will use industry best practices and durable best-of-breed security technology to protect life, property, and electric system reliability while complying with Local, State, and Federal regulatory guidance that control and protect the SDG&E Transmission system.

- **SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA) and SYNCHROPHASORS:** San Juan Capistrano substation will utilize both SCADA infrastructure and Synchrophasor technology. SCADA infrastructure allows for remote operational control and visibility of the electric system which directly increases reliability to customers. SCADA enables centralized operators to remotely see voltage, current, open/close, and alarm status of equipment. It also allows remote operation of circuit breakers, load tap changers, and other devices. Synchrophasor technology goes above and beyond standard data collection by providing high fidelity, high resolution data across high speed data streams. Synchrophasors, or Phasor Measurement Units (PMU), measure the electrical waves on an electric system in real-time using a common GPS time source for synchronization. This time synchronization allows correlating of measurements of multiple remote measurement points on the electric system, which is required for precisely timed operations and situational awareness. Synchrophasors improve the sampling rate over traditional data collection by a hundred fold and advance data accuracy down to fractions of microseconds. Synchorphasors are considered one of the most important measuring devices in the future of electric system and may lend to monitor system stresses, improve voltage stability, detect oscillations and instabilities, validate system models, provide wide area protection and automation, efficient integration of distributed generation and renewable energy, and allow for accurate post disturbance analysis.

- **ULTRA FAST ACTING EARTHING SWITCH (UFAS)**: SDG&E's new 12kV switchgear are retrofitted with this technology that is designed to protect personnel from potentially hazardous arc flashovers. This relaying system detects the ultra violet light associated with an arc flash and closes an ultra fast acting earthing-switch to ground the electrical bus where the arc flash originates, thus lowering the available arc flash energy and reducing potential harm to personnel in close proximity to the flashover.

D. Proposed Project Design (Witness Willie Thomas)

The Proposed Project is designed to improve transmission system reliability and safely increase capacity for projected load growth in the South Orange County service area. Specific design elements that accomplish the Proposed Project's safety and reliability objectives include the following:

- *Existing ROW, Access Roads and Work Pads*
  - The construction of the new 230 kV transmission line between Talega and the proposed San Juan Capistrano Substations will utilize approximately 7.5 miles of existing ROW, and approximately 1,900 feet of franchise and ROW in the City of San Juan Capistrano along an existing street (Vista Montana). The Proposed

Project therefore requires very little new additional ROW, which is consistent with state law guiding the use of existing transmission corridors, known as the Garamendi Principle.[161]

- o Due to the fact that the existing ROW for the Proposed Project contains existing transmission and power line structures, access roads and work pads, the need to create additional infrastructure is minimized. Existing structures, access roads and works pads will be utilized to the extent feasible. Some access roads and work pads will be expanded where necessary to accommodate the safe construction and maintenance of the new structures.

- *Standard SDG&E Components*
  - o The Proposed Project will use many components that are standard and familiar to SDG&E including but not limited to:
    - Overhead Conductor (ACSR/AW and ACSS/AW),
    - Underground Cable (XLPE),
    - Polymer Insulators,
    - Foundational Poles that do not require guys and anchors,
    - Standard 12kV, 69kV, 138kV, and 230 kV Hardware.
  - o By utilizing standard components, no significant change in SDG&E's operations and maintenance practices and restrictions along the Proposed Project overhead

[161] Garamendi Principle – Transmission Siting SB 2431 (Garamendi), Chapter 1457, 62, Statutes of 1988: 1) Encourage the use of existing ROW by upgrading existing transmission facilities where technically and economically feasible; 2) When construction of new transmission lines is required, encourage expansion of existing ROW, when technically and economically feasible; and 3) Provide for the creation of new ROW when justified by environmental, technical, or economic reasons defined by the appropriate licensing agency.

route is anticipated. Additionally, replacement material and parts are typically much more readily available which further increases the reliability of the line.

- *Electric Standard Practice 113.1 – Wildland Fire Prevention and Fire Safety.*
  - The Proposed Project will be constructed consistent with Electric Standard Practice 113.1 – Wildland Fire Prevention and Fire Safety which outlines practices and procedures for SDG&E activities occurring within areas of potential wildland fire threat within SDG&E's service territory. The Proposed Project design includes replacement of wood poles with steel poles, increased conductor spacing to maximize line clearances, installation of steel poles to withstand an extreme wind loading case and known local conditions, and undergrounding of a portion of the power line. These design components of the Proposed Project minimize the fire risk through enhanced safety and reliability of the power line system, particularly during extreme weather conditions. The standard practices in Electrical Standard Practice 113.1 include avoidance and minimization measures to comply with state and local fire ordinances.
- *Steel Poles*
  - New structures are designed utilizing dulled galvanized steel to avoid potential adverse effects relating to fire and fire damage, as well as adverse effects due to high moisture content in coastal areas. The dulled aspect of the steel poles also minimizes the potential for visual impacts relating to glare.
- *Engineered Foundations*
  - The Proposed Project will use concrete pier foundations for all new 230 kV steel poles and the majority of the new 69 kV steel poles. Concrete pier foundations

are types of engineered foundations that are specifically designed to support the new steel poles and are typically much stronger than a direct embedded type of foundation. Additionally, with the use of an engineered foundation, the need for guying is typically eliminated further reducing the footprint of structure locations and improving reliability.

- *Reconductoring, Insulation and Hardware*
  - Where lines are being replaced or transferred for the Proposed Project, the existing conductor will be replaced and reconductored with new conductor creating a newer, more safe line. Additionally, all hardware including insulators associated with the replacement conductor will also be replaced with new hardware.
  - All new and reconductored structures will utilize polymer insulators. These polymer insulators are stronger and require less maintenance as compared to the existing insulators that are made with porcelain. Corona rings and dampers will be utilized as needed.
- *Shield Wire/Optical Ground Wire (OPGW)*
  - The Proposed Project includes installation of OPGW on the new 230 kV structures as well as replacement of existing shield wire with new OPGW when possible. The OPGW will serve as a new communication line between the existing substations. Additionally the OPGW will serve as lightning shielding for the conductor below and will further improve reliability.

- *Underground Segment –Vista Montana*
  - The new 230 kV cables will be installed in a new duct bank package. Each package will consist of 8-inch conduits for electrical cable and 2-inch conduits for telecommunications fiber optic cable. The duct package will be protected by a 2,000 pounds per square inch (psi) concrete encasement to 6 inches above the ducts. The remainder of the trench will be filled with backfill concrete or fluidized thermal backfill. One splice vault will be installed mid-way along the underground alignment. The new splice vault will be designed to accommodate all local and federal safety and loading requirements including the American Association of State Highway and Transportation Officials highway loading guidelines. The trenches will be widened and shored where necessary to meet California Occupational Safety and Health Administration safety requirements.
  - By undergrounding a segment of the Proposed Project, certain unforeseen events including the following may be minimized or limited:
    - Chance of damage from severe weather (high winds, etc.)
    - Susceptibility to fires
    - Vehicular contact

    This minimization of unforeseen events therefore has the potential to create additional safety and reliability measures by reducing the frequency and duration of outages due to unforeseen events.
- *Operations and Maintenance (O&M)*
  - By utilizing taller, stronger steel poles, the Proposed Project is able to decrease the overall amount of structures within the existing ROW. The design as proposed

reduces the overall amount of structures by approximately 52 and therefore SDG&E needs to maintain approximately 52 less structures.

- Replacement of wood poles with steel further reduces the O&M of the structures as galvanized steel lasts longer, stands up to weather elements better and requires overall less maintenance than wood.
- Utilization of polymer insulators reduces the maintenance required for the existing lines because polymer insulators require less washing than the existing porcelain. This reduction in washing potentially reduces the need for additional outages due to maintenance on the line.

- *Safe Worker and Environmental Awareness Program*
  - To ensure safe and environmentally compliant construction, SDG&E will prepare a Safe Worker and Environmental Awareness Program (SWEAP) for project-personnel. A dedicated field safety representative will be assigned to the project to provide oversight to all contract and SDG&E personnel. The SWEAP may include training for relevant topics such as:
    - General safety procedures
    - General environmental procedures
    - Fire safety
    - Biological resources
    - Water Resources
    - Cultural resources
    - Paleontological resources
    - Hazardous materials protocols and BMPs

        - SWPPP

- *Hazardous Materials*
    - SDG&E shall address potential impacts relating to the handling and use of hazardous materials through compliance with numerous state and federal regulations, including, but not limited to:
        - Federal Occupational Safety and Health Administration (OSHA) regulations for worker safety in hazardous material remediation and hazardous waste operations (29 CFR Section 1910.120),
        - Federal OSHA regulations hazard communication for workers (29 CFR Section 1910.1200).
- *Proposed Project Fire Plan*
    - A project-specific fire prevention plan will be drafted for the Proposed Project consistent with Electric Standard Practice 113.1 and the SDG&E Operations & Maintenance Wildland Fire Prevention Plan. The project-specific fire plan identifies project-specific risk-related activities as well as measures (including tools and procedures) to address said risks.
- *SDG&E Subregional NCCP*
    - The Proposed Project will avoid and minimize impacts to biological resources through implementation of the SDG&E Subregional NCCP. The SDG&E Subregional NCCP establishes a mechanism for addressing biological resource impacts incidental to the development, maintenance, and repair of SDG&E facilities within the SDG&E Subregional NCCP coverage area. The Proposed Project is located within the SDG&E Subregional NCCP coverage area.

- Specific NCCP Operational Protocols that are incorporated into the Proposed Project design to comply with the SDG&E Subregional NCCP include but are not limited to the following:
    - Vehicles will be kept on access roads and limited to 15 miles per hour,
    - Supplies, equipment, or construction excavations where wildlife could hide (e.g., pipes, culverts, poles holes, trenches) would be inspected prior to removing or working on/in them,
    - Field crews would refer all environmental issues, including wildlife relocations, dead or sick wildlife, or questions regarding environmental impacts to the Environmental Surveyor. Biologist or experts in wildlife handling may be necessary to assist with wildlife relocations,
    - No pets are allowed within the ROW,
    - Measures to prevent or minimize wild fires will be implemented, including exercising care when driving and not parking vehicles where catalytic converters can ignite dry vegetation,
    - All SDG&E personnel will participate in an environmental training program conducted by SDG&E, with annual updates.

- *Standard Traffic Control Procedures*
    - SDG&E will implement traffic control plans to address potential disruption of traffic circulation during construction activities and address any safety issues. These traffic control plans will be prepared by the project engineer or contractor and subject to review by the appropriate jurisdictional agency, such as the Cities of San Juan Capistrano and San Clemente, the County of Orange and Caltrans.

- *Encroachment Permits*
  - SDG&E will obtain any required encroachment permits from the Cities of San Juan Capistrano and San Clemente and the County of Orange for crossings at city streets and Caltrans for work near I-5, and will ensure that proper safety measures are in place while construction work is occurring near public roadways. These safety measures include flagging, proper signage, and orange cones to alert the public to construction activities near the roadway.
- *Clear Working Space*
  - SDG&E maintains a clear working space area around certain poles pursuant to requirements found within General Order 95 and Public Resources Code (PRC) 4292. SDG&E keeps these areas clear of shrubs and other obstructions for fire prevention purposes. In addition, vegetation that has a mature height of 15 feet or taller are not allowed to grow within 10 horizontal feet of any conductor within the ROW for safety and reliability reasons.
- *Outage Coordination*
  - SDG&E will coordinate any necessary line outages in order to maintain system reliability and construction personnel safety. Based upon preliminary engineering, SDG&E does not anticipate any project based interruption of service to customers during construction.

CHAPTER 9 ECONOMIC AND SOCIAL IMPACTS OF AN OUTAGE OF THE TALEGA SUBSTATION (Witness Michael Sullivan)

Section 1. Estimated Total Outage Cost for South Orange County

A. Overview of Outage Cost Study

San Diego Gas and Electric (SDG&E) has retained Nexant Inc. to estimate the economic costs arising from power outages that could result from a catastrophic failure of the equipment located in or near the Talega Substation. This station is the single connection to the California grid for 7 substations serving approximately 120,000 customers including about 8,000 businesses and 108,000 households (comprising about 300,000 people) in and around the cities of Dana Point, San Clemente, San Juan Capistrano, Laguna Beach, Laguna Hills, Laguna Niguel and Mission Viejo – the area known as South Orange County (SOC).

To estimate the costs of outages of varying duration for customers in this area, Nexant first estimated outage costs on a per customer basis for a relatively short duration outage (16 hours), based on the outage cost estimation equations reported in: "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States", Lawrence Berkeley National Laboratory, January 2015 (Attachment 21). This is the most authoritative source of information about the economic impacts of electric outages in the US.

To estimate the costs for longer duration outages, these short duration costs were scaled up to longer duration costs using the observed relationship between short and long duration outage costs reported by PG&E in conjunction with its justification for constructing a third transmission line to serve the downtown San Francisco Embarcadero substation. That study included a careful estimate of the economic costs that its downtown customers would experience as a result of an electric outage lasting from 24 hours to 7 weeks (Attachment 22).

Table 1 summarizes the estimated direct economic costs to businesses and households in SOC by customer class for a 16-hour outage. The direct cost of a 16-hour outage to customers in SOC is estimated to be approximately $105.2 million. As Table 1 indicates, most of this cost will be borne by the 8,558 business customers operating in the area.[162] The average costs per event reported in this table are similar to those reported for businesses in the updated LBNL report in Attachment 21. However, they were not taken directly from the report. Rather they were estimated from the econometric models contained in the report for each customer on SDG&E's SOC system and then rolled up to the sums and averages displayed in the table.

Table 1: Estimated Direct Outage Costs in SOC ($ Millions) – 16 Hour Outage

Customer Type	Number of Customers	Cost per Customer ($)	Range of Cost per Customer ($)		Total 16-hour Cost ($ Millions)
			Minimum	Maximum	
Medium and Large C&I (> 50,000 Annual kWh)	1,806	$27,131	$14,638	$167,396	$49.0
Small C&I (<= 50,000 Annual kWh)	6,752	$7,904	$2,038	$21,089	$53.4
Residential	108,407	$25.7	$2.8	$113.6	$2.8
All	**116,965**	**$899.1**	**$2.8**	**$167,396**	**$105.2**

Table 2 displays the estimated range of total costs arising from an outage of the area served by SDG&E in SOC for outages lasting from 16 hours to 3 weeks. The estimated outage costs are divided into two components: (1) direct outage costs experienced by businesses and households in the area as a result of outages of varying duration; and (2) indirect outage costs experienced by businesses and households inside and outside the area served by SDG&E that are not directly experienced by the individual customers in the area (also known as spillover costs).

[162] About 1,800 small business customer accounts were removed from the file before estimation of the outage cost because they are believed to represent traffic signals, cable transponders, cell towers and other automated equipment for which outage costs are not well represented in the cost estimation data base.

The 16-hour direct costs were estimated based on the econometric equations described in the LBNL report cited above. The indirect outage costs were obtained from a careful review of the literature on hazard losses summarized in Attachment 23. Indirect outage costs are reported as a range because a relatively wide range of indirect outage cost ratios have been reported in the hazard loss literature. Although indirect costs are impossible to precisely estimate, they are no less real and tangible than the direct costs reported Combining the direct and indirect cost in Table 2, a 16-hour outage to businesses and households inside and outside the area is estimated to cost between $158 million and $316 million.

Table 2: Estimated Total Outage Cost for SOC by Duration ($ Millions)

Outage Duration	Direct Cost ($ Millions)	Indirect Cost ($ Millions)	Total Outage Cost ($ Millions)
16 hours	$105.2	$52.6 to $210.3	$157.8 to $315.5
24 hours	$141.3	$70.6 to $282.5	$211.9 to $423.8
4 days	$457.9	$228.9 to $915.7	$686.8 to $1,373.6
3 weeks	$1,592.5	$796.3 to $3,185.0	$2,388.8 to $4,777.5

Costs for outages lasting longer than 16 hours cannot be estimated from the econometric equations reported in the updated LBNL report because the costs of long duration outages have not been extensively studied. Surveys designed to estimate long duration outage costs have been conducted only very recently and then only for one geographical area (Downtown San Francisco). However, it is possible to extrapolate the estimated costs from the 16-hour outage cost estimate to longer duration outages by taking account of the relationships that were observed for long and short duration outages in the instance where the costs of long duration outages have been carefully studied. The assumptions required to make this extrapolation are described in detail in the next section.

Applying reasonable assumptions about the likely increase in outage cost as duration increases from 16 to 24 hours results in a direct cost to SOC customers of $141 million. When duration rises to 4 days, the direct outage cost is $458 million; and by the time the duration reaches 3 weeks the direct outage cost is about $1.6 billion. Including indirect costs, the projected impact on the surrounding economy becomes more severe. At 4 days, the total projected outage cost ranges from about $687 million to nearly $1.4 billion. If the area is without power for 3 weeks, the total projected outage cost ranges from about $2.4 billion to nearly $4.8 billion.

B. Estimating Direct Costs

Ideally, the direct costs of a long duration outage should be estimated by surveying potentially affected customers to ask them to estimate the direct costs they would experience as a result of long duration outages of varying length (e.g., 24 hours, 4 days, one week or longer). Nexant employed this approach in estimating the cost of electricity service interruptions that might occur in downtown San Francisco if both 230 kV lines serving the Embarcadero substation were simultaneously forced out for an extended period of time. The costs were estimated for outages ranging in duration from 24 hours to 7 weeks. The CPUC authorized construction of a third 230 kV line to serve the downtown area of San Francisco based in part on the estimated economic impacts on customers in the event of an outage.

Unfortunately, time constraints prevent the use of this approach in the present case. Instead, the cost of long duration outages for SOC were estimated by inflating reliable estimates of the costs from a short duration outage costs for SOC (i.e., 16 hours) using the observed relationships between (1) the 8 hour and 24 hour outage costs reported in PG&E's 2012 VOS study; and (2) the relationship between long duration outage costs observed in PG&E's 2013 survey of downtown customers which included outage cost estimates for interruptions ranging from 24 hours to 7 weeks. The estimated costs for long duration outages for SOC were derived in a three step process.

In the first step, Nexant used outage cost estimation equations published in the "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States" to estimate the direct cost that each customer in SOC would experience as a result of a 16-hour outage. To derive these cost estimates, Nexant obtained a digital file containing customer characteristics required to estimate the per event interruption costs for all the customers served by the Talega 230 kV interconnection. The information for each customer included:

- Annual electricity consumption for the most recent year;
- Type of customer (i.e., household, large to medium sized business and small business), and
- For businesses, the type of enterprise (from NAICS codes).

The direct outage costs for the 16-hour outage were calculated by applying the outage cost estimation equations in the above referenced report, inserting the appropriate outage and customer characteristics for each customer. As explained in this 2015 report, the econometric models for predicting interruption costs are based on an analysis of 34 outage cost surveys (and over 100,000 outage cost survey responses) conducted by the utility industry over the past 25 years using a standard survey methodology developed and published by EPRI in the 1990s. The econometric models developed in the report are called customer damage functions. They express customer damages (outage costs) as a function of interruption characteristics (e.g. duration, onset time, season) and customer characteristics (e.g., customer type, electricity consumption, type of business, etc.). The customer damage functions provided in the updated report cited above are two- part econometric equations. They are called two-part models because predicted customer outage costs are calculated in two parts. In the first part, the likelihood that a customer's outage costs are zero is estimated. This part is necessary because some customers experience no real outage costs under some circumstances (e.g., outages of short duration occurring at times when customers are not using much electricity or outages to customers with full backup generation). The likelihood that customers experience no outage costs as a result of a given outage is estimated using a Probit model that predicts the likelihood that customers report they will experience zero cost given the characteristics of the interruption and characteristics of the customers. The output from this step is the likelihood that the outage cost is positive for a given customer. The Probit model output can range from 0 to 1.

In the second part of the estimation process, a generalized linear model (GLM) regression equation is used to estimate the magnitude of the outage costs <u>for customers who have positive outage costs</u> using the same predictors of outage costs as were used in the first part. The relationship between outage costs and the predictor variables in the econometric equations used to estimate outage costs for medium and large commercial and industrial customers are presented in Tables 3-4 and 3-5 in the updated interruption cost report on pages 28 and 29. To estimate the direct cost of the 16-hour outage, the output from the GLM regression equation is multiplied by the output from the Probit equation – in effect scaling the estimate to take account of the likelihood that the outage cost is zero for a given customer.

The parameters used in the estimation equations for medium and large commercial and industrial customers are presented in Table 3. Because the model is non-linear with respect to a number of variables in the equation, the parameters in the model are not directly interpretable.

Table 3: Model Estimation Parameters for Medium and Large C&I Customers

Variable	Probit		GLM	
	Coefficient	Std. Error	Coefficient	Std. Error
Interruption Characteristics				
duration	0.005	0.000	0.006	0.001
duration^2	-2.820E-06	0.000	-3.260E-06	0.000
summer	0.410	0.023	0.113	0.060
Customer Characteristics				
ln(annual MWh)	0.118	0.006	0.495	0.016
Interactions				
duration x ln(annual MWh)	-3.416E-04	0.000	-1.882E-04	0.000
duration^2 *x ln(annual MWh)*	1.640E-07	0.000	1.480E-07	0.000
Industry				
manufacturing	0.200	0.025	0.823	0.069
Constant	-0.958	0.047	5.292	0.127

Tables 4 and 5 summarize the model estimation parameters for small commercial customers and households respectively.

Table 4: Model Estimation Parameters for Small C&I Customers

Variable	Probit		GLM	
	Coefficient	Std. Error	Coefficient	Std. Error
Interruption Characteristics				
duration	0.003	0.000	0.004	0.000
duration^2	-1.780E-06	0.000	-2.160E-06	0.000
summer	0.215	0.030	-0.384	0.073
morning	0.537	0.022	-0.057	0.070
afternoon	0.664	0.029	-0.032	0.083
Customer Characteristics				
ln(annual MWh)	0.124	0.013	0.069	0.035
backupgen or power conditioning	0.082	0.025	0.308	0.058
backupgen and power conditioning	0.272	0.059	0.538	0.129
Industry				
construction	0.261	0.054	0.786	0.153
manufacturing	0.176	0.042	0.587	0.104
Constant	-1.332	0.048	7.000	0.135

Table 5: Model Estimation Parameters for Households[163]

Variable	Probit		GLM	
	Coefficient	Std. Error	Coefficient	Std. Error
Interruption Characteristics				
duration	0.003	0.000	0.002	0.000
duration^2	-1.130E-06	0.000	-9.450E-07	0.000
summer	0.541	0.019	0.161	0.029
afternoon	-0.266	0.026	-0.282	0.041
evening	-0.755	0.024	-0.095	0.047
Customer Characteristics				
ln(annual MWh)	0.038	0.018	0.249	0.028
household income	9.660E-07	0.000	1.850E-06	0.000
Constant	-0.266	0.051	1.379	0.080

Using the above described model parameters, outage costs are estimated for every customer in SOC; and the results reported for the direct costs of a 16-hour outage in Tables 1 and 2 are obtained by statistically summarizing this customer file to obtain total outage costs and averages.

The next step in calculating longer duration outage costs that will be experienced in SOC is to escalate the estimated direct outage cost estimate for SOC from 16 to 24 hours. This is necessary because the outage cost estimation equations in the LBNL report are only reliable for outages of 16 hours duration or shorter.

In 2012, Nexant (then Freeman, Sullivan & Co.) carried out a Value of Service study for the Pacific Gas and Electric Company in which outage costs for 8-hour and 24-hour outages were reported. The report entitled: "Pacific Gas and Electric Co.'s 2012 Value of Service

[163] Income information for residential customers was not included in the estimation model because of uncertainty about the reliability of this information in the utility's records. Eliminating this parameter has the effect of setting the income in the households for SOC at the average value of income observed in prior outage cost studies. Eliminating this parameter will introduce a small downward bias in the estimated interruption costs for residential customers, but is not expected to significantly affect the overall outage cost estimate because of the small impact that residential outage costs have on the total outage cost for the area.

Study," was filed with the CPUC in support of its November 2012 GRC filing (A.12-11-009). In that report (Attachment 24), the costs per event for outages of different durations in the PG&E service territory were reported in Table 1-2 on page 6. To extrapolate the per event costs from the 16-hour outage for SOC to 24 hours, Nexant calculated the ratio of the cost per event for the 24-hour outage to the cost per event of the 16-hour outage for each customer type in the PG&E short duration outage cost survey and then applied that ratio to estimate the cost of the 24-hour event for SOC. The use of this ratio to inflate the 16-hour outage costs to 24 hours effectively rests on the assumption that the increase in cost for customers in SOC (going from 16 to 24 hours) is proportional to increase in cost observed for PG&E customers in the Bay Area going from 16 to 24 hours. Table 6 displays the results of the calculation.

Table 6: Imputed Cost of 24 Hour Outage in South Orange County

Customer Type	Outage Cost Per Customer Per Event PG&E 2012 VOS Study Bay Area			Escalation Ratio 24/16	South Orange County Total Outage Cost $ million	
	8 Hour	16 Hour	24 Hour		16 Hour	24 Hour
Households	$27	$32	$38	1.174	$2.80	*$3.30*
Small and Medium Businesses	$16,464	$25,122	$33,781	1.345	$53.40	*$71.55*
Large Businesses	$1,080,310	$1,666,302	$2,252,293	1.352	$49.00	*$66.25*

There is a slight difference in the way that business customers are segmented in the Updated VOS report for the US and PG&E's segmentation of business customers. The Updated VOS for the US groups medium and large sized C&I customers together into a single segment, leaving the small customers to stand alone, while the PG&E segmentation groups the small and medium sized customers together leaving the large customers to stand alone. This difference in segmentation does not significantly impact the imputation of 24-hour costs from 16-hour costs in this case because the escalation ratios for both business segments are essentially the same (i.e. 1.35).

The final step in calculating the long duration outage costs for SOC is to extrapolate the 24-hour outage costs for SOC for outages of longer duration based on the observed relationship between duration and outage cost reported in PG&E's study of long duration outage costs for downtown San Francisco. To our knowledge, this is the only robust, survey-based study of the cost of long duration outages that has been conducted to date. It employed a value of service survey designed to measure the cost of outages ranging from 24 hours to 7 weeks, including outages lasting 4 days and 3 weeks.

For obvious reasons, one would expect the actual cost of a long duration outage for the central business district of downtown San Francisco and the cost for SOC to be quite different. However, it is reasonable to expect that the change in the magnitude of outage cost as duration increases will be similar, regardless of location. In other words, if the cost of a 4-day outage for the area served by the Embarcadero substation in San Francisco is 3.2 times the cost of a 24-hour outage for the area, the cost of a 4-day outage in SOC should be assumed to rise at the same rate. This is the assumption we are making to estimate the cost of long duration outage costs for SOC, that is, that the cost rises in proportion to the cost increase observed for long duration outage costs reported in PG&E's long duration outage cost study. As described above, time constraints prevent the use of a survey of SOC customers in this case.

In 2012, the estimated direct cost of a 24-hour outage for the customers served by the Embarcadero substation in downtown San Francisco (serving about 3,000 commercial accounts and 24,000 residences) was estimated to be about $126 million. After four days, the reported estimated direct cost increased to about $407 million – a factor of 3.2. After three weeks, the estimated direct cost increased to about $1.4 billion – a factor of 11.3. After applying these same factors to the 24-hour outage costs for SOC, the direct cost of a 4-day outage is about $458 million, while the direct cost of a 3-week outage is about $1.6 billion. These are the estimates reported in Table 2 above.

C. Estimating Indirect Costs

Indirect costs come in three forms. For businesses and residents in the affected area, indirect costs result from the chain reaction of economic losses stemming from direct costs: interactions between businesses (e.g., changes in quantities of inputs bought or outputs sold, changes in relative prices) and interactions between consumers and businesses (e.g., lost wages and reduced spending). Indirect costs are thus incurred not only by people and firms subject to an outage, but also to people and firms located outside of the affected area.

A second category of indirect costs arise from the loss of vital publicly available services (e.g. communications systems, signs, signals, water supply and treatment, etc,) and from public and private expenditures required to overcome the societal effects of the outage. (e.g., homeland security overtime, assistance programs, emergency services, etc.)

Finally, in a third category of indirect costs are injury, sickness, property damage and loss of life that can result from the outage. These kinds of losses can be extremely difficult to predict and are even more difficult to value economically.

Measuring indirect costs is challenging for several reasons. By their very nature, indirect losses cannot be readily determined through a survey in the way that direct economic costs can. Indirect effects on businesses and residents are spatially dispersed; if a firm in SOC suspends operations for a significant period of time, it may affect businesses elsewhere in the Southern California, the US or the world. These interactions are difficult to capture in an outage cost survey.

A further challenge is that indirect losses vary *substantially* with the resiliency of the social infrastructure in the affected area (i.e., the ability of the market area to adapt to the conditions of the outage). An area in which essential services such as police, fire, communications, water treatment health services and transportation have been "hardened" against electric supply interruptions will have much lower indirect outage costs than one in which these services depend significantly on the electric grid for operations.

A good example of the difference between direct and indirect costs is the electric service interruption of the Exxon refinery in Torrance, California in 2012. In that year, the refinery experienced a momentary power outage that caused it to shut down for approximately 5 days – a rare but historically likely event. The direct outage cost to the Exxon refinery was essentially the lost margin on 5 days of lost production (a very significant cost) plus the damage caused by the momentary interruption – which also may have been significant. The indirect costs on the other hand were arguably even more dramatic. The curtailment of production from the Exxon refinery *at that particular time* caused wholesale gasoline supplies to tighten significantly in the California market, which in turn caused the retail price of gasoline to spike dramatically over a period of about 10 days. Under normal conditions, removal of the productive output of that refinery would not have materially changed the wholesale price of gasoline because other suppliers would take up the slack. Unfortunately, these were not normal conditions because producers were drawing down their summer gasoline formulation stocks and the Chevron Richmond refinery was off line because of a fire in the preceding month. While we are not aware of any efforts to calculate the indirect cost to gasoline consumers of this outage, there is no doubt that this cost was dramatically higher than it would have been if it occurred either one month earlier or one month later in the annual production cycle. This outage also illustrates another very perplexing issue with estimating indirect costs. As with direct costs, indirect costs represent a net value, since some California businesses stand to benefit in the case of an outage – whether by substituting for adversely-affected competitors or responding to new demand.

Given the above problems, any calculation of indirect costs must necessarily be understood as simply an order-of-magnitude approximation. It is our view that indirect costs should be estimated from a simple multiplier based on the literature or a regional economic model, and estimates can vary substantially based on the approach used to model them and the scope of costs under consideration. One thing, however, is clear: accounting for indirect costs always leads to a significant increase in the total cost estimate. A wide range of indirect costs have been calculated for real and hypothetical electricity outages in the hazard loss literature. These cost estimates and the methods and procedures that were used to calculate them are discussed in detail in Attachment 23. Based on our review of this literature, we believe it is reasonable to expect indirect costs to be between one-half and two times the direct costs experienced by households and businesses in SOC.

Section 2. Other Considerations

In addition to the outage impacts that have economic consequences that can be readily identified, there are outage impacts that profoundly affect the functioning of society that have costs that have not been well documented. A report submitted for publication in National Hazard Review in 2012 by Miles, Gallagher and Huxford provides a careful analysis of the societal impacts of the widespread outage that occurred in San Diego County in 2011 as a result of the collapse of the electric grid serving San Diego County, Imperial County, Yuma Arizona and Baja Del Norte. The outage lasted 6 to 12 hours depending on location and affected virtually all electric service. From the situation observed in this recent outage to San Diego County, it is reasonable to infer that a number of problems will occur in addition to the outage costs set forth above. They are discussed below and described in detail in Attachment 25.

A. Displaced Residents

The human population served by the Talega substation comprises some 108,000 households containing over 300,000 residents. An outage lasting 3 weeks would certainly cause a major disruption in the lives of most of these households -- in many cases leading to outage costs that are dramatically higher than those derived from the LBNL study of interruption costs. Without electric power from the grid, the only light at night would come from backup generation, kerosene lamps, battery powered flashlights and lamps or candles. After about 24 hours, battery backup in the cell towers would fail and unless cell tower providers brought in backup generation, there would be no phone service available for many households.

From the San Diego County outage, it is reasonable to assume that most traffic signals in the area would be off line within 24 hours of the onset of a long duration outage. Because of the dangers from traffic, schools would probably close until power to the traffic control system was restored – and in any event would be prevented from operating until portable backup generators were installed at significant cost. The lost funding due to the decline in average daily attendance (ADA) alone would be a staggering cost to school systems.

From the report of the 2011 outage is also reasonable to assume that essential services such as food and fuel would be difficult, to obtain in the affected area because retail facilities that provide these products seldom have backup generators. It is impossible to predict how many residents might be displaced as a result of such a long duration outage, but it is reasonable to imagine that a substantial percentage of the residents in the area would relocate to temporary residences outside the area while the electricity system was repaired. It is doubtful that sufficient short term housing exists within a reasonable distance from the area to accommodate a large percentage of the affected population.

B. Environmental Impacts

Municipal water and wastewater systems in SOC rely on electricity from the grid to deliver fresh water and remove and treat contaminated water produced by the communities served by SDG&E in SOC. These systems are vital yet nearly invisible parts of the public health infrastructure in modern human communities. Without clean, fresh water, human populations cannot be maintained at the densities found in much of SOC without the onset of life threatening diseases such as dysentery, hepatitis and cholera.

We have not done a careful analysis of the vulnerability of water supply and wastewater treatment systems to interruption of the grid electricity supply in SOC. However the performance of these systems in San Diego County during the relatively short 2011 outage of San Diego County suggests that interruption of grid supplied electricity to water and wastewater systems could cause serious problems within hours of the onset of the outage (See Attachment 25). Interruptions to pumps moving wastewater caused significant sewage spills into local rivers, lagoons and the ocean within only a few hours of the interruption of electric service. Had the outage persisted, the situation would have become much worse and would not have been rectified until long after sufficient backup generation had been delivered to key pumps and processing systems to resume normal operation. Sewage spills are not just an aesthetic problem. They are a potentially serious threat to public health – particularly if they persist for a long time.

On the water supply side, serious risks to public health emerged within hours of the interruption of electric service to San Diego County because pressure was lost at significant lines in the water supply system where pumps were off line, raising the possibility that contaminated water could back flow into the fresh water supply. As a preventative measure, residents and food services operators were instructed to start using boiled water within a few hours of the outage; and were told to continue to do so for days after the electricity service was restored. Again, if contamination of the water delivery system occurs, the situation may persist for days or weeks following the restoration of electricity service to vital system components. Based on the events that occurred in San Diego County just a few years ago, it is reasonable to assume that similar results would occur in SOC in the event of a long duration outage.

C. Transportation

The findings from the investigation of the 6-12 hour outage to San Diego County in 2011 are also instructive of the likely impacts of a long duration outage on the transportation infrastructure serving SOC. Within seconds of the onset of the outage to San Diego County, gasoline supplies to the entire area were completely interrupted causing many residents and their vehicles to become physically stranded over the course of the ensuing hours. To make matters worse, the failure of traffic signals and grade crossing controls that did not have long lasting battery backup caused gridlock in the transportation system lasting long into the night (the outage occurred at 3:26 PM). These impacts occurred immediately and lasted throughout the duration of the outage. It is unknown whether the situation as a result of a long duration outage in SOC in 2015 would be significantly different from the situation that occurred in San Diego County in 2011. It is reasonable to assume that it would not be – particularly in light of the extended duration of the potential SOC outage (i.e., 3 weeks).

D. Lost Businesses and Employment

Another important impact of a long duration outage in SOC is the likely increase in business failures and unemployment. Among the small and medium businesses surveyed in PG&E's recent long duration outage cost survey, the average reported likelihood of complete business failure (i.e., going out of business) as a result of an extended outage was 20% for an outage lasting 3-weeks. More than one out of 10 small and medium businesses report that they have a 70% or greater likelihood of going out of business as a result of an outage lasting 3 to 7 weeks. In contrast, the average reported likelihood among large businesses is 1.5% for a 3-week outage and 4.1% for a 7-week outage. Only one large business respondent indicated that they had a greater than 10% likelihood of going out of business. Clearly, smaller businesses would be disproportionately impacted by a long duration outage.

Survey respondents were also asked to report the percentage of employees by labor category that they would forego paying during the 4-day, 3-week and 7-week power outages. As expected, contract/temporary employees would be most seriously affected by a long duration outage. For an outage lasting 3 to 7 weeks, businesses said they would stop paying around 35% of their contract/temporary employees on average. Part-time employees working for small and medium businesses would be similarly affected by a long duration outage, with those businesses reporting that over 40% of part-time employees would not be paid throughout a 3-week outage.

STATEMENT OF QUALIFICATIONS

SCOTT BOCZKIEWICZ

My name is Scott Boczkiewicz and my business address is 8316 Century Park Court, San Diego, California 92123. I am the Air and Water Team Lead in the Environmental Programs Group, within the Environmental Services Department of San Diego Gas & Electric (SDG&E). My primary responsibilities include administrative, supervisory and technical oversight of a team that ensures company compliance with all aspects of the Federal Clean Air and Clean Water Acts, as well as compliance with state and local regulations and ordinances that protect air and water quality. I administer technical review, permitting and environmental compliance programs for both capital projects and operations and maintenance programs.

I began work at SDG&E in June 2012 as a Senior Waters and Wetlands Specialist, and have held my current supervisory position with the Air and Water Team since November 2013. I have over 20 years of experience completing biotechnical project impact analysis and regulatory permitting for utility and commercial development projects, and specialize in wetlands science, compensatory mitigation planning and mitigation program implementation for large-scale projects. I worked as a professional consultant for 11 years in Southern California prior to joining SDG&E, and have comparable work experience from prior positons in Oregon, Washington, New Mexico, North Dakota and Wisconsin.

I graduated from the University of Wisconsin, Madison with a Bachelor of Science in Conservation Biology and a concentration in Restoration Ecology and Environmental Law.

I have not previously testified before the Commission in a proceeding.

DON HOUSTON

My name is Don Houston and my business address is 1010 Tavern Road, Alpine, California 91901. I am the Major Projects Environmental Manager in the Environmental Services Department of San Diego Gas & Electric (SDG&E). My primary responsibilities include overall management of environmental compliance during construction of SDG&E's larger electric infrastructure projects that are permitted by the California Public Utilities Commission and other state and federal regulatory agencies.

I began work at SDG&E in September 2002 as a District Biologist and have held multiple positions of increasing responsibility in the Environmental Services Department at both SDG&E and Southern California Gas Company (SoCalGas) ranging from Senior Biologist, Team Lead to Project Manager. My job responsibilities have included conducting habitat assessments and endangered species surveys to identify environmental constraints for operations, maintenance and new construction activities; recruiting, hiring and managing a staff of environmental subject matter experts that support environmental compliance management; and managing environmental budgets and environmental consultant contracts associated with large electric infrastructure projects.

I graduated from San Diego State University with a Bachelor of Science in Biological Sciences. In 1999, I earned a Professional Certificate in Natural Resource Management from the University of California, San Diego.

I have not previously testified before the Commission in a proceeding.

JOHN M. JONTRY

My name is John M. Jontry. My business address is 8330 Century Park Court, San Diego, California, 92123. I am employed by San Diego Gas & Electric Company (SDG&E) as Transmission Planning Manager. I have been employed by SDG&E since 2005. For the past five years I have managed the Grid Planning group within the Transmission Planning department, with the primary responsibility of overseeing the annual grid reliability studies and the planning studies for major special projects such as the South Orange Country Reliability Enhancement project (SOCRE). Prior to working for SDG&E, I worked for electric utilities in Texas and Illinois and for the Midwest Independent System Operator (MISO) in Indiana in various engineering and operational roles for approximately fifteen years. I hold a bachelor's degree in Electrical Engineering from the University of Illinois and a master's degree in Industrial Technology from Eastern Illinois University. I am a Registered Professional Engineer in the states of Illinois and Texas.

I have previously testified before this Commission.

KARL ILIEV, PE

My name is Karl Iliev and my business address is 8316 Century Park Court, San Diego, California 92123. I am the System Protection & Control Engineering Manager in the Electric Transmission & Distribution Engineering Department of San Diego Gas & Electric (SDG&E). My section's primary responsibities are to provide protective relay and control schemes, settings, and communication systems for a safe and reliable grid, including providing technical support, scoping advice, and review of substation electrical designs.

I began work at SDG&E in June 1999 as an Engineering Intern and have held positions around the company on both transmission and distribution sides ranging from planning to engineering to construction and operations. Since 2003, I've held positions of increasing responsibility related to substation design and construction including work in System Protection Engineering & Maintenance, Substation Construction & Maintenance, and Substation Engineering & Design. I was the Substation Engineering & Design Manager for over 4 years from 2009 into 2014 where my responsibities included cost estimatation, design specifications and scoping, material procurement, apparatus assessment, engineering review, substation drawing management, construction support, and real-time operational involvement for all of SDG&E's substations and substation related capital projects.

Immediately prior to obtaining full time employment with SDG&E in 2001, I graduated California State University of Sacramento with a Bachelor of Science in Electrical and Electronic Engineering with a concentration in Power Systems and a minor in Physics. In 2004, I earned my license as a Professional Engineer in the State of California.

I have previously testified before this Commission.

HAL MORTIER

My name is Hal Mortier and my business address is 9060 Friars Rd. San Diego, CA 92108. I am the Fire Program Manager for San Diego Gas & Electric. I started with SDG&E just over 11 years ago as the lone Fire Coordinator within the company. The program has since grown to (4) full-time fire positions in which I oversee the group as the manager. Our group is essentially the hub for all fire related activities within the company and serves as the conduit to all 1st Responder agencies within our service territory both on and off emergencies. My qualifying experience for this position came from 30 years with the U.S. Forest Service in Fire Management. I retired as a Division Chief on the Cleveland National Forest having occupied a diverse set of positions leading up to this level. I served as a National Incident Commander on a Type 1 fire management team comprised of about 50 people who traveled the United States and beyond managing complex fires and other "all risk" catastrophic events. I have had extensive training in fire behavior, firefighting tactics & strategy and the Incident Command System (ICS). I have served in a leadership capacity for the management of numerous large wildfires, hurricanes, the Northridge Earthquake, and the Columbia Space Shuttle recovery efforts.

HENRY NEMBACH

My name is Henry Nembach and my business address is 101 Ash Street, San Diego, CA 92101. I am a Manager for Sempra Energy, Corporate Security. As Manager of Corporate Security, my primary duties include the protection of company employees, property, and assets. Among my responsibilities is the consideration of the risk of terrorism, vandalism or theft that may impact SDG&E's ability to maintain customer electric service. I've performed numerous site security evaluations and facilitate physical security upgrades for SDG&E infrastructure.

Prior to working for Sempra Energy, I was a Federal Bureau of Investigation (FBI) Special Agent for more than 20 years. My primary responsibilities included investigating a wide variety of federal crimes, developing cases to support federal prosecutors, and managing professional law enforcement agents. I was also the Supervisory Special Agent for the FBI Special Weapons and Tactics (SWAT) team responds to crisis management/major critical incidents, including execution of arrest and search warrants, hostage rescue, executive protection detail, special events management, and airport hijackings.

CORY SMITH

My name is Cory Smith and my business address is 8330 Century Park Court, San Diego, California 92123. I am employed as a Principal Engineer in the Transmission Planning Department of San Diego Gas & Electric where I have worked since 2008. My duties include assessing SDG&E's transmission system for compliance with NERC Transmission Planning Standards and creating technical models of SDG&E's high voltage transmission system to assess transmission system performance.

Prior to joining SDG&E, I was employed by Northeast Utilities in Berlin, Connecticut as a Senior Engineer. My duties included the creation of technical models and the application of specialized software to assess the reliability performance of the high voltage transmission system owned by Northeast Utilities. Before my employment with Northeast Utilities I was employed as an Engineer by the New York Independent System Operator in Schenectady, New York. My duties included reliability assessments of the high voltage transmission system serving the State of New York.

I received my Bachelor of Science degree in Electrical Engineering from Arizona State University in 1989, my Master of Engineering degree in Electric Power Engineering from Rensselaer Polytechnic Institute in 1994 and my Master of Business Administration degree from The College of Saint Rose in 2003. In addition, I am a Registered Professional Engineer in the states of California and New York.

WILLIE THOMAS

My name is Willie Thomas and my business address is 8316 Century Park Court, San Diego, California 92123. I am currently the manager of Electric Transmission Engineering and Design at San Diego Gas & Electric (SDG&E). My duties for the two years include managing a diverse group of designers and engineers in the design, engineering, construction and management of electric transmission facilities in the SDG&E service territory. In addition, my duties include the development of specifications, cost estimates, budgeting, managing material and engineering service contracts, and ensuring the proper application of electrical codes, safety regulations, and regulatory agency requirements governing the design and installation of electric transmission facilities. My previous experience includes the design and engineering for the Sycamore Penasquitos 230kV project (CPCN), the transmission facility relocations for the County of Orange La Pata Avenue Gap Closure project (Advice Letter), and the South Bay Substation relocation project (PTC). I hold a Bachelor's of Science in Electrical Engineering from California Polytechnic University of San Luis Obispo in 2004. I am a licensed Professional Engineer (Electrical) in the State of California and an active IEEE member.

I have previously testified before this Commission.

Michael Sullivan | Ph.D.

Senior Vice President

Dr. Sullivan is a Senior Vice President of Nexant, Inc. and is a recognized expert in utility business planning, research design, and program evaluation. He has directed numerous research and business planning projects involving utility customers including: the design of pricing and information feedback studies, end-use surveys, customer value of service studies, studies of customer satisfaction with service, evaluations of DSM programs, and studies of utility customer preferences for new service offerings and rates.

Dr. Sullivan co-leads Nexant's Customer Strategy, Planning and Analysis (CSPA) practice – a department containing approximately 70 professionals with expertise in engineering and the social sciences. He currently leads Nexant's Resilience and Reliability Risk and Cost Benefit Analysis Project for the U.S. Department of Energy / Lawrence Berkeley National Laboratory – a project to provide assistance to utilities and regulators in applying customer outage costs to assess the economic worth of investments in projects designed to improve resilience and reliability. Consulting in the utility industry for over 30 years, Dr. Sullivan's clients have included many of the country's largest utilities, such as: Pacific Gas and Electric, SEMPRA Energy, Southern California Edison, Sacramento Municipal Utility District, Consolidated Edison, Exelon, Puget Sound Energy, Duke Energy, Southern Company, Salt River Project, and Iberdrola. Outside the utility industry, Dr. Sullivan consults with a variety of Fortune 100 companies including Toyota Motor Corporation, International Paper Company, and Google in matters related to product performance and cost of failure.

Representative Project Experience

LBNL/DOE – 2015 Resilience and Reliability Risk and Cost Benefit Analysis Project

Dr. Sullivan currently leads Nexant's project with DOE and LBNL assembling data, information and economic analysis techniques to be integrated into a national resource web portal making technical papers, data and computer software available to utilities and regulators to support the economic evaluation of resilience and reliability reinforcement projects. The project involves:

- Assembling a library of robust technical papers describing methodologies for estimating the economic value of reliability and resilience;
- Providing technical assistance to utilities seeking to employ VBRP;

Education

Ph.D. Sociology–Research Methods and Statistics, Washington State University, WA

BA, Political Science, University of California, CA

Work History

Nexant, Inc. San Francisco, CA
Senior Vice President
(2014–Present)

Freeman, Sullivan & Co. (FSC), San Francisco, CA
Chairman (1984–2013)

PG&E, San Francisco, CA
Operations Coordinator for Load Management (1984–1991)

Haas School of Business Administration, Berkeley, CA
Lecturer (1984–1988)

Kendall Associates, San Francisco, CA
Vice President (1980–1981)

Seattle Energy Office, Seattle, WA
Program Coordinator (1979–1980)

Kendall Associates, San Francisco, CA
Associate Senior Scientist
(1978–1979)

- Publishing case studies describing practical applications of VBRP by utilities; and
- Providing ongoing support in the maintenance and improvement of statistical and economic models including DOE's ICE calculator.

Confidential Client – Cost and Risk Benefit Analysis of Transmission Reinforcement Project

Dr. Sullivan is leading Nexant's effort to assess the economic benefits and costs associated with alternative designs for reinforcing a transmission corridor serving a major metropolitan area in the US. Nexant is assisting the client in identifying the impacts of different outage scenarios (to lines and transformers) on load flows and resulting service interruptions required to maintain compliance with NERC operational guidelines. Based on the service interruptions that will occur under some circumstances, Nexant is calculating and reporting the outage costs that may occur for customers served by substations and feeders that may be forced out to maintain safety and security of the grid.

U.S. Department of Energy – Meta Analysis of Value of Service Studies

Since 2003 Dr. Sullivan has directed three research projects designed to estimate customer damage functions for residential, commercial and industrial electricity customers in the US for the US DOE. The first time Nexant carried out this project (in 2003) it obtained raw survey responses from all utilities that had completed outage cost studies in the United States between 1987 and 2002 using the protocols described in EPRI's Outage Cost Estimation Guidebook. In two subsequent updates of the national outage cost database, Nexant obtained outage cost survey responses from utilities that had completed outage cost surveys between 2002 and 2009 and in the most recent update, outage cost survey information was incorporated for outage cost surveys undertaken between 2009 and 2012. In each update, the responses from the customer surveys were used to estimate customer damage functions describing the statistical relationships between estimated outage costs reported by customers and outage characteristics (i.e., type, duration, time of day, and season), and customer characteristics (i.e., customer type, geographical location, size, and business activities). The most recent update of the national outage cost database entitled "Updated 2015 Outage Cost Estimation Report", was published in January 2015.

LBNL/DOE –Development of and Technical Support for DOE/LBNL ICE Calculator

In 2011, Dr. Sullivan led Nexant's effort to develop an on-line software system capable of calculating customer outage costs from data supplied by utilities concerning the customers connected to utility circuits. Since transmission and distribution planners are not familiar with econometric techniques, DOE and LBNL commissioned the development of an easy to use on-line computational tool that could be used to estimate outage costs using the customer damage functions contained in the report. The system allows users to input information describing the customers served by a given circuit and assumptions about the performance of the circuit CAIDI and SAIFI (before and after investment). It reports estimated customer outage costs based on the inputs. The system is now regularly used by a number of utilities and consultants to assess the economic consequences of reliability investments.

PG&E – 2012 Value of Service Study (2012)

Dr. Sullivan directed PG&E's 2012 Customer Value of Service Study. PG&E was ordered by the CPUC to study the cost of service interruptions for its electricity customers and to measure their willingness to pay for service reliability. Dr. Sullivan was retained by PG&E to carry out this study and report the results to PG&E and the CPUC. To complete this work, Dr. Sullivan surveyed all of PG&E's rate classes and gathered information about outage costs using industry standard measurement protocols. Results were filed with the CPUC and used by PG&E in transmission and distribution planning and evaluation of smart grid initiatives.

PG&E – 2012 Downtown San Francisco Long Duration Outage Cost Study (2013)

Dr. Sullivan directed PG&E's 2012 Downtown San Francisco Long Duration Outage Cost Study. PG&E retained Nexant (then Freeman, Sullivan & Company) to estimate the outage cost resulting from long term outages that might result if the 230 kV lines serving San Francisco's Embarcadero substation were forced out as a result of an earthquake or other calamity. To assess the costs that might arise Nexant surveyed business customers served by the downtown substation asking them to estimate the costs they would experience as a result of outages of durations ranging from 24 hours to 7 weeks. The survey collected information from 224 randomly selected customers including large building operators, small and medium sized building operators and tenants of master metered facilities.

Southern Company – 2012 Value of Service Study

Dr. Sullivan directed Southern Company's 2012 Customer Value of Service Study. Southern Company was ordered by the Georgia Public Utilities Commission to study the cost of service interruptions for its electricity customers and to measure their willingness to pay for service reliability. Dr. Sullivan has been retained by Southern Company to carry out this study and report the results to Southern Company and the Georgia PUC. To complete this work, Dr. Sullivan surveyed all of Southern Company's rate classes in Georgia and Mississippi and gathered information about outage costs using industry standard measurement protocols. Results were reported to the GPUC.

Southern Company – 2007 Power Quality and Value of Service Customer Needs Assessment

In 1998, Dr. Sullivan directed the Value of Service (VOS) study for Southern Company, addressing their customers' willingness to pay for reliable electric service. Nine years later, Southern Company's management retained Dr. Sullivan again to assess its customers' power quality needs and its employees' familiarity with and knowledge of power quality issues, reasoning that addressing customer PQ needs would enable it to maintain its strong customer satisfaction scores. Dr. Sullivan directed the preparation of a survey that was given to PQ employees at Alabama Power and Mississippi Power designed to assess their comfort and familiarity with PQ issues and how they address such questions when contacted by customers. Strategic advice was given to

Southern Company on the basis of these results addressing training needs and recommended practices and organizational structures to improve its handling of customer PQ inquiries.

After addressing Southern Company's internal PQ needs, Dr. Sullivan directed the development of a customer needs assessment tool for Company account representatives to use in addressing its customers' PQ needs. Dr. Sullivan trained a select group of the Company's experienced account representatives in the use of this tool and then monitored their progress in a beta test of administering the tool with their larger customers. Feedback from the account representatives was gathered and the information—along with additional insights—was presented to Southern Company. These insights were used to improve the needs-assessment tool. Dr. Sullivan then trained a larger group of Company account representatives in the implementation of the tool and monitored their progress. The results of this series of customer interviews was then analyzed to identify opportunities for Southern Company to improve its PQ services, and a PQ services enhancement action plan was developed and presented to the Company.

PG&E – Value of Service Reliability Study (2005)

PG&E was ordered by the CPUC to study the cost of service interruptions for its electricity customers and to measure their willingness to pay for service reliability. Dr. Sullivan was retained by PG&E to carry out this study and report the results to PG&E and the CPUC. To complete this work, Dr. Sullivan surveyed all of PG&E's rate classes and gathered information about outage costs using industry standard measurement protocols. The interruption cost and willingness to pay measurements were obtained using mail surveys and executive in-person interviews. Dr. Sullivan integrated the results from the 2005 outage cost study with data from prior PG&E value of service studies (conducted in 1989, 1991, and 1993) and conducted statistical comparisons to determine whether and by how much outage costs and customer expectations about reliability had changed over time. In addition, Dr. Sullivan estimated customer damage functions for all major customer classes in PG&E's territory, providing insights into factors that affect outage costs and their impact, as well as allowing tailored estimates of customer interruption costs for specific banks, circuits, substations, and transmission lines. The data was also incorporated into a meta-database of customer interruption costs from surveys conducted across various regions of the U.S., and analyzed. Results of the study, including interruption cost estimates and customer damage functions, were reported to PG&E and the CPUC and filed as part of its 2006 General Rate Case.

SDG&E – Non-core Customer Interruption Cost Study

Dr. Sullivan directed the study of non-core gas customers of the SDG&E's to determine the economic costs they would experience given natural gas outages of different durations. These cost estimates were used to establish an appropriate level of investment in their gas distribution system and were filed with the California Public Utilities Commission.

Cinergy – Customer Value of Service Studies

Dr. Sullivan directed the survey of 200 of the largest and most sensitive customers of Cinergy as well as 400 of their small and medium-sized commercial and industrial customers to determine their satisfaction with service, cost of interruptions, and expectations for service reliability. Cinergy uses these costs estimates in targeted marketing and in evaluating transmission and distribution reliability investments.

Duke Power Company – System Planning Department, Charlotte, North Carolina, Customer Value of Service Study

Duke Power Company uses customer interruption costs in a number of reliability planning applications to represent the economic benefits obtained from decision alternatives. Dr. Sullivan directed the survey of 1,500 residential and 1,250 small and medium-sized commercial and industrial customers of Duke Power Company to update Duke Power's interruption costs in 1997.

Sacramento Municipal Utility District – Power Quality Surveys

Dr. Sullivan directed the on-site interviews with selected large commercial and industrial customers to identify causes and costs of power quality problems for purposes of evaluating the economic benefits associated with enhanced transmission services.

Duke Power – Customer Value of Service Study

Dr. Sullivan directed the survey of 210 of the largest and most sensitive customers of Duke Power Company, 1,250 of its small and medium-sized commercial and industrial customers, and 1,500 of its residential customers to determine their satisfaction with service reliability, costs of interruption, and expectations for service reliability. In addition, Dr. Sullivan developed a circuit level interruption cost data base for the utility, which contained estimated costs for different kinds of service interruptions for all of the transmission and distribution circuits on the Duke Power System. The study was jointly funded by Duke Power and the Electric Power Research Institute.

PG&E – Agricultural Value of Service Survey

Dr. Sullivan directed the design and management of a combined telephone and mail survey of 1,500 agricultural customers to estimate interruption costs experienced under different conditions.

PG&E – Evaluation of Impacts of OPOWER Home Energy Reports (2010–Current)

Since the summer of 2010, Dr. Sullivan has directed the study of the impacts of OPOWER Home Energy Reports on residential home energy consumption. The study consists of a randomized controlled trial (RCT) containing more than 1,300,000 treatment and control customers. In collaboration with the PG&E EM&V department, Dr. Sullivan specified the experimental design, the sample design, surveying, and other activities required to estimate impacts of HERs on electricity and gas consumption. As PG&E's evaluator, Dr. Sullivan has also been responsible for development of stratified random samples of customers to participate in the test; for assigning customers to treatment and control conditions; and for analyzing and reporting the impacts of HERs on customer energy consumption. The study will also isolate the impacts of the HERs from the impacts of other utility programs.

Salt River Project – Evaluation of Impacts of Energy Scorecard (2012-2014)

Dr. Sullivan assisted SRP in the design and execution of an evaluation of a pilot study of its Energy Scorecard Service. This service is a home energy report similar to the product offered by OPOWER . Dr. Sullivan reviewed the evaluation activities undertaken by SRP staff including experimental design, sample design, implementation, and oversaw Nexant's third-party evaluation of the impacts of the program on customer energy consumption.

HECO – Design of Commercial and Industrial Dynamic Pricing Pilot (2011–2012)

In 2011, Dr. Sullivan directed the design of a Commercial and Industrial Dynamic Pricing Pilot for HECO. The pilot is intended to assess the usefulness of dynamic pricing in meeting short and long term capacity requirements arising out of the increasing installation of renewable resources on the island of Oahu. In designing the pilot, FSC assessed the available demand response program alternatives that could meet 10-minute reserve, 20 minute reserve, and 24-hour reserve requirements on the electric system serving Oahu and recommended testing a two part critical peak pricing strategy in which participating customers would receive significant discounts in return for agreeing to interrupt loads to a designated firm service level given varying amounts of notice. Dr. Sullivan completed the pilot study design and implementation plan in late 2011 and HECO filed the plan in early 2012.

PG&E – Evaluation of Impacts of Smart Phone Controllable Thermostat

Dr. Sullivan was one of three senior consultants at Nexant who worked with PG&E, Honeywell, and OPOWER to design and carry out a pilot study of the use of a new smart phone enabled programmable thermostat. The technology allowed utility customers with smart phones to control their home thermostats using their smart phones from anywhere at any time. The technology was tested in a randomized controlled trial containing approximately 500 treatment customers and 500 controls who volunteered for the study but were not treated.

KCP&L – Evaluation of Smart Meter Enabled Rates and Technologies

Dr. Sullivan is directing the effort to evaluate the impacts of time of use rates in combination with in home displays, programmable communicating thermostats, and home area networks. Dr. Sullivan has advised KCP&L in the development of an experimental design to be used to observe changes in energy consumption resulting from the different combinations of rate design and enabling technology. The size of the target market (about 14,000) and design of the marketing campaign make the use of RCT and RED designs impractical. So, Dr. Sullivan has developed an evaluation design calling for comparison of changes in electricity consumption for treatment and non-participating customers located outside the target market area based on similarity of their load shape and energy use to customers who are participants in the study.

Pacific Gas and Electric Company and Lawrence Berkeley National Laboratory – Ancillary Services Pilot—Phase I (2009)

In the summer of 2009, Dr. Sullivan designed and directed a pilot study of the ability of PG&E's 130,000 customer air conditioner direct control program to provide 10-minute reserve in the CAISO ancillary services market. In the pilot project, the responsiveness of AC loads of 8,000 customers (on four feeders) was observed during 75 test operations (notch tests). The notch tests took place under varying temperature conditions and at all hours of the afternoon and evenings during the months of August and September. Load impacts were observed at SCADA nodes as well as on telemetered air conditioners. A total of 400 sites within the feeders were directly observed on each test. Over the course of the tests, both the signal latency (i.e., time to appliance control) and load impacts were observed. The results of this effort were published in a report to the California Public Utilities Commission entitled: *2009 SmartAC Ancillary Services Pilot available from the California Public Utilities Commission*.

Electric Power Research Institute (EPRI) – Design of Information Feedback Pilot

Dr. Sullivan and Dr. Stephen George assisted CenterPoint (under contract with EPRI) in developing a pilot study of the use of in home display devices to foster energy efficiency on the part of residential customers. CenterPoint had installed over 600,000 AMI meters in its service territory. In the study, Nexant recruited approximately 1,000 residential customers to receive an home display devices capable of displaying electricity consumption and cost at 15-second intervals. Recruiting took place in selected neighborhoods in which customers were offered the IHD (a $125 value) for $25. The impact of the IHD and goal setting was tested over the course of two summers.

Central Maine Power – Design of Information Feedback Pilot

Dr. Sullivan and Dr. George were retained by Central Maine Power to design an information feedback pilot intended to test the impacts of different feedback strategies on customer electricity consumption. In the pilot, four different information feedback strategies are being tested including: bill alerts, in-home displays, real time consumption, and cost information pushed to PCs and Smart Phones on a day-late basis. Dr. Sullivan prepared an RFP describing the project suitable for use in acquiring the services of a support service contractor qualified to carry out the pilot.

Philadelphia Electric Company – Design of Information Feedback Pilot

Dr. Sullivan and Dr. George were by Philadelphia Electric Company to design a pilot project to develop an effective combination of marketing strategy, pricing, and technology to be used in conjunction with the deployment of its AMI system. The pilot used a "test and learn" experimental strategy offering various combinations of dynamic pricing (CPP, CPP/TOU and RTP) with and without enabling technology (IHD) to residential and commercial customers, using different marketing strategies and information. The purpose of the pilot was to identify the most cost-effective methodology for recruiting and retaining customers on cost-effective dynamic pricing arrangements. Dr. Sullivan and Dr. George assisted in the design of the experiment and in seeking approval for going forward with the pilot from regulators and stakeholders in the process.

Sacramento Municipal Utility District – Design of Pricing and Information Feedback Pilot

Dr. Sullivan and Dr. George assisted SMUD in designing the Customer Behavior Study (CBS) that was implemented in the context of its Smart Grid Investment Grant received under the ARRA. The pilot study tested alternative market strategies (opt out and opt in) for recruiting customers to dynamic pricing (CPP and TOU) and enabling technology (in home displays and programmable communicating thermostats). Dr. Sullivan was responsible for assisting SMUD in identifying appropriate pricing and enabling technologies to test over the course of the pilot and in developing the sample designs that supplied sufficient statistical precision to support going forward with the program development.

Lawrence Berkeley National Laboratory and the U.S. Department of Energy (DOE) – Smart Grid Investment Grant Technical Advisory Group (TAG)

Dr. Sullivan and Dr. George were members of a technical advisory group that provided assistance to utilities carrying out Customer Behavior Studies (CBS) in conjunction with the Smart Grid Investment Grants. They were responsible for guiding several utilities through the course of developing experimental designs intended to assess the impacts of dynamic pricing and enabling technologies on customer loads. They also provided advice concerning experimental design, customer recruiting strategies, sample design, and econometric analysis to the US DOE and LBNL in the course of the project.

Electric Power Research Institute (EPRI) – Protocols for Designing Information Feedback and Pricing Trials

Dr. Sullivan and Dr. George worked with EPRI to develop protocols and guidelines for the design of customer feedback experiments appropriate for examining the impacts of information feedback and time-varying pricing options enabled by Smart Grid investments. These protocols are designed to help guide the design of customer trials that will clearly establish causality between program treatments and changes in consumer behavior. Another objective is to establish a common set of outputs that will support comparisons of impacts and data pooling across various utility trials. The results of the effort were published in: *Guidelines for Designing Effective Information Feedback Pilots: Research Protocols (2010)* – publically available on the EPRI website.

Understanding the Impact of Lifestyles and Perceptions on DR Behavior

Dr. Sullivan led a team of experts that investigated how customer lifestyles and perceptions influence energy use and how such information can be used to improve DR program effectiveness. This exploratory research included the use of appliance level usage data as input to in-person surveys to understand household behaviors that underlie energy use. The goal of the project was to develop a useful framework for incorporating information about lifestyles and behavior into DR program design and to determine how best to obtain valid information on lifestyles and behavior from a statistically representative sample of consumers. The results of the project have been provided in draft form to the California Demand Response Measurement and Evaluation Committee.

California Investor-Owned Utility Consortium – Demand Response Load Impact Protocols Development

Dr. Sullivan worked with experts to develop a comprehensive set of protocols and guidance for estimating the load impacts of DR resources for the three California investor-owned utilities: Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison. The protocols developed focused on what impacts should be estimated; what issues should be considered when selecting an estimation approach; and what to report. The goal of the project was to ensure that the load impact estimates provided were useful for planners and operators and that the robustness, precision, and bias (or lack thereof) of the methods employed were transparent. As part of the effort, Dr. Sullivan conducted a detailed critical analysis of regression, day-matching, and other methods common to load impact research. The final product was a set of protocols and guidance for planning and conducting load impact evaluations of DR programs and time-varying pricing, which encompassed both ex post evaluation and ex ante estimation.

Lawrence Berkeley National Laboratory – Demand Response Valuation—Phase I

Dr. Sullivan assisted in scoping out a robust demand response benefit-cost valuation framework tailored to California. Dr. Sullivan provided expertise in the valuation of reliability as well as participant benefits and costs. The research team’s initial analytical phase consisted of creating a topology of candidate benefit/cost methodologies; evaluating those methodologies; identifying alternative approaches for valuing demand response in California; and identifying key data gaps and other issues that require further research. The more detailed task of crafting a complete delineation of identified research gaps (as well as potential resolutions) was left for the second phase of the research.

Lawrence Berkeley National Laboratory – Incentives and Rate Design for Efficiency and Demand Response—Phase I

Dr. Sullivan assisted in identifying and developing alternative incentives and rate designs to support long-run integration of demand response into the California electric industry landscape. Dr. Sullivan led the development of customer participation and acceptance screening tools to help produce effective demand response designs. As part of the development of the screening tools, Dr. Sullivan systematically reviewed the literature on participation rates and customer acceptance, while paying special attention to the strength of the underlying methodologies; applicability to California; and the ability to provide insight into new DR designs. Screens for technical potential, resource value (to the system), bill impacts, and customer acceptance and participation were then applied to the catalogue of different demand response rates and programs to identify those with high potential. The process provided a proof of-concept that was refined and will be applied in the second phase of the research.

California Institute for Energy and the Environment – White Paper on Behavioral Assumptions Underlying Energy Efficiency Programs

This white paper examined the assumptions underlying the design and implementation of energy efficiency programs and the basis and validity of these assumptions. For example, one assumption is the rational economic actor model (where a person makes logical, rational self-interested decisions that weigh costs against benefits and maximize value and profit to the person). Another assumption is that changing attitudes changes behavior. The paper was developed for CIEE and subsequently distributed to the various stakeholders within California's energy efficiency arena.

California Institute for Energy and the Environment – White Paper on Experimental Design Parameters for Energy Efficiency Programs

This white paper examined how experimental design a) Is currently being used in designing and implementing energy efficiency programs; both in California as well as in other markets, and b) Could be used or improved relative to future energy efficiency initiatives within California. The paper also explored how competition can come into play among companies, communities, and other resources such as schools in terms of how best to promote energy efficiency among the general populace. The paper was developed for CIEE and subsequently distributed to the various stakeholders within California's energy efficiency arena.

Pacific Gas & Electric – Plug-in Hybrid Electric Vehicle (PHEV) Market Assessment

PG&E was interested in developing a better understanding of the incremental impacts various utility-related incentives could have on PHEV market potential. Dr. Sullivan directed the development of a study plan that included baseline research (which consisted of a literature search as well as interviews with globally positioned OEMs). The results of the baseline research then drove the content associated with four focus groups conducted among recent automotive buyers who were segmented into vehicle strata. The focus groups probed on how much value the participants placed on the variety of utility-oriented incentives which were being discussed. The focus group results then fed development and implementation of a choice modeling exercise that provided Dr. Sullivan with a more quantitative sense of customers' preferences surrounding the various incentive options. The collective results allowed Dr. Sullivan to provide bounded estimates of the incentives that were considered by the utility client.

Large West Coast Utility – Solar Power Demand Study

Dr. Sullivan directed this project to assess the impact, feasibility, and market potential for a proposed solar program designed to increase solar presence in local communities and provide additional solar educational resources. Dr. Sullivan embedded an experiment into a choice exercise used to define attitudes toward, and demand for, solar power. The study, survey, and analysis methods were designed to help answer six specific research questions: 1) How did customers view the reliability of information about solar power from the utility, compared to other sources of information? 2) What were the impacts of the candidate program on attitudes and knowledge about solar power? 3) What was the impact of the candidate program on demand for solar power? 4) How would utility inspection and certification of solar power systems impact the demand for solar power? 5) What does the full-demand curve for solar power look like and what are the key drivers of demand for it? 6) Are customers willing to finance the candidate program via a public goods charge? Dr. Sullivan developed an extensive survey about customer attitudes and knowledge about solar power designed to answer the above research questions. The experiment that was embedded in the survey consisted of three experimental narrative videos developed by Dr. Sullivan, which involved varying levels of exposure to imagery and information about solar panels. Participants viewed the experimental videos and completed the survey online. Results of the work were then summarized statistically and reported to the client.

BC Hydro – Customer Engagement Process—Business Town Halls for Commercial/Industrial Customers (2008)

In the latter portion of 2008, Dr. Sullivan was contracted to work closely with BC Hydro in designing, developing, scheduling, recruiting, and facilitating a series of seven customer engagement sessions with representatives of their Large General Service customer class. These in-depth, four-hour sessions were designed with three goals in mind: 1) Provide the attending customers (who, in aggregate, added up to almost 400 individuals) with sufficient rate design education and background to inform their preferences; 2) Gather their input on a series of rate design conceptual questions and options; and 3) provide an opportunity for meaningful dialogue and customer engagement. The sessions incorporated the benefits of the qualitative inputs that are strived for with focus groups, as well as quantitative feedback on specific questions that were posed to all the attendees. The polling aspect of the Town Halls was made possible through the use of an Audience Response System, which allowed for real-time compilation of the results and immediate probing of the attendees in terms of how they collectively responded.

Southern Company – AMR Service Concept Evaluation

Dr. Sullivan directed the evaluation of the technical and economic potential of automated meter reading technologies applied to electric, water, and gas meters located in the southeastern U.S. In the evaluation, Dr. Sullivan identified the costs and benefits of alternative technologies and business models; interviewed potential customers to identify interest in, and willingness to, pay for AMR services offered under various business models; quantified the size of the potential and near term actual market; and recommended a going forward business strategy.

Pacific Gas and Electric – Compact Fluorescent Lighting Program Evaluation

Dr. Sullivan directed the evaluation of the impact of the Statewide Compact Fluorescent Lighting Program on the market penetration of compact fluorescent lighting products in retail stores, consumer purchases of the products, and their reactions to the products they had purchased. In this project, Dr. Sullivan conducted in-store surveys throughout California; interviews with representative samples of consumers; and analyses of sales records provided by participating manufacturers. Results were summarized and reported to PG&E.

Pacific Gas and Electric – Residential Retrofit Market Needs Assessment

Dr. Sullivan directed the evaluation of PG&E's Residential Retrofit Market Needs Assessment and the assessment of training needs and programs designed to encourage energy efficient construction in the residential retrofit market. In the course of the project, Dr. Sullivan reviewed and summarized training needs identified in prior research and presented it to the Residential Retrofit and Renovation Planning Public Input Workshop. After obtaining comments from the public, Dr.

Sullivan interviewed representatives of specific groups, including general contractors, retailers, and building inspectors. The results were summarized and reported to the California Energy Commission.

Representative Publications

"Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States", January 2015, LBNL -XXXX

"*Incorporating Customer Interruption Costs Into Reliability Planning*", Published in IEEE. August 2014. (with Josh Schellenberg and Joe Eto).

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Experimentation and the Evaluation of Energy Efficiency Programs. January 2014. Published in Energy Efficiency. (with Edward Vine, Loren Lutzenhiser, Carl Blumstein, and Bill Miller).

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ATTACHMENT 8

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ATTACHMENT 13

CAISO Planning Standards, effective April 1, 2015

California ISO
Planning Standards

Effective April 1, 2015

Table of Contents

I. Introduction

The California ISO (ISO) tariff provides for the establishment of planning guidelines and standards above those established by NERC and WECC to ensure the secure and reliable operation of the ISO controlled grid. The primary guiding principle of these Planning Standards is to develop consistent reliability standards for the ISO grid that will maintain or improve transmission system reliability to a level appropriate for the California system.

These ISO Planning Standards are not intended to duplicate the NERC and WECC reliability standards, but to complement them where it is in the best interests of the security and reliability of the ISO controlled grid. The ISO planning standards will be revised from time to time to ensure they are consistent with the current state of the electrical industry and in conformance with NERC Reliability Standards and WECC Regional Criteria. In particular, the ISO planning standards:

- Address specifics not covered in the NERC Reliability Standards and WECC Regional Criteria;
- Provide interpretations of the NERC Reliability Standards and WECC Regional Criteria specific to the ISO Grid;
- Identify whether specific criteria should be adopted that are more stringent than the NERC Reliability Standards and WECC Regional Criteria where it is in the best interest of ensuring the ISO controlled grid remains secure and reliable.

NERC Reliability Standards and WECC Regional Criteria:

The following links provide the minimum standards that ISO needs to follow in its planning process unless NERC or WECC formally grants an exemption or deference to the ISO. They are the NERC Transmission Planning (TPL) standards, other applicable NERC standards (i.e., NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant), and the WECC Regional Criteria:

http://www.nerc.com/page.php?cid=2|20

http://www.wecc.biz/library/Documentation%20Categorization%20Files/Forms/AllItems.aspx?RootFolder=%2flibrary%2fDocumentation%20Categorization%20Files%2fRegional%20Criteria&FolderCTID=&View=%7bAD6002B2%2d0E39%2d48DD%2dB4B5%2d9AFC9F8A8DB3%7d

Section II of this document provides additional details about the ISO Planning Standards. Guidelines are provided in subsequent sections to address certain ISO planning standards, such as the use of new Special Protection Systems, which are not specifically addressed at the regional level of NERC and WECC. Where appropriate, background information behind the development of these standards and references (web links) to subjects associated with reliable transmission planning and operation are provided.

II. ISO Planning Standards

The ISO Planning Standards are:

1. Applicability of NERC Reliability Standards to Low Voltage Facilities under ISO Operational Control

The ISO will apply NERC Transmission Planning (TPL) standards, the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant, and the approved WECC Regional Criteria to facilities with voltages levels less than 100 kV or otherwise not covered under the NERC Bulk Electric System definition that have been turned over to the ISO operational control.

2. Voltage Standard

Standardization of low and high voltage levels as well as voltage deviations across the TPL-001-4 standard is required across all transmission elements in the ISO controlled grid. The low voltage and voltage deviation guideline applies only to load and generating buses within the ISO controlled grid (including generator auxiliary load) since they are impacted by the magnitude of low voltage and voltage deviations. The high voltage standard applies to all buses since unacceptable high voltages can damage station and transmission equipment. These voltage standards are shown in Table 1.

All buses within the ISO controlled grid that cannot meet the requirements specified in Table 1 will require further investigation. Exceptions to this voltage standard may be granted by the ISO based on documented evidence vetted through an open stakeholder process. The ISO will make public all exceptions through its website.

Table 1
(Voltages are relative to the nominal voltage of the system studied)

Voltage level	Normal Conditions (P0)		Contingency Conditions (P1-P7)		Voltage Deviation	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	P1-P3	P4-P7
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05	0.90	1.1	≤5%	≤10%

The maximum total voltage deviation for standard TPL-001-4 category P3 is ≤5% measured from the voltage that exists after the initial condition (loss of generator unit followed by system adjustments) and therefore takes in consideration only voltage deviation due to the second event.

Voltage and system performance must also meet WECC Regional Criteria TPL-001-WECC-CRT-2.1:
http://www.wecc.biz/library/Documentation%20Categorization%20Files/Regional%20Criteria/TPL-001-WECC-CRT-2.1.pdf

The bus voltage at the San Onofre Switchyard must be maintained within established limits as determined by transmission entities (Southern California Edison and San Diego Gas & Electric) through grid operations procedures.

3. Specific Nuclear Unit Standards

The criteria pertaining to the Diablo Canyon Power Plant (DCPP), as specified in the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for DCPP, and Appendix E of the Transmission Control Agreement located on the ISO web site at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=3972DF1A-2A18-4104-825C-E24350BA838F

4. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

A single module of a combined cycle power plant is considered a single contingency (G-1) and shall meet the performance requirements of the NERC TPL-001-4 standard for single contingencies (P1). Supporting information is located in Section IV of this document. Furthermore any reference to the loss of a "generator unit" in the NERC multiple contingency standards (P3-P5) shall be similar to the loss of a "single module of a combined cycle power plant".

A re-categorization of any combined cycle facility that falls under this standard to a less stringent requirement is allowed if the operating performance of the combined cycle facility demonstrates a re-categorization is warranted. The ISO will assess re-categorization on a case by case based on the following:

a) Due to high historical outage rates in the first few years of operation no exceptions will be given for the first two years of operation of a new combined cycle module.
b) After two years, an exception can be given upon request if historical data proves that no outage of the combined cycle module was encountered since start-up.
c) After three years, an exception can be given upon request if historical data proves that outage frequency is less than once in three years.

The ISO may withdraw the re-categorization if the operating performance of the combined cycle facility demonstrates that the combined cycle module exceeds a failure rate of once in three year. The ISO will make public all exceptions through its website.

5. Planning for New Transmission versus Involuntary Load Interruption Standard

This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements. It does not address all circumstances under which load dropping is permitted under NERC and WECC planning standards.

1. No single contingency (TPL-001-4 P1) should result in loss of more than 250 MW of load.
2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines “closed in” during normal operation.
3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more constraining.
4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure, through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

6. Planning for High Density Urban Load Area Standard

6.1 Local Area Planning

A local area is characterized by relatively small geographical size, with limited transmission import capability and most often with scarce resources that usually can be procured at somewhat higher prices than system resources.[1] The local areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local generation and transmission capacity. Increased reliance on load shedding to meet these needs would run counter to historical and current practices, resulting in general deterioration of service levels.

For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

[1] A “local area” for purposes of this Planning Standard is not necessarily the same as a Local Capacity Area as defined in the CAISO Tariff.

- In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.
- In considering if load shedding, where allowed by NERC standards, is a viable mitigation in either the near-term, or the long-term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, number of customers impacted by the outage, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

6.2 System Wide Planning

System planning is characterized by much broader geographical size, with greater transmission import capability and most often with plentiful resources that usually can be procured at somewhat lower prices than local area resources. Due to this fact more resources are available and are easier to find, procure and dispatch. Provided it is allowed under NERC reliability standards, the ISO will allow non-consequential load dropping system-wide SPS schemes that include some non-consequential load dropping to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

7. Extreme Event Reliability Standard

The requirements of NERC TPL-001-4 require Extreme Event contingencies to be assessed; however the standard does not require mitigation plans to be developed for these Extreme Events. The ISO has identified in Section 7.1 below that the San Francisco Peninsula area has unique characteristics requiring consideration of corrective action plans to mitigate the risk of extreme events. Other areas of the system may also be considered on a case-by-case basis as a part of the transmission planning assessments.

7.1 San Francisco-Peninsula -Extreme Event Reliability Standard

The ISO has determined through its Extreme Event assessments, conducted as a part of the annual transmission planning process, that there are unique characteristics of the San Francisco Peninsula area requiring consideration for mitigation as follows.

- high density urban load area,
- geographic and system configuration,
- potential risks of outages including seismic, third party action and collocating facilities; and
- challenging restoration times.

The unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages that are beyond the application of mitigation of extreme events in the reliability standards to the rest of the ISO controlled grid. The ISO will consider the overall impact of the mitigation on the identified risk and the associated benefits that the mitigation provides to the San Francisco Peninsula area.

III. ISO Planning Guidelines

The ISO Planning Guidelines include the following:

1. Special Protection Systems

As stated in the NERC glossary, a Special Protection System (SPS) is “an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition of faulted components to maintain system reliability.” In the context of new projects, the possible action of an SPS would be to detect a transmission outage (either a single contingency or credible multiple contingencies) or an overloaded transmission facility and then curtail generation output and/or load in order to avoid potentially overloading facilities or prevent the situation of not meeting other system performance criteria. A SPS can also have different functions such as executing plant generation reduction requested by other SPS; detecting unit outages and transmitting commands to other locations for specific action to be taken; forced excitation pulsing; capacitor and reactor switching; out-of-step tripping; and load dropping among other things.

The primary reasons why SPS might be selected over building new transmission facilities are that SPS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, SPS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, SPS is a commonly considered alternative to building new infrastructure in an effort to keep costs down when integrating new generation into the grid and/or addressing reliability concerns under multiple contingency conditions. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability. These reliability concerns necessarily dictate that guidelines be established to ensure that performance of all SPSs are consistent across the ISO controlled grid. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of existing transmission facilities while maintaining system reliability and optimizing operability of the ISO controlled grid. Needless to say, with the large number of generator interconnections that are occurring on the ISO controlled grid, the need for these guidelines has become more critical.

It needs to be emphasized that these are guidelines rather than standards and should be used in the development of any new SPS. In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies). This is to emphasize that best engineering practice and judgment will need to be exercised by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of SPS in all potential applications.

ISO SPS1
The overall reliability of the system should not be degraded after the combined addition of the SPS.

ISO SPS2
The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. In situations where the design of the SPS requires WECC approval, the WECC Remedial Action Scheme Design Guide will be followed.

ISO SPS3
The total net amount of generation tripped by a SPS for a single contingency cannot exceed the ISO's largest single generation contingency (currently one Diablo Canyon unit at 1150 MW). The total net amount of generation tripped by a SPS for a double contingency cannot exceed 1400 MW. This amount is related to the minimum amount of spinning reserves that the ISO has historically been required to carry. The quantities of generation specified in this standard represent the current upper limits for generation tripping. These quantities will be reviewed periodically and revised as needed. In addition, the actual amount of generation that can be tripped is project specific and may depend on specific system performance issues to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts provided in this guide. The net amount of generation is the gross plant output less the plant's and other auxiliary load tripped by the same SPS.

ISO SPS4
For SPSs, the following consequences are unacceptable should the SPS fail to operate correctly:

A) Cascading outages beyond the outage of the facility that the SPS is intended to protect: For example, if a SPS were to fail to operate as designed for a single contingency and the transmission line that the SPS was intended to protect were to trip on overload protection, then the subsequent loss of additional facilities due to overloads or system stability would not be an acceptable consequence.

B) Voltage instability, transient instability, or small signal instability: While these are rare concerns associated with the addition of new generation, the consequences can be so severe that they are deemed to be unacceptable results following SPS failure.

ISO SPS5

Close coordination of SPS is required to eliminate cascading events. All SPS in a local area (such as SDG&E, Fresno, etc.) and grid-wide need to be evaluated as a whole and studied as such.

ISO SPS6

The SPS must be simple and manageable. As a general guideline:

A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS.

B) The SPS should not be monitoring more than 4 system elements or variables. A variable can be a combination of related elements, such as a path flow, if it is used as a single variable in the logic equation. Exceptions include:

   i. The number of elements or variables being monitored may be increased if it results in the elimination of unnecessary actions, for example: generation tripping, line sectionalizing or load shedding.

   ii. If the new SPS is part of an existing SPS that is triggered by more than 4 local contingencies or that monitors more than 4 system elements or variables, then the new generation cannot materially increase the complexity of the existing SPS scheme. However, additions to an existing SPS using a modular design should be considered as preferable to the addition of a new SPS that deals with the same contingencies covered by an existing SPS.

C) Generally, the SPS should only monitor facilities that are connected to the plant or to the first point of interconnection with the grid. Monitoring remote facilities may add substantial complexity to system operation and should be avoided.

D) An SPS should not require real-time operator actions to arm or disarm the SPS or change its set points.

ISO SPS7

If the SPS is designed for new generation interconnection, the SPS may not include the involuntary interruption of load. Voluntary interruption of load paid for by the generator is acceptable. The exception is that the new generator can be added to an existing SPS that includes involuntary load tripping. However, the amount of involuntary load tripped by the combined SPS may not be increased as a result of the addition of the generator.

ISO SPS8

Action of the SPS shall limit the post-disturbance loadings and voltages on the system to be within all applicable ratings and shall ultimately bring the system to within the long-term (4 hour or longer) emergency ratings of the transmission equipment. For example, the operation of SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back additional generation (or trip load if not already addressed under ISO SPS7 above) to bring the line loading within the line's four-hour or longer rating. This is intended to minimize real-time operator intervention.

ISO SPS9

The SPS needs to be agreed upon by the ISO and may need to be approved by the WECC Remedial Action Scheme Reliability Task Force.

ISO SPS10

The ISO, in coordination with affected parties, may relax SPS requirements as a temporary "bridge" to system reinforcements. Normally this "bridging" period would be limited to the time it takes to implement a specified alternative solution. An example of a relaxation of SPS requirement would be to allow 8 initiating events rather than limiting the SPS to 6 initiating events until the identified system reinforcements are placed into service.

ISO SPS11

The ISO will consider the expected frequency of operation in its review of SPS proposals.

ISO SPS12

The actual performance of existing and new SPS schemes will be documented by the transmission owners and periodically reviewed by the ISO and other interested parties so that poorly performing schemes may be identified and revised.

ISO SPS13

All SPS schemes will be documented by the owner of the transmission system where the SPS exists. The generation owner, the transmission owner, and the ISO shall retain copies of this documentation.

ISO SPS14

To ensure that the ISO's transmission planning process consistently reflects the utilization of SPS in its annual plan, the ISO will maintain documentation of all SPS utilized to meet its reliability obligations under the NERC reliability standards, WECC regional criteria, and ISO planning standards.

ISO SPS15
The transmission owner in whose territory the SPS is installed will, in coordination with affected parties, be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO SPS16 Generally, the SPS should trip load and/or resources that have the highest effectiveness factors to the constraints that need mitigation such that the magnitude of load and/or resources to be tripped is minimized. As a matter of principle, voluntary load tripping and other pre-determined mitigations should be implemented before involuntary load tripping is utilized.

ISO SPS17
Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO is required unless otherwise deemed unnecessary by the ISO. Specific telemetry requirements will be determined by the Transmission Owner and the ISO on a project specific basis.

IV. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard Supporting Information

Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard - A single module of a combined cycle power plant is considered a single (G-1) contingency and shall meet the performance requirements of the NERC TPL-001-4 standard for single contingencies (P1).

The purpose of this standard is to require that an outage of any turbine element of a combustion turbine be considered as a single outage of the entire plant and therefore must meet the same performance level as the NERC TPL-001-4 standard P1.

The ISO has determined that, a combined cycle module should be treated as a single contingency. In making this determination, the ISO reviewed the actual operating experience to date with similar (but not identical) combined cycle units currently in operation in California. The ISO's determination is based in large part on the performance history of new combined cycle units and experience to date with these units. The number of combined cycle facility forced outages that have taken place does not support a double contingency categorization for combined cycle module units in general. It should be noted that all of the combined cycle units that are online today are treated as single contingencies.

Immediately after the first few combined cycle modules became operational, the ISO undertook a review of their performance. In defining the appropriate categorization for combined cycle modules, the ISO reviewed the forced outage history for the following three combined cycle facilities in California: Los Medanos Energy Center (Los

Medanos), Delta Energy Center (Delta), and Sutter Energy Center (Sutter)[2]. Los Medanos and Sutter have been in service since the summer of 2001, Delta has only been operational since early summer 2002.

Table 2 below sets forth the facility forced outages for each of these facilities after they went into operation (i.e. forced outages [3]that resulted in an output of zero MWs.) The table demonstrates that facility forced outages have significantly exceeded once every 3 to 30 years. Moreover**,** the ISO considers that the level of facility forced outages is significantly above the once every 3 to 30 years even accounting for the fact that new combined cycle facilities tend to be less reliable during start-up periods and during the initial weeks of operation. For example, four of the forced outages that caused all the three units at Los Medanos to go off-line took place more than nine months after the facility went into operation.

Facility	Date	# units lost
Sutter[4]	08/17/01	No visibility
Sutter	10/08/01	1 CT
Sutter	12/29/01	All 3
Sutter	04/15/02	1 CT + ST
Sutter	05/28/02	1 CT
Sutter	09/06/02	All 3
Los Medanos[5]	10/04/01	All 3
Los Medanos	06/05/02	All 3
Los Medanos	06/17/02	All 3
Los Medanos	06/23/02	1CT+ST
Los Medanos	07/19/02	All 3
Los Medanos	07/23/02	1CT+ST
Los Medanos	09/12/02	All 3
Delta[6]	06/23/02	All 4
Delta	06/29/02	2 CT's + ST
Delta	08/07/02	2 CT's + ST

Table 2: Forced outages that have resulted in 0 MW output from Sutter, Los Medanos and Delta after they became operational

[2] Los Medanos and Sutter have two combustion turbines (CT's) and one steam turbine (ST) each in a 2x1 configuration. Delta has three combustion turbines (CT's) and one steam turbine (ST) in a 3x1 configuration. All three are owned by the Calpine Corporation.
[3] Only forced outages due to failure at the power plant itself are reported, forced outages due to failure on the transmission system/switchyard are excluded. The fact that a facility experienced a forced outage on a particular day is public information. In fact, information on unavailable generating units has been posted daily on the ISO website since January 1, 2001. However, the ISO treats information regarding the cause of an outage as confidential information.
[4] Data for Sutter is recorded from 07/03/01 to 08/10/02
[5] Data for Los Medanos is recorded from 08/23/01 to 08/10/02
[6] Data for Delta is recorded from 06/17/02 to 08/10/02

The ISO realizes that this data is very limited. Nevertheless, the data adequately justifies the current classification of each module of these three power plants as a single contingency.

V. Background behind Planning for New Transmission versus Involuntary Load Interruption Standard

For practical and economic reasons, all electric transmission systems are planned to allow for some involuntary loss of firm load under certain contingency conditions. For some systems, such a loss of load may require several contingencies to occur while for other systems, loss of load may occur in the event of a specific single contingency. Historically, a wide variation among the PTOs has existed predominantly due to slightly differing planning and design philosophies. This standard is intended to provide a consistent framework upon which involuntary load interruption decisions can be made by the ISO when planning infrastructure needs for the ISO controlled grid.

The overarching requirement is that implementation of these standards should not result in lower levels of reliability to end-use customers than existed prior to restructuring. As such, the following is required:

1. No single contingency (TPL-001-4 P1) may result in loss of more than 250 MW of load.

   This standard is intended to coordinate ISO planning standards with the WECC requirement that all transmission outages with at least 300 MW or more be directly reported to WECC. It is the ISO's intent that no single contingency (TPL-001-4 P1) should trigger loss of 300 MW or more of load. The 250 MW level is chosen in order to allow for differences between the load forecast and actual real time load that can be higher in some instances than the forecast and to also allow time for transmission projects to become operational since some require 5-6 years of planning and permitting with inherent delays. It is also ISO's intent to put a cap on the radial and/or consequential loss of load allowed under NERC standard TPL-001-4 single contingencies (P1).

2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines "closed in" during normal operation.

   This standard is intended to bring consistency between the PTOs' substation designs. It is not the ISO's intention to disallow substations with load below 100 MW from having looped connections; however it is ISO's intention that all substations with peak load above 100 MW must be connected through a looped configuration to the grid.

3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the

yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more stringent.

This standard is intended to insure that the system is maintained at the level that existed prior to restructuring. It is obvious that as load grows, existing back-ties for radial loads (or remaining feed after a single contingency for looped substations) may not be able to pick up the entire load; therefore the reliability to customers connected to this system may deteriorate over time. It is the ISO's intention to establish a minimum level of back-up tie capability that needs to be maintained.

4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

   It is ISO's intention to allow the build-up of transmission projects that are proven to have a positive benefit to ratepayers by reducing load drop exposure.

Information Required for BCR calculation: For each of the outages that required involuntary interruption of load, the following should be estimated:

- The maximum amount of load that would need to be interrupted.
- The duration of the interruption.
- The annual energy that would not be served or delivered.
- The number of interruptions per year.
- The time of occurrence of the interruption (e.g., week day summer afternoon).
- The number of customers that would be interrupted.
- The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural).
- Value of service or performance-based ratemaking assumptions concerning the dollar impact of a load interruption.

The above information will be documented in the ISO Transmission Plan for areas where additional transmission reinforcement is needed or justified through benefit to cost ratio determination.

VI. Background behind Planning for High Density Urban Load Area Standard for Local Areas

A local area is characterized by relatively small geographical size, with limited transmission import capability and most often with scarce resources that usually can be procured at somewhat higher prices than system resources. These areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local resource and transmission capacity. The need for system reinforcement in a number of local areas is expected to climb due to projected resource retirements, with single and double contingency conditions playing a material role in driving the need for reinforcement. Relying on load shedding on a broad basis to meet these emerging needs would run counter to historical and current practices, resulting in general deterioration of service levels. One of the fundamental ISO Tariff requirements is to maintain service reliability at pre-ISO levels, and it drives the need to codify the circumstances in which load shedding is not an acceptable long-term solution:

1. For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

   This standard is intended to continue avoiding the need to drop load in high density urban load areas due to, among other reasons, high impacts to the community from hospitals and elevators to traffic lights and potential crime.

   The following is a link to the 2010 Census Urban Area Reference Maps:

   http://www.census.gov/geo/maps-data/maps/2010ua.html

   This site has diagrams of the following urbanized areas which contain over one million persons.

   Los Angeles--Long Beach--Anaheim, CA
   San Francisco--Oakland, CA
   San Diego, CA
   Riverside--San Bernardino, CA
   San Jose, CA

2. In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.

   This standard is intended to insure that a reliable transition exists between the time when problems could arise until long-term transmission upgrades are placed in service.

3. In considering if load shedding, where allowed by NERC standards, is a viable mitigation in either the near-term, or the long-term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common

substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

It is ISO's intention to thoroughly evaluate the risk of outages and their consequences any time a load shedding SPS is proposed regardless of population density.

VII. Interpretations of terms from NERC Reliability Standard and WECC Regional Criteria

Listed below are several ISO interpretations of the terms that are used in the NERC standards that are not already addressed by NERC.

Combined Cycle Power Plant Module: A **combined cycle** is an assembly of heat engines that work in tandem off the same source of heat, converting it into mechanical energy, which in turn usually drives electrical generators. In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, one or more gas turbine generator(s) generates electricity and heat in the exhaust is used to make steam, which in turn drives a steam turbine to generate additional electricity.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTO and the ISO subject to appropriate coordination and review with the relevant local, state, regional and federal regulatory authorities.

Entity Required to Develop Load Models: The PTOs, in coordination with the utility distribution companies (UDCs) and others, develop load models.

Entity Required to Develop Load Forecast: The California Energy Commission (CEC) has the main responsibility for providing load forecast. If load forecast is not provided by the CEC or is not detailed and/or specific enough for a certain study then the ISO, at its sole discretion, may use load forecasts developed by the PTOs in coordination with the UDCs and others.

Footnote 12 of TPL-001-4 Interpretation and Applicable Timeline[7]: The shedding of Non-Consequential load following P1, P2-1 and P3 contingencies on the Bulk Electric System of the ISO Controlled Grid is not considered appropriate in meeting the performance requirements. In the near-term planning horizon the requirements of Footnote 12 may be applied until the long-term mitigation plans are

[7] Implementation and applicable timeline will remain the same as the "Effective Date:"(s) described in the NERC TPL-001-4 standard.

in-service. In the near-term transmission planning horizon, the non-consequential load loss will be limited to 75 MW and has to meet the conditions specified in Attachment 1 of TPL-001-4.

High Density Urban Load Area: Is an Urbanized Area, as defined by the US Census Bureau[8] with a population over one million persons.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. For studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level. The more stringent requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. Having a more stringent standard for local areas will help minimize the potential for interruption of end-use customers.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified and corresponding operating procedures are in place when required.

Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

[8] Urbanized Area (UA): A statistical geographic entity consisting of a densely settled core created from census tracts or blocks and contiguous qualifying territory that together have a minimum population of at least 50,000 persons.

ATTACHMENT 14

Excerpts of FERC Order 693,
72 Federal Register 16416 (April 4, 2007)

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM06-16--000; Order No. 693]

Mandatory Reliability Standards for the Bulk-Power System

Issued March 16, 2007.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Pursuant to section 215 of the Federal Power Act (FPA), the Commission approves 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the Glossary of Terms Used in Reliability Standards developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. Those Reliability Standards meet the requirements of section 215 of the FPA and Part 39 of the Commission's regulations. However, although we believe it is in the public interest to make these Reliability Standards mandatory and enforceable, we also find that much work remains to be done. Specifically, we believe that many of these Reliability Standards require significant improvement to address, among other things, the recommendations of the Blackout Report. Therefore, pursuant to section 215(d)(5), we require the ERO to submit significant improvements to 56 of the 83 Reliability Standards that are being approved as mandatory and enforceable. The remaining 24 Reliability Standards will remain pending at the Commission until further information is provided.

The Final Rule adds a new part to the Commission's regulations, which states that this part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska or Hawaii) and requires that each Reliability Standard identify the subset of users, owners and operators to which that particular Reliability Standard applies. The new regulations also require that each Reliability Standard that is approved by the Commission will be maintained on the ERO's Internet Web site for public inspection.

EFFECTIVE DATE: This rule will become effective June 4, 2007.

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

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adversely affected, our goal is to ensure that they are involved in the determination and review of system assessments to permit an early opportunity to provide input and coordinate plans. We discussed above the issue of information sharing as it applies to the TPL group of Reliability Standards generally and, consistent with our conclusions there, we direct the ERO to modify TPL-001-0 to require a peer review of planning assessments with neighboring entities.

1768. The Commission received no comments on its proposal that Requirement R1.3 be modified to substitute the reference to the regional reliability organization with a reference to the Regional Entity. The Commission has explained the need for this modification above, and therefore it directs the ERO to modify Requirement R1.3 of TPL-001-0 to substitute the reference to the regional reliability organization with a reference to the Regional Entity.

1769. While some commenters support the consideration of planned outages at load levels for conditions under which they are performed, others disagree on the grounds that the goal of TPL-001-0 is to ensure that the Bulk-Power System can perform reliably when all elements are in service and operating as expected. The Commission notes that Reliability Standards TPL-002-0 through TPL-004-0 include consideration of planned outages, as initial system conditions, at load levels for conditions under which they are performed. Because these Reliability Standards, and not TPL-001-0, will govern the adequacy of the Bulk-Power System under planned outage conditions, the Commission will not adopt the NOPR proposal to require consideration of planned outages at load levels for conditions under which they are performed for Reliability Standard TPL-001-0. However, consistent with our discussion above on spare equipment strategy, the Commission directs a modification to this Reliability Standard to require assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. Thus, for example, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a "hot spare" or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions. However, if the spare equipment strategy entails acquisition of a replacement transformer that has a one-year or longer lead time, then the outage of the transformer must be assessed under peak loading conditions likely to be experienced. This approach will ensure that system conditions are adequately assessed.

1770. While commenters generally agree with the Commission's proposal to modify footnote (a) of Table 1, they caution that any changes to the footnotes affect Table 1 and should be reviewed through NERC's Reliability Standards development process. International Transmission states that the footnotes in Table 1 are not footnotes but rather requirements for transmission system performance and therefore should be made Requirements in the Reliability Standard. The Commission agrees with International Transmission because this will promote clarity in and consistent application of the Reliability Standard. The Commission therefore directs the ERO to modify the Reliability Standard to address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards. As with any modification to a Reliability Standard, modifications to TPL-001-0 should be developed through the ERO's Reliability Standards development process.

1771. Accordingly, the Commission approves Reliability Standard TPL-001-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-001-0 through the Reliability Standards development process that: (1) Requires that critical system conditions and study years be determined by conducting sensitivity studies with due consideration of the range of factors outlined above; (2) requires a peer review of planning assessments with neighboring entities; (3) modifies Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity; (4) requires assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy; and (5) address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards and the concerns raised by International Transmission in regard to the footnotes in Table 1.

c. System Performance Following Loss of a Single Element (TPL-002-0)

1772. Reliability Standard TPL-002-0 addresses system planning related to performance under contingency conditions involving the failure of a single element with or without a fault, *i.e.*, the occurrence of an event such as a short circuit, a broken wire or an intermittent connection. The Reliability Standard seeks to ensure that the future Bulk-Power System is planned to meet the system performance requirements, with the loss of one element, by requiring that the transmission planner and planning authority annually evaluate and document the ability of the transmission system to meet the performance requirements where an event results in the loss of a single element.[452] Meeting these requirements means two things. First, it means that the system can be operated following the event to supply projected firm customer demands and projected firm (non-recallable reserved) transmission services at all demand levels over the range of forecast system demands. Second, it means that the system remains stable and within the applicable ratings for thermal and voltage limits, no loss of demand or curtailed firm transfers occurs, and no cascading outages occur.[453] The Reliability Standard applies both to near-term and longer-term planning horizons.

1773. TPL-002-0 specifies that the planning authority and transmission planner must demonstrate through a valid assessment that the Reliability Standard's system performance requirements can be met. The assessment must be supported by a current or past study and/or system simulation testing that addresses various categories of conditions to be simulated, as set forth in the Reliability Standard, to verify system performance under contingency conditions involving the failure of a single element with or without a fault. The Reliability Standard requires that planned outages of transmission equipment be considered for those demand levels for which planned outages are performed. When system simulations indicate that the system cannot meet the performance requirements stipulated in the Reliability Standard, a documented plan to achieve system performance requirements must be prepared. The specific study elements selected from each of the categories for assessments are subject to approval by the associated regional reliability organization.

1774. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and

[452] The performance requirements are set forth in Category B of Table 1 of the Reliability Standard.

[453] Footnote b to Table 1 allows for the interruption of firm load for consequential load loss.

enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) Requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss.

i. Comments

1775. APPA agrees that TPL-002-0 is sufficient for approval as a mandatory and enforceable reliability standard.

1776. In response to the Commission's proposal[454] that NERC modify TPL-002-0, in part, because it does not address situations in which critical equipment may be unavailable for a prolonged period, Northern Indiana states that systems depicted in planning studies cannot possibly contain complete planned and forced outage schedules for the next ten years. For this reason TPL-003-0 deals with double contingencies, *i.e.*, contingencies that allow operator intervention after the first outage, and then capture system response to an additional outage. Operator intervention includes coordination of contingency plans and may impact strategies for spare equipment, particularly for critical equipment.

1777. EEI and MidAmerican support requiring all generators to ride through the same contingencies as required for wind generators. Constellation notes that while it supports the Commission's proposed modifications to TPL-002-0, an explicit requirement that all generators stay online during the same set of Category B and C events, as is required for wind generators, is too broad. Constellation requests that the Commission modify this requirement to recognize that NRC has specific requirements for how nuclear generation must respond to disturbances on the Bulk-Power System, and that those NRC rules should apply. Moreover, Constellation generally recommends that the Reliability Standards applied to nuclear generation should be consistent with NRC requirements and that NRC rules should control in the event of conflict.

1778. NRC notes that there appears to be significant variation in the interpretation of this Reliability Standard. It states that some of its licensees interpret the TPL-002-0 Reliability Standard to state that if a licensee is operating in an N-1 condition another single contingency does not need to be considered. NRC states that its interpretation has been that the N-1 condition is always analyzed from the conditions being experienced. They state that this Reliability Standard should be clarified and recommend specific revisions to Requirements R1.6, R2.1, R2.2 and Levels of Non-Compliance.

1779. Northern Indiana expresses concern about the statement in P 1062 of the NOPR that "load models used in system studies have a significant impact on system performance * * *." Northern Indiana believes the opposite is true, *i.e.*, system performance has a significant impact on load models. The goal of the models is to attempt to capture system performance.

1780. MidAmerican supports the proposed clarifications to operating steps and to footnote (b). International Transmission states that more clarification should be provided for the thresholds of normal and emergency ratings. There are potential inconsistencies with respect to whether or not an entity can plan to operate above normal ratings, but below emergency ratings, and for how long.

1781. Northern Indiana also takes issue with the NOPR proposal that no load or transactions be interrupted except for consequential load loss. Attempting to reduce the probability of load loss to zero would greatly increase capital spending, and therefore increase rates to customers, and all in the name of achieving an unattainable goal. PG&E disputes that the Reliability Standard should provide limits on the magnitude and duration of consequential load loss. Determining the magnitude and consequences of load loss is a factor in the economic evaluation during the development of transmission expansion plans. This economic evaluation is not an appropriate subject for this Reliability Standard. Northern Indiana urges the Commission to acknowledge that planning studies by nature must balance infrastructure improvement and expansion against site-specific and regional load projections, using available resources. It questions whether the NOPR reflects a proper balance between the many costs involved and the benefits, if any, that would be realized.

1782. Entergy opposes the Commission's proposed guidance concerning footnote (b) to Table 1 for two reasons. First, Entergy believes the Commission should give due weight to the technical expertise of NERC and permit NERC to address these matters through Reliability Standards development process. Second, the Commission's guidance suggests that it views all transmission outages as having the same level of importance to and impact on the interconnected transmission grid. Entergy states that the Commission should recognize that the effect of transmission outages can be local in nature and have no impact on the reliability of the Bulk Power System. Removing the transmission operator's ability to shed load or enact other system adjustments as appropriate for a single contingency would result in significant facility upgrade costs simply to avoid the consequence of a local outage. Entergy requests that the Commission clarify that its guidance does not constrain the transmission operator's ability to determine the best course of action to take to address any reliability constraint that may result from these local outages.

1783. PG&E disagrees with the Commission's proposal to delete from footnote (b) of this Reliability Standard the phrase "to prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers."[455] PG&E states that this phrase permits critical system adjustments to reduce the potential for and impact of future contingencies. It would allow re-scheduling power (but not load shedding) as part of manual system adjustment after the first Category B contingency (first N-1) to bring the system back to a safe operating point before the next Category B contingency (second N-1). This phrase is consistent with the manual system adjustment allowed in Category C.3.[456] PG&E states that, contrary to the Commission's interpretation, footnote (c) does not capture this phrase. The difference between footnote (b) as part of Category B and Category C.3 is that footnote (b) applies before the second N-1, whereas Category C.3 applies after the second N-1. Without this phrase in footnote (b), no manual system adjustment would be

[454] NOPR at P 1081.

[455] *Id.* at P 1084.

[456] From TPL Standards Table 1, Category C.3 is Category B (B1, BZ, B3 or B4) contingency, manual system adjustments, followed by another Category B (B1, BZ, B3 or B4) contingency.

allowed after a Category B contingency, which would be inconsistent with Category C.3.

1784. APPA and LPPC recommend that changes to the footnotes of Table 1 be subject to the NERC Reliability Standards development process. They state that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts. Changes to the footnotes affect Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original standard. APPA also states that consideration of reliability impacts of spare equipment strategies and obligations of all generators to have the same voltage ride through capabilities are important changes that should not be made by Commission fiat.

ii. Commission Determination

1785. The Commission approves TPL-002-0 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to TPL-002-0 through the Reliability Standards development process, as discussed below.

1786. The Commission notes that, like Requirement Rl.3.1 of TPL-001-0, Rl.3.2 of TPL-002-0 requires an entity assessing system performance to cover "critical system conditions and study years" as deemed appropriate by the entity performing the study, but it does not specify the rationale for determining critical system conditions and study years. The Commission directs the ERO to modify TPL-o02-0 to require that critical system conditions and study years be determined in the same manner as it directed with regard to TPL-001-0. The Commission's explanation of the need for that change applies equally here.

1787. With regard to Northern Indiana's concerns, we disagree that the proposal to address situations in which critical equipment may be unavailable for a prolonged period requires planned and forced outage schedules for the next ten years. Reliability Standard TPL-002-0 requires consideration of planned outages at those demand levels for which planned outages are performed but does not address situations in which critical long lead time equipment, such as a transformer or phase angle regulator, may be unavailable for a prolonged period that could extend into periods where planned outages of such equipment would not normally be performed. Assessments of these situations do not require outage schedules for the next ten years but rather identification of which facilities are deemed to be critical that have long lead times for repair or replacement. Given that planned outage considerations of such long lead time equipment are inexorably linked to spare equipment strategy, consistent with our discussion of the issue above in connection with spare equipment strategy, the Commission directs the ERO to modify the Reliability Standard to require assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy.

1788. In the NOPR, the Commission identified an implicit assumption in the TPL Reliability Standards that all generators are required to ride through the same types of voltage disturbances and remain in service after the fault is cleared. This implicit assumption should be made explicit. Commenters agree with the proposed requirement for all generators to ride through the same set of Category B and C events as required for wind generators. The Commission understands that NRC has both degraded voltage and loss of voltage requirements. The degraded voltage requirement allows the voltage at the auxiliary power system busses to go below the minimum value for a time frame that is usually much longer than normal fault clearing time.[457] If a specific nuclear power plant has an NRC requirement that would force it to trip off-line if its auxiliary power system voltage was depressed below some minimum voltage, the simulation should include the tripping of the plant in addition to the faulted facilities. In this regard, the Commission agrees that NRC requirements should be used when implementing the Reliability Standards. Using NRC requirements as input will assure that there is consistency between the Reliability Standards and the NRC requirement that the system is accurately modeled. Accordingly, the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. If a generator trips due to low voltage from a single contingency, the initial trip of the faulted element and the resulting trip of the generator would be governed by Category B contingencies and performance criteria.

1789. The Commission agrees with NRC that for operations purposes the N-1 condition is always analyzed from the conditions being experienced. In other words, allowing for the 30 minute system adjustment period, the system must be capable of withstanding an N-1 contingency, with load shedding available to system operators as a measure of last resort to prevent cascading failures. However, for planning purposes, a different analysis applies. The N-1 condition is a Category B event under TPL-002-0, and, following the N-1 contingency, the system must be stable and thermal loading and voltages be within applicable limits. Some adjustment of generation or other controls is permitted to return loadings to within continuous ratings, provided the loadings before adjustments are within the emergency or short-term ratings. Under TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-o03-0. The Commission has addressed NRC's comment concerning N-1 contingencies in real-time operation in TOP-002. In regard to the specific revisions proposed by NRC, the Commission directs the ERO to consider these as part of the Reliability Standards development process.

1790. In regard to Northern Indiana's comment concerning the load modeling statement made in the NOPR, it should be clear that the context of the discussion is system performance during simulations. Load models used in simulations clearly should, to the extent feasible, represent the actual performance of the aggregate mix of industrial, commercial and residential loads. If the load model representations used in simulations do not mirror the actual performance of loads, especially during dynamic simulations, but also when carrying out voltage stability studies, the simulation results will not be accurate. Because load representation in simulations has a significant impact on simulation results and often load models are not well known, it is common practice for planners to perform sensitivity studies with a range of load models. Accordingly, as proposed in the NOPR, the Commission directs the ERO to modify the Reliability Standard to require documentation of load models used in system studies and the supporting rationale for their use.

1791. In the NOPR, the Commission set forth its rationale for proposing that the ERO clarify the phrase "permit operating steps necessary to maintain system control" in footnote (a) to Table 1.[458] Specifically, the Commission stated that the operating steps required

[457] 10 CFR 50, Appendix a, GDC17.

[458] NOPR at P 1083.

to relieve emergency loadings and return the system to a normal state should not include firm load shedding. MidArp.erican agrees with the Commission. International Transmission states clarification is required on the thresholds for normal and emergency ratings and, in particular, on whether an entity can plan to operate above normal ratings but below emergency ratings and for how long. The Commission agrees that this issue requires clarification and therefore directs the ERO to modify the standard to clarify the phrase of footnote (a) that states "permit operating steps necessary to maintain system control" to clarify the use of emergency ratings.

1792. The Commission stated in the NOPR that footnote (b) raises three issues that need to be addressed.[459] Two relate to the use of planned or controlled load interruption under certain circumstances, and the third relates to the use of system adjustments including curtailment of firm transfers to prepare for the next contingency. Northern Indiana and Entergy disagree with the Commission's proposal to modify footnote (b) to state that load shedding fo;r a single contingency is not permitted except in very special circumstances where such interruption is limited to the firm load associated with the failure (consequential load loss). The commenters argue that the impact of transmission outages can be local in nature and have no impact on the reliability of the Bulk-Power System and that removing the option to shed load in a local area for a single contingency would result in significant facility upgrade costs and therefore increased rates to customers simply to avoid a local outage. Entergy seeks clarification that the Commission does not intend to constrain the transmission operator's ability to determine the best course of action to addtess local reliability constraints.

1793. The NOPR proposed a modification that would clarify footnote (b) as disallowing loss of such firm load or the curtailment of firm transactions after a first contingency of the bulk electric system. In its comments to the Staff Preliminary Assessment, NERC agreed with this interpretation, representing that a practice that permits the planned interruption of "firm transmission service" is a misapplication of the Reliability Standard.[460] Some commenters now argue otherwise, and in some cases cite examples where, based on a balance of economic and reliability considerations, it may be preferable to plan the bulk electric system in such a manner that contemplates the interruption of some firm load customers in the event of a N-1contingency. We view these arguments as based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios. Therefore, they argue, the ambiguities of footnote (b) should be interpreted to allow that an entity plan for some amount of load loss to avoid costly infrastructure investments.

1794. The Commission considers this matter to be a fundamental issue of transmission service. Indeed, the ERO's definition of "firm transmission service" specifically states that it is the "highest quality (priority) service offered to customers under a filedrate schedule that anticipates no planned interruption."

1795. Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency.[461] The Commission directs the ERO to clarify the Reliability Standard. Regarding the comments of Entergy and Northern Indiana that the Reliability Standard should allow entities to plan for the loss of firm service for a single contingency, the Commission finds that their comments may be considered through the Reliability Standards development process. However, we strongly discourage an approach that reflects the lowest common denominator.[462] The Commission also clarifies that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances.

1796. PG&E disputes that the Reliability Standard should provide limits on the magnitude and duration of consequential load loss, as this is an economic evaluation and is not an appropriate goal for this Reliability Standard. The Commission disagrees. Indeed in its comments to the Staff Preliminary Assessment, the ERO raised the issue of what is an acceptable magnitude and duration of consequential load loss.[463] The Commission notes that most utilities have guidelines for the magnitude and duration of load loss that is acceptable on radial facilities before the facilities are looped to provide a second source of supply to accommodate load growth. NERC also stated that it recognizes that looped configurations are key to the reliable operation of the Interconnection and to meet reasonable expectations for reliable service to loads.[464] The Commission, therefore, suggests that the ERO consider developing a ceiling on the amount and duration of consequential load loss that will be acceptable. If the ERO determines that such a ceiling is appropriate, it should be developed through the ERO's Reliability Standards development process. Further, we note that the DOE thresholds for reporting disturbances on Form EIA-417 would be one example of an appropriate starting point for developing such a ceiling. These thresholds for load loss are 300 MW for 15 minutes or 50,000 customers for one hour, whichever is greater.

1797. The third issue with footnote (b) relates to the Commission's proposal in the NOPR to delete the footnote's second sentence, which states "[t]o prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers."[465] PG&E disagrees with the Commission's proposal because it allows re-scheduling power (but not load shedding) as part of manual adjustment after the first Category B contingency to bring the system back to a safe operating point. The Commission agrees that footnote (b) should permit manual adjustments including generation redispatch and transmission reconfiguration, but not load shedding, to return the system to a normal operating state within the time period permitted by the emergency or short term ratings. The Commission understands that this is the normal practice used by most transmission planners. However, the system adjustments permitted in the statement above includes curtailments of contracted firm, non-recallable reserved and electric power transfers and this is not acceptable for Category B single contingencies. Therefore, the ERO should modify the sentence to indicate that manual system adjustments, except

459 *Id.* at P 1084.

460 "NERC standards, including footnote (b), are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for a single contingency." NERC comments to the Staff Preliminary Assessment at 57-58.

461 Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.

462 *See* Order No. 672 at P 329.

463 NERC Comments to Staff Preliminary Assessment at 56-57.

464 "NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads." *Id.* at 57.

465 NOPR at P 1083.

for shedding firm load or curtailment of firm transfers, are permitted after the first contingency to bring the system back to a normal operating state. The Commission disagrees with PG&E's statement that the difference between footnote (b) as part of Category B and Category C.3 is that footnote (b) applies before the second N-1contingency, whereas Category C.3 applies after the second N-1contingency. Rather, manual adjustments referred to in both cases apply after the first N-1 contingency. The Commission, therefore, directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.

1798. Accordingly, the Commission approves Reliability Standard TPL--002-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-002-0 through the Reliability Standards development process that: (1) Requires that critical system conditions be determined in the same manner as we propose to require for TPL-001-0; (2) requires assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy; (3) requires all generators to ride through the same set of Category B and C contingencies as required by wind generators in Order No. 661, or to simulate those generators that cannot ride through as tripping; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" in footnote (a) and the use of emergency ratings and (6) clarifies footnote (b) in regard to load loss following a single contingency, specifying the amount and duration of consequential load loss and system adjustments permitted after the first contingency to return the system to a normal operating state, as discussed above.

d. System Performance Following Loss of Two or More Elements (TPL--003-0)

1799. Reliability Standard TPL-003-0 seeks to ensure that the future Bulk-Power System is planned to meet the system performance requirements of a system with the loss of multiple elements. It does this by requiring that the transmission planner and the planning authority annually evaluate and document the ability of its transmission system to meet the performance requirements of Category C contingencies specified in Table 1 (*i.e.*, events resulting in the loss of two or more elements) for both the near-term and the longer-term planning horizons. TPL-003-0 requires the preparation of a documented plan to achieve the necessary performance requirements if the system is unable to meet the Category C performance criteria.

1800. TPL--003-0 applies to each planning authority and transmission planner. They must demonstrate annually through valid assessments that their portion of the interconnected transmission system is planned to meet the performance requirements of Category C with all transmission facilities in service over a planning horizon that takes into account lead times for corrective plans. The Reliability Standard also requires the applicable entities to consider planned outages of transmission equipment for those demand levels for which they perform such outages. The Reliability Standard defines various categories of conditions to be simulated. The specific study elements selected from each of the categories for assessments, including the subset of Category C contingencies to be evaluated, require approval by the associated regional reliability organization.

1801. The Commission proposed in the NOPR to approve Reliability Standard TPL-003-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(0 of our regulations, we proposed to direct NERC to submit a modification to TPL-003-0 that: (1) Requires that critical system conditions be determined by conducting sensitivity studies (as elaborated in our discussion of TPL-001-0); (2) makes certain clarifications to footnote (c) to Table 1; (3) requires the applicable entities to define and document the proxies necessary to simulate cascading outages and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

1802. The Commission also sought comments on one potential addition to TPL-003-0. It noted that Category C3 of this Reliability Standard involves a situation in which two single contingencies occur, with manual system adjustments permitted after the first contingency to prepare for the next one (generally referred to as N-1-1). However, the Commission also noted that should the second contingency occur before the manual system adjustments can be completed, the local area and potentially the system would be exposed to risk of cascading outages. For that reason some entities plan and operate their systems so that they are able to withstand the simultaneous occurrence of the two contingencies (normally referred to as N-2) for major load pockets. The Commission sought comments on the value and appropriateness of including such a requirement in TPL-003-0.

i. Comments

1803. LPPC recommends that changes to footnotes of Table 1be subject to the NERC Reliability Standards development process. It states that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts which should be given due weight by the Commission. Changes to the footnotes impact Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original Reliability Standard.

1804. FirstEnergy supports the proposed requirement to document proxies of subsequent line trips due to thermal overload and low voltage generation trips to evaluate potential cascading conditions. FirstEnergy states it currently is required to account for these items in its planning process.

1805. EEI questions the value of providing proxies when planners conduct thousands of studies based on combinations of contingencies under a broad range of circumstances and conditions, especially in longer-term planning horizons where the uncertainty around the value of any one variable is already very high. SoCal Edison states that one can determine the cascading outages in load flow studies. In transient stability studies, if the outage is severe, then the thermal overload relays and undervoltage relays, if modeled, will trip the load. If the load tripped was not planned to be tripped for this outage, then the planning authority should take the necessary steps to avoid this situation, as cascading is not allowed.

1806. LPPC and Northern Indiana oppose the proposal to require proxies necessary to simulate cascading outages be defined and documented. Northern Indiana states that there is no consensus on what these proxies should be. LPPC states that utility planners have traditionally used their engineering judgment to simulate a conservative estimate of the level of thermal overload or low voltage that will cause the likelihood of subsequent line or generator trips and cascading events. LPPC states that this approach has been

ATTACHMENT 15

Excerpts of FERC Order 762,
77 Federal Register 26686 (May 7, 2012)

markets serving 19.2 million customers. NYISO manages a nearly 11,000-mile network of high-voltage transmission lines.

100. PJM is comprised of more than 700 members including power generators, transmission owners, electricity distributers, power marketers, and large industrial customers and serves 13 states and the District of Columbia.

101. SPP is comprised of 63 members serving 6.2 million households in nine states and has 48,930 miles of transmission lines.

102. MISO is a nonprofit organization with over 145,000 megawatts of installed generation. MISO has over 57,600 miles of transmission lines and serves 13 states and one Canadian province.

103. ISO–NE is a regional transmission organization serving six states in New England. The system is comprised of more than 8,000 miles of high-voltage transmission lines and over 300 generators.

104. The Commission certifies that this rule will not have a significant economic impact on a substantial number of small entities, and therefore no regulatory flexibility analysis is required.

VII. Document Availability

105. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

106. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

107. User assistance is available for eLibrary and the the Commission's Web site during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202)502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

VIII. Effective Date and Congressional Notification

108. These regulations are effective July 6, 2012. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends Part 35, Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. In § 35.28, paragraphs (g)(4) through (g)(7) are redesignated as paragraphs (g)(5) through (g)(8) and a new paragraph (g)(4) is added to read as follows:

§ 35.28. Non-discriminatory open access transmission tariff.

* * * * *

(g) * * *

(4) *Electronic delivery of data.* Each Commission-approved regional transmission organization and independent system operator must electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the Commission, data related to the markets that the regional transmission organization or independent system operator administers.

* * * * *

Note: The following appendix will not be published in the Code of Federal Regulations.

Appendix A

Commenters on the NOPR

American Public Power Association (APPA)
California Department of Water Resources State Water Project (SWP)
Cogeneration Association of California and the Energy Producers and Users Coalition (CAC/EPUC)
Edison Electric Institute and the Electric Power Supply Association (EEI/EPSA)
ISO New England Inc. (ISO–NE)
ISO/RTO Council (IRC)
New York Public Service Commission (NYPSC)
Pennsylvania Public Utility Commission (PA PUC)
Powerex Corp. (Powerex)

[FR Doc. 2012–9847 Filed 5–4–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM11–18–000; Order No. 762]

Transmission Planning Reliability Standards

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission remands proposed Transmission Planning (TPL) Reliability Standard TPL–002–0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process. The Commission finds that this provision is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Final Rule remands NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest.

DATES: This rule will become effective July 6, 2012.

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- *Agency Web Site: http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

Eugene Blick (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, Telephone: (202) 502–8066, *Eugene.Blick@ferc.gov.*

Robert T. Stroh (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, Telephone: (202) 502–8473, *Robert.Stroh@ferc.gov.*

SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,060

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

Final Rule

Issued April 19, 2012.

1. Under section 215(d) of the Federal Power Act,[1] the Commission remands proposed Transmission Planning (TPL) Reliability Standard TPL–002–0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process.[2] The Commission finds that this provision is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Final Rule remands NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. We require NERC to utilize its Expedited Reliability Standards Development Process to develop timely modifications to TPL–002–0b, Table 1 footnote 'b' in response to our remand.[3]

I. Background

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Approved Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard TPL–002–0.[4] In addition, pursuant to section 215(d)(5) of the FPA,[5] the Commission directed NERC to develop modifications to 56 of the 83 approved Reliability Standards, including footnote 'b' of Reliability Standard TPL–002–0.[6]

A. Transmission Planning (TPL) Reliability Standards

3. Currently-effective Reliability Standard TPL–002–0b addresses Bulk-Power System planning and related transmission system performance for single element contingency conditions. Requirement R1 of TPL–002–0b requires that each planning authority and transmission planner ''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 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.'' [7] Table I identifies different categories of contingencies and allowable system impacts in the planning process. With regard to system impacts, Table I further provides that a Category B (single) contingency must not result in cascading outages, loss of demand or curtailed firm transfers, system instability or exceeded voltage or thermal limits. With regard to loss of demand, current footnote 'b' of Table 1 states:

> Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

B. Order No. 693 Directive

4. In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency.[8] The Commission directed the ERO to develop certain modifications, including a clarification of Table 1, footnote 'b.'

5. In a subsequent clarifying order, the Commission stated that it believed that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service would be acceptable in limited circumstances.[9] Specifically, the Commission stated that ''a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service at the fringes of various systems would be an acceptable approach.'' [10]

C. NERC Petition

6. On March 31, 2011, NERC filed a petition seeking approval of its proposal to revise and clarify footnote 'b' ''in regard to load loss following a single contingency.'' [11] NERC stated that it did not eliminate the ability of an entity to plan for the loss of non-consequential load in the event of a single contingency but drafted a footnote that, according to NERC, ''meets the Commission's directive while simultaneously meeting the needs of industry and respecting jurisdictional bounds.'' [12] NERC stated that its proposed footnote 'b' establishes the requirements for the limited circumstances when and how an entity can plan to interrupt Firm Demand for Category B contingencies. According to NERC, the provision allows for planned interruption of Firm Demand when ''subject to review in an open and transparent stakeholder process.'' [13] NERC's proposed footnote 'b' states:

> An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when

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[1] 16 U.S.C. 824o(d)(4) (2006).

[2] NERC filed a petition seeking approval of Table 1, footnote 'b' of four Reliability Standards: Transmission Planning: TPL–001–1—System Performance Under Normal (No Contingency) Conditions (Category A), TPL–002–1b—System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL–003–1a—System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL–004–1—System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). While footnote 'b' appears in all four of the above referenced TPL Reliability Standards, its relevance and practical applicability is limited to TPL–002–0a.

[3] NERC Rules of Procedure, Appendix 3A, Standard Processes Manual at 34 (effective January 31, 2012).

[4] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[5] 16 U.S.C. 824o(d)(5)(2006).

[6] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1797.

[7] Reliability Standard TPL–002–0a, Requirement R1.

[8] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1794.

[9] *Mandatory Reliability Standards for the Bulk Power System,* 131 FERC ¶ 61,231, at P 21 (2010) (June 2010 Order).

[10] *Id.*

[11] NERC Petition at 10.

[12] *Id.*

[13] *Id.*

achieved through the appropriate redispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

7. NERC supplemented the filing on June 7, 2011, in response to a Commission deficiency letter. NERC explained that ''the approach proposed in footnote 'b' is equally efficient because many of the stakeholder processes that will be used in footnote 'b' planning decisions are already in place, as implemented by FERC in Order No. 890 and in state regulatory jurisdictions.'' [14] NERC also pointed to state public utility commission processes or processes existing in local jurisdictions that address transmission planning issues that could serve to provide a case-specific review of the planned interruption of Firm Demand. According to NERC, such processes would more likely engage the appropriate local-level decision-makers and policy-makers.

8. With respect to review and oversight by NERC and the Regional Entities, NERC submitted that an ERO-specific process would place the ERO in the position of managing and actively participating in a planning process, which conflicts with its role as the compliance monitor and enforcement authority. NERC also stated that neither the ERO nor the Regional Entities will review decisions regarding planned interruptions. Their role will be limited to reviewing whether the registered entity participated in a stakeholder process when planning to interrupt Firm Demand. NERC explained that Regional Entities will have oversight after-the-fact by auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.'

9. Furthermore, NERC stated that an objective of the planning process should be to minimize the likelihood and magnitude of planned Firm Demand interruptions. NERC contended that, due to the wide variety of system configurations and regulatory compacts, it is not feasible for the ERO to develop a one-size-fits-all criterion for limiting the planned firm load interruptions for Category B events. According to NERC, the standards drafting team evaluated setting a certain magnitude of planned interruption of Firm Demand, but there was no analytical data to support a single value, and it would be viewed as arbitrary.

D. Notice of Proposed Rulemaking

10. On October 20, 2011, the Commission issued a Notice of Proposed Rulemaking (NOPR [15]) proposing to remand NERC's proposal to modify footnote 'b.' In the NOPR, the Commission stated that it believed that NERC's proposal does not meet the directives in Order No. 693 and the June 2010 Order and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single contingency. The Commission expressed concern that the procedural and substantive parameters of NERC's proposed stakeholder process are too undefined to provide assurances that the process will be effective in determining when it is appropriate to plan for interrupting Firm Demand, does not contain NERC-defined criteria on circumstances to determine when an exception for planned interruption of Firm Demand is permissible, and could result in inconsistent results in implementation. The NOPR stated that the proposed footnote effectively turns the processes into a reliability standards development process outside of NERC's existing procedures. Furthermore, the NOPR stated that regardless of the process used, the result could lead to inconsistent reliability requirements within and across reliability regions. While the Commission recognized that some variation among regions or entities is reasonable, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions.

11. The Commission proposed to provide further guidance on acceptable approaches to footnote 'b' and sought comment on certain options for revising footnote 'b', as well as other potential options to solve the concerns outlined in the NOPR. In response to the NOPR, comments were filed by seventeen interested parties.[16]

II. Discussion

12. For the reasons discussed below, the Commission concludes that NERC's proposed TPL–002–0b does not meet the Commission's Order No. 693 directives, nor is it an equally effective and efficient alternative. Further, the Commission finds that the proposal is vague, potentially unenforceable and may lack safeguards to produce consistent results. On this basis, the Commission remands the proposal to NERC as unjust, unreasonable, unduly discriminatory or preferential and not in the public interest. Below, the Commission also provides guidance on acceptable approaches to footnote 'b.'

13. The Commission adopts the proposed NOPR finding that the footnote 'b' process lacks adequate parameters. The Reliability Standard requires that, when planning to interrupt Firm Demand, the Firm Demand interruption must be ''subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.'' [17] Without meaningful substantive parameters governing the stakeholder process, the enforceability of this obligation by NERC and the Regional Entities would be limited to a review to ensure only that a stakeholder process occurred. As NERC explained, Regional Entities' involvement is limited to after-the-fact oversight by auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.' [18]

[14] NERC Data Response at 4.

[15] *Transmission Planning Reliability Standards,* Notice of Proposed Rulemaking, 76 FR 66229 (Oct. 20, 2011), FERC Stats. & Regs. ¶ 32,683 (2011).

[16] NERC, The Edison Electric Institute (EEI), American Public Power Association (APPA), National Association of Regulatory Utility Commissioners (NARUC), ITC Holdings Corp. (ITC), Manitoba Hydro, California Department of Water Resources State Water Project (California SWP) Hydro One Networks, Inc and the Ontario Independent Electricity System Operator (Hydro One and IESO), Duke Energy Corporation (Duke), New York State Public Service Commission (NYPSC), Bonneville Power Administration (BPA), Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company (KCPL), Midwest Independent System Operator, Inc. (MISO), Public Utility District No. 1 of Snohomish County, Washington (Snohomish), Transmission Access Policy Study Group (TAPS), Powerex Corp. (Powerex), and Florida Reliability Coordinating Council (FRCC).

[17] NERC Petition at 10.

[18] NERC Data Response at 7–9.

ATTACHMENT 16

R. Sparks’ 4/25/12 Email to SDG&E and W.Stephenson

From: Sparks, Robert <RSparks@caiso.com>
Sent: Wednesday, April 25, 2012 5:43 PM
To: Jontry, John; Barave, Sushant
Cc: Lin, Huang; Fernandez, Juan C; WSTEPALPHA@aol.com
Subject: RE: Request for clarification on CAISO planning standard

John,

Here is some information on ISO practices regarding load loss due to NERC Category B contingencies.

ISO Grid Planning Standards follow the standards specified by NERC and WECC. NERC TPL 002 states the following:

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 (non-recallable 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.

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No

Within the current FERC approved version of the NERC Reliability Standard, TPL-002-0a, there is the existing footnote b) which states the following.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

However when FERC approved the Reliability Standards in Order 693 it provided guidance with respect to non-consequential load loss which were to be brought forward in future submission for approval. NERC submitted in TPL-002-0b a revised to footnote b), however this has been remanded by FERC.

FERC recently remanded the proposed revision to TPL-002 footnote b because it includes a provision that allows for planned load loss due to a single contingency. FERC found that this provision is vague, unenforceable and not responsive to previous FERC directives on this matter. Please see , item 4 (FERC 693 directive) would provide further support to your response. It's referenced in http://www.ferc.gov/whats-new/comm-meet/2012/041912/E-8.pdf

Order No. 693 Directive

4. In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard {TPL-002} should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency.[8] *The Commission directed the ERO to develop certain modifications, including a clarification of Table 1, footnote 'b.'*

With this uncertainty regarding the applicability of footnote b, the ISO does not plan for load loss for category B contingencies other than on:

- radial supplied load within the allowable load levels identified in the ISO Planning Standards; and
- interim basis prior to the completion of needed transmission upgrades.

Robert

From: Jontry, John [mailto:JJontry@semprautilities.com]
Sent: Friday, April 20, 2012 5:07 PM
To: Barave, Sushant; Sparks, Robert
Cc: Lin, Huang; Fernandez, Juan C; 'WSTEPALPHA@aol.com'
Subject: Request for clarification on CAISO planning standard

Sushant & Robert – Per our discussion last week with the gentleman working on the CPUC's Cycle 6 audit. Attached is a document outlining his methodology for the Value of Service (VOS) calculations he will be performing on several SDG&E transmission projects, and a request for a short statement on the CAISO's expectation for the use of VOS for project justification. Please review and respond at your convenience.

Have a good weekend!

John M. Jontry, PE
Manager - SDG&E Electric Transmission Grid Planning
858-654-1577 vox
858-472-2751 mobile
858-654-1692 fax
jjontry@semprautilities.com

ATTACHMENT 17

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ATTACHMENT 18

“Rooftop solar finds out utilities can disrupt, too”

Tuesday, January 20, 2015 6:16 AM PT Exclusive

Rooftop solar finds out utilities can disrupt, too

By Michael Copley

There is a pervasive thought that U.S. utilities face disruptive risks as distributed solar moves into the mainstream. Utilities, the reasoning goes, could find themselves trapped in a "death spiral" in which declining demand puts pressure on revenues as costs hold or even increase. But as utilities move to shield themselves from that hazard, some say solar companies are the ones in the precarious position.

With the solar industry working to open new markets and speed up development, fights between the two sides are playing out in statehouses and public utility commissions across the country.

Faced with slumping sales and increasing amounts of customer-generated power, utilities are pushing regulations broadly aimed at protecting their balance sheets and non-solar ratepayers, changing the rules of the game that have so far benefited solar companies. Some say those efforts could hollow out policies that are vital to rooftop solar and shake investor confidence in the sector.

"We're only one small code or rule change away from being dead in the water, all of us," Morten Lund, a partner at Stoel Rives LLP and co-chairman of the firm's Solar Energy Initiative, said at an October 2014 solar conference in Las Vegas.

That same month, Barclays Capital Inc. Managing Director Steven Berkenfeld told solar executives in Washington, D.C., that to continue attracting Wall Street money, the industry has to ensure favorable policies are not rolled back.

"People who want to be critical of the industry — from an analyst perspective, from an investor perspective — are worried about … additional costs that are going to be put onto distributed generation," Berkenfeld said.

> **“We're only one small code or rule change away from being dead in the water, all of us.”**
> **–– Morten Lund, a partner at Stoel Rives LLP**

Utilities, pursuing what they say are fairer and more transparent policies, have opened new fronts in a battle that solar advocates say once was fought almost exclusively over net-energy metering — a policy in many states that requires utilities to compensate ratepayers for surplus electricity they send from their solar panels back to the grid. Utilities are proposing higher fixed charges, solar-specific fees and lower compensation for customer-generated power. In some cases, they are trying to get into the residential solar business themselves.

Roadblocks to new markets

Wisconsin is one state to expose such vulnerabilities, with policymakers moving to tamp down the advantages of distributed solar before the industry could really take root.

In a stinging set of decisions in 2014, the Public Service Commission of Wisconsin gave the go-ahead to hike fixed charges 82% for MGE Energy Inc. subsidiary Madison Gas and Electric Co.; 83% for Integrys Energy Group Inc. subsidiary Wisconsin Public Service Corp.; and roughly 78% for Wisconsin Electric Power Co., a Wisconsin Energy Corp. subsidiary that along with Wisconsin Gas LLC does business as We Energies.

The shift from variable to fixed charges is "the most evident and frankly the most troubling" approach utilities are taking to redesigning rates, Tom Starrs, vice president of market strategy and policy at Total SA subsidiary SunPower Corp., said at a December 2014 solar conference in San Diego. It "radically undermines the solar industry's value proposition to its customers," he said.

"If you make a fixed charge high enough, at some point … it tends to neutralize the benefits of net metering," Swami Venkataraman, a vice president and senior credit officer at Moody's, said an interview. Moody's has said higher fixed charges are credit positive for utilities because they make revenues more predictable.

Before voting in the Wisconsin cases, state Public Service Commissioner Ellen Nowak said she was looking for "innovative rate design ideas that assess … the cost to the cost causer." A commission spokesman, in an email, said Nowak for years has pushed for "a more fair and balanced fixed charge."

In at least one of the Wisconsin cases — We Energies' — regulators also approved a fixed demand charge on solar customers and lower utility payments for customer-generated power.

Before commissioners voted, SolarCity Corp. CEO Lyndon Rive warned that a solar market would not take hold in Wisconsin if the measures were approved, the *Milwaukee Journal Sentinel* reported.

“ If you make a fixed charge high enough, at some point … it tends to neutralize the benefits of net metering.” –– Swami Venkataraman, Moody's

After the vote, Bryan Miller, vice president of public policy and power markets at Sunrun Inc., echoed Rive. "Right now [Wisconsin] is not a solar market — there are less than 400 solar customers in the whole state. It has great potential to become a solar market. But … it's certainly the case that until this is reversed, no companies will enter the state, and the very few that are struggling to sell anything will cease to be able to do that," he said in an interview.

Estimated savings from residential PV systems in Arizona Public Service's territory

	25-year electric savings	Average annual savings
No fixed-cost recovery charge	$55,018	$2,201
Approved fixed-cost recovery charge	$53,548	$2,143
APS-proposed fixed-cost recovery charge	$28,563	$1,143

* Estimated savings based on 7-kW system on the rooftop of a high-usage customer.
Sources: NC Clean Energy Technology Center, Meister Consultants Group

GTM Research Senior Vice President Shayle Kann said Wisconsin will not be the only state where "something like this" happens.

The Connecticut Public Utilities Regulatory Authority in December 2014 approved increased monthly fees on residential customers of Northeast Utilities subsidiary Connecticut Light and Power Co. AES Corp. subsidiary Indianapolis Power & Light Co. is trying to increase rates with a shift toward higher fixed fees, a move that is becoming something of a trend in the Midwest, the *Indianapolis Business Journal* reported. And the utilities of Hawaiian Electric Industries Inc. proposed increasing fixed charges and imposing a monthly solar charge.

"This is why things like cost reductions matter; this is why financial innovation matters; this is why … regulatory battles that are happening matter; because any given thing that doesn't go quite right can push a meaningful portion of the market out of the money," Kann said.

Rooftop solar companies also warn that utilities could hijack the market by forming residential solar operations inside of their regulated monopolies.

In December 2014, the Arizona Corporation Commission approved limited rooftop solar programs proposed by Pinnacle West Capital Corp. subsidiary Arizona Public Service Co. and Fortis Inc. subsidiary Tucson Electric Power Co. While advocacy groups backed by big-name solar companies fought the proposals, saying they would kill competition and stifle innovation, some state regulators responded that the utilities could help create a more robust market by contracting with local installers that have felt boxed out by national competitors.

But it has not been all wins for utilities.

Solar advocates scored a victory when electric utilities in South Carolina signed onto a deal setting favorable net-metering terms in the state. The agreement shows the "strength and fairness" of such policies and is a sign of the difficulty utilities face in their "attempts to eliminate rooftop solar across the country," said Miller, who also is co-chairman of an advocacy group called The Alliance for Solar Choice.

Regulatory battlegrounds

For utilities, the idea is simple: A new technology and market entrant needs new policies.

“Any given state is potentially in play, even if unlikely, and they're all important.” –– Justin Barnes, a senior research analyst at Keyes Fox & Wiedman LLP

"Right now we have situations where our rates were designed based upon the way we built the service system 20 or 30 years ago. … They don't reflect the costs of doing business today," James Avery, senior vice president of power supply at Sempra Energy subsidiary San Diego Gas & Electric Co., said at the December 2014 solar conference in San Diego. "What we would like to do is for everything to be transparent and people to see our costs."

There is little reason to think the regulatory fights will end any time soon.

"It is, literally, a national conversation about net metering and cost shifting and rate design, and we're kind of past the point where the issue really respects state borders, and we're at the point where each individual action on the state level … has something of a precedential quality," Justin Barnes, a senior research analyst at Keyes Fox & Wiedman LLP, said at the October solar conference in Las Vegas. "Any given state is potentially in play, even if unlikely, and they're all important."

Expecting the Midwest to be a hotspot in 2015, Sunrun recently hired the former sustainability and solar program manager for the city of Milwaukee "to help lead the defense against monopolist utilities trying to eliminate the growing rooftop solar industry" in the region. Miller said the solar industry has already won the fight over net metering. But "I'm not suggesting utilities are going to stop trying to eliminate competition," he added. "This is a battle. It's just that they're losing."

David Raskin, a partner at Steptoe & Johnson LLP, said utilities have no choice but to continue looking for ways to recoup their investments. Net-metering policies that compensate customers at the retail rate for their surplus solar power can keep utilities from recovering some of their infrastructure spending, according to EnerKnol Inc., an energy research and data firm.

"What investors have historically provided to this industry, they can refuse to provide; and they will refuse to provide capital to an industry that … chooses to stop asking regulators for rates that fully recover costs," Raskin wrote in the November 2014 issue of *Energy Law Journal*. "Policies that restrict access to this capital are and will remain harmful to the public interest."

Agreeing to change, but not the change

Solar advocates and utilities generally agree that utility rates need reforming, but they differ on the specifics.

Higher fixed charges are "too simplistic," James Tong, vice president of strategy at Clean Power Finance, wrote in an email.

"When they assess a blunt fixed fee, utilities lose the levers they could otherwise use to influence consumer behavior to make the entire grid more cost effective," Tong wrote, adding that the grid should be treated as a marketplace where utilities make money through transaction or access fees.

"We've charged for electricity in the same way for a long, long time, and I think that many utilities and the regulators, frankly, think that these are too hard to change."
–– Owen Smith, principal at the Rocky Mountain Institute

Even in California, which IHS Technology expects will have the highest market share of annual solar power generation globally by the end of 2015, regulators are putting more thought into solar, asking, "Where are the places on the grid where there's extra value and how do we get to price" technology such as distributed generation and battery storage, California Public Utilities Commissioner Michael Picker said at the December 2014 solar conference in San Diego.

Intrinsic in that question is the idea that little strategy is going into siting and using new distributed solar generation.

Miller said time-of-use rates are an "excellent way of sending the right transparent price signals" to ratepayers. But Owen Smith, principal at the Rocky Mountain Institute, said utilities are approaching the issue with rate filings that they think are practical.

"We've charged for electricity in the same way for a long, long time, and I think that many utilities and the regulators, frankly, think that these are too hard to change, and that customers will never understand them, and that it will create a backlash if we go from a flat-rate structure to demand charges or time-varying rates and things of that sort," Smith said at the December 2014 solar conference in San Diego.

Moody's Senior Vice President Mihoko Manabe said utilities and regulators are not looking for ways to "stanch rooftop solar but to accommodate it, encourage it, while at the same time making sure that the issue of cost shifting is dealt with" and utilities are able to respond to shifting market dynamics.

Regulators are not likely to get rid of net metering, she said in an interview. But "it's going to be reformed, and it's going to be amended."

Room for accommodation?

In SEC filings, solar companies warn that regulatory and policy changes, including utility rate designs, could cause demand for their product to wane and markets to contract. Opinions vary over how much change those companies could withstand.

While Lund warned that the solar industry is "one small" change away from trouble, Venkataraman said companies have "some leeway."

"A lot of residential customers who are installing rooftop solar right now are kind of like the low-hanging fruit. It's quite profitable for [companies]," he said. "And in many cases, we know that it's more profitable than what they would consider to be their threshold return requirements, if you will. There is some leeway there … to maybe accept a slightly lower level of profitability than in the past. So it's not that it's a question of [having] losses or being profitable; there is something in between there as well."

SolarCity, which racked up $71.7 million in net losses attributable to stockholders during the first half of 2014, reported third-quarter 2014 net income of $19.2 million and a gross margin of 51%. "Our long-term value creation for shareholders has never been stronger," Rive and CFO Brad Buss wrote in a third-quarter 2014 shareholder letter.

In a Jan. 8 report, Deutsche Bank Securities Inc. said the rooftop solar sector will be a "key highlight" for the U.S. industry in 2015, with expanding margins going forward. However, the bank noted widespread uncertainty, with some utilities taking steps to compete with the likes of SolarCity and others lobbying against the sector. But if Arizona is any indication, policy fights should not slow solar deployment, analysts said. Arizona Public Service and the solar industry battled in 2013 over a utility proposal that ultimately led to a monthly 70-cents-per-kW surcharge — roughly $4.90 per month for customers with a 7-kW system — for APS ratepayers who install rooftop solar panels after Jan. 1, 2014.

"Arizona is generally considered one of the most contentious regions for debate in the U.S., yet solar leasing companies … have continued to ramp their installation rates despite this," Deutsche Bank analysts wrote.

New York State Public Service Commission Chair Audrey Zibelman said markets and regulations are likely to remain in a state of flux. "If anyone … is sitting here and saying, 'This is going to be it,' it's not going to be it; things will change," she told a gathering of solar companies in Washington, D.C., in October 2014. "So everyone needs to be flexible in thinking about it."

ATTACHMENT 19

"SolarCity sues Salt River Project over 'anti-competitive' solar customer rates"

Tuesday, March 03, 2015 2:48 PM PT Exclusive

SolarCity sues Salt River Project over 'anti-competitive' solar customer rates

By Jeff Stanfield

SolarCity Corp. filed suit in federal court late March 2, asking for a judicial order to stop Arizona's second-largest electric utility from imposing what the nation's largest solar provider terms an anti-competitive price plan that has made new solar rooftop installations prohibitively expensive for most of the utility's customers.

The Salt River Project's board of directors on Feb. 26 approved a new pricing plan designed to punish customers who choose to go solar, SolarCity contended. Any customers who install solar panels on their properties now have to pay additional demand and distribution charges that other SRP customers do not have to pay, including about 15,000 customers the board "grandfathered" in under old rates for the next 20 years.

"These discriminatory penalties add up to hundreds of dollars per year, and make a competitive rooftop solar business impossible within SRP territory," SolarCity said in a blog posted March 3 on its website.

Alleging an unlawful abuse of monopoly power, SolarCity said SRP has sabotaged the ability of its consumers to choose distributed solar since the unreasonable rates were first proposed to include all customers who install solar systems from Dec. 8, 2014, forward. Applications for distributed solar systems have fallen by 96% in SRP's service territory since that date, said SolarCity, which has more than 7,000 customers in that territory.

In the complaint for antitrust violations, SolarCity accuses SRP of violating federal and state antitrust laws and demands a jury trial, saying SRP is unlawfully seeking to preserve its existing monopoly over retail electric service by adopting punishing prices for new solar customers to eliminate competition from solar providers. SRP wants to keep its customers from generating any of their own power, according to the suit filed in the U.S. District Court for the District of Arizona.

Solar customers still need power from SRP at times when their energy demands exceed what their distributed solar systems produce, so they cannot completely disconnect from the grid and escape SRP's punitive rates, the complaint continues.

Payment of damages from SRP sought

"SRP has designed its price plan to make it irrational for any customer to obtain solar power from a competitor because SRP knows that every customer depends on it for some part of its power demand," SolarCity said in the complaint filed by attorney Richard Pocker of Boies Schiller & Flexner LLP, a national law firm that has won multibillion-dollar settlements in antitrust litigation.

In addition to seeking injunctive relief, SolarCity is seeking monetary damages, including treble damages, and is accusing SRP of damaging SolarCity's customer relationships and causing the company considerable economic harm.

SRP imposed charges for a typical solar customer of about $600 per year, thereby increasing the customer's bill about 65% compared to previous rates, SolarCity said. Those charges include a new distribution charge of either $12.44 or $37.88 per month, depending on whether the customer has service below or above 200 amps.

Also, for the typical solar customer profile provided by SRP, a new demand charge will range from about $30 per month in the winter to around $125 per month in the summer peak months. Customers without distributed solar face no demand charge at all, the complaint said.

In addition, SRP has substantially cut the value of its bill credits to customers who send power to the utility to re-sell to other customers under a net-metering tariff.

For years SRP provided incentives averaging $4,000 per customer to encourage them to buy and lease distributed solar systems, but the new charges will amount to $12,000 more for a 20-year solar amortization period, compared to what existing "grandfathered" solar customers pay under the old rates, SolarCity said.

SRP has not justified the price increases to recoup reasonable grid-related costs from distributed solar customers, but rather to prevent solar companies from competing with the monopoly, the complaint alleged.

Salt River said to favor a powerful few

SRP was set up in 1903 to serve real property owners, especially those with large land holdings. Only real property owners can serve on SRP's board and only real property owners can vote for board members, according to the complaint. Their votes are counted in proportion to their land holdings. A third of SRP's customers are unable to vote because they do not own real estate.

"This structure encourages SRP to serve the private interests of landowners, particularly large landowners who value cheap water, at the expense of a broad base of electric customers," the complaint contended, charging that the utility uses profits from its electricity business to support its water operations.

In its 2014 fiscal year, SRP reported net revenues of $212.1 million and said $62.2 million from electric revenues were used to support water operations.

Because of the voting restrictions, SolarCity asserted that the hundreds of solar-supporting residents who turned out for the rate hearings had little impact on the board, as illustrated by the comments of numerous SRP customers who protested the new rates.

Solar City contended SRP's conduct substantially affects interstate commerce in that it harms competition from SolarCity and other out-of-state companies, as well as new entry from out-of-state competitors. SRP, meanwhile, engages in interstate commerce by purchasing, delivering and selling electricity across state lines. For example, it owns interests in power plants in Colorado and New Mexico.

Until the latest rate proposal and decision, SRP had seen a steep increase in the number of solar systems installed in its territory. The district said the annual installation of residential solar systems increased from 1,344 systems in 2010 to 2,616 systems in 2013 and then jumped to 4,059 systems in 2014, according to a Jan. 14 email from SRP spokeswoman Patricia Likens.

SolarCity said SRP received about 500 distributed-solar applications per month from May through October 2014, but between the time SRP published its proposed rate schedule on Dec. 12, 2014, and Jan. 15, 2015, it received just 20 distributed-solar applications.

A substantial negative impact has been seen on commercial and institutional customers, too. Maricopa Community Colleges officials unanimously agreed on Dec. 9 to have SolarCity install more than 12 MW of capacity across multiple solar installations, but SRP's establishment of the Dec. 8, 2014, retroactive date for its new solar charges sabotaged that agreement, SolarCity contended.

Commercial customers typically will pay a 2% annual penalty and lose net metering altogether if they install distributed solar. As a consequence, it will cost an average commercial customer $24,000 a year in new charges and penalties to install solar. Consequently, SRP has rendered it impossible for commercial, municipal and educational customers to obtain any viable return on new solar equipment, the complaint alleged.

SRP disputes SolarCity's claims

SRP spokesman Scott Harelson said by email on March 3 the utility "firmly rejects" SolarCity's meritless claims the utility's rate process and decision-making were improper and contrary to law.

After an extensive three-month public process in which thousands of individuals and industry organizations provided input, SRP's publicly elected board of directors approved the new price plan that ensures the utility is fairly recovering the costs necessary to continue to maintain and improve the electric grid for all of its customers, including rooftop solar customers, Harelson said.

"In fact, as SRP demonstrated throughout the public price process, the new price structure properly aligns costs and revenues with respect to the distributed generation customers," Harelson said. "SolarCity's lawsuit is without merit and [the price plan] will be aggressively defended. SolarCity's efforts to mischaracterize what the SRP board approved are unfortunate as is its filing of a meritless lawsuit."

SRP is confident its new price plan will be determined to be appropriate and that it will prevail in all such challenges to it, Harelson said.

Meanwhile, SRP will reach out and work with its distributed solar customers to assist them in managing their costs and will help them use new technologies for that purpose, he said.

He quoted SRP General Manager and CEO Mark Bonsall as saying the new price plan ensures fairness in arresting the cost-shift to the utility's 985,000 non-solar customers.

"As a community-based, not-for-profit public power utility, SRP's obligation is to provide low-cost and reliable power to its more than 1 million customers," Bonsall said. "SRP has done so for generations of Arizona citizens and will continue to do so by seeking low-cost alternatives that provide maximum financial and reliability benefits for all of our nearly 1 million customers."

ATTACHMENT 20

City of San Juan Capistrano Agenda Report
(March 17, 2015)

3/17/2015

D7

City of San Juan Capistrano Agenda Report

TO: Karen P. Brust, City Manager

FROM: Charlie View, Development Services Director MM for CV

DATE: March 17, 2015

SUBJECT: Consideration of Authorization to Retain Consulting Services for Reviewing and Assisting the City with Preparing Comments on the Draft Environmental Impact Report for the San Diego Gas and Electric Company's South Orange County Reliability Enhancement Project (SOCRE) and to Appropriate up to $30,000 from the General Fund Reserves

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RECOMMENDATION:

By motion,

1) Authorize the City Manager to execute a contract, as approved to form by the City Attorney, for consulting services for reviewing and assisting the City with preparing comments on the Draft Environmental Impact Report for the South Orange County Reliability Enhancement Project; and,

2) Approve an appropriation based on the approved contract amount for these consulting services, not to exceed $30,000 from General Fund Reserves.

EXECUTIVE SUMMARY:

San Diego Gas & Electric Company (SDG&E) has filed an application with the California Public Utilities Commission (CPUC) for a Certificate of Public Convenience and Necessity (CPCN) to construct the South Orange County Reliability Enhancement Project (SOCRE, proposed project) within the City. The CPUC is the lead agency for review of the proposed project, pursuant to the California Environmental Quality Act (CEQA), and has prepared a Draft Environmental Impact Report (Draft EIR). The proposed project would serve customers within the applicant's South Orange County Service Area. The CPUC has released the Draft EIR for a 45 day public review period that will end on April 10, 2015. This Draft EIR is the primary public disclosure document to inform the community, staff, and the City Council of the impacts of this proposed project. As such, staff is recommending the retention of one or more consultants who have expertise in utility related matters and CEQA to assist with reviewing the Draft EIR and providing the City with the recommendations on preparing comments on the Draft EIR and the technical reports associated with it. As time is limited, staff is requesting an appropriation not to exceed $30,000 to provide the funding necessary to retain the appropriate consultant team. Staff distributed a Request For Proposals for the service and received several proposals on March 6, 2015. Given the complexity of the project, staff is continuing to work with the consultant teams to define the scope of work and final cost. The consultant team is expected to be selected by the end of the week following City Council action.

The City has participated in previous activities addressing the SOCRE project including reviewing and commenting on the Notice of Public Convenience and Necessity (CPCN), the Notice of Preparation for the Draft EIR and attending the Public Scoping meeting held at the Community Center on January 23, 2013.

In recognition of the scope of the proposed project and the importance of preparing a comprehensive review of the Draft EIR, the City Council directed staff to request the CPUC extend the public review period for the Draft EIR to a minimum of ninety (90) days from the release date of February 23, 2015. In recognition of our long standing partnership with Capistrano Unified School District, we have communicated our concerns regarding the proposed project and informed them of this request for an extension of the public review period. The response from the CPUC is pending. If this request is approved, the review period could be extended until May 24, 2015.

FISCAL IMPACT:

As of the Second Quarter Financial Report (presented to City Council on February 17, 2015), the City's General Fund Reserves (contingency reserve and available reserve) are projected to be $11.81 million (50.4%) by June 30, 2015. Staff is recommending the City Council approve an appropriation from General Fund Reserves not to exceed $30,000 to fund these consulting services. If approved, the General Fund reserves are projected to be $11.78 million (50.3%) by June 30, 2015.

ENVIRONMENTAL IMPACT:

The appropriation of funds for environmental consulting services is not considered a project and therefore not subject to review under the California Environmental Quality Act (CEQA).

PRIOR CITY COUNCIL REVIEW:

- On February 21, 2012, the Mayor appointed an "Aesthetics and Mitigation Subcomittee" to address design concerns pertaining to the SDG&E substation, perimeter wall, and landscaping. The subcommittee has met with SDG&E several times and most recently on July 29, 2014.

- On April 18, 2012, the City forwarded a letter to SDG&E along with a City Council resolution passed by the City Council on February 21, 2012, opposing negative impacts of the proposed project, unless fully mitigated.
- On June 19, 2012, the City forwarded a letter to the CPUC Administrative Law Judge, Darwin Farrar opposing the CPCN and requesting public meetings in San Juan Capistrano.
- On February 5, 2013 the City Council provided staff direction regarding comments addressing the Notice of Preparation for the Draft EIR.
- On March 3, 2015 the City Council authorized a Support Letter to the State of California's Office of Historic Preservation Nominating the San Diego Gas and Electric Company Building to the National Register of Historic Places.

NOTIFICATION:

A notification list is attached to this report.

ATTACHMENTS:

Attachment 1- Request for Proposal
Attachment 2- Notification List

CITY OF SAN JUAN CAPISTRANO

REQUEST FOR PROPOSALS FOR PEER REVIEW OF DRAFT ENVIRONMENTAL IMPACT REPORT FOR THE SAN DIEGO GAS AND ELECTRIC COMPANY SOUTH ORANGE COUNTY RELIABILITY ENHANCEMENT PROJECT (SOCRE) (SCH NO. 2013011011)

SUBMIT OR E-MAIL YOUR PROPOSAL BY 4:00 PM ON FRIDAY, MARCH 6 2015 TO:

City of San Juan Capistrano
Attn: Charlie View, Development Services Director
Development Services Department
32400 Paseo Adelanto
San Juan Capistrano, California 92675
cview@sanjuancapistrano.org
(949) 234-4410

---

1. INTRODUCTION

The City of San Juan Capistrano is soliciting proposals for the preparation of a peer review of the DRAFT EIR prepared by *ecology and environment, inc.* on behalf of the California Public Utilities Commission (CPUC) for the proposed expansion and reconfiguration of SDG&E infrastructure serving Southern Orange County (State Clearinghouse Number 2013011011). The City is seeking proposals from qualified CEQA experts to assist in the City's review and comment on the adequacy of the DRAFT EIR for the project. This project as proposed represents a significant alternation to the environment of San Juan Capistrano and as such the City is committed to insuring the EIR fulfills the purposes of CEQA. Due to limited staff availability, the City seeks the services of a proven expert in the preparation and review of Environmental Impact Reports to provide consultation and prepare draft comments on the DRAFT EIR document. Outlined below are requirements to be considered in preparing a responsive proposal.

The DRAFT EIR document is available on-line through the California Public Utilities Commission (CPUC) at http://tinyurl.com/clsee4q

2. SCOPE OF WORK

1. Review of the document for compliance with applicable laws, regulations and CEQA guidelines.

2. Review of the project description for consistency with the project's stated purpose.

3. Topic specific review of areas identified as Less than Significant Impact, including; Aesthetics, Cultural Resources, Hazards, Land Use and Planning, Noise, Recreation.

4. Review of areas identified as significant impact: Air Quality, Transportation and Traffic, Cumulative Impacts.

5. Review of project alternatives with focus on the viability of the Environmentally Superior Alternatives.

6. Preparation of draft comments on the DRAFT EIR for incorporation in a City prepared comment document. Draft comments to be provided in digital files in a format specified by the City.

7. Tasks not identified above that in the judgment of the consultant would assist in the stated purpose of the RFP.

3. PROPOSAL REQUIREMENTS

Consultant proposals will include a transmittal letter incorporating a statement of understanding of the scope of the project, the general methodology/approach to be used, a description of the firm's background and experience. The Proposal shall be signed by an individual authorized to bind the consultant and shall contain a statement that the proposal is valid for at least a 90-calendar day period. The proposal will also include the following:

3.1 A proposed scope-of-work (SOW), consistent with the City's S-O-W requirements, including a description of the specific work tasks that will be completed and work products that will be produced.

3.2 A list of similar projects completed by the project manager and key staff to be used on this project.

3.3 One-page resume of the project manager highlighting that individual's relevant experience, skills, and education.

3.4 Project Schedule.

3.5 Total project budget and not-to-exceed cost including a tabular breakdown of all costs by position, hourly rate, task, hours budgeted for each task as well as any reimbursable costs (i.e. travel, meeting attendance, copying, etc.). The proposed budget may include optional tasks/budget items which in the judgment of the consultant would assist in the review and comment on the adequacy and accuracy of the DRAFT EIR for the project.

4. PROPOSAL SUBMISSION

Interested firms or persons should submit their proposal in pdf format (600 dpi resolution, color or black & white) by e-mail to cview@sanjuancapistrano.org in the Development Services Department, City of San Juan Capistrano by the time and date indicated on the coversheet of this RFP.

5. SELECTION PROCESS

A selection committee composed of City staff will review the proposals pursuant to City Council Consultant Selection Policy with particular emphasis on the following factors consistent with the City's adopted Purchasing Policies and Procedures to select the most qualified consultant:

5.1 A proposed scope-of-work (SOW) including a description of the specific work tasks that will be completed and work products that will be produced.

5.2 Completeness of proposal.

5.3 Firm's experience and resources.

5.4 Professional qualifications of key personnel.

After evaluation of the proposal, and subsequent interviews if needed, the City will select the most qualified consultant with whom to negotiate an agreement to provide the consulting services through the completion of the Project.

The City reserves the right to reject any or all proposals, to waive any informality or irregularity in any proposal received, and to be the sole judge of the merits of the respective proposals received.

6. AGREEMENT / INSURANCE REQUIREMENTS

The consultant selected for the study will be required to execute a standard City of San Juan Capistrano Personal Services Agreement (Attachment 1). Proposals will include a statement that the submitting firm/person is amenable to all provisions in the City's standard agreement. If a proposing firm/person takes exception to any of the terms in the Personal Services Agreement, the firm/person must notify the City of their specific issue(s) as soon as possible and determine whether the provision may be modified. Insurance and indemnification requirements are not negotiable.

7. CITY'S RIGHTS

The City may investigate the qualifications of any proposer under consideration, require confirmation of information furnished by a proposer, and require additional evidence of qualifications to perform the services described herein. The CITY reserves the right to:

7.1 Reject any or all of the proposals and issue a subsequent Request for Proposals.

7.2 Cancel the entire Request for Proposal.

7.3 Remedy technical errors in the Request for Proposal process.

7.4 Appoint an evaluation committee to review proposals.

7.5 Seek the assistance of outside technical experts in proposal evaluation.

7.6 Approve or disapprove the use of particular subcontractors.

7.7 Award a contract to one or more proposers.

7.8 Waive non-substantive errors or irregularities in proposals.

This RFP in no way commits the City to enter into a contract, nor does it obligate the City to pay for any costs incurred in the preparation and submission of proposals or in anticipation of a contract.

8. PUBLIC RECORDS ACT

Responses to this RFP become the exclusive property of the City and subject to the California Public Records Act. Those elements in each proposal which are trade secrets as that term is defined in Civil Code section 3426.1(d) or otherwise exempt by law from disclosure and which are prominently marked as "TRADE SECRET", "CONFIDENTIAL", or "PROPRIETARY" may not be subject to disclosure. The City shall not in any way be liable or responsible for the disclosure of any such records including, without limitation, those so marked if disclosure is deemed to be required by law or by an order of the Court. Proposers which indiscriminately identify all or most of their proposal as exempt from disclosure without justification may be deemed non-responsive.

In the event the City is required to defend an action on a Public Records Act request for any of the contents of a proposal marked "confidential", "proprietary", or "trade secret", the proposer agrees, upon submission of its proposal for City's consideration, to defend and indemnify the City from all costs and expenses, including attorneys' fees, in any action or liability arising under the Public Records Act.

9. QUESTIONS

Questions regarding this RFP should be sent in writing to David Contreras, Senior Planner via e-mail to: cview@sanjuancapistrano.org. Questions concerning information already contained in the RFP will be answered in writing and provided to all firms who have been sent the RFP or have advised the City's project manager that they are preparing a proposal. Questions requiring clarification or additional information may be addressed in an addendum to this RFP. All City correspondence involving questions and answers related to this RFP, will be provided to all other known proposers.

Attachments:

1- Standard City Personal Services Agreement (PSA)

PERSONAL SERVICES AGREEMENT

THIS AGREEMENT is made, entered into, and shall become effective this ____ day of _____, 2013, by and between the City of San Juan Capistrano (hereinafter referred to as the "City") and _______________ (hereinafter referred to as the "Consultant").

RECITALS:

WHEREAS, City desires to retain the services of Consultant regarding the City's proposal to____; and

WHEREAS, Consultant is qualified by virtue of experience, training, education and expertise to accomplish such services.

NOW, THEREFORE, City and Consultant mutually agree as follows:

Section 1. Scope of Work.

The scope of work to be performed by the Consultant shall consist of those tasks as set forth in Exhibit "A," attached and incorporated herein by reference. To the extent that there are any conflicts between the provisions described in Exhibit "A" and those provisions contained within this Agreement, the provisions in this Agreement shall control.

Section 2. Term.

[OPTION 1: ONGOING SERVICES, NO END DATE] This Agreement shall commence on the effective date of this Agreement and services required hereunder shall continue until notified that said services are no longer required, subject to 15 days notice of termination.

[OPTION2: SPECIFIC TERM] This Agreement shall commence on the effective date and shall terminate, and all services required hereunder shall be completed, no later than _________.

Section 3. Compensation.

3.1 Amount.

Total compensation for the services hereunder shall not exceed $_____ [either, total contract amount, or amount per month or per fiscal year; also specify whether the total compensation includes expenses, etc.], [as set forth in Exhibit "B," attached and incorporated herein by reference [if Consultant provides a cost proposal or rate schedule]].

3.2 Method of Payment.

Subject to Section 3.1, Consultant shall submit monthly invoices based on total services which have been satisfactorily completed for such monthly period. The City will pay monthly progress payments based on approved invoices in accordance with this Section.

3.3 Records of Expenses.

Consultant shall keep complete and accurate records of all costs and expenses incidental to services covered by this Agreement. These records will be made available at reasonable times to the City. Invoices shall be addressed as provided for in Section 16 below.

Section 4. Independent Contractor.

It is agreed that Consultant shall act and be an independent contractor and not an agent or employee of the City, and shall obtain no rights to any benefits which accrue to Agency's employees.

Section 5. Limitations Upon Subcontracting and Assignment.

The experience, knowledge, capability and reputation of Consultant, its principals and employees were a substantial inducement for the City to enter into this Agreement. Consultant shall not contract with any other entity to perform the services required without written approval of the City. This Agreement may not be assigned, voluntarily or by operation of law, without the prior written approval of the City. If Consultant is permitted to subcontract any part of this Agreement by City, Consultant shall be responsible to the City for the acts and omissions of its subcontractor as it is for persons directly employed. Nothing contained in this Agreement shall create any contractual relationships between any subcontractor and City. All persons engaged in the work will be considered employees of Consultant. City will deal directly with and will make all payments to Consultant.

Section 6. Changes to Scope of Work.

For extra work not part of this Agreement, a written authorization from City is required prior to Consultant undertaking any extra work. In the event of a change in the Scope of Work provided for in the contract documents as requested by the City, the Parties hereto shall execute an addendum to this Agreement setting forth with particularity all terms of the new agreement, including but not limited to any additional Consultant's fees.

Section 7. Familiarity with Work and/or Construction Site.

By executing this Agreement, Consultant warrants that: (1) it has investigated the work to be performed; (2) if applicable, it has investigated the work site(s), and is aware of all conditions there; and (3) it understands the facilities, difficulties and restrictions of the work to be performed under this Agreement. Should Consultant discover any latent or unknown conditions materially differing from those inherent in the work or as represented by City, it shall immediately inform the City of this and shall not proceed with further work under this Agreement until written instructions are received from the City.

Section 8. Time of Essence.

Time is of the essence in the performance of this Agreement.

Section 9. Compliance with Law.

Consultant shall comply with all applicable laws, ordinances, codes and regulations of federal, state and local government.

Section 10. Conflicts of Interest.

Consultant covenants that it presently has no interest and shall not acquire any interest, direct or indirect, which would conflict in any manner or degree with the performance of the services contemplated by this Agreement. No person having such interest shall be employed by or associated with Consultant.

Section 11. Copies of Work Product.

At the completion of the work, Consultant shall have delivered to City at least one (1) copy of any final reports and/or notes or drawings containing Consultant's findings, conclusions, and recommendations with any supporting documentation. All reports submitted to the City shall be in reproducible format, or in the format otherwise approved by the City in writing.

Section 12. Ownership of Documents.

All reports, information, data and exhibits prepared or assembled by Consultant in connection with the performance of its services pursuant to this Agreement are confidential to the extent permitted by law, and Consultant agrees that they shall not be made available to any individual or organization without prior written consent of the City. All such reports, information, data, and exhibits shall be the property of the City and shall be delivered to the City upon demand without additional costs or expense to the City. The City acknowledges such documents are instruments of Consultant's professional services.

Section 13. Indemnity.

To the fullest extent permitted by law, Consultant agrees to protect, defend, and hold harmless the City and its elective and appointive boards, officers, agents, and employees from any and all claims, liabilities, expenses, or damages of any nature, including attorneys' fees, for injury or death of any person, or damages of any nature, including interference with use of property, arising out of, or in any way connected with the negligence, recklessness and/or intentional wrongful conduct of Consultant, Consultant's agents, officers, employees, subcontractors, or independent contractors hired by Consultant in the performance of the Agreement. The only exception to Consultant's responsibility to protect, defend, and hold harmless the City, is due to the negligence, recklessness and/or wrongful conduct of the City, or any of its elective or appointive boards, officers, agents, or employees.

This hold harmless agreement shall apply to all liability regardless of whether any insurance policies are applicable. The policy limits do not act as a limitation upon the amount of indemnification to be provided by Consultant.

Section 14. Insurance.

On or before beginning any of the services or work called for by any term of this Agreement, Consultant, at its own cost and expense, shall carry, maintain for the duration of the agreement, and provide proof thereof that is acceptable to the City, the insurance specified below with insurers and under forms of insurance satisfactory in all respects to the City. Consultant shall not allow any subcontractor to commence work on any subcontract until all insurance required of the Consultant has also been obtained for the subcontractor. Insurance required herein shall be provided by Insurers in good standing with the State of California and having a minimum Best's Guide Rating of A- Class VII or better.

14.1 Comprehensive General Liability.

Throughout the term of this Agreement, Consultant shall maintain in full force and effect Comprehensive General Liability coverage in an amount not less than one million dollars per occurrence ($1,000,000.00), combined single limit coverage for risks associated with the work contemplated by this agreement. If a Commercial General Liability Insurance form or other form with a general aggregate limit is used, either the general aggregate limit shall apply separately to the work to be performed under this agreement or the general aggregate limit shall be at least twice the required occurrence limit.

14.2 Comprehensive Automobile Liability.

Throughout the term of this Agreement, Consultant shall maintain in full force and effect Comprehensive Automobile Liability coverage, including owned, hired and non-owned vehicles in an amount not less than one million dollars per occurrence ($1,000,000.00).

14.3 Workers' Compensation.

If Consultant intends to employ employees to perform services under this Agreement, Consultant shall obtain and maintain, during the term of this Agreement, Workers' Compensation Employer's Liability Insurance in the statutory amount as required by state law.

14.4 Proof of Insurance Requirements/Endorsement.

Prior to beginning any work under this Agreement, Consultant shall submit the insurance certificates, including the deductible or self-retention amount, and an additional insured endorsement naming City, its officers, employees, agents, and volunteers as additional insured as respects each of the following: Liability arising out of activities performed by or on behalf of Consultant, including the insured's general supervision of Consultant; products and completed operations of Consultant; premises owned, occupied or used by Consultant; or automobiles owned, leased, hired, or borrowed by Consultant. The coverage shall contain no special limitations on the scope of protection afforded City, its officers, employees, agents, or volunteers.

14.5 Errors and Omissions Coverage [FOR PROFESSIONS/WORK EXCLUDED FROM GENERAL LIABILITY]

Throughout the term of this Agreement, Consultant shall maintain Errors and Omissions Coverage (professional liability coverage) in an amount of not less than One Million Dollars ($1,000,000). Prior to beginning any work under this Agreement, Consultant shall submit an insurance certificate to the City's General Counsel for certification that the insurance requirements of this Agreement have been satisfied.

14.6 Notice of Cancellation/Termination of Insurance.

The above policy/policies shall not terminate, nor shall they be cancelled, nor the coverages reduced, until after thirty (30) days' written notice is given to City, except that ten (10) days' notice shall be given if there is a cancellation due to failure to pay a premium.

14.7 Terms of Compensation.

Consultant shall not receive any compensation until all insurance provisions have been satisfied.

14.8 Notice to Proceed.

Consultant shall not proceed with any work under this Agreement until the City has issued a written "Notice to Proceed" verifying that Consultant has complied with all insurance requirements of this Agreement.

Section 15. Termination.

City shall have the right to terminate this Agreement without cause by giving thirty (30) days' advance written notice of termination to Consultant.

In addition, this Agreement may be terminated by any party for cause by providing ten (10) days' notice to the other party of a material breach of contract. If the other party does not cure the breach of contract, then the agreement may be terminated subsequent to the ten (10) day cure period.

Section 16. Notice.

All notices shall be personally delivered or mailed to the below listed addresses, or to such other addresses as may be designated by written notice. These addresses shall be used for delivery of service of process:

To City: City of San Juan Capistrano
32400 Paseo Adelanto
San Juan Capistrano, CA 92675
Attn:______________________________

To Consultant: ______________________________
____
____

Section 17. Attorneys' Fees.

If any action at law or in equity is necessary to enforce or interpret the terms of this Agreement, the prevailing party shall be entitled to reasonable attorneys' fees, costs and necessary disbursements in addition to any other relief to which he may be entitled.

Section 18. Dispute Resolution.

In the event of a dispute arising between the parties regarding performance or interpretation of this Agreement, the dispute shall be resolved by binding arbitration under the auspices of the Judicial Arbitration and Mediation Service ("JAMS").

Section 19. Entire Agreement.

This Agreement constitutes the entire understanding and agreement between the parties and supersedes all previous negotiations between them pertaining to the subject matter thereof.

Section 20. Counterparts and Facsimile signatures.

This Agreement may be executed by the Parties in counterparts, which counterparts shall be construed together and have the same effect as if all the Parties had executed the same instrument. Counterpart signatures may be transmitted by facsimile, email, or other electronic means and have the same force and effect as if they were original signatures.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the parties hereto have executed this Agreement.

CITY OF SAN JUAN CAPISTRANO

By: ______________________________
Karen P. Brust, City Manager

CONSULTANT

By: ______________________________

ATTEST:

____
Maria Morris, City Clerk

APPROVED AS TO FORM:

____
Hans Van Ligten, City Attorney

Notification List

Bonny O'Connor	Ecology and Environment, Inc.
Capistrano Unified School District	
Clint Worthington	
Colleen Lynn Edwards	
Dana Van Slyke	
Duane Cave	SDG&E
Helen Reardon	
Heritage Tourist Association	
Ian and Deborah Smith	
Jim Leach	South Orange County Regional Economic Coalition
John Whitman	South Orange County Regional Economic Coalition
Kathleen Peterson	
Kim Lefner	
Luara Freese	
Mark Bodenhamer	Chamber of Commerce
Mechelle Lawrence Adams	Mission San Juan Capistrano
Reed Royalty	
Rhen Kohan	
Robert Cardoza	
Robert Williams	
Roger Hogan	Capistrano Toyota
Roy and Ilse Byrnes	

ATTACHMENT 2

ATTACHMENT 21

"Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States", Lawrence Berkeley National Laboratory, January 2015

Attachment 21

Updated 2015 Outage Cost Estimation Report

Reimagine tomorrow.

Ernest Orlando Lawrence
Berkeley National Laboratory

Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States

Principal Authors
Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell
Nexant, Inc.

January 2015

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Disclaimer

Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States

Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell
Nexant, Inc.
101 Montgomery Street, 15th Floor
San Francisco, CA

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Acknowledgments

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The authors thank Joseph Paladino of the DOE Office of Electricity Delivery and Energy Reliability, and Joseph H. Eto of the Lawrence Berkeley National Laboratory for support and guidance in the development of this research. We would also like to thank Emily Fisher, Gary Fauth, Peter Larsen, Kristina Hamachi-LaCommare, Peter Cappers, and Julia Frayer for their careful reviews and comments on the earlier drafts of this report. Their comments were extremely thoughtful and useful.

Abstract

This report updates the 2009 meta-analysis that provides estimates of the value of service reliability for electricity customers in the United States (U.S.). The meta-dataset now includes 34 different datasets from surveys fielded by 10 different utility companies between 1989 and 2012. Because these studies used nearly identical interruption cost estimation or willingness-to-pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers. This report focuses on the backwards stepwise selection process that was used to develop the final revised model for all customer classes. Across customer classes, the revised customer interruption cost model has improved significantly because it incorporates more data and does not include the many extraneous variables that were in the original specification from the 2009 meta-analysis. The backwards stepwise selection process led to a more parsimonious model that only included key variables, while still achieving comparable out-of-sample predictive performance. In turn, users of interruption cost estimation tools such as the Interruption Cost Estimate (ICE) Calculator will have less customer characteristics information to provide and the associated inputs page will be far less cumbersome. The upcoming new version of the ICE Calculator is anticipated to be released in 2015.

Table of Contents

List of Figures and Tables

Acronyms and Abbreviations

AIC	Akaike's Information Criterion
C&I	Commercial and Industrial
GLM	Generalized Linear Model
ICE	Interruption Cost Estimate
MAE	Mean Absolute Error
OLS	Ordinary Least Squares
RMSE	Root Mean Square Error

Executive Summary

In 2009, Freeman, Sullivan & Co. (now Nexant) conducted a meta-analysis that provided estimates of the value of service reliability for electricity customers in the United States (U.S.). These estimates were obtained by analyzing the results from 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005. Because these studies used nearly identical interruption cost estimation or willingness-to-pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. The meta-analysis and its associated econometric models were summarized in a report entitled "Estimated Value of Service Reliability for Electric Utility Customers in the United States,"[1] which was prepared for Lawrence Berkeley National Laboratory (LBNL) and the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy (DOE). The econometric models were subsequently integrated into the Interruption Cost Estimate (ICE) Calculator (available at icecalculator.com), which is an online tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements (also funded by LBNL and DOE).

Since the report was finalized in June 2009 and the ICE Calculator was released in July 2011, Nexant, LBNL, DOE, and ICE Calculator users have identified several ways to improve the interruption cost estimates and the ICE Calculator user experience. These improvements include:

- Incorporating more recent utility interruption cost studies;
- Enabling the ICE Calculator to provide estimates for power interruptions lasting longer than eight hours;
- Reducing the amount of detailed customer characteristics information that ICE Calculator users must provide;
- Subjecting the econometric model selection process to rigorous cross-validation techniques, using the most recent model validation methods;[2] and
- Providing a batch processing feature that allows the user to save results and modify inputs.

These improvements will be addressed through this updated report and the upcoming new version of the ICE Calculator, which is anticipated to be released in 2015. This report provides updated value of service reliability estimates and details the revised econometric model, which is based on a meta-analysis that includes two new interruption cost studies. The upcoming new version of the ICE Calculator will incorporate the revised econometric model and include a batch processing feature that will allow the user to save results and modify inputs.

---

[1] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[2] For a discussion of these methods, see: Varian, Hal R. "Big Data: New Tricks for Econometrics." *Journal of Economic Perspectives*. Volume 28, Number 2. Spring 2014. Pages 3–28. Available here: http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.28.2.3

Updated Interruption Cost Estimates

For each customer class, Table ES-1 provides the three key metrics that are most useful for planning purposes. These metrics are:

- Cost per event (cost for an individual interruption for a typical customer[3]);
- Cost per average kW (cost per event normalized by average demand); and
- Cost per unserved kWh (cost per event normalized by the expected amount of unserved kWh for each interruption duration).

Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

In general, even though the econometric model has been considerably simplified, it produces similar estimates to those of the 2009 model. As in the 2009 study, medium and large C&I customers have the highest interruption costs, but when normalized by average kW, interruption costs are highest in the small C&I customer class. On both an absolute and normalized basis, residential customers experience the lowest costs as a result of a power interruption.

Table ES-1: Estimated Interruption Cost per Event, Average kW and Unserved kWh (U.S.2013$) by Duration and Customer Class

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Table ES-2 shows how customer interruption costs vary by season and time of day, based on the key drivers of interruption costs that were identified in the model selection process. For medium and large C&I customers, interruption costs only meaningfully vary by season (summer vs. non-summer). For medium and large C&I customers, the cost of a summer power interruption is

[3] The interruption costs in Table ES- 1 are for the average-sized customer in the meta-database. The average annual kWh usages for the respondents in the meta-database are 7,140,501 kWh for medium and large C&I customers, 19,214 kWh for small C&I customers and 13,351 kWh for residential customers.

around 21% to 43% higher than a non-summer one, depending on duration (the percent difference lowers as duration increases). For small C&I customers, the seasonal pattern is the opposite, with the cost of summer power interruptions lower by around 9% to 30%, depending on duration, season, and time of day. Small C&I interruption costs also vary by time of day, with the highest costs in the afternoon and morning. In the evening and nighttime, small C&I interruption costs are substantially lower, which makes sense given that small businesses typically operate during daytime hours. For residential customers, interruption costs are generally higher during the summer and in the morning and night (10 PM to 12 noon). The table also includes a weighted-average interruption cost estimate (equal to the cost per event estimates in Table ES-1), which is weighted by the proportion of hours of the year that each interruption scenario represents, depending on season and time of day. This weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season and time of day is known and accounted for in the analysis.

Table ES-2: Estimated Customer Interruption Costs (U.S.2013$) by Duration, Timing of Interruption and Customer Class

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I							
Summer	33%	$16,172	$18,861	$21,850	$46,546	$96,252	$186,983
Non-summer	67%	$11,342	$13,431	$15,781	$35,915	$77,998	$154,731
Weighted Average		*$12,952*	*$15,241*	*$17,804*	*$39,458*	*$84,083*	*$165,482*
Small C&I							
Summer Morning	8%	$461	$569	$692	$1,798	$4,073	$7,409
Summer Afternoon	7%	$527	$645	$780	$1,954	$4,313	$7,737
Summer Evening/Night	18%	$272	$349	$440	$1,357	$3,518	$6,916
Non-summer Morning	17%	$549	$687	$848	$2,350	$5,592	$10,452
Non-summer Afternoon	14%	$640	$794	$972	$2,590	$5,980	$10,992
Non-summer Evening/Night	36%	$298	$388	$497	$1,656	$4,577	$9,367
Weighted Average		*$412*	*$520*	*$647*	*$1,880*	*$4,690*	*$9,055*
Residential							
Summer Morning/Night	19%	$6.8	$7.5	$8.4	$14.3	$24.0	$42.4
Summer Afternoon	7%	$4.3	$4.9	$5.5	$9.8	$17.1	$31.1
Summer Evening	7%	$3.5	$4.0	$4.6	$9.2	$17.5	$34.1
Non-summer Morning/Night	39%	$3.9	$4.5	$5.1	$9.8	$17.8	$33.5
Non-summer Afternoon	14%	$2.3	$2.7	$3.1	$6.2	$12.1	$23.7
Non-summer Evening	14%	$1.5	$1.8	$2.2	$5.0	$10.8	$23.6
Weighted Average		*$3.9*	*$4.5*	*$5.1*	*$9.5*	*$17.2*	*$32.4*

Study Limitations

As in the 2009 study, there are limitations to how the data from this meta-analysis should be used. It is important to fully understand these limitations, so they are further described in this section and in more detail in Section 6. These limitations are:

- Certain very important variables in the data are confounded among the studies we examined. In particular, region of the country and year of the study are correlated in such a way that it is impossible to separate the effects of these two variables on customer interruption costs;
- There is further correlation between regions and scenario characteristics. The sponsors of the interruption cost studies were generally interested in measuring interruption costs for conditions that were important for planning their specific systems. As a result, interruption conditions described in the surveys for a given region tended to focus on periods of time when interruptions were more problematic for that region;
- A further limitation of our research is that the surveys that formed the basis of the studies we examined were limited to certain parts of the country. No data were available from the northeast/mid-Atlantic region, and limited data were available for cities along the Great Lakes;
- Another caveat is that around half of the data from the meta-database is from surveys that are 15 or more years old. Although the intertemporal analysis in the 2009 study showed that interruption costs have not changed significantly over time, the outdated vintage of the data presents concerns that, in addition to the limitations above, underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method; and
- Finally, although the revised model is able to estimate costs for interruptions lasting longer than eight hours, it is important to note that the estimates in this report are not appropriate for resiliency planning. This meta-study focuses on the direct costs that customers experience as a result of relatively short power interruptions of up to 24 hours at most. For resiliency considerations that involve planning for long duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered.[4] These factors are not captured in this meta-analysis.

[4] For a detailed study and literature review on estimating the costs associated with long duration power interruptions lasting 24 hours to 7 weeks, see: Sullivan, Michael and Schellenberg, Josh. *Downtown San Francisco Long Duration Outage Cost Study*. March 27, 2013. Prepared for Pacific Gas & Electric Company.

1. Introduction

In 2009, Freeman, Sullivan & Co. (now Nexant) conducted a meta-analysis that provided estimates of the value of service reliability for electricity customers in the United States (U.S.). These estimates were obtained by analyzing the results from 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005. Because these studies used nearly identical interruption cost estimation or willingness-to-pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers. The meta-analysis and its associated econometric models were summarized in a report entitled "Estimated Value of Service Reliability for Electric Utility Customers in the United States,"[5] which was prepared for Lawrence Berkeley National Laboratory (LBNL) and the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy (DOE). The econometric models were subsequently integrated into the Interruption Cost Estimate (ICE) Calculator (available at icecalculator.com), which is an online tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements (also funded by LBNL and DOE).

Since the report was finalized in June 2009 and the ICE Calculator was released in July 2011, Nexant, LBNL, DOE, and ICE Calculator users have identified several ways to improve the interruption cost estimates and the ICE Calculator user experience. These improvements include:

- Incorporating more recent utility interruption cost studies;
- Enabling the ICE Calculator to provide estimates for power interruptions lasting longer than eight hours;
- Reducing the amount of detailed customer characteristics information that ICE Calculator users must provide;
- Subjecting the econometric model selection process to rigorous cross-validation techniques, using the most recent model validation methods;[6] and
- Providing a batch processing feature that allows the user to save results and modify inputs.

These improvements will be addressed through this updated report and the upcoming new version of the ICE Calculator, which is anticipated to be released in 2015. This report provides updated value of service reliability estimates and details the revised econometric model, which is based on a meta-analysis that includes two new interruption cost studies. The upcoming new

[5] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[6] For a discussion of these methods, see: Varian, Hal R. "Big Data: New Tricks for Econometrics." *Journal of Economic Perspectives*. Volume 28, Number 2. Spring 2014. Pages 3–28. Available here: http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.28.2.3

version of the ICE Calculator will incorporate the revised econometric model and include a batch processing feature that will allow the user to save results and modify inputs.

1.1 Recent Interruption Cost Studies

Since conducting the meta-analysis in 2009, there have been two large interruption cost surveys in the U.S., one in the southeast and another in the west. The 2011 study in the southeast involved a systemwide interruption cost survey of over 3,300 residential and small/medium business customers and nearly 100 in-person interviews of large business customers. The 2012 study in the west involved a systemwide interruption cost survey of nearly 2,700 residential and small/medium business customers and 210 in-person interviews of large business customers. Although the basic survey methodology is similar to previous work, the 2012 interruption cost study in the west featured several noteworthy methodological improvements. In particular, a dynamic survey instrument design for that study produced interruption cost estimates from 5 minutes to 24 hours, for weekdays and weekends and across many different times of the day (morning, afternoon, evening and night). As such, incorporating the 2012 data and re-estimating the underlying econometric models will enable the ICE Calculator to estimate costs for interruptions lasting longer than 8 hours, which will address one of the improvements above.

Table 1-1 provides an updated inventory of interruption cost studies that are included in the meta-dataset. The number of observations for each study is provided along with the minimum and maximum duration of power interruption scenarios in each study. Altogether, the meta-dataset now includes 34 different datasets from surveys fielded by 10 different utility companies between 1989 and 2012, totaling over 105,000 observations.[7] Some of the utilities surveyed all three customer types – medium and large commercial and industrial (C&I), small C&I, and residential – while others did not. In some cases there was only one dataset for C&I customers, in which case they were sorted into medium and large C&I or small C&I according to electricity usage. The split between small C&I and medium/large C&I is at 50,000 annual kWh. In total, the meta-dataset includes 44,328 observations for medium and large C&I customers, 27,751 observations for small C&I customers and 34,212 observations for residential customers. Each observation corresponds to a response for a single power interruption scenario. The surveys usually included four to six power interruption scenarios.

Table 1-1: Updated Inventory of Interruption Cost Studies in the Meta-dataset

Utility Company	Survey Year	Number of Observations			Min. Duration (Hours)	Max. Duration (hours)
		Medium and Large C&I	Small C&I	Residential		
Southeast-1	1997	90			0	1
Southeast-2	1993	3,926	1,559	3,107	0	4
	1997	3,055	2,787	3,608	0	12
Southeast-3	1990	2,095	765		0.5	4

[7] To the knowledge of the authors, this dataset includes nearly all large power interruption cost studies that have been conducted in the US. Some studies may not have been included for data confidentiality reasons.

Utility Company	Survey Year	Number of Observations			Min. Duration (Hours)	Max. Duration (hours)
		Medium and Large C&I	Small C&I	Residential		
	2011	7,941	2,480	3,969	1	8
Midwest-1	2002	3,171			0	8
Midwest-2	1996	1,956	206		0	4
West-1	2000	2,379	3,236	3,137	1	8
West-2	1989	2,025	5		0	4
	1993	1,790	825	2,005	0	4
	2005	3,052	3,223	4,257	0	8
	2012	5,342	4,632	4,106	0	24
Southwest	2000	3,991	2,247	3,598	0	4
Northwest-1	1989	2,210		2,126	0.25	8
Northwest-2	1999	7,091		4,299	0	12

= Recently incorporated data

Prior to adding the 2012 West-2 survey, the meta-dataset included power interruption scenarios with durations of up to 12 hours. However, the 2009 model for each customer class estimated interruption costs that reached a maximum at 8 hours, and then the estimated interruption costs would decrease, which indicated that the prior model clearly did not provide reliable predictions beyond 8 hours (i.e., it is unreasonable that a 9-hour power interruption would cost less than an 8-hour one). As discussed in Sections 3 through 5, for interruptions from 8 to 16 hours, the new model produces estimates that are more reasonable and show gradually increasing costs up to 16 hours. This improvement in model performance is attributed to the addition of the 24-hour interruption scenarios (2012 West-2) and to the much simpler model specification that resulted from the rigorous selection process.

Although the revised model is able to estimate costs for interruptions lasting longer than 8 hours, it is important to note that the estimates in this report are not appropriate for resiliency planning. This meta-study focuses on the direct costs that customers experience as a result of relatively short power interruptions of up to 24 hours at most. In fact, the final models and results that are presented in Sections 3 through 5 truncate the estimates at 16 hours, due to the relatively few number of observations beyond 12 hours (scenarios of more than 12 hours account for around 2% to 3% of observations for all customer classes). For resiliency considerations that involve planning for long duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered.[8] These factors are not captured in this meta-analysis.

[8] For a detailed study and literature review on estimating the costs associated with long duration power interruptions lasting 24 hours to 7 weeks, see: Sullivan, Michael and Schellenberg, Josh. *Downtown San Francisco Long Duration Outage Cost Study*. March 27, 2013. Prepared for Pacific Gas & Electric Company.

As discussed in Section 6, another caveat is that this meta-analysis may not accurately reflect current interruption costs, given that around half of the data in the meta-database is from surveys that are 15 or more years old. To address this issue, the 2009 study included an intertemporal analysis, which suggested that interruption costs did not change significantly throughout the 1990s and early 2000s. However, during the past decade in particular, technology trends may have led to an increase in interruption costs. For example, home and business life has become increasingly reliant on data centers and “cloud” computing, which may have led to an increase in interruption costs for both producers and consumers of these services. Therefore, the outdated vintage of the data presents concerns that underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method.

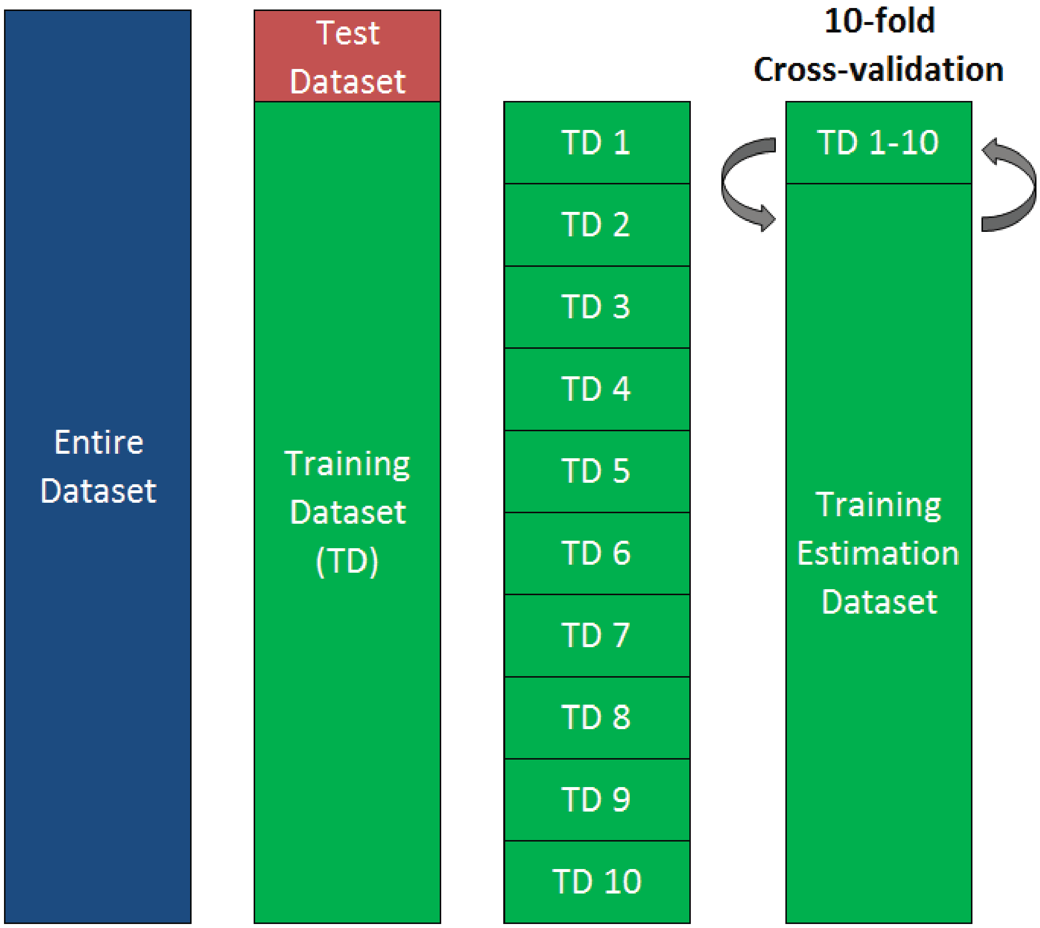
1.2 Re-estimating Econometric Models

Using the new meta-dataset, Nexant re-estimated the econometric models that relate interruption costs to duration, customer characteristics such as annual kWh, and other factors. Nexant then compared the results of the original model specification to those of several alternatives that included a reduced number of variables. This model selection process addressed another ICE Calculator improvement – reducing the amount of detailed customer characteristics information that ICE Calculator users must provide, which has been a significant barrier to the tool’s use. When the econometric models were originally estimated in 2009, statistical significance was the focus of the analysis and, due to the large number of observations in the meta-dataset, many of the customer characteristics variables were statistically significant in the model, even if the marginal effect of the variable was negligible and/or collinear with other variables. Basically, many of the variables in the original specification were statistically significant, but not practically significant. In re-estimating the models, Nexant focused on the practical significance of each variable by conducting sensitivity tests to determine which variables have a substantive impact on the interruption cost estimates. Nexant also employed more recent model selection methods that have been developed since 2009, which significantly improved the rigor with which variables were selected for the model. This process led to a more parsimonious model that only included key variables. In turn, ICE Calculator users will have less customer characteristics information to provide and the associated inputs page will be far less cumbersome.

1.3 Overview of Model Selection Process

Figure 1-1 provides an overview of the model selection process. The entire dataset of interruption cost estimates for each customer class is first randomly divided into a test dataset (10% of the entire dataset) and a training dataset (the remaining 90%). The training dataset is used to train the model, which refers to the process of selecting variables for the final specification. The test dataset is excluded from the model training process so that it can be used as a test of the final model performance on unseen data, which refers to data that is completely separate from the model training process. Next, the training dataset is randomly divided into 10 equally sized parts. Then, each candidate model specification is estimated on nine of 10 parts of the training dataset. The estimated coefficients for each candidate model specification are subsequently used to predict interruption costs on the tenth part of the training dataset. This process, which is referred to as 10-fold cross-validation, is repeated nine times while withholding one of the remaining nine parts of the training dataset each time. Relevant accuracy metrics for each model specification are computed for each of the 10 parts of the training dataset. Those accuracy metrics are ranked to determine the final model specification through a backwards stepwise selection process. Next, the final model specification is run on the entire training dataset and the estimated coefficients are used to predict interruption costs for the test dataset. Relevant accuracy metrics for the test dataset are also computed. If model performance on the test dataset is similar, the final specification is then estimated on the entire dataset and those estimated coefficients make up the final model. This process is conducted for each of the three customer classes separately.

Figure 1-1: Overview of Model Selection Process



1.4 Variable Definitions and Units

There are many variables that are common among customer classes, so all variable definitions and units are provided in this section. Table 1-2 provides the units and definitions of variables that are used in the models for all customer classes.

Table 1-2: Units and Definitions of Variables for All Customer Classes

Variable Name	Variable Definition	Units
annual MWh	Annual MWh of customer	MWh
duration	Duration of power interruption scenario	Minutes
time of day	Time of day of power interruption scenario	Categorical – Morning (6 AM to 12 PM); Afternoon (12 to 5 PM; Evening (5 to 10 PM); Night (10 PM to 6 AM)
weekday	Time of week of power interruption scenario	Binary – Weekday = 1; Weekend = 0
summer	Time of year of power interruption scenario	Binary – Summer = 1; Non-summer = 0
warning	Whether power interruption scenario had advance warning	Binary – Warning = 1; No warning = 0

Table 1-3 provides the units and definitions of variables that are used in the models for both the small and medium/large C&I customer classes. For both C&I customer classes, the model selection process begins with separate variables for all eight of the industry groups in the table, with Agriculture, Forestry & Fishing as the reference category by default. However, given that each industry group is tested separately for inclusion in the model, only one or two industry variables may remain in the final model, in which case the dropped industry variables are relegated to the reference category. Within the reference category, there may be multiple industries with presumably varying interruption costs, but if the model selection process has shown that there are not any meaningful differences within the industries in the reference category, those industry variables will be grouped together. The same logic applies for other categorical variables.

Table 1-3: Units and Definitions of Variables for C&I Customers

Variable Name	Variable Definition	Units
industry	Customer business type, based on NAICS or SIC code	Categorical – Agriculture, Forestry & Fishing; Mining; Construction; Manufacturing; Transportation, Communication & Utilities; Wholesale & Retail Trade; Finance, Insurance & Real Estate; Services; Public Administration; Unknown
backup equipment	Presence of backup equipment at facility	Categorical – None; Backup Gen or Power Conditioning; Backup Gen and Power Conditioning

Finally, Table 1-4 provides the units and definitions of variables that are only used in the residential customer models.

Table 1-4: Units and Definitions of Variables for Residential Customers

Variable Name	Variable Definition	Units
household income	Household income	$
medical equip.	Presence of medical equipment in home	Binary – Medical equipment = 1; No medical equipment = 0
backup generation	Presence of backup generation in home	Binary – Backup = 1; No backup = 0
outage in last 12 months	Interruption of longer than 5 minutes within past year	Binary – Yes = 1; No = 0
# residents X-Y	Number of residents in home within X-Y age range	Number of people
housing	Type of housing	Categorical – Detached; Attached; Apartment/Condo; Mobile; Manufactured; Unknown

1.5 Report Organization

The remainder of this report proceeds as follows. Section 2 summarizes the regression modeling methodology and selection process that applies to all three customer classes – medium and large C&I, small C&I and residential. This is followed by three sections that describe the final model selection and provide the final regression coefficients for each customer class. Finally, Section 6 describes some of the study's limitations.

2. Methodology

This section summarizes the study methodology, including the regression model structure and selection process.

2.1 Model Structure

A two-part regression model was used to estimate the customer interruption cost functions (also referred to as customer damage functions). This is the same class of model used in the previous meta-study. The two-part model assumes that the zero values in the distribution of interruption costs are correctly observed zero values, rather than censored values. In the first step, a probit model is used to predict the probability that a particular customer will report any positive value versus a value of zero for a particular interruption scenario. This model is based on a set of independent variables that describe the nature of the interruption as well as customer characteristics. The predicted probabilities from this first stage are retained. In the second step, using a generalized linear model (GLM), interruption costs for only those customers who report positive costs are related to the same set of independent variables used in the first stage. Predictions are made from this model for all observations, including those with a reported interruption cost of zero. Finally, the predicted probabilities from the first part are multiplied by the estimated interruption costs from the second part to generate the final interruption cost predictions.

The functional form for the second part of the two-part model must take into account that the interruption cost distribution is bounded at zero and extremely right skewed (i.e. it has a long tail in the upper end of the distribution). Ordinary least squares (OLS) is not an appropriate functional form given these conditions. A simple way to define the customer damage function given the above constraints is to estimate the mean interruption cost, which is linked to the predictor variables through a logarithmic link function using a GLM.

The parameter values in the two-part model cannot be directly interpreted in terms of their influence on interruption costs because the relationships are among the variables in their logarithms. However, the estimated model produces a predicted interruption cost, given the values of variables in the models. To analyze the magnitude of the impact of variables in the model on interruption cost, it is necessary to compare the predictions made by the function under varying assumptions. For example, it is possible to observe the effect of duration on interruption cost by holding the other variables constant at their sample means. In this way one can predict average customer interruption costs of varying durations holding other factors constant statistically.

For a more detailed discussion of the two-part model, its functional form and the reasons why it is most appropriate for this type of data, refer to the methodology section of the 2009 report.

2.2 Summary of Model Selection Process

Nexant aimed to estimate a more parsimonious model that only included key predictor variables. This facilitates interruption cost estimation by simplifying the ICE Calculator interface and reducing the burden that ICE Calculator users face in providing numerous, accurate customer characteristics information. This section first outlines the steps involved in the model selection process that Nexant undertook, followed by a more detailed exposition of the problem at hand, and a justification for the method.

To select a more parsimonious model, Nexant conducted the following steps for each of the three customer classes:

1. Randomly sample 10% of the data and hold it out as the test dataset (assign other 90% as the training dataset);
2. Split training dataset into 10 randomly assigned, equally sized parts;
3. Start with the original specification (the global model) and identify model variables that are candidates for removal (all variables except ineligible lower power terms);
4. Remove one of the eligible model variables to yield a new model;
5. Estimate model on nine of 10 parts of the training dataset and retain estimates;
6. Use retained estimates from step 5 to predict on the tenth part of the training dataset, computing relevant accuracy metrics;
7. Repeat steps 5 and 6, cycling over each of the remaining 9 parts of the training dataset;
8. Take the average and standard deviation of the accuracy metrics from the predictions for each of 10 parts of the training dataset;
9. Repeat steps 4 through 8, for each possible candidate variable for removal;
10. Use saved accuracy metrics to rank models;
11. Exclude from the global model the variable, which when dropped, produced estimates that outperformed the rest;
12. Repeat steps 2 through 11 until only a constant remains;
13. Inspect results and select model that is parsimonious, yet sufficiently accurate according to the out-of-sample accuracy metrics described above; and
14. Test final model against the original global model using the test dataset to estimate model's performance on unseen data (ensures that the model predicts well for data that was not included in the model training process).

As discussed in Section 1, this model selection process draws from the recent model selection methods that have been developed since 2009,[9] which significantly improves the rigor with which variables are selected for the model. The remainder of this section describes this process in more detail.

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[9] For a discussion of these methods, see: Varian, Hal R. "Big Data: New Tricks for Econometrics." *Journal of Economic Perspectives*. Volume 28, Number 2. Spring 2014. Pages 3–28. Available here: http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.28.2.3

2.3 Details of Model Selection Process

A model selection problem involves choosing a statistical model from a set of candidate models, given some data. In this case, the data were the pre-existing set of interruption cost surveys for each customer class. Nexant selected a candidate set of models that included the original model specification from the 2009 study, henceforth referred to as the global model, as well as all models that were nested in the global model, that is to say all models that occur when removing one of more predictor variables from the global model. This candidate set is appropriate for several reasons. First of all, nearly all of the variables that were available in the meta-dataset were already included in the global model. Secondly, all the variables in the global model are plausibly related to interruption costs, and are not simply spuriously correlated. For example, it is reasonable to conclude that a resident with medical equipment that requires a power supply would be willing to pay more to avoid a power interruption than a resident without such medical equipment. Similar conclusions can be made for the other predictor variables in the global model, across sectors, making all of them viable to include in candidate models. Furthermore, to introduce candidate models that feature predictors not already included in the global model, such as new characteristics or higher power terms, would make the task of selecting a more parsimonious model significantly more challenging. Adding new predictors to candidate models not only increases the complexity of those candidate models, but the number of candidate models increases exponentially, making selecting among them computationally challenging.[10] It therefore makes practical sense to limit the predictors used in candidate models to those used in the global model. Also in the interest of simplifying the selection process, Nexant restricted the specifications of the probit and GLM models to be identical. This was the same form that the original regression model took.

Nexant developed an iterative process to choose among the candidate set of models. This is a backwards stepwise selection method that parses down the global model one variable at a time. At each step of the process, a variable is removed from the prior model (the global model in the first step) and the resulting model is evaluated in out-of-sample tests using a variety of metrics. This is performed for all possible variables that can be excluded, and the model that performs best on average across the various metrics is retained, or rather its exclusion is retained, and becomes the prior model in the next step of the process. (Alternatively, one can consider the excluded variable as that which diminished the performance of the global model the least, relative to the other possible exclusions, although it was often the case that the performance improved.) The outcome at each step is carefully examined to determine whether an acceptably parsimonious model has been selected, and whether excluding a particular variable will severely diminish the model's predictive power, in which case that variable is retained in the final model.

The selection process uses rigorous out-of-sample testing to evaluate the performance of various models and ensure that the final model is not over-fitted.[11] Nexant divided the sample into a training dataset, used to fit models; a validation dataset, used to compare models; and a test

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[10] It can be shown that a global model with n predictors has $2^n - 1$ possible nested models. Furthermore, when m new predictors are added to the global model, the number of possible nested models increases by $(2^m - 1)2^n$.

[11] Over-fitting occurs when a model describes random variation in the data. The problem manifests itself through good predictive performance on the fitted data, but poor predictive performance on unseen data that the model was not fitted to.

dataset, used as a final independent test to show how well the selected model will generalize to unseen data. The test dataset comprised 10% of the sample, and was "held out" throughout the model fitting and selection process. At each step of the selection process, the models were compared using 10-fold cross-validation. Ten-fold cross-validation divides the remaining sample data into ten equal size subsamples. Nine of those subsamples are used as the training dataset to fit the model, and the tenth is used to validate the performance of that fitted model and choose among models. This process is repeated ten times with each of the subsamples used once to validate the fitted model. This method reduces the likelihood of over-fitting the model by using unseen data in the validation step; models that generalize well to new data will be selected over those that do not. Furthermore, by "folding" the data and iterating over subsamples, each observation is used exactly once in the validation step, so all of the available data (other than the 10% in the test dataset) are used to select models.

Rather than rely on a single metric to select a model, Nexant computed several metrics, ranked models by each of these metrics, then averaged the ranks to give an overall rank across metrics. Root-mean-square error (RMSE), mean absolute error (MAE), and the coefficient of determination (R-squared) are computed in out-of-sample tests. RMSE measures the average prediction error of a model. The differences between observed and predicted values are computed, squared, and then averaged before the square root is taken to correct the units. Because errors are squared before the average, RMSE penalizes larger errors more than smaller errors. MAE also measures the average prediction error of a model. The differences between observed and predicted values are computed, their absolute value is taken, and then the absolute errors are averaged. Errors of every magnitude are penalized equally. In the case of both RMSE and MAE, values range from zero to infinity, and smaller values are preferred. R-squared measures the fraction of variation of the dependent variable that is explained by a model. Its values range from 0 to 1, and a larger value is preferred. At each step, an information theoretic approach is also used to produce a fourth ranking of models that is incorporated into the average. This ranking uses Akaike's Information Criterion (AIC), which is an estimate of the expected, relative distance between the fitted model and the unknown true mechanism that generated the observed data. It is a measure of the information that is lost when a model is used to approximate the true mechanism. A thorough exposition of the relative advantages and disadvantages of these different metrics is beyond the scope of this report. That said, by averaging the ranks obtained from each metric and choosing an overall winner, Nexant does not prioritize minimizing one kind of error over another, but rather adopts a holistic approach.

3. Medium and Large C&I Results

This section summarizes the results of the model selection process and provides the model coefficients for medium and large C&I customers, which are C&I customers with annual usage of 50,000 kWh or above.

3.1 Final Model Selection

The global model for medium and large C&I customers is shown below:

$$\mathit{Interruption\ Cost} = f(\ln(\mathit{annual\ MWH}), \mathit{duration}, \mathit{duration}^2, \mathit{duration} \times \ln(\mathit{annual\ MWh}), \mathit{duration}^2 \times \ln(\mathit{annual\ MWh}), \mathit{weekday}, \mathit{warning}, \mathit{summer}, \mathit{industry}, \mathit{time\ of\ day}, \mathit{backup\ equipment})$$

Interruption cost is expressed as a function of various explanatory variables. Note that the dependent variables differ between the probit and GLM models; hence the above equation expresses the two-part model in its most general form. Industry, time of day and backup equipment are all categorical variables, and their respective categories are shown in Table 3-1 below. As is typical in indicatory coding, the first category within each categorical variable is not included explicitly as a binary variable, but rather serves as a reference category.

Table 3-1: Breakdown of Categorical Variables Featured in Global Model – Medium and Large C&I

Variable	Categories
industry	Agriculture, Forestry & Fishing; Mining; Construction; Manufacturing; Transportation, Communication & Utilities; Wholesale & Retail Trade; Finance, Insurance & Real Estate; Services; Public Administration; Unknown
time of day	Night (10 PM to 6 AM); Morning (6 AM to 12 PM); Afternoon (12 to 5 PM); Evening (5 to 10 PM)
backup equipment	None; Backup Gen or Power Conditioning; Backup Gen and Power Conditioning

The global model was successfully parsed down to only key variables. In selecting among variables, categorical variables were not treated as a set (either all or none removed), but rather each binary variable was removed one at a time. This allowed for a particularly important category to remain, while others that might have had a smaller effect were no longer represented. Table 3-2 shows the results of each step in the process. Each iteration represents the exclusion of a variable from the global model, and the variable listed is the one that, when excluded, produces the model with the best performance across various metrics in out-of-sample tests. The model's value and rank (relative to the other possible exclusions) in the metrics is listed, along with its overall rank, which is an average of the individual ranks. Note that iteration zero represents the global model alone, so some metrics that are only meaningful when compared with other models, such as ranks and AICs, are not listed. The highlighted row shows the final exclusion that was made; the rows that follow show the variables that remain in the final model. Ultimately, interruption costs for medium and large C&I customers can be estimated relatively accurately with a few variables and interactions representing customer usage and interruption duration, along with binary variables for manufacturing customers and for power interruptions that occur during the summer. A few of the 15 excluded variables show a minor improvement in predictive accuracy, but considering how difficult it can be for ICE Calculator users to find information for some of those inputs, this minor improvement in predictive accuracy was not sufficient to justify keeping those variables in the final model.

Table 3-2: Excluded Variables and Relevant Metrics from Backwards Stepwise Selection Process – Medium and Large C&I

Iteration	Excluded Variable	RMSE		MAE		R2		AIC			Overall Rank
		Value (Thousands)	Rank	Value (Thousands)	Rank	Value	Rank	Probit Value (Thousands)	GLM Value (Thousands)	Rank	
0	-	116	-	29.6	-	0.143	-	-	-	-	-
1	*evening*	116	1	29.5	1	0.148	1	44.1	589	4.5	1.9
2	*weekday*	116	1	29.5	2	0.150	1	44.1	589	7.0	2.8
3	*morning*	116	1	29.5	2	0.151	1	44.3	589	9.5	3.4
4	*afternoon*	116	1	29.4	1	0.153	1	44.5	589	10.0	3.3
5	*wholesale & retail trade*	116	2	29.4	2	0.153	2	44.5	589	4.0	2.5
6	*backupgen and power conditioning*	116	1	29.4	3	0.155	1	44.6	589	8.5	3.4
7	*services*	116	1	29.4	1	0.155	1	44.7	589	8.5	2.9
8	*public administration*	116	3	29.5	2	0.155	3	44.7	589	2.5	2.6
9	*unknown*	116	1	29.5	3	0.155	1	44.7	590	3.0	2.0
10	*finance, insurance & real estate*	116	1	29.5	1	0.154	1	44.7	590	4.0	1.8
11	*transportation, communication & utilities*	116	1	29.5	2	0.154	1	44.7	591	4.5	2.1
12	*construction*	116	1	29.5	1	0.154	1	44.8	591	4.5	1.9
13	*mining*	116	1	29.5	1	0.153	1	44.8	591	2.5	1.4
14	*backupgen or power conditioning*	116	1	29.5	1	0.152	1	44.8	591	1.0	1.0
15	*warning*	116	1	29.6	1	0.148	1	44.9	592	2.5	1.4
16	*manufacturing*	117	1	29.9	2	0.137	1	45.0	595	2.5	1.6
17	*summer*	117	1	30.0	1	0.128	1	45.4	595	1.5	1.1
18	*duration^2 x ln(annual MWh)*	119	1	30.5	1	0.106	1	45.5	595	1.0	1.0
19	*duration x ln(annual MWh)*	120	1	30.7	1	0.096	1	45.5	595	1.0	1.0
20	*duration ^{2}*	129	2	32.8	1	-0.054	2	46.2	598	1.0	1.5
21	*duration*	118	1	31.3	1	0.118	1	47.8	604	1.5	1.1
22	*ln(MWh annual)*	126	1	37.4	1	0.000	1	48.7	640	1.0	1.0

The final model for medium/large C&I customers is shown below:

$$\begin{aligned} &Interruption\ Cost \\ &\quad = f(\ln(annual\ MWH)\,,\ duration, duration^2\,,\ duration \\ &\quad \times \ln(annual\ MWh)\,,\ duration^2 \times \ln(annual\ MWh)\,,\ summer, industry) \end{aligned}$$

Manufacturing is the only remaining industry category in the model. Note that as categories are removed, they are relegated to the reference category, so for example the manufacturing binary variable should now be interpreted as the average impact on interruption cost associated with being in the manufacturing industry, relative to all other industries.

To confirm that the selection process did not produce an over-fitted model, and to estimate the predictive performance of the final model when evaluated on unseen data, Nexant evaluated the final model against the global model using the test dataset, which is the 10% of data that was held out from the backwards stepwise selection process. Both models were fitted to the remaining data, and then the test dataset was used to evaluate their predictive performance.

The results are shown in Table 3-3. The final model outperforms the global model in each accuracy metric.

Table 3-3: Test Dataset Predictive Performance Metrics for Final and Initial Models – Medium and Large C&I

Model	RMSE (Thousands)	MAE (Thousands)	R-squared
Final	111	29.6	0.118
Global	111	29.8	0.115

3.2 Model Coefficients

Nexant then estimated the final two-part regression model specification on the full dataset for medium and large C&I customers. Table 3-4 describes the final probit regression model that specifies the relationship between the presence of zero interruption costs and a set of independent variables that includes interruption characteristics, customer usage, and industry designation. Although the purpose of this preliminary limited dependent variable model is only to normalize the predictions from the interruption costs regression in the second part of the two-part model, there are a few interesting results to note (these remain consistent with the original specification):

- All of the coefficients are statistically significant at a less than 1% level;
- The longer the interruption, the more likely that the costs associated with it are positive (the presence of a negative coefficient on the square of duration indicates that this effect diminishes for longer durations);
- Summer interruptions are more likely to incur costs than non-summer interruptions; and
- Manufacturing industry customers are more likely to incur costs than non-manufacturing industry customers.

Table 3-4: Regression Output for Probit Estimation – Medium and Large C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.005	0.000	0.000
duration^2	-2.820E-06	0.000	0.000
summer	0.410	0.023	0.000
Customer Characteristics			
ln(annual MWh)	0.118	0.006	0.000
Interactions			
duration x ln(annual MWh)	-3.416E-04	0.000	0.000
duration^2 x ln(annual MWh)	1.640E-07	0.000	0.000
Industry			
manufacturing	0.200	0.025	0.000
Constant	-0.958	0.047	0.000

Table 3-5 describes the final GLM regression model, which relates the level of interruption costs to customer usage and interruption characteristics as well as industry designation. A few results of note:

- The longer the interruption, the higher the interruption cost;
- Larger customers (in terms of annual MWh usage) incur larger costs for similar interruptions (however, interruption costs increase at a decreasing rate as usage increases);
- Manufacturing industry customers incur larger costs for similar interruptions than equivalent non-manufacturing customers;
- The difference between summer and non-summer interruption costs is statistically insignificant (all other coefficients are statistically significant).

Table 3-5: Customer Regression Output for GLM Estimation – Medium and Large C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.006	0.001	0.000
duration^2	-3.260E-06	0.000	0.000
summer	0.113	0.060	0.058
Customer Characteristics			
ln(annual MWh)	0.495	0.016	0.000
Interactions			
duration x ln(annual MWh)	-1.882E-04	0.000	0.047
duration^2 *x ln(annual MWh)*	1.480E-07	0.000	0.028
Industry			
manufacturing	0.823	0.069	0.000
Constant	5.292	0.127	0.000

Finally, Table 3-6 shows the average values of the regression inputs for medium and large C&I customers, which are useful for modeling purposes and for assessing marginal effects. Other descriptive statistics are also provided.

Table 3-6: Descriptive Statistics for Regression Inputs – Medium and Large C&I

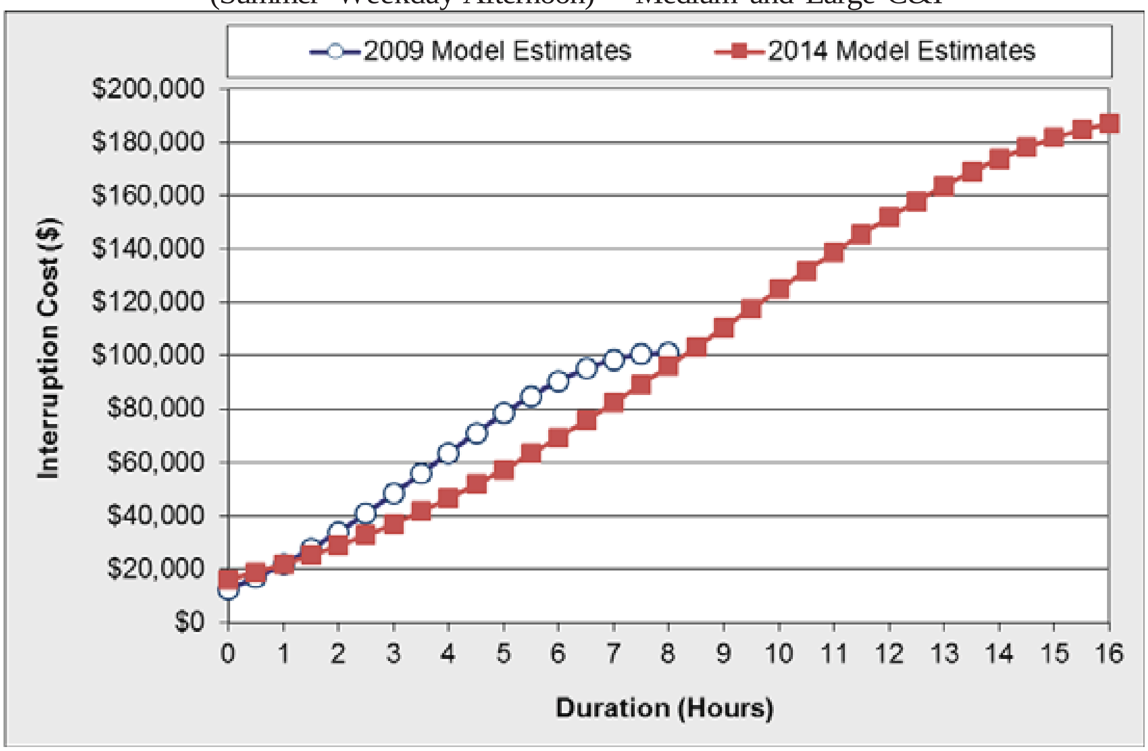
Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interruption Characteristics							
duration	44,328	162	0	60	60	240	1,440
duration^2	44,328	82,724	0	3,600	3,600	57,600	2,073,600
summer	44,328	86.5%	0%	100%	100%	100%	100%
Customer Characteristics							
ln(annual MWh)	44,328	6.6	3.9	4.9	6.2	7.9	13.9

Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interactions							
duration x ln(annual MWh)	44,328	1,060	0	255	437	1,327	17,064
duration^2 x ln(annual MWh)	44,328	530,872	0	14,881	26,250	317,870	24,600,000
Industry							
manufacturing	44,328	23.3%	0%	0%	0%	0%	100%

3.3 Comparison of 2009 and 2014 Model Estimates

Figure 3-1 provides a comparison of the 2009 model estimates and the 2014 model estimates by interruption duration, in 2013 dollars. The 2014 model estimates have been extended to 16 hours because the addition of data on 24-hour power interruption scenarios has allowed to model to more reliably predict costs up to 16 hours. The magnitude of the interruption cost estimates is similar between the two models, but there is a noticeable change in the functional form, which is attributable to the addition of the longer duration scenarios and to the significant change in the model specification. The functional form is more linear and no longer levels off at 8 hours, which seems more plausible.

Figure 3-1: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Model (Summer Weekday Afternoon) – Medium and Large C&I



3.4 Interruption Cost Estimates and Key Drivers

Table 3-7 shows how medium and large C&I customer interruption costs vary by season. Considering that time of day and day of week were not important factors in the model for medium and large C&I customers, the only temporal variable to consider is season (summer or non-summer). The cost of a summer power interruption is around 21% to 43% higher than a non-summer one, depending on duration (the percent difference lowers as duration increases). Considering that the non-summer time period (October through May) accounts for two-thirds of the year, the weighted-average interruption cost estimate is closer to the non-summer estimate. This weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season is known.

Table 3-7: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Timing of Interruption – Medium and Large C&I

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Summer	33%	$16,172	$18,861	$21,850	$46,546	$96,252	$186,983
Non-summer	67%	$11,342	$13,431	$15,781	$35,915	$77,998	$154,731
Weighted Average		**$12,952**	**$15,241**	**$17,804**	**$39,458**	**$84,083**	**$165,482**

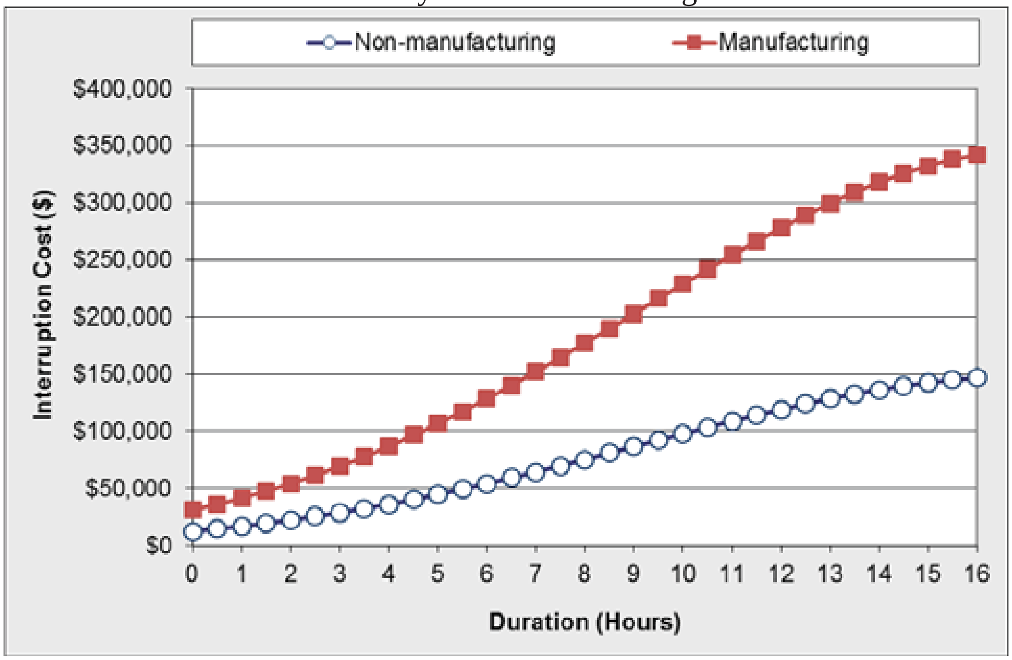
Based on the weighted-average interruption cost estimate, Table 3-8 provides cost per event (equal to the weighted-average interruption cost), cost per average kW and cost per unserved kWh for medium and large C&I customers. Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

Table 3-8: Cost per Event, Average kW and Unserved kWh – Medium and Large C&I

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7

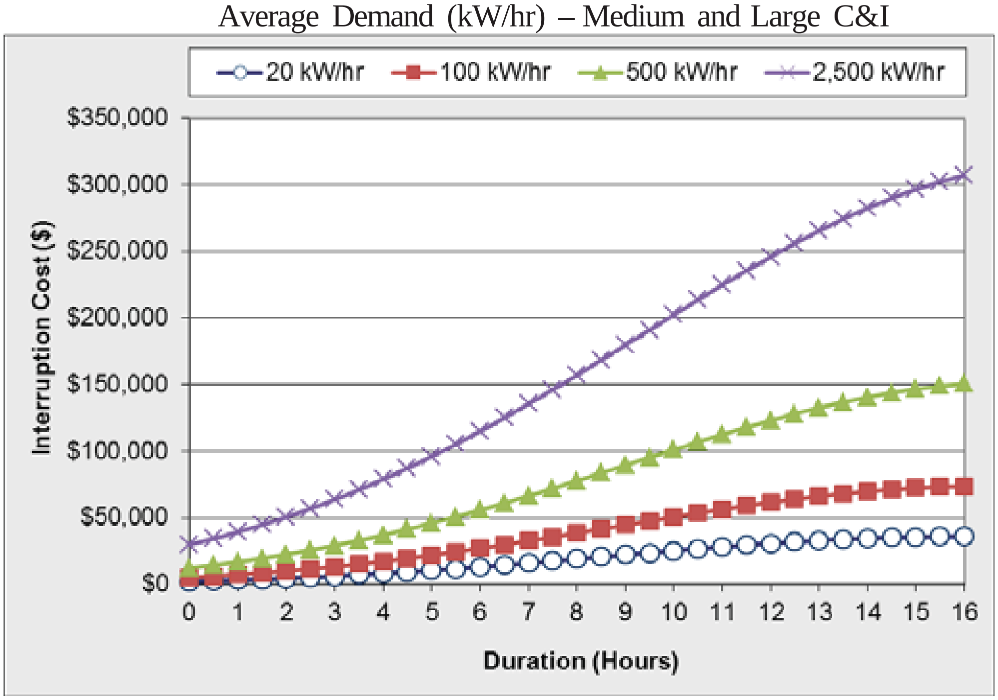
Figure 3-2 shows the medium and large C&I interruption costs in the summer for non-manufacturing and manufacturing customers. As in the 2009 model, interruption costs in the manufacturing sector are relatively high. At all durations, the estimated interruption cost for manufacturing customers is more than double the cost for non-manufacturing customers. This is a key driver to consider for planning purposes – whether the planning area of interest includes medium and large C&I customers with manufacturing facilities that may be particularly sensitive to power interruptions.

Figure 3-2: Estimated Summer Customer Interruption Costs (U.S.2013$) by Duration and Industry – Medium and Large C&I



Finally, Figure 3-3 shows the medium and large C&I interruption costs in the summer for various levels of average demand. As discussed above, medium and large C&I interruption costs increase at a decreasing rate as usage increases. This pattern is notable in the figure. Each increment in average demand represents a 5-fold increase in usage, but interruption costs only increase by a factor of 2.0 to 2.5 from one level of average demand to the next.

Figure 3-3: Estimated Summer Customer Interruption Costs (U.S.2013$) by Duration and Average Demand (kW/hr) – Medium and Large C&I



4. Small C&I Results

This section summarizes the results of the model selection process and provides the model coefficients for small C&I customers, which are C&I customers with annual usage of less than 50,000 kWh.

4.1 Final Model Selection

The global model for small C&I customers was identical to that for the medium and large C&I customers. Refer to Section 3.1 above for a discussion of the global model specification. The global model was successfully parsed down to only key variables. In selecting among variables, categorical variables were not treated as a set (either all or none removed), but rather each binary variable was removed one at a time. This allowed for a particularly important category to remain, while others that might have had a smaller effect were no longer represented. Table 4-1 shows the results of each step in the process. Each iteration represents the exclusion of a variable from the global model, and the variable listed is the one that, when excluded, produces the model with the best performance across various metrics in out-of-sample tests. The model's value and rank (relative to the other possible exclusions) in the metrics is listed, along with its overall rank, which is an average of the individual ranks. Note that iteration zero represents the global model alone, so some metrics that are only meaningful when compared with other models, such as ranks and AICs, are not listed. The highlighted row shows the final exclusion that was made; the rows that follow show the variables that remain in the final model. Ultimately, interruption costs for small C&I customers can be estimated relatively accurately with variables representing customer usage and interruption duration, along with some binary variables for customer characteristics and interruption timing. Considering how difficult it can be for ICE Calculator users to find information for some of the 12 excluded variables (especially for small C&I customers), this final model will be much easier to use.

Table 4-1: Excluded Variables and Relevant Metrics from Backwards Stepwise Selection Process – Small C&I

Iteration	Excluded Variable	RMSE		MAE		R2		AIC			Overall Rank
		Value (Thousands)	Rank	Value (Thousands)	Rank	Value	Rank	Probit Value (Thousands)	GLM Value (Thousands)	Rank	
0	-	6.17	-	1.95	-	0.044	-	-	-	-	-
1	*transportation, comunication & utilities*	6.16	1	1.94	2	0.048	1	30.6	245	8.0	3.0
2	*mining*	6.16	1	1.94	1	0.049	1	30.6	245	7.0	2.5
3	*warning*	6.16	1	1.94	3	0.049	1	30.6	245	4.5	2.4
4	*evening*	6.16	1	1.94	2	0.049	2	30.6	245	4.0	2.3
5	*duration^2 x ln(annual MWh)*	6.16	1	1.94	3	0.049	2	30.6	245	3.0	2.3
6	*finance, insurance & real estate*	6.16	2	1.94	4	0.049	2	30.7	245	5.5	3.4
7	*unknown industry*	6.16	5	1.94	2	0.049	2	30.7	245	5.5	3.6
8	*duration x ln(annual MWh)*	6.16	3	1.94	2	0.049	2	30.7	245	1.5	2.1
9	*public administration*	6.16	2	1.94	3	0.049	4	30.7	245	2.0	2.8
10	*weekday*	6.16	2	1.94	3	0.048	3	30.7	245	3.5	2.9
11	*wholesale & retail trade*	6.16	1	1.94	1	0.049	1	30.9	245	7.5	2.6
12	*services*	6.16	2	1.94	1	0.049	3	30.9	245	2.0	2.0
13	*morning*	6.16	2	1.95	2	0.048	2	31.4	245	4.5	2.6
14	*afternoon*	6.16	1	1.95	2	0.048	1	31.5	245	3.0	1.8
15	*summer*	6.17	1	1.95	1	0.047	1	31.8	245	4.5	1.9
16	*ln(annual MWh)*	6.17	1	1.96	3	0.045	1	32.0	245	3.0	2.0
17	*backupgen and power conditioning*	6.19	2	1.97	1	0.041	1	32.1	246	2.5	1.6
18	*backupgen or power conditioning*	6.20	1	1.98	1	0.036	1	32.1	246	2.0	1.3
19	*manufacturing*	6.22	1	2.00	2	0.029	1	32.1	246	1.5	1.4
20	*construction*	6.24	1	2.01	1	0.023	1	32.2	247	1.0	1.0
21	*duration^2*	6.52	1	2.16	1	-0.089	1	32.8	248	1.0	1.0
22	*duration*	6.32	1	2.13	1	-0.001	1	34.2	251	1.0	1.0

The final model for small C&I customers is shown below:

$$\textit{Interruption Cost} = f(\ln(\textit{annual MWH}), \textit{duration}, \textit{duration}^2, \textit{summer}, \textit{industry}, \textit{backup equipment}, \textit{time of day})$$

Industry, backup equipment and time of day are the only categorical variables remaining, and many of the categories were removed. Note that as categories are removed, they are relegated to the reference category, so for example the construction binary variable should now be interpreted as the average impact on interruption cost associated with being in the construction industry, relative to all industries other than manufacturing, which is the only other industry that was retained as a binary variable. The categories that remain in the final model are shown in Table 4-2 below.

Table 4-2: Breakdown of Categorical Variables Featured in Final Model – Small C&I

Variable	Categories
industry	Other; Construction; Manufacturing
backup equipment	None; Backup Gen or Power Conditioning; Backup Gen and Power Conditioning
time of day	Other (5 PM to 6 AM); Morning (6 AM to 12 PM); Afternoon (12 to 5 PM)

To confirm that the selection process did not produce an overfitted model, and to estimate the predictive performance of the final model when evaluated on unseen data, Nexant evaluated the final model against the global model using the test dataset, which is the 10% of data that was held out from the backwards stepwise selection process. Both models were fitted to the remaining data, and then the test dataset was used to evaluate their predictive performance. The results are shown in Table 4-3. Note that while the global model outperforms the final model in each metric, the differences between the values are very small. The final model offers a much simpler solution with comparable performance to the global model.

Table 4-3: Test Dataset Predictive Performance Metrics for Final and Initial Models – Small C&I

Model	RMSE (Thousands)	MAE (Thousands)	R-squared
Final	5.50	1.82	0.045
Global	5.49	1.82	0.048

4.2 Model Coefficients

Nexant then estimated the final two-part regression model specification on the full dataset for residential customers. Table 4-4 describes the final probit regression model that specifies the relationship between the presence of zero interruption costs and a set of independent variables that includes interruption characteristics, customer characteristics, and industry designation. Although the purpose of this preliminary limited dependent variable model is only to normalize the predictions from the interruption costs regression in the second part of the two-part model, there are a few interesting results to note (these remain consistent with the original specification):

- All of the coefficients are statistically significant at a less than 1% level;
- The longer the interruption, the more likely that the costs associated with it are positive (the presence of a negative coefficient on the square of duration indicates that this effect diminishes for longer durations);
- Summer interruptions are more likely to incur costs than non-summer interruptions;
- Afternoon interruptions are more likely to incur costs than any other time of day; and
- Manufacturing and construction customers are more likely to incur costs than customers in other industries.

Table 4-4: Customer Regression Output for Probit Estimation – Small C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.003	0.000	0.000
duration^2	-1.780E-06	0.000	0.000
summer	0.215	0.030	0.000
morning	0.537	0.022	0.000
afternoon	0.664	0.029	0.000

Variable	Coefficient	Standard Error	P-Value
Customer Characteristics			
ln(annual MWh)	0.124	0.013	0.000
backupgen or power conditioning	0.082	0.025	0.001
backupgen and power conditioning	0.272	0.059	0.000
Industry			
construction	0.261	0.054	0.000
manufacturing	0.176	0.042	0.000
Constant	-1.332	0.048	0.000

Table 4-5 describes the final GLM regression model, which relates the level of interruption costs to customer and interruption characteristics as well as industry designation. A few results of note:

- The longer the interruption, the higher the interruption cost;
- Larger customers (in terms of annual MWh usage) incur larger costs for similar interruptions (however, interruption costs increase at a decreasing rate as usage increases);
- Manufacturing and construction industry customers incur larger costs for similar interruptions than equivalent customers in other industries; and
- Summer interruptions incur lower interruption costs than other times of the year.

Table 4-5: Customer Regression Output for GLM Estimation – Small C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.004	0.000	0.000
duration^2	-2.160E-06	0.000	0.000
summer	-0.384	0.073	0.000
morning	-0.057	0.070	0.413
afternoon	-0.032	0.083	0.701
Customer Characteristics			
ln(annual MWh)	0.069	0.035	0.046
backupgen or power conditioning	0.308	0.058	0.000
backupgen and power conditioning	0.538	0.129	0.000
Industry			
construction	0.786	0.153	0.000
manufacturing	0.587	0.104	0.000
Constant	7.000	0.135	0.000

Finally, Table 4-6 shows the average values of the regression inputs for small C&I customers, which are useful for modeling purposes and for assessing marginal effects. Other descriptive statistics are also provided.

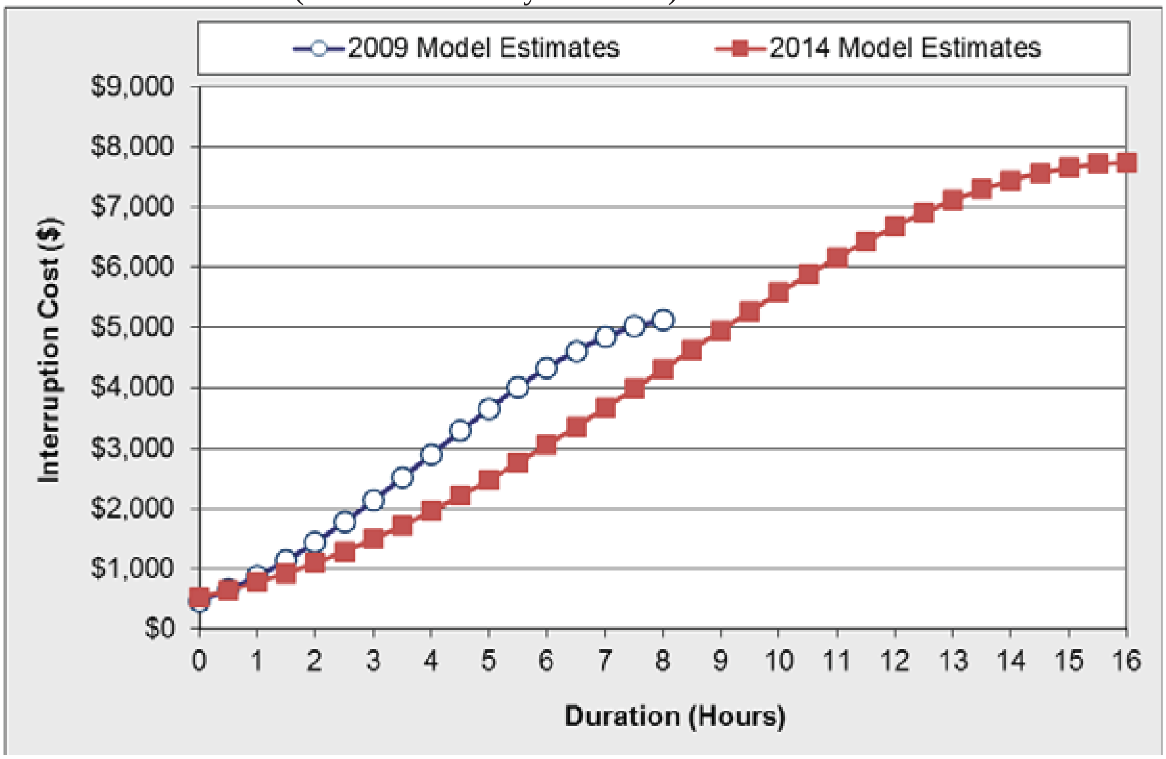
Table 4-6: Descriptive Statistics for Regression Inputs – Small C&I

Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interruption Characteristics							
duration	27,751	191	0	60	60	240	1,440
duration^2	27,751	107,425	0	3,600	3,600	57,600	2,073,600
summer	27,751	89.3%	0%	100%	100%	100%	100%
morning	27,751	45.5%	0%	0%	0%	100%	100%
afternoon	27,751	37.6%	0%	0%	0%	100%	100%
Customer Characteristics							
ln(annual MWh)	27,751	2.6	-2.0	2.2	2.8	3.3	3.9
backupgen or power conditioning	27,751	27.1%	0%	0%	0%	100%	100%
backupgen and power conditioning	27,751	3.5%	0%	0%	0%	0%	100%
Industry							
construction	27,751	4.6%	0%	0%	0%	0%	100%
manufacturing	27,751	7.8%	0%	0%	0%	0%	100%

4.3 Comparison of 2009 and 2014 Model Estimates

Figure 4-1 provides a comparison of the 2009 model estimates and the 2014 model estimates by interruption duration, in 2013 dollars. The 2014 model estimates have been extended to 16 hours because the addition of data on 24-hour power interruption scenarios has allowed to model to more reliably predict costs up to 16 hours. As with medium and large C&I customers, the magnitude of the interruption cost estimates is similar between the two small C&I models, but there is a noticeable change in the functional form. This change is attributable to the addition of the longer duration scenarios and to the significant change in the model specification. The functional form is more linear and no longer levels off at 8 hours, which seems more plausible.

Figure 4-1: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Model (Summer Weekday Afternoon) – Small C&I



4.4 Interruption Cost Estimates and Key Drivers

Table 4-7 shows how small C&I customer interruption costs vary by season and time of day. The cost of a summer power interruption is around 9% to 30% lower than a non-summer one, depending on duration, season, and time of day. Interestingly, this is opposite the pattern of medium and large C&I customers, which experience higher interruption costs during the summer. As for how interruption costs vary by time of day, costs are highest in the afternoon and are similarly high in the morning. In the evening and nighttime, small C&I interruption costs are substantially lower, which makes sense given that small businesses typically operate during daytime hours. Considering that the evening/night time period (5 PM to 6 AM) accounts for a majority of the hours of the day, the weighted-average interruption cost estimate is closer to the evening/night estimates. This weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season and time of day is known.

Table 4-7: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Timing of Interruption – Small C&I

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Summer Morning	8%	$461	$569	$692	$1,798	$4,073	$7,409
Summer Afternoon	7%	$527	$645	$780	$1,954	$4,313	$7,737
Summer Evening/Night	18%	$272	$349	$440	$1,357	$3,518	$6,916
Non-summer Morning	17%	$549	$687	$848	$2,350	$5,592	$10,452
Non-summer Afternoon	14%	$640	$794	$972	$2,590	$5,980	$10,992
Non-summer Evening/Night	36%	$298	$388	$497	$1,656	$4,577	$9,367
Weighted Average		**$412**	**$520**	**$647**	**$1,880**	**$4,690**	**$9,055**

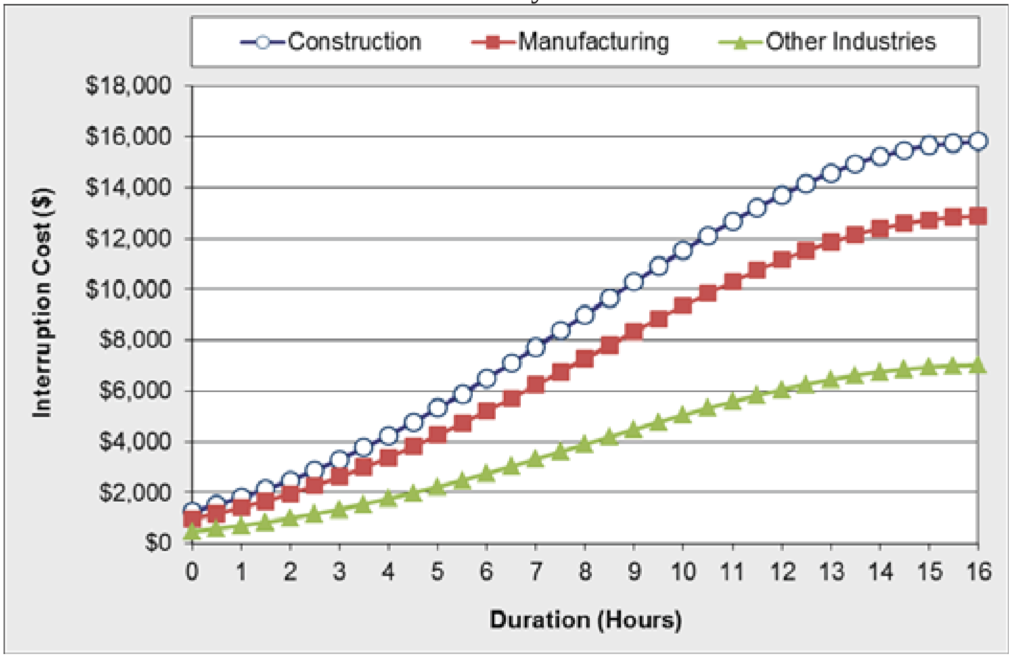
Based on the weighted-average interruption cost estimate, Table 4-8 provides cost per event (equal to the weighted-average interruption cost), cost per average kW, and cost per unserved kWh for small C&I customers. Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

Table 4-8: Cost per Event, Average kW and Unserved kWh – Small C&I

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0

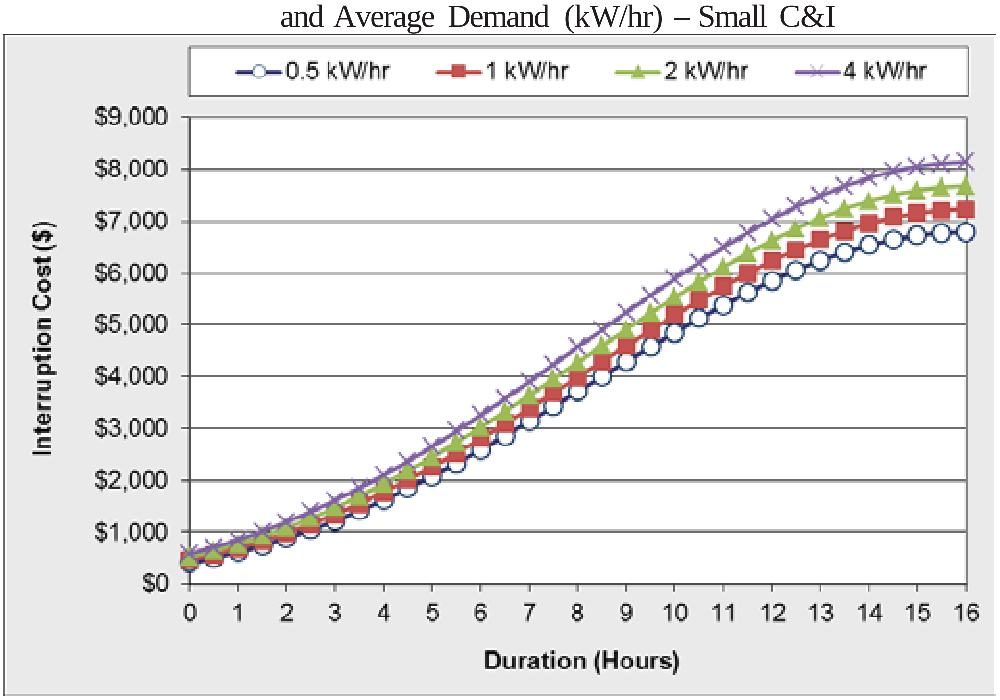
Figure 4-2 shows the small C&I interruption costs in the summer afternoon by industry. As in the 2009 model, interruption costs in the manufacturing and construction sectors are relatively high. At all durations, the estimated interruption cost for manufacturing and construction customers is around double or more the cost for customers in other industries. As in the medium and large C&I customer class, this is a key driver to consider for planning purposes – whether the planning area of interest includes small C&I customers with manufacturing or construction facilities that may be particularly sensitive to power interruptions.

Figure 4-2: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Industry – Small C&I



Finally, Figure 4-3 shows the small C&I interruption costs in the summer afternoon for various levels of average demand. Small C&I interruption costs are not highly sensitive to the average demand of a customer. In the figure, each increment in average demand represents a 2-fold increase in usage, but interruption costs only increase by around 10% from one level of average demand to the next.

Figure 4-3: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Average Demand (kW/hr) – Small C&I



5. Residential Results

This section summarizes the results of the model selection process and provides the model coefficients for residential customers.

5.1 Final Model Selection

The global model for residential customers is shown below:

Interruption Cost = f(ln(annual MWh), duration, duration², household income, medical equip., backup generation, summer, weekday, outage in last 12 months, # residents 0-6, # residents 7-18,

 # residents 19-24, # residents 25-49, # residents 50-64, # residents over 64, time of day, housing)

Interruption cost is expressed as a function of various explanatory variables. Note that the dependent variables differ between the probit and GLM models; hence the above equation expresses the two-part model in its most general form. Time of day and housing are categorical variables, and their respective categories are shown in Table 5-1 below. As is typical in indicatory coding, the first category within each categorical variable is not included explicitly as a binary variable, but rather serves as a reference category.

Table 5-1: Breakdown of Categorical Variables Featured in Global Model – Residential

Variable	Categories
time of day	Morning (6 AM to 12 PM); Afternoon (12 to 5 PM); Evening (5 to 10 PM); Late Evening/Early Morning
housing	Detached; Attached; Apartment/Condo; Mobile; Manufactured; Unknown

The global model was successfully parsed down to only key variables. In selecting among variables, categorical variables were not treated as a set (either all or none removed), but rather each binary variable was removed one at a time. This allowed for a particularly important category to remain, while others that might have had a smaller effect were no longer represented. Table 5-2 shows the results of each step in the process. Each iteration represents the exclusion of a variable from the global model, and the variable listed is the one that, when excluded, produces the model with the best performance across various metrics in out-of-sample tests. The model's value and rank (relative to the other possible exclusions) in the metrics is listed, along with its overall rank, which is an average of the individual ranks. Note that iteration zero represents the global model alone, so some metrics that are only meaningful when compared with other models, such as ranks and AICs, are not listed. The highlighted row shows the final exclusion that was made; the rows that follow show the variables that remain in the final model. Ultimately, interruption costs for residential customers can be estimated relatively accurately with variables representing customer usage, household income, and interruption duration, along with some binary variables for interruption timing. A few of the 16 excluded variables show a minor improvement in predictive accuracy, but considering how difficult it can be for ICE Calculator users to find information for some of those inputs, this minor improvement in predictive accuracy was not sufficient to justify keeping those variables in the final model.

Table 5-2: Excluded Variables and Relevant Metrics from Backwards Stepwise Selection Process – Residential

Iteration	Excluded Variable	RMSE		MAE		R2		AIC			Overall Rank
		Value	Rank	Value	Rank	Value	Rank	Probit Value (Thousands)	GLM Value (Thousands)	Rank	
0	-	16.6	-	8.50	-	0.145	-	-	-	-	-
1	*late evening/early morning*	16.5	1	8.49	1	0.147	1	37.3	126	9.5	3.1
2	*mobile housing*	16.5	3	8.48	2	0.148	3	37.3	126	3.5	2.9
3	*outage in last 12 months*	16.5	1	8.48	1	0.149	1	37.3	126	9.5	3.1
4	*# residents 7-18 years old*	16.5	1	8.48	5	0.149	1	37.3	126	6.0	3.3
5	*# residents 25-49 years old*	16.5	2	8.48	3	0.149	2	37.3	126	6.5	3.4
6	*# residents 50-64 years old*	16.5	2	8.48	2	0.149	2	37.3	126	1.0	1.8
7	*manufactured housing*	16.5	2	8.48	2	0.149	2	37.3	126	4.0	2.5
8	*weekday*	16.5	1	8.48	2	0.149	1	37.3	126	5.5	2.4
9	*attached housing*	16.5	1	8.48	1	0.149	1	37.4	126	5.5	2.1
10	*apartment/condo*	16.5	3	8.48	2	0.149	3	37.4	126	1.0	2.3
11	*# residents 19-24 years old*	16.5	1	8.48	2	0.149	1	37.4	126	3.5	1.9
12	*backup generation*	16.5	1	8.48	1	0.149	1	37.4	126	4.0	1.8
13	*# residents 0-6 years old*	16.5	2	8.48	2	0.149	2	37.4	126	1.5	1.9
14	*unknown housing*	16.5	2	8.49	1	0.148	2	37.4	126	1.5	1.6
15	*medical equipment*	16.5	1	8.49	2	0.148	1	37.5	126	2.5	1.6
16	*# residents 65 and over*	16.6	1	8.49	1	0.146	1	37.5	126	2.5	1.4
17	*household income*	16.6	1	8.53	1	0.140	1	37.5	127	2.5	1.4
18	*evening, 5 pm to 8 pm*	16.7	1	8.61	2	0.133	1	38.7	127	3.0	1.8
19	*afternoon, 12 noon to 4 pm*	16.7	1	8.63	1	0.127	1	38.9	127	2.0	1.3
20	*summer*	16.8	1	8.71	1	0.119	1	39.7	127	2.0	1.3
21	*ln(annual MWh)*	17.0	1	8.82	1	0.098	1	39.7	128	1.5	1.1
22	*duration*^{2}	17.3	1	8.95	1	0.072	1	39.9	128	1.0	1.0
23	*duration*	17.9	1	9.44	1	0.000	1	41.6	130	1.0	1.0

The final model for residential customers is shown below:

Interruption Cost = f(ln(annual MWh), duration, duration^2*, household income, summer, time of day)*

To confirm that the selection process did not produce an over-fitted model, and to estimate the predictive performance of the final model when evaluated on unseen data, Nexant evaluated the final model against the global model using the test dataset, which is the 10% of data that was held out from the backwards stepwise selection process. Both models were fitted to the remaining data, and then the test dataset was used to evaluate their predictive performance. The results are shown in Table 5-3. Note that while the global model outperforms the final model in each metric, the differences between the values are very small. The final model offers a much simpler solution with comparable performance to the global model.

Table 5-3: Test Dataset Predictive Performance Metrics for Final and Initial Models – Residential

Model	RMSE	MAE	R-squared
Final	17.5	8.34	0.148
Global	17.3	8.28	0.165

5.2 Model Coefficients

Nexant then estimated the final two-part regression model specification on the full dataset for residential customers. Table 5-4 describes the final probit regression model that specifies the relationship between the presence of zero interruption costs and a set of independent variables that includes interruption characteristics and customer characteristics. Although the purpose of this preliminary limited dependent variable model is only to normalize the predictions from the interruption costs regression in the second part of the two-part model, there are a few interesting results to note (these remain consistent with the original specification):

- All of the coefficients are statistically significant at a less than 5% level;
- The longer the interruption, the more likely that the costs are positive (the presence of a negative coefficient on the square of duration indicates that this effect diminishes for longer durations);
- Customers are less likely to have a positive cost for an afternoon or an evening interruption versus any other time of day.

Table 5-4: Regression Output for Probit Estimation – Residential

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.003	0.000	0.000
duration^2	-1.130E-06	0.000	0.000
summer	0.541	0.019	0.000
afternoon	-0.266	0.026	0.000
evening	-0.755	0.024	0.000
Customer Characteristics			
ln(annual MWh)	0.038	0.018	0.035
household income	9.660E-07	0.000	0.004
Constant	-0.266	0.051	0.000

Table 5-5 describes the final GLM regression model which relates the level of interruption costs to customer and interruption characteristics. A few results of note:

- All of the coefficients are statistically significant at a less than 5% level;
- The longer the interruption, the higher the interruption cost;

- Customers have lower interruption costs for afternoon and evening interruptions than for those that occur at other times of day;
- Customers experience higher costs for summer interruptions than for non-summer interruptions; and
- Larger customers (in terms of annual MWh usage) have a higher cost for similar interruptions than otherwise equivalent, smaller customers.

Table 5-5: Regression Output for GLM Estimation – Residential

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.002	0.000	0.000
duration^2	-9.450E-07	0.000	0.000
summer	0.161	0.029	0.000
afternoon	-0.282	0.041	0.000
evening	-0.095	0.047	0.044
Customer Characteristics			
ln(annual MWh)	0.249	0.028	0.000
household income	1.850E-06	0.000	0.000
Constant	1.379	0.080	0.000

Finally, Table 5-6 shows the average values of the regression inputs for residential customers, which are useful for modeling purposes and for assessing marginal effects. Other descriptive statistics are also provided.

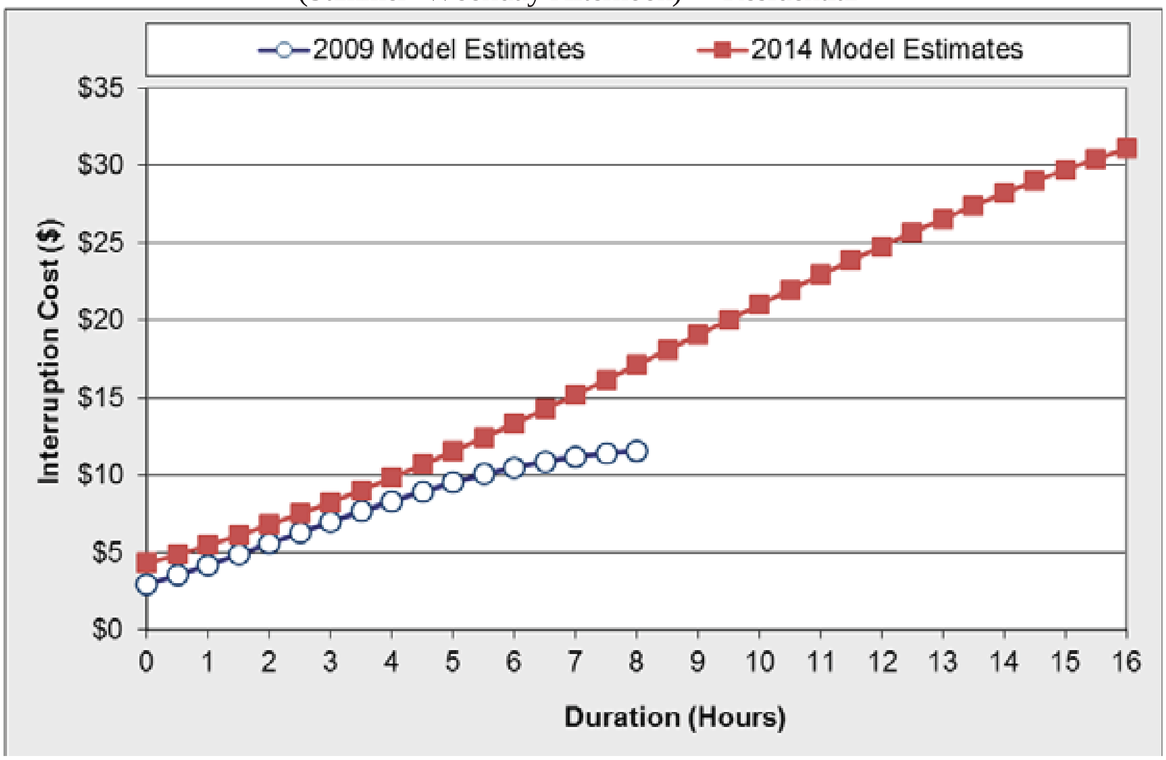
Table 5-6: Descriptive Statistics for Regression Inputs – Residential

Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interruption Characteristics							
duration	34,212	168	0	60	60	240	1,440
duration^2	34,212	82,198	0	3,600	3,600	57,600	2,073,600
summer	34,212	73.4%	0%	0%	100%	100%	100%
afternoon	34,212	48.8%	0%	0%	0%	100%	100%
evening	34,212	29.1%	0%	0%	0%	100%	100%
Customer Characteristics							
ln(annual MWh)	34,212	2.4	0.3	1.9	2.4	2.9	4.4
household income	34,212	69,243	5,076	36,846	63,445	97,618	173,611

5.3 Comparison of 2009 and 2014 Model Estimates

Figure 5-1 provides a comparison of the 2009 model estimates and the 2014 model estimates by interruption duration, in 2013 dollars. The 2014 model estimates have been extended to 16 hours because the addition of data on 24-hour power interruption scenarios has allowed to model to more reliably predict costs up to 16 hours. As with C&I customers, the magnitude of the interruption cost estimates is similar between the two small C&I models, but there is a noticeable change in the functional form. This change is attributable to the addition of the longer duration scenarios and to the significant change in the model specification. The functional form is more linear and no longer levels off at 8 hours, which seems more plausible.

Figure 5-1: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Model (Summer Weekday Afternoon) – Residential



5.4 Interruption Cost Estimates and Key Drivers

Table 5-7 shows how residential customer interruption costs vary by season and time of day. The cost of a summer power interruption is substantially higher than a non-summer one, for all durations, seasons, and times of day. As for how interruption costs vary by time of day, costs are highest in the morning and night (10 PM to 12 noon). The weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season and time of day is known.

Table 5-7: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Timing of Interruption – Residential

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Summer Morning/Night	19%	$6.8	$7.5	$8.4	$14.3	$24.0	$42.4
Summer Afternoon	7%	$4.3	$4.9	$5.5	$9.8	$17.1	$31.1
Summer Evening	7%	$3.5	$4.0	$4.6	$9.2	$17.5	$34.1
Non-summer Morning/Night	39%	$3.9	$4.5	$5.1	$9.8	$17.8	$33.5
Non-summer Afternoon	14%	$2.3	$2.7	$3.1	$6.2	$12.1	$23.7
Non-summer Evening	14%	$1.5	$1.8	$2.2	$5.0	$10.8	$23.6
Weighted Average		**$3.9**	**$4.5**	**$5.1**	**$9.5**	**$17.2**	**$32.4**

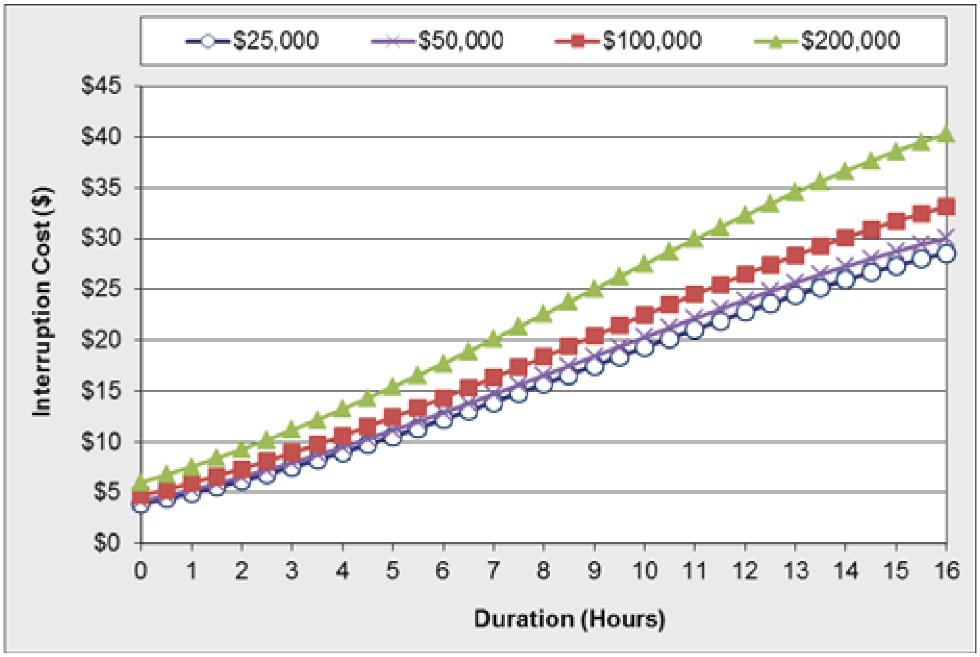
Based on the weighted-average interruption cost estimate, Table 5-8 provides cost per event (equal to the weighted-average interruption cost), cost per average kW, and cost per unserved kWh for residential customers. Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

Table 5-8: Cost per Event, Average kW and Unserved kWh – Residential

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

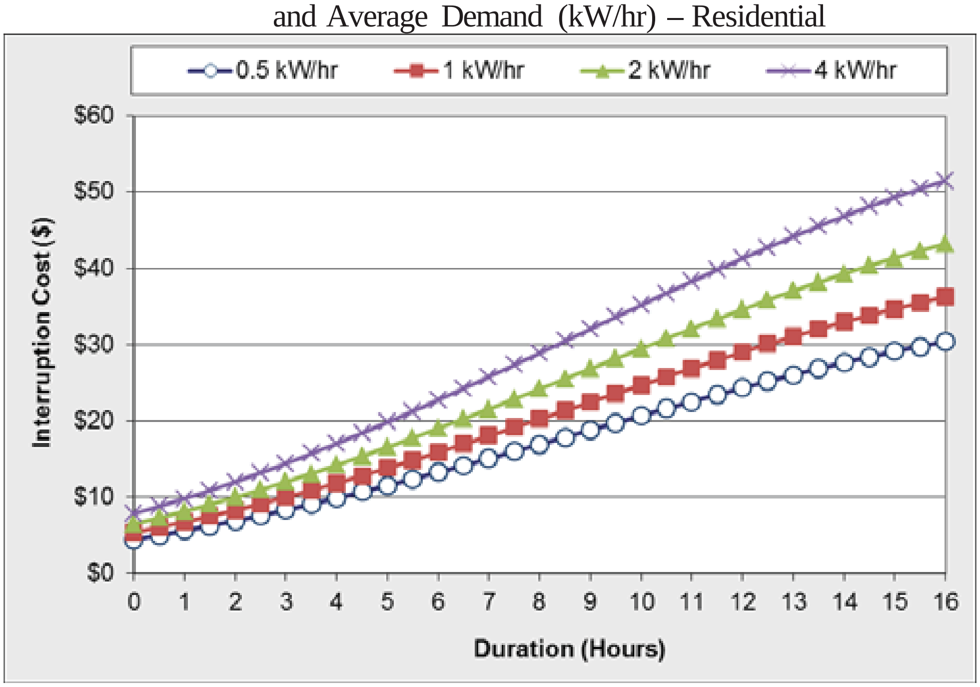
Figure 5-2 shows the residential interruption costs in the summer afternoon by levels of household income. Household income has a relatively modest impact on interruption costs. Between a household income of $50,000 and $100,000, the difference in interruption costs is only around 10% for all durations.

Figure 5-2: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Household Income – Residential



Finally, Figure 5-3 shows the residential interruption costs in the summer afternoon for various levels of average demand. Residential interruption costs are not highly sensitive to the average demand of a customer. In the figure, each increment in average demand represents a 2-fold increase in usage, but interruption costs only increase by around 20% from one level of average demand to the next.

Figure 5-3: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Average Demand (kW/hr) – Residential



6. Study Limitations

As in the 2009 study, there are limitations to how the data from this meta-analysis should be used. It is important to fully understand these limitations, so they are further described in this section. First, certain very important variables in the data are confounded among the studies we examined. In particular, region of the country and year of the study are correlated in such a way that it is impossible to separate the effects of these two variables on customer interruption costs. Thus, for example, it is unclear whether the higher interruption cost values for the southwest are purely the result of the hot summer climate in that region or whether those costs are higher in part because of the particular economic and market conditions that prevailed during the year when the study for that region was done. The same logic applies to the 2012 west study, which was the only survey to include power interruption scenarios of more than 12 hours, which makes it difficult to separate the effect of region and year from the effect of the relatively long interruption duration.

There is further correlation between regions and scenario characteristics. The sponsors of the interruption cost studies were generally interested in measuring interruption costs for conditions that were important for planning for their specific systems. As a result, interruption conditions described in the surveys for a given region tended to focus on periods of time when interruptions were more problematic for that region. Unfortunately, the time periods when the chance of interruptions is greatest are not identical for all sponsors of the studies we relied upon, so interruption scenario characteristics tended to be different in different regions. Fortunately, most of the studies we examined included a summer afternoon interruption, so we could compare that condition among studies.

A further limitation of our research is that the surveys that formed the basis of the studies we examined were limited to certain parts of the country. No data were available from the northeast/mid-Atlantic region, and limited data were available for cities along the Great Lakes. The absence of interruption cost information for the northeast/mid-Atlantic region is particularly troublesome because of the unique population density and economic intensity of that region. It is unknown whether, when weather and customer compositions are controlled, the average interruption costs from this region are different than those in other parts of the country.

Another caveat is that around half of the data from the meta-database is from surveys that are 15 or more years old. Although the intertemporal analysis in the 2009 study showed that interruption costs have not changed significantly over time, the outdated vintage of the data presents concerns that, in addition to the limitations above, underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method.

Finally, as described in Section 1, although the revised model is able to estimate costs for interruptions lasting longer than 8 hours, it is important to note that the estimates in this report are not appropriate for resiliency planning. This meta-study focuses on the direct costs that customers experience as a result of relatively short power interruptions of up to 24 hours at most. In fact, the final models and results that are presented in Sections 3 through 5 truncate the estimates at 16 hours, due to the relatively few number of observations beyond 12 hours (scenarios of more than 12 hours account for around 2% to 3% of observations for all customer classes). For resiliency considerations that involve planning for long duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered.[12] These factors are not captured in this meta-analysis.

[12] For a detailed study and literature review on estimating the costs associated with long duration power interruptions lasting 24 hours to 7 weeks, see: Sullivan, Michael and Schellenberg, Josh. *Downtown San Francisco Long Duration Outage Cost Study*. March 27, 2013. Prepared for Pacific Gas & Electric Company.

ATTACHMENT 22

PG&E Downtown San Francisco Long Duration Outage Cost Study, 2013

Attachment 22

PG&E Downtown San Francisco Long Duration Outage Cost Study

FREEMAN, SULLIVAN & CO.
A MEMBER OF THE FSC GROUP

Downtown San Francisco Long Duration Outage Cost Study

Prepared for:
Pacific Gas & Electric Company

March 27, 2013

Prepared by:
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Table of Contents

1 Executive Summary

Pacific Gas & Electric Company (PG&E) retained Freeman, Sullivan & Co. (FSC) to estimate the costs associated with power outages lasting from 24 hours to 7 weeks in downtown San Francisco, specifically for customers (and tenants of customers) served by PG&E's Embarcadero substation (also referred to as the *target population*). Nearly 3,000 direct business customers and over 24,000 residential accounts (and each person residing at that residence) are served by this substation. In addition, FSC estimates that there are roughly 2,500 businesses that are tenants of master metered buildings in the target population.[1] This report summarizes the study methodology and results for estimating the costs that these customers would experience as a result of such long duration power outages.

The study estimated outage costs for four outage scenarios – 24 hours, 4 days, 3 weeks and 7 weeks. The estimated outage costs are divided into two components:

- Direct outage costs experienced by businesses in the target population; and
- Indirect outage costs experienced by businesses in California as a whole (also known as *spillover* costs).

To develop the direct outage cost estimates for businesses, FSC carried out a survey of a stratified random sample of businesses in the target population. Indirect outage costs were estimated using a range of cost multipliers that were obtained through a careful review of the hazard loss estimation literature. Residential direct costs have been omitted from the quantitative total cost estimate. Nonetheless, the inconvenience and economic impact on each affected resident should not be understated. FSC also considered, and discusses below, other impacts of a long duration outage, including social disruption and associated costs, loss of employment and displacement of residents.

1.1 Outage Cost Estimates

Table 1-1 summarizes the total outage cost estimates obtained in the study by cost category and outage duration. Indirect outage costs are reported as a range because a relatively wide range of indirect cost ratios were reported in the hazard loss literature. In total, a 24-hour outage among customers in the target population would result in an outage cost ranging from about $190 million to nearly $380 million. As outage duration increases, the impact on the California economy becomes more severe. At 3 weeks, the total outage cost ranges from $2.1 billion to over $4.2 billion. If PG&E's Embarcadero substation lost power for 7 weeks, the total outage cost would range from $4.4 billion to nearly $8.8 billion. Although FSC did not study cost impacts of longer outages, it is reasonable to expect that outages extending beyond 7 weeks would have higher costs than those reported in this report.

[1] Due to the removal of inactive PG&E accounts from the analysis population and aggregation procedures that were required for unbiased sampling and surveying of representative businesses in the target population, the customer counts in this report do not directly correspond to the number of PG&E service agreements or customer accounts. Section 3 provides more details on these aggregation procedures and why they were required.

Table 1-1: Total Outage Cost Estimates by Cost Category and Outage Duration ($ Millions)

Outage Duration	Direct Cost ($ Millions)	Indirect Cost ($ Millions)	Total Outage Cost ($ Millions)
24 hours	$125.7	$62.9 to $251.4	$188.6 to $377.1
4 days	$407.4	$203.7 to $814.8	$611.1 to $1,222.2
3 weeks	$1,417.0	$708.5 to $2,833.9	$2,125.5 to $4,250.9
7 weeks	$2,922.6	$1,461.3 to $5,845.2	$4,383.9 to $8,767.8

1.2 Potential Social Disruption

The costs of government response and assistance, damage from looting and rioting have been quite significant in the aftermath of some major outages and disasters, particularly in urban areas. Due to the costs of property damage and additional emergency services as a result of looting and rioting during a 25-hour blackout in New York City in 1977, researchers found that the indirect cost estimate was more than five times the direct cost estimate, which is well outside the range of multipliers used in this study (0.5x to 2x). In present day downtown San Francisco, it is reasonable to expect that the costs from looting and rioting would be relatively less than in New York City in 1977, but given that it is impossible to predict the potential level of damages from looting and rioting and the costs of government response, the indirect cost estimate is likely to be toward the higher end of the range of estimates that is provided in this study.

Another source of social disruption reported during the 1977 New York City blackout is the interruption in transportation flows. The Bay Area Rapid Transit (BART) and the San Francisco Municipal Railway (MUNI) could experience substantial impacts from a long duration outage of power to the Embarcadero Substation. This station is roughly at the center of the four major BART lines running through the Bay Area. Although traction power for both BART and MUNI comes from different sources, Embarcadero Station power is from Embarcadero Substation. Loss of Embarcadero Station during the outage would disrupt BART and MUNI commuting; if BART and/or MUNI are unable or unwilling to send trains through the Embarcadero Station during a long duration outage, the resulting costs to BART/MUNI and impacts on Bay Area commuters and businesses would be considerable.

1.3 Lost Businesses and Employment

Another important impact of a long duration outage that the survey measured was the likely magnitude of lost business and employment as a result of a long duration outage. Among small and medium businesses, the average reported likelihood of complete business failure (i.e., going out of business) as a result of an extended outage ranged from around 20% to slightly over 28% for the 3-week and 7-week outage scenarios. More than one out of 10 small and medium businesses report that they have a 70% or greater likelihood of going out of business as a result of an outage lasting 3 to 7 weeks. In contrast, the average reported likelihood among large businesses is 1.5% for a 3-week outage and 4.1% for a 7-week outage. Only one large business respondent indicated that they had a greater than 10% likelihood of going out of business. Perhaps, not surprisingly, smaller businesses would be disproportionately impacted by a long duration outage.

Survey respondents were also asked to report the percentage of employees by labor category that they would forego paying during the 4-day, 3-week and 7-week power outages. As expected, contract/temporary employees would be most impacted by a long duration outage. For an outage lasting 3 to 7 weeks, businesses in each segment would stop paying around 35% or more of their contract/temporary employees on average. Part-time employees working for small and medium businesses would be similarly impacted by a long duration outage, with those businesses reporting that over 40% of part-time employees would not be paid throughout a 7-week outage. Among full-time employees, lost pay is relatively low, but it would still be substantial. For a 7-week outage, businesses would stop paying an average of 16.4% to 27% of their full-time employees (depending on segment), which would be a substantial loss of income to the region.

1.4 Displaced Residents

Most of the residential customers in the target population live in residential hotels, low rise and high rise buildings that would need to be evacuated as a result of a long duration outage. In the survey, some property managers of residential buildings reported that their residents would have to be evacuated in the event of an outage because elevator, heating, cooling and ventilation systems would not be able to operate, which would lead to health and safety hazards for residents. In addition to the inconvenience of being displaced, these residential customers (or their property managers) would likely be required to bear the cost of living elsewhere for the duration of the outage. However, because residential relocation costs are so small relative to business interruption costs, even in the worst case scenario, direct costs for residential customers would only lead to a slight increase in the quantifiable total cost. Therefore, residential direct costs have been omitted from the total cost estimate. Nonetheless, the inconvenience and economic impact on each affected resident should not be understated. Although the aggregate direct financial impact would not be substantial in comparison to that of business customers, the economic impact to the affected resident might be significant. In addition, imagine how difficult it would be to find temporary housing for even 2,000 families, not to mention 25,000.

2 Introduction

FSC has conducted many outage cost studies (also known as *value of service* studies) over the past 25 years for various utilities around the U.S., including PG&E. However, these previous studies focused primarily on short duration outages (i.e., outages of 24 hours or less). The procedures used to collect information about such outages are well established. However, because customers inevitably must alter their operations in response to long duration outages in important ways, the impacts of long duration outages are very different from those of short duration outages. Therefore, FSC modified its survey instruments in order to account for issues specific to estimating the costs associated with a 24-hour to 7-week outage. To begin this project, FSC reviewed the literature associated with estimating costs from long duration power outages. While there is a substantial body of literature on shorter duration power outages, the literature on long duration, widespread power outages is fairly thin and more journalistic than scientific – if only because such outages are highly uncommon. When long duration outages do occur, it is often in the aftermath of a natural disaster. FSC therefore turned to the literature on hazard loss estimation to review methods applicable to a long duration outage scenario in downtown San Francisco. This literature focuses on two types of costs that result from business interruptions – direct costs and indirect costs. FSC's summary of the literature on hazard loss estimation is attached as Appendix B.

2.1 Estimating Direct Costs

Direct costs of outages include the net revenue losses, equipment damage and response costs for customers that lose power. These costs are primarily attributed to commercial and industrial customers. There are three methods for direct cost estimation, including:

- Scaling of macroeconomic indicators;
- Extrapolation from prior case studies; and
- Primary data collection through surveys.

Although uncommon in the hazard loss estimation literature due to their relatively high data collection cost, survey methods provide the most reliable evidence of direct costs. Simpler and less expensive methods that rely on scaling output losses from macroeconomic variables (such as annual gross output), while easy to undertake, rely on fundamentally unrealistic assumptions (i.e., scalar adjustments for resiliency). Similarly, methods that use estimates from prior case studies rely on conditions and assumptions that may have little bearing on the situation under study (i.e., a long duration outage in San Francisco). Approaches based on primary data collection, on the other hand, take into account assumptions and heterogeneity of customers. Surveys derive estimates directly from representatives of the firms that will experience the outage – the agents in the best position to understand their firms and assess the likely costs of disruption. Surveys rely on scientific sampling techniques to ensure that answers obtained from surveys are representative of the customer population of interest, thereby enabling survey results to be scaled to the affected population. Although surveys ask respondents about hypothetical scenarios, and thus obtain estimates of likely costs, alternatives are much less accurate.

In the hazard loss estimation field, most experts use scaled macroeconomic variables as the basis for direct cost estimates, including Dr. Adam Rose who is one of the premier hazard loss estimation experts and wrote a seminal methodological comparison of the different cost estimation techniques in

2004.[2] While most hazard loss estimation experts, including Dr. Rose, agree that surveys are the preferred approach for estimating direct costs, this method is relatively uncommon because of cost concerns. Because this study focuses on a few thousand businesses served by PG&E's Embarcadero substation, survey methods are feasible because the cost to complete a statistically valid survey of these business is not very high for such a small, relatively homogeneous population. More importantly, there is good reason to believe that macroeconomic indicators, such as Gross Domestic Product (GDP), are simply unavailable for such a small geographical area, so a macroeconomic estimate would rely on tenuous assumptions to estimate revenue specifically for the target population.

We know this is the case because we developed an estimate of the direct outage cost that would occur as a result of an interruption of electric service using GDP. To do this, FSC identified the smallest geographical area containing downtown San Francisco for which GDP is published. The U.S. Department of Commerce Bureau of Economic Analysis provides GDP information down to the level of metropolitan statistical area (MSA). The entire target population is located within the San Francisco-Oakland-Fremont MSA. Within this MSA, FSC estimated that the target population accounts for roughly 2% of PG&E non-residential accounts and 12.6% of non-residential electrical usage.
Considering that the target population comprises a relatively small portion of the MSA as a whole (that is known to have a very high concentration of high value added businesses), it is problematic to accurately interpolate a localized GDP estimate. With an MSA annual GDP of $335,563 million and 12.6% allocated towards the target population, FSC estimated an annual GDP of $42,355 million within the target population, but this estimate was developed by a highly oversimplified scalar. To develop a GDP-based estimate of outage costs, we assumed that annual GDP is evenly distributed among the hours of the year. Therefore, we divide $42,355 million by 8,760 hours in the year to develop an hourly GDP-based outage cost estimate of $4.8 million per hour. On a daily basis, the GDP-based outage cost estimate is $116 million; $464 million for a 4-day outage; $2.4 billion over 3 weeks; and $5.7 billion for a 7-week business interruption.

Although the GDP-based estimate serves as an interesting comparison to the survey-based results in this study, there are many drawbacks for this GDP-based outage cost estimate, including:

- GDP is a proxy for outage costs as opposed to a direct measurement provided by a survey;
- GDP-generating activities are not evenly distributed throughout the year or the day; and
- Given that GDP is not available at a local level, we rely on the assumption that GDP is evenly distributed (by annual GWh usage) throughout businesses in the MSA. However, it is unknown if the target population produces more or less GDP per GWh relative to the remaining population in the MSA.

These drawbacks highlight many of the reasons why survey-based estimates have become the more commonly accepted practice in the direct outage cost estimation literature, as well as the hazard loss estimation literature (particularly if accurate, localized GDP information for the population of interest is unavailable). Indeed, the California Public Utilities Commission (CPUC) has also found survey-based outage cost estimates to be most appropriate on multiple occasions. Prior to PG&E's 2005 outage cost study, the CPUC, PG&E and other stakeholders compared various methodologies and the CPUC

[2] Rose, Adam. "Economic Principles, Issues, and Research Priorities in Natural Hazard Loss Estimation," in Y. Okuyama and S. Chang (eds.) Modeling the Spatial Economic Impacts of Natural Hazards, Heidelberg: Springer, 2004, pp.13-36.

ultimately directed PG&E to use a survey-based approach in conducting its 2005 outage cost study.[3] The CPUC again directed PG&E to use survey-based methods in its 2012 outage cost study.[4] Both the 2005 and 2012 outage cost studies were carried out successfully by FSC, and we have applied the same high standard for estimating direct costs in this study.

2.2 Estimating Indirect Costs

Indirect costs to commercial and industrial customers result from the chain reaction of economic losses stemming from direct costs: interactions between businesses (e.g., changes in quantities of inputs bought or outputs sold, changes in relative prices) and interactions between consumers and businesses (e.g., lost wages and reduced spending). Indirect costs are thus incurred not only by people and firms subject to an outage, but also to people and firms outside of the affected area. Additionally, outage costs associated with public expenditures (e.g., assistance programs, emergency services, loss of taxes), public goods (e.g., water treatment) and injury or loss of life can be considered a part of indirect costs.

Measuring indirect costs is challenging for several reasons. Indirect losses cannot be readily verified through a survey like direct losses. Moreover, indirect effects are spatially dispersed; if a firm in San Francisco suspends operations, it may affect businesses elsewhere in the Bay Area, the United States, or the world. Finally, indirect losses vary *substantially* with the resiliency – the adaptive behaviors – of affected firms, which in turn varies substantially with specific market conditions that cannot be anticipated or modeled a priori. For example, in the fall of 2012, an Exxon refinery in Torrance experienced a momentary power outage that caused the refinery to shut down for approximately 5 days. This caused wholesale gasoline supplies to tighten significantly in the California market, which in turn caused the retail price of gasoline to spike dramatically over a period of about 10 days. Under normal conditions, removal of the productive output of that refinery would not have materially changed the wholesale price of gasoline because other suppliers would take up the slack. Unfortunately, these were not normal conditions because producers were drawing down their summer gasoline formulation stocks and the Chevron Richmond refinery was off line because of a fire in the preceding month. While we are not aware of any efforts to calculate the indirect cost to gasoline consumers of this outage, there is no doubt that this cost was dramatically higher than it would have been if it occurred either one month earlier or one month later in the annual production cycle

This outage also illustrates another very perplexing issue with estimating indirect costs. As with direct costs, indirect costs represent a net value, since some California businesses stand to benefit in the case of an outage – whether by substituting for adversely-affected competitors or responding to new demand.

Given the above problems, any calculation of indirect costs must necessarily be understood as simply an order-of-magnitude approximation. Indirect costs cannot be captured directly by surveys. It is our view that indirect costs should be estimated from a simple multiplier based on the literature or a regional economic model, and estimates can vary substantially based on the approach used to model them and the scope of costs under consideration. One thing, however, is clear: accounting for indirect

[3] CPUC Resolution E-3922

[4] D.10-06-048

costs always leads to an increase in the total cost estimate. A wide range of indirect costs have been calculated for real and hypothetical electricity outages in the hazard loss literature. These cost estimates and the methods and procedures that were used to calculate them are discussed in detail in Appendix B. Based on our review of this literature, we believe it is reasonable to expect indirect costs to be between one-half and two times direct costs for this study. In this report, we employ these multipliers to develop a range of indirect cost estimates in Section 6.

2.3 Potential Social Disruption

Another important consideration specifically for downtown San Francisco is the potential social disruption, and resulting costs, that could occur as a result of a long duration power outage.

In July 1977, New York City experienced a 25-hour blackout that affected 9 million people and resulted in widespread criminal activity. Corwin and Miles' 1978 study of the New York blackout continues to be widely cited in the literature on the costs of major power outages.[5] They constructed a summary of economic impacts by bringing together separate and independent reports of costs from businesses and business associations, governments, public service agencies, non-profit service organizations, insurers and health institutions. While Corwin and Miles disclaimed that their list was not comprehensive, the summation of reports resulted in an estimated indirect outage cost of $290 million in nominal dollars, which is about $1 billion in 2012 dollars and more than 5 times their direct cost estimate, which is well outside the range of multipliers used in this study (0.5x to 2x). Additionally, Corwin and Miles discussed non-quantified costs associated with social impacts, such as the cancellation of planned activities, the alteration of transportation flows and the inconvenience of everyday life functions.

While it seems unlikely that a long duration outage in San Francisco would result in similar levels of chaos and security response as that 1977 New York City outage, Corwin and Miles' study demonstrates that damage from looting and rioting, and the costs of government response and assistance, can be quite significant in the aftermath of a major outage or disaster, particularly in urban areas. Because business and residential buildings would not be occupied during the outage, there would be costs to secure such buildings, either through a police presence, private security or both. The loss of traffic signals would result in traffic control costs. For a unique area like downtown San Francisco, it is impossible to predict the potential level of damages from looting and rioting and the costs of government response.

Loss of Embarcadero Substation also would disrupt transportation flows in the directly impacted area and beyond. The Bay Area Rapid Transit (BART) and the San Francisco Municipal Railway (MUNI) could experience substantial impacts from a long duration outage of the Embarcadero Substation. The outage would impact the BART/Muni Embarcadero Station (station power), the Temporary TransBay Terminal (currently in operation), and the future TransBay Terminal. Although BART trains run on power that would not be affected by an Embarcadero Substation outage, the BART/Muni Embarcadero Station is roughly at the center of the four major BART lines running through the Bay Area. Similarly, the MUNI system also other sources of track power, but many important MUNI bus and light rail lines run through the Embarcadero Station, so the impact on those key transportation lines could also be

[5] Corwin, J. & Miles, W., 1978. *Impact Assessment of the 1977 New York City Blackout*, Palo Alto, CA: Systems Control, Inc.

considerable. San Francisco's Cruise Terminal also would lose power. The costs to these transportation systems, and additional costs to consumers who might need them, are bound to be substantial. However, these public transportation providers may not be willing to provide detailed impact estimates for security reasons.

As a result of these costs, the indirect cost estimate is likely to be toward the higher end of the range of estimates that is provided in this study.

2.4 Report Organization

The remainder of this report proceeds as follows. Section 3 summarizes the survey methodology that FSC implemented among a stratified random sample of businesses in the target population. Section 4 describes survey response and assesses any potential sources of non-response bias in the survey results. In Section 5, the survey results are presented. Section 6 summarizes the estimated indirect costs that would result from a long duration outage. The full survey instrument is included in Appendix A. Appendix B provides the review of literature focused on direct and indirect cost estimation.

3 Survey Methodology

FSC conducted the survey among a stratified random sample of PG&E business customers in the target population. These business customers were split into three main customer segments:

- Listed small and medium business (SMB) customers;
- Listed large business customers (LB); and
- Master metered tenants.

Listed customers are those that are represented in PG&E's customer database. Throughout the data collection process, FSC had to develop the information for a separate segment of master metered tenants because there are a number of high rise, master metered office buildings in the Embarcadero area. Tenants in these master metered buildings are not represented in PG&E's customer database and if costs for this segment were not including the study, the cost estimates would be drastically underestimated. The process for identifying a master metered building and surveying its tenants is described at the end of this section.

3.1 Survey Implementation Approach

Table 3-1 provides an overview of the survey implementation approach by segment. All customer segments were recruited by telephone. After a respondent verbally committed to participating in the survey, listed SMB customers and master metered tenants were emailed a link to the online survey and a unique access code. For LB customers, FSC scheduled in-person interviews because their business operations are generally more complex and require a trained survey interviewer to properly guide respondents through the survey. The incentive for completing the survey or in-person interview varied by segment and, for listed SMB customers and master metered tenants, the incentive varied over time as the data collection efforts proceeded. FSC initially tested a $75 incentive for completion of the survey by listed SMB customers and master metered tenants, but we quickly determined that a larger incentive was required to achieve reasonable response rates among busy downtown San Francisco businesses. Therefore, FSC first increased the incentive for completing the online survey to $100, which was sufficient to achieve the target of 150 completed surveys among listed SMB customers. For master metered tenants, FSC ultimately had to increase the incentive to $200 in order to achieve an acceptable response rate in that segment. The incentive for listed LB customers was held at $200 throughout the data collection process.

Table 3-1: Survey Implementation Approach by Segment

Segment	Sample Design Target	Recruitment Method	Data Collection Approach	Incentive Provided
Listed SMB Customers	150	Telephone	Online Survey	$75 to $100
Listed LB Customers	20	Telephone	In-person Interview	$200
Master Metered Tenants	50	Telephone	Online Survey	$75 to $200

3.2 Survey Instrument Design

The survey instrument included 6 main sections:

- Description of business, including employment and revenue;
- Case 1: Costs of a 24-hour outage;
- General issues associated with responding to long duration outages;
- Case 2: Costs of a 4-day outage;
- Case 3: Costs of a 3-week outage; and
- Case 4: Costs of a 7-week outage.

Considering that most customers have never experienced an outage that lasts multiple days or weeks, the survey instrument included a section between Case 1 and Case 2 that addresses general issues associated with responding to long duration outages, such as the use of backup generation, telecommuting capabilities and temporary/permanent relocation possibilities. After respondents think about these issues, they are able to more accurately answer more specific questions associated with how their business would respond to a long duration outage and how much it would cost their business. FSC identified these issues by pre-testing the survey instrument among 40 businesses in the New Orleans area that experienced a long duration business interruption after Hurricane Katrina. This pre-testing, as well as pre-testing among customers in the target population, greatly improved the validity of the survey instrument and ensured that the survey covered key issues and cost categories to consider when a long duration business interruption occurs.

For each case, the total outage cost is calculated by the following equation:

$$Total\,Outage\,Cost = Net\,Revenue\,Loss + Total\,Out\text{-}of\text{-}Pocket\,Cost$$

In the above equation, *Net Revenue Loss* is the revenue loss during the outage minus the revenue loss recovered after the outage, which are measured through two questions in the survey and only apply to the affected business in the target population. *Total Out-of-Pocket Cost* is the sum of all costs associated with responding to the outage, including:

- Temporary/permanent relocation cost;
- Salaries/wages to staff unable to work;
- Extra shifts/overtime pay;
- Damage to equipment;
- Damage to materials;
- Restart costs;
- Backup generation cost;
- Telecommuting costs; and
- Other out-of-pocket costs.

The temporary/permanent relocation cost was a key factor that FSC identified while pre-testing the survey among business affected by Hurricane Katrina. Therefore, questions regarding relocation are included at various points in the survey instrument. For more details on the survey instrument, refer to Appendix A, which includes the full survey instrument.

3.3 Sample Design

Before detailing the sample design methodology and how these sample points were distributed among usage categories, it is important to note that a *customer* refers to each individual business at each address, not an individual account at each address. When business customers complete an outage cost survey, they provide answers associated with all of their accounts at a certain address. Many of these businesses only have one account at that address, in which case the customer-level estimates and account-level estimates are identical. However, there are some businesses that have multiple accounts at the same address, especially in downtown San Francisco, in which case the respondent is rarely able to provide the cost estimates for an individual account within a building. Therefore, usage and customer contact information were aggregated across all of the accounts associated with each business at each address before sampling customers.

Listed SMB customers were split into four usage categories and listed LB customers were split into three usage categories. The optimal stratum boundaries were determined using the Delanius-Hodges technique, with the natural logarithm of customer usage as the indicator variable. The same variable was used in a Neyman allocation to determine the optimal number of targeted sample points within each stratum. The natural logarithm of customer usage was used as the indicator variable because it is the observable variable that is most highly correlated with customer outage costs, as shown in many prior outage cost studies, including the PG&E's 2012 systemwide value of service study. This sampling approach is necessary because the distribution of usage per customer is highly skewed. As shown in Figure 3-1, a vast majority of customers is clustered towards the lower end of the usage distribution for each segment and there is a *long tail* of high usage customers towards the upper end of the distribution. Considering that usage is a proxy for outage costs, a key objective of the sample design methodology was to ensure that the sample included a sufficient amount of high usage customers. A simple random sample would not accomplish this objective because high usage customers would have a very low probability of being selected for the sample considering that they account for a small percentage of each segment.

Figure 3-1: Distribution of Average Hourly Usage by Segment (Top 5th Percentile for Each Customer Class Omitted)

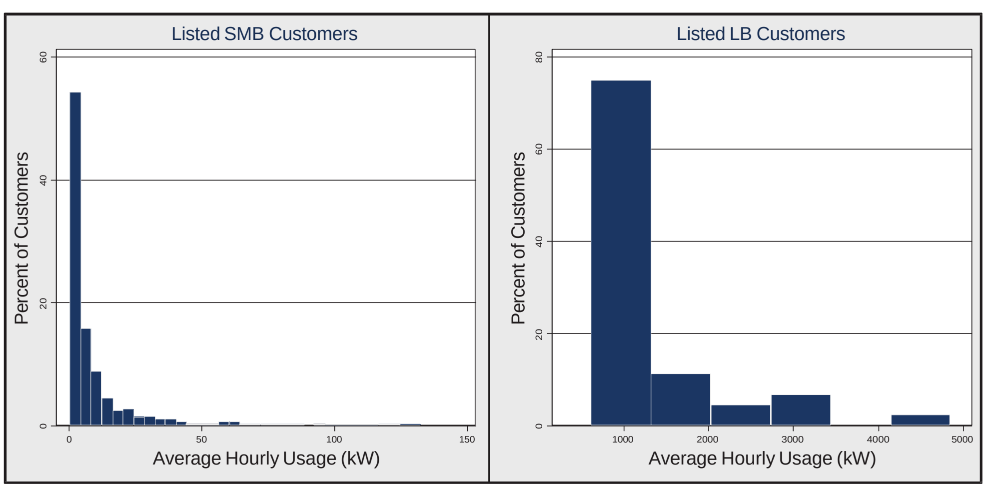


Table 3-2 summarizes the sample design for listed SMB and LB customers. Aggregate average hourly usage is 56.2 MW among all listed SMB customers in PG&E's database and 63.4 MW among all listed LB customers. The target population is defined as the customers served by the Embarcadero substation in San Francisco. Customers with less than 0.5 kW average hourly electricity usage are excluded from the survey because many of these facilities are unmanned (i.e., signals, signs and communications transponders) and collectively they account for a tiny fraction of electricity consumption in the target market. It is simply not cost-effective to expend survey resources on facilities that make up a very small percentage of the aggregate electricity consumption (and presumably outage cost) and are extremely difficult to recruit because they are unmanned. As shown in Table 3-2, these small customers comprise 0.2% of aggregate usage among listed SMB customers, so their impact on the final results is negligible even though they comprise 23.6% of customers in the SMB target population. The 150 sample points for listed SMB customers are divided roughly evenly between the 4 usage categories above 0.5 average kW. Half of the sample points for listed LB customers are allocated toward the largest usage category even though it only accounts for 24.4% of customers in the LB target population. This sample design ensured that the study included a sufficient amount of high usage customers that were likely to have higher and more variable outage costs, which improves the precision of the results but does not introduce bias because population weights are employed to ensure that estimates are representative of the target population.

Table 3-2: Sample Design Summary by Segment

Segment	Usage Category (Average kW)	Target Population				Sample	
		Total MW	% of Total MW	Number of Obs.	% of Population	Target	% of Sample
Listed SMB Customers	0 to 0.5	0.1	0.2%	692	23.6%	0	0.0%
	0.5 to 1.8	0.7	1.2%	656	22.4%	36	24.0%
	1.8 to 6.4	2.5	4.5%	691	23.6%	37	24.7%
	6.4 to 30.5	7.9	14.0%	587	20.0%	37	24.7%
	30.5 to 600	45.0	80.1%	306	10.4%	40	26.7%
	SMB Overall	*56.2*	*100%*	*2,932*	*100%*	*150*	*100%*
Listed LB Customers	600 to 855	15.4	24.3%	21	46.7%	5	25.0%
	855 to 1,353	14.5	22.9%	13	28.9%	5	25.0%
	1,353 to 8,900	33.5	52.8%	11	24.4%	10	50.0%
	LB Overall	*63.4*	*100%*	*45*	*100%*	*20*	*100%*

A stratified random sample for master metered tenants could not be developed a priori because the identity and number of these customers was not known at the time of the sample design. In fact, FSC did not have information on exactly which buildings had master metered tenants until after a directly served customer completed the survey. During the phone recruitment process, FSC filtered out customers that were clearly not property managers with master metered tenants. However, if respondents were unsure or may have been a property manager with master metered tenants, FSC waited until they finished the survey and then called back to verify that the customer was a property manager with master metered tenants. If so, FSC also asked how many tenants were at the address and attempted to obtain their identities. Using this verified information for listed SMB and LB customers that completed the survey, FSC focused its efforts on recruiting a representative sample of tenants in those master metered buildings.

FSC employed several options to develop a sampling frame within each of these master metered buildings. The options, in order of priority, included:

- Working with the property manager to identify all master metered tenants in the building;
- Visiting the building and gathering tenant information from the building directory;
- Standing outside the building and asking people leaving and entering which business they are visiting; and
- Searching online for businesses that are located at the building address.

If a building had 25 or fewer master metered tenants, FSC released[6] all of the records and attempted to recruit all tenants for the survey. If a building had more than 25 master metered tenants, FSC released a random sample of 25 tenants for survey recruitment. In total, FSC released 269 records that were associated with identified business tenants in master metered buildings.

6 A released record represents a customer that FSC tried to recruit for the survey.

4 Survey Response and Non-response Bias Assessment

Table 4-1 summarizes survey response by segment and usage category. With 224 total completed surveys, customer response was above the overall sample design target of 220. Overall, the survey had a 18.8% response rate among listed SMB customers and this SMB response rate was roughly consistent across usage categories. At 20.4%, master metered tenants had a similar response rate. In the listed LB segment, the response rate increased as usage increased, which is expected considering that larger customers generally have a close relationship with their account managers who helped with recruitment efforts. Nonetheless, non-response bias among high usage LB customers is not a significant concern for the outage cost estimates because usage category is factored into the population weights in the analysis.

Table 4-1: Customer Survey Response Summary by Segment and Usage Category

Segment	Usage Category (Average kW)	Population	Sample Design Target	Records Released	Survey Responses	Response Rate
Listed SMB Customers	0.5 to 1.8	656	36	192	34	17.7%
	1.8 to 6.4	691	37	200	39	19.5%
	6.4 to 30.5	587	37	200	38	19.0%
	30.5 to 600	306	40	208	39	18.8%
	SMB Overall	*2,240*	*150*	*800*	*150*	*18.8%*
Listed LB Customers	600 to 855	21	5	21	6	28.6%
	855 to 1,353	13	5	13	6	46.2%
	1,353 to 8,900	11	10	11	7	63.6%
	LB Overall	*45*	*20*	*45*	*19*	*42.2%*
Master Metered Tenants		2,444	50	269	55	20.4%
Overall		**4,729**	**220**	**1,114**	**224**	**20.1%**

The remainder of this section analyzes survey response for listed customers. This analysis was not conducted for master metered tenants because we only have information for tenants that ultimately completed the survey. Without information for tenants who did not complete the survey, it is not possible to analyze response by usage and industry category and assess the potential sources of non-response. Nonetheless, master metered tenants have a comparable response rate and a similar magnitude of outage costs relative to listed SMB customers (see Section 5), which ensures that the tenant estimates are reasonable.

4.1 Survey Response by Industry Category

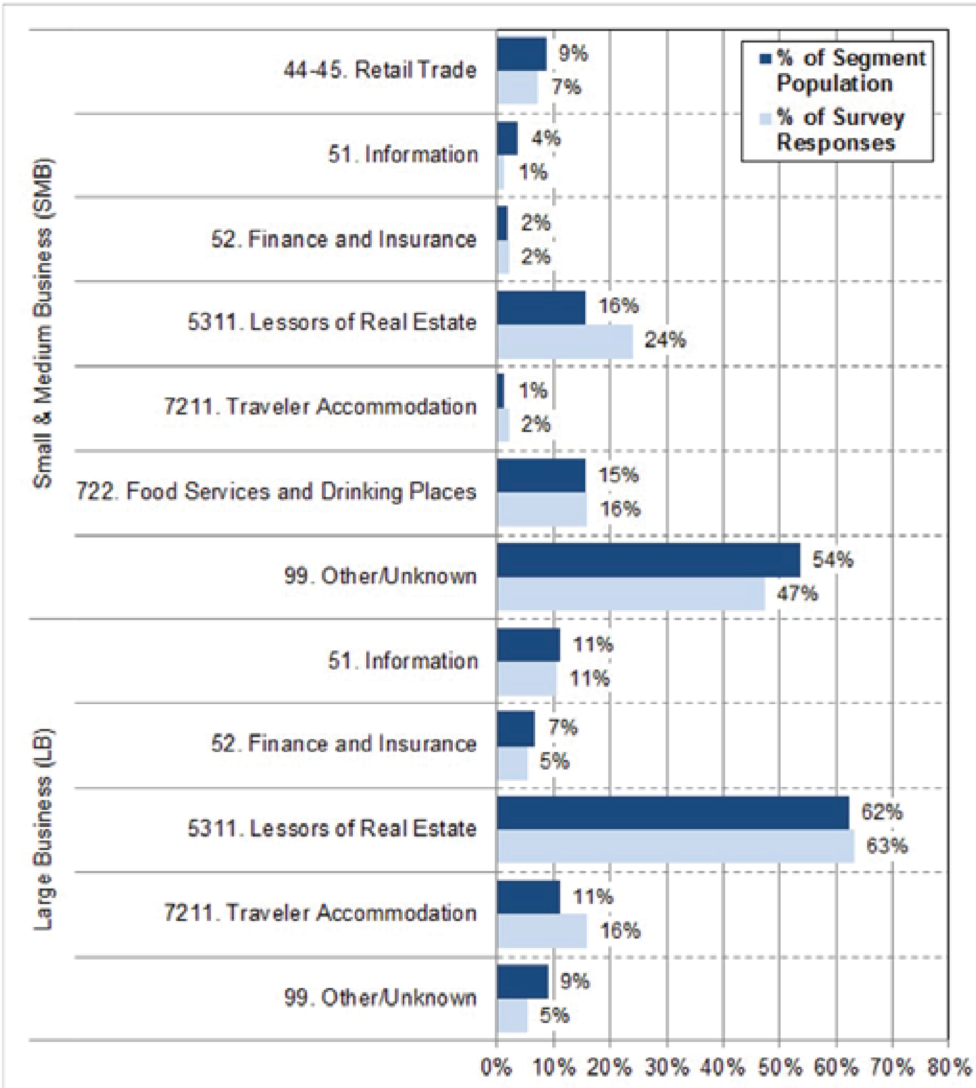
Table 4-2 provides the response rates by segment and industry category. Sample design targets are not included in this table because the survey implementation did not have specific quotas of survey responses by industry category. Stratifying the sample by usage category and industry category would have added substantial costs to the survey implementation and the benefit of doing so is not certain. Nonetheless, it is important to analyze survey response by industry category to ensure that key industry categories are represented in the survey data and that response rates are roughly consistent across business types. Other than customers in the information sector, response rates for listed SMB customers are relatively consistent across industry categories. Response rates for listed LB customers are more variable, but given the relatively small number of customers in each industry category, more variation is expected. This section concludes with a more rigorous non-response bias assessment to determine if these differences are statistically significant.

Table 4-2: Customer Survey Response Summary by Segment and Industry Category

Segment	Industry Category	Population	Records Released	Survey Responses	Response Rate
Listed SMB Customers	44-45. Retail Trade	192	74	11	14.9%
	51. Information	80	28	2	7.1%
	52. Finance and Insurance	41	15	3	20.0%
	5311. Lessors of Real Estate	352	170	36	21.2%
	7211. Traveler Accommodation	27	12	3	25.0%
	722. Food Services and Drinking Places	347	114	24	21.1%
	99. Other/Unknown	1,201	387	71	18.3%
	SMB Overall	*2,240*	*800*	*150*	*18.8%*
Listed LB Customers	51. Information	5	5	2	40.0%
	52. Finance and Insurance	3	3	1	33.3%
	5311. Lessors of Real Estate	28	28	12	42.9%
	7211. Traveler Accommodation	5	5	3	60.0%
	99. Other/Unknown	4	4	1	25.0%
	LB Overall	*45*	*45*	*19*	*42.2%*

Figure 4-1 compares the distribution of the population and survey respondents by segment and industry category. Even though response rates do not vary substantially by industry category, there can still be differences between the population mix and respondent mix if the sampled records were not representative of the population. As shown in the figure, the percentage of the population and respondents that fall into each industry category are highly correlated. In each segment, the other/unknown industry category is underrepresented in the sample, but this trend is expected because those customers generally have lower usage and the sample design targets a relatively low percentage of these smaller customers. Conversely, as a result of targeting relatively large customers more intensively, lessors of real estate in the SMB segment comprise a relatively high percentage of survey respondents. After weighting the results to the population by usage category, these differences are reduced.

Figure 4-1: Distribution of Population and Survey Respondents by Segment and Industry Category



4.2 Detailed Non-response Bias Assessment

Although a 20% overall response rate is reasonable considering that the target population is comprised of busy downtown San Francisco establishments, it is important to conduct a detailed assessment of the potential sources of non-response bias. If the 80% of customers in the released sample who did not respond to the survey are significantly different from the 20% who completed the survey, the outage cost estimates will be biased and adjustments to the population weights may be necessary. To assess potential sources of non-response bias, FSC conducted an analysis of the response trends in the survey. For listed SMB and LB customers, a Probit econometric regression model was run at the individual customer level among all of the released records throughout the data collection process.

Each Probit regression model was run using all of the released records for each segment, with records that completed the survey assigned with a one in the analysis dataset and records that did not complete the survey assigned with a zero in the dataset. Therefore, the Probit regression models summarized in this section show the factors that contributed to the likelihood that a customer completed the survey. A positive regression coefficient is interpreted as an increase in the likelihood of survey response and a negative regression coefficient is interpreted as a decrease in the likelihood of survey response. Any factors that significantly affect the likelihood that a customer completed the survey that were not accounted for in the population weights may lead to non-response bias in the results. As in any survey, there may be unobservable factors that contribute to non-response bias as well, but data is not available for those variables, so those factors are not considered in this analysis.

The variables in the models are usage and industry category (based on the North American Industry Classification System codes). Within each segment, four Probit models with different specifications of the usage variable were run:

- **Model 1:** Usage specified as a linear relationship (average kW variable included in the model)
- **Model 2:** Usage specified as a second order polynomial relationship (average kW and average kW squared variables included in the model)
- **Model 3:** Usage specified as a logarithmic relationship (log of average kW variable included in the model)
- **Model 4:** Usage specified as a categorical relationship (each usage category included in the model as binary variables)

Results for all four models are provided for each segment so that the analysis tests whether or not a finding is robust to the model specification. If a coefficient is statistically significant across all four models, we can conclude that its underlying variable has an effect on response likelihood.

Table 4-3 provides the Probit regression results for the SMB segment. The information sector variable produces the only statistically significant coefficient in all four models, suggesting that customers in the information sector were less likely to respond to the survey. Considering that the information sector in downtown San Francisco consists of many lightly staffed data centers, relatively lower response rates in this industry category would not be surprising. However, even though this coefficient is statistically significant in all four models, there is no evidence for non-response bias because the models as a whole are jointly insignificant, as indicated by the high Chi-square statistics and very low R-squared values. Therefore, we conclude that there may be relatively lower response among customers in the information sector, but given that the models are jointly insignificant, it is not a concern for the final results and adjustments to the population weights are not necessary. Even if adjustments were made, customers in the information sector comprise only 4% of the listed SMB population, so the impact of such adjustments on the overall results would be negligible.

Table 4-3: Probit Regression for Assessment of Non-Response Bias – Listed SMB Customers (Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable Category	Variable	Model 1	Model 2	Model 3	Model 4
Usage	Average kW	-0.0007	0.0016	—	—
	Average kW Squared	—	0.0000	—	—
	Log of Average kW	—	—	-0.0205	—
	Usage Category 1 (0.5 to 1.8 kW)	—	—	—	(Base)
	Usage Category 2 (1.8 to 6.4 kW)	—	—	—	0.0347
	Usage Category 3 (6.4 to 30.5 kW)	—	—	—	0.0017
	Usage Category 4 (30.5 to 600 kW)	—	—	—	-0.0439
Industry	44-45. Retail Trade	-0.2953	-0.2502	-0.2836	-0.2689
	51. Information	-0.7033*	-0.6751*	-0.6933*	-0.6785*
	52. Finance and Insurance	-0.0725	-0.0126	-0.0657	-0.0664
	5311. Lessors of Real Estate	(Base Industry Category)			
	7211. Traveler Accommodation	0.1430	0.1386	0.1349	0.1303
	722. Food Services and Drinking Places	-0.0636	-0.0302	-0.0315	-0.0289
	99. Other/Unknown	-0.1533	-0.1221	-0.1381	-0.1258
Number of Observations		800	800	800	800
Chi Squared Statistic		0.52	0.28	0.63	0.84
R-Squared		0.0084	0.0106	0.0073	0.0071

Table 4-3 provides the Probit regression results for the LB segment. The only statistically significant variables in all four models are the log of average kW in model 3 and the largest usage category in model 4. As discussed above, this result is expected considering that larger customers generally have a close relationship with their account managers who helped with recruitment efforts. Considering that usage category is factored into the population weights in the analysis, non-response bias among high usage LB customers is not a significant concern for the outage cost estimates. In addition, as in the SMB segment, even though there are statistically significant coefficients, there is no evidence for non-response bias because the models as a whole are jointly insignificant, as indicated by the high Chi-square statistics and low R-squared values.

Table 4-4: Probit Regression for Assessment of Non-Response Bias – Listed LB Customers (Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable Category	Variable	Model 1	Model 2	Model 3	Model 4
Usage	Average kW	0.0003	0.0004	—	—
	Average kW Squared	—	0.0000	—	—
	Log of Average kW	—	—	0.7479*	—
	Usage Category 1 (600 to 855 kW)	—	—	—	(Base)
	Usage Category 2 (855 to 1,353 kW)	—	—	—	0.5408
	Usage Category 3 (1,353 to 8,900 kW)	—	—	—	0.9931**
Industry Category	51. Information	-0.5009	-0.4488	-0.4733	-0.2106
	52. Finance and Insurance	-0.1865	-0.1797	-0.2142	-0.2266
	5311. Lessors of Real Estate	(Base Industry Category)			
	7211. Traveler Accommodation	0.5086	0.5257	0.5605	0.5686
	99. Other/Unknown	-0.5349	-0.5605	-0.6188	-0.5679
Number of Observations		45	45	45	45
Chi Squared Statistic		0.57	0.65	0.41	0.42
R-Squared		0.0671	0.0700	0.0937	0.0910

5 Survey Results

This section provides two sets of survey results. The direct outage cost estimates summarize the direct costs that businesses in the target population would experience as a result of a long duration outage. The second set of survey results focuses on the likelihood of lost businesses and employment in the target population.

5.1 Direct Outage Cost Estimates

Table 5-1 provides the average cost per outage event estimates by customer segment and outage duration. For a 24-hour outage, listed SMB customers experience an average cost of $20,536 per customer. As outage duration increases, the average cost increases to nearly $300,000 per customer at 3 weeks and over $600,000 per customer at 7 weeks. The incremental cost per day decreases slightly as outage duration increases for listed SMB customers. Between 24 hours and 4 days, the incremental cost per additional outage day is around $15,000. For the 45 additional outage days between 4 days and 7 weeks, the incremental cost per day is slightly lower at roughly $12,000. Although listed SMB customers are able to mitigate some daily costs as outage duration increases, there are still substantial costs for each additional outage day, even after 3 weeks to 7 weeks without power.

Master metered tenants have a similar magnitude of outage costs relative to listed SMB customers. For a 24-hour outage, master metered tenants experience an average cost of $29,086 per customer, which is 42% higher than that of listed SMB customers. As outage duration increases, the average cost for master metered tenants increases to around $250,000 per customer at 3 weeks and over $526,000 per customer at 7 weeks, estimates that are roughly 15% lower relative to those of listed SMB customers. As such, the incremental cost per day decreases relatively more quickly as outage duration increases for master metered tenants, perhaps because they stop paying rent or because they are relatively more capable of adapting by relocating or telecommuting. Between 24 hours and 4 days, the incremental cost per additional outage day is around $22,000. For the 45 additional outage days between 4 days and 7 weeks, the incremental cost per day is slightly lower at roughly $9,500, which is still a significant cost for each additional outage day. Even though average cost per outage event among master metered tenants is estimated from relatively few observations (55), the similar magnitude relative to the estimates for listed SMB customers (which are based on 150 observations) ensures that the tenant estimates are reasonable.

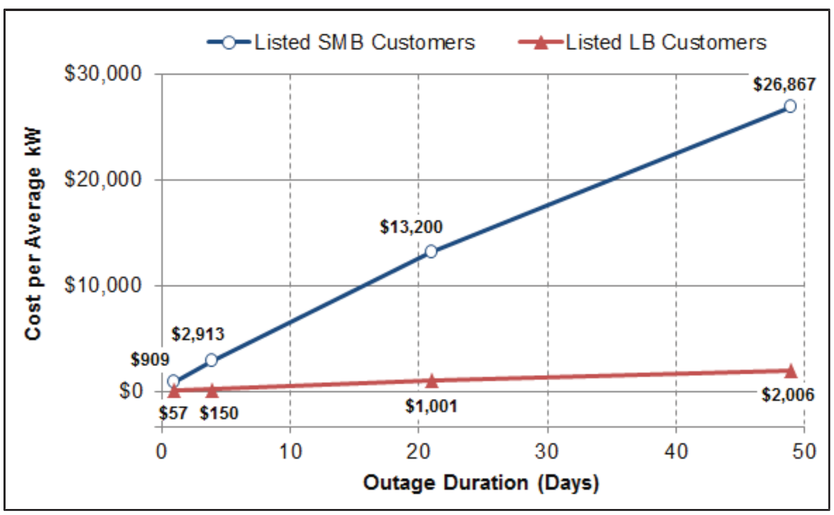
Table 5-1: Average Cost per Outage Event Estimates by Segment and Outage Duration

Segment	Outage Duration	Number of Obs.	Average Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Listed SMB Customers	24 hours	150	$20,536	$9,226	$31,845
	4 days	150	$65,848	$35,408	$96,287
	3 weeks	150	$298,359	$177,931	$418,787
	7 weeks	150	$607,265	$339,206	$875,323
Listed LB Customers	24 hours	19	$82,104	$8,427	$155,781
	4 days	19	$218,041	$11,890	$424,192
	3 weeks	19	$1,452,069	$3,445	$2,900,693
	7 weeks	19	$2,911,383	$583,527	$5,239,240

Segment	Outage Duration	Number of Obs.	Average Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Master Metered Tenants	24 hours	55	$29,086	$12,225	$45,948
	4 days	55	$95,836	$40,803	$150,868
	3 weeks	55	$250,477	$123,341	$377,614
	7 weeks	55	$526,370	$263,740	$789,000

Across outage durations, listed LB customers experience average costs per outage event that are roughly 3.3 to 5 times greater than those of listed SMB customers. However, considering that average demand is 1,451 kW among listed LB respondents and 22.6 kW among listed SMB respondents (98.4% less than LB average demand), the percentage difference in outage cost between segments is substantially lower than the percentage difference in average demand. As a result, outage costs for listed SMB customers are significantly higher when normalized by average kW. As shown in Figure 5-1, the outage cost per average kW estimates among listed SMB customers are more than an order of magnitude higher than those of listed LB customers at each outage duration. Considering that most listed LB customers are property managers that have master metered tenants in their buildings, this finding is expected given that those incremental tenant costs are separate from the cost per average kW estimates. Therefore, the outage cost estimates for listed LB customers are relatively low when normalized by average kW, even though the per event estimates are as high as around $2.9 million per customer for 7-week outage. Between 4 days and 7 weeks, the incremental cost per day is nearly $60,000 for listed LB customers, which is substantial cost for each additional outage day.

Figure 5-1: Cost per Average kW Estimates by Segment and Outage Duration[7]



With these cost per average kW estimates, it is relatively straightforward to develop the aggregate cost estimate for all listed customers in the target population. As discussed in Section 3, aggregate

[7] Cost per average kW estimates for mastered metered tenants are not included in this figure because usage information specifically for these customers is not available. Therefore, the cost per outage event estimates for master metered tenants cannot be normalized by average kW.

hourly usage is 56.2 MW among listed SMB customers and 63.4 MW among listed LB customers. These values are multiplied by the cost per average kW estimates in Figure 5-1 to develop the aggregate cost estimate for each outage duration.

For master metered tenants, calculating the aggregate cost is not as straightforward because we must estimate the total amount of these unlisted businesses in the target population. Table 5-2 summarizes this calculation. The estimated number of master metered tenants is 0.62 tenants per listed customer in the SMB segment and 23.2 tenants per listed customer in the LB segment. These averages are calculated and weighted to the population in the same manner that the average cost per outage event estimates are calculated in Table 5-1. The estimated number of mastered metered tenants is simply another result from the data collection efforts, except these responses were collected during the recruitment phase and then verified over the phone after a listed customer completed the survey. The total number of listed customers by segment is multiplied by the average number of master metered tenants per listed customer to develop the estimated total number by segment. Overall, we estimate that there are 2,444 total master metered tenants in the target population. This value is multiplied by the average cost per outage event estimates in Table 5-1 to develop the aggregate cost estimate among master metered tenants for each outage duration.

Table 5-2: Summary Calculation of the Estimated Total Number of Master Metered Tenants in the Target Population

Variable / Estimate	SMB	LB	Overall
Estimated Number of Master Metered Tenants per Listed Customer	0.62	23.2	1.07
Total Number of Listed Customers	2,240	45	2,285
Estimated Total Number of Master Metered Tenants	**1,399**	**1,045**	**2,444**

Table 5-3 provides the aggregate outage cost estimates by segment and outage duration. If the entire target population lost electric power for 7 weeks, businesses would experience a total direct outage cost of over $2.9 billion. A 3-week outage would lead to an aggregate outage cost of around $1.4 billion among businesses in the target population. For outages lasting 24 hours to 4 days, master metered tenants comprise around 57% of the aggregate outage cost, listed SMB customers account for roughly 40% of the total and the remaining 2% to 3% is in the listed LB segment. For a 3-week to 7-week outage, listed SMB customers account for the majority of the aggregate cost (around 52%), master metered tenants comprise over 43% of the total and the remaining 4% to 4.5% is in the listed LB segment.

Table 5-3: Aggregate Outage Cost Estimates by Segment and Outage Duration ($ Millions)

Outage Duration	Listed Customers		Master Metered Tenants	Total
	SMB	LB		
24 hours	$51.0	$3.6	$71.1	**$125.7**
4 days	$163.6	$9.5	$234.3	**$407.4**
3 weeks	$741.3	$63.4	$612.3	**$1,417.0**
7 weeks	$1,508.8	$127.1	$1,286.7	**$2,922.6**

5.2 Lost Businesses and Employment

Another important impact of a long duration outage that the survey measured was the likely magnitude of lost business and employment as a result of a long duration outage. At the end of the 3-week and 7-week outage scenarios, the survey instrument included an additional question, “How likely is it that this outage would cause you to go out of business?” Table 5-3 provides the results to this question by outage duration and segment. Among listed SMB customers and master metered tenants, the average reported likelihood of going out of business as a result of the outage ranged from around 20% to slightly over 28%. More than one out of 10 customers in these two segments report that they have a 70% or greater likelihood of going out of business as a result of an outage lasting 3 to 7 weeks. In contrast, the average reported likelihood among listed LB customers is 1.5% for a 3-week outage and 4.1% for a 7-week outage. Only one listed LB respondent indicated that they had a greater than 10% likelihood of going out of business. As such, smaller businesses (listed SMB customers and master metered tenant) would be disproportionately impacted by a long duration outage.

Table 5-3: Reported Likelihood of Going Out of Business as a Result of 3-week and 7-week Outages

Segment	Outage Duration	Number of Obs.	Average Reported Likelihood	Distribution of Responses				
				0%	10% to 30%	40% to 60%	70% to 90%	100%
Listed SMB Customers	3 weeks	150	23.1%	44%	31%	14%	7%	4%
	7 weeks	150	28.2%	39%	28%	18%	8%	8%
Listed LB Customers	3 weeks	19	1.5%	89%	11%	0%	0%	0%
	7 weeks	19	4.1%	80%	16%	0%	3%	0%
Master Metered Tenants	3 weeks	55	19.6%	49%	33%	5%	7%	5%
	7 weeks	55	20.7%	51%	27%	9%	7%	5%

Survey respondents were also asked to report the percentage of employees by labor category that they would forego paying during the 4-day, 3-week and 7-week power outages. As shown in Table 5-4, contract/temporary employees would be most impacted by a long duration outage. For an outage lasting 3 to 7 weeks, businesses in each segment would forgo paying around 35% or more of their contract/temporary employees on average. Part-time employees working for listed SMB businesses would be similarly impacted by a long duration outage, with those businesses reporting that over 40% of part-time employees would not receive pay throughout a 7-week outage. Among full-time employees, lost pay is relatively low, but it would still be substantial. For a 7-week outage, listed SMB customers would forgo paying an average of 27% of their full-time employees, which would be a substantial loss of income to the region. This lost income would not only result less commercial activity by the affected employees, but reduce income tax revenues for government and increase unemployment insurance payouts.

Table 5-4: Average Reported Percentage of Unpaid Employees by Segment and Labor Category

Segment	Outage Duration	Full-time	Part-time	Contract/ Temporary
Listed SMB Customers	4 days	19.1%	35.9%	35.4%
	3 weeks	22.0%	38.4%	35.7%
	7 weeks	27.0%	40.4%	40.4%
Listed LB Customers	4 days	9.9%	10.5%	17.2%
	3 weeks	18.4%	10.5%	38.9%
	7 weeks	19.5%	10.5%	38.9%
Master Metered Tenants	4 days	9.2%	15.5%	34.5%
	3 weeks	14.8%	21.8%	35.9%
	7 weeks	16.4%	22.2%	36.8%

5.3 Direct Outage Costs for Residential Customers

Although the Embarcadero area is primarily a business district, it is important to remember that many people live there as well. In fact, there are over 24,000 PG&E residential accounts that are served by the Embarcadero substation. Most of these residential customers live in high and low rise buildings that would need to be evacuated as a result of a long duration outage. In the survey, some property managers of residential buildings reported that their residents would have to be evacuated in the event of an outage because elevator, heating, cooling and ventilation systems would not be able to operate, which would lead to health and safety hazards for residents. In addition to the inconvenience of being displaced, these residential customers (or their property managers) would likely be required to bear the cost of living in a hotel, motel or short-term apartment (at considerable distance from the city) for the duration of the outage. Residential customers that do not live in high rise buildings may not be required to evacuate, but they would still experience substantial inconvenience costs as a result of a long duration outage.

Considering that we did not survey residential customers, it is difficult to determine what percentage would be required to evacuate and the extent of the inconvenience costs they would experience. As discussed in Section 2.1, direct costs of outages are primarily attributed to commercial and industrial customers. If we assume a worst case scenario in which living and accommodation costs $200 per day and 90% of the 24,000 residential accounts must evacuate, the cost as a result of displaced residents would be $17.3 million for a 4-day outage, $90.7 million for a 3-week outage and $212 million for a 7-week outage. Considering that these direct costs for residential customers would result in a proportionately small increase in the quantifiable total cost even in the worst case scenario, these costs have been omitted from the total cost estimate. Nonetheless, the inconvenience and economic impact that these residential customers would experience should not be ignored. The resulting costs could be quite significant for individuals or families, and all would suffer significant inconvenience.

6 Indirect Outage Cost Estimates

As a result of lost revenue and increased costs to businesses in the target population, there would be significant indirect spillover effects in the greater California economy as a result of a long duration outage. These indirect costs to commercial and industrial customers represent the chain reaction of economic losses stemming from direct costs: interactions between businesses (e.g., changes in quantities of inputs bought or outputs sold, changes in relative prices) and interactions between consumers and businesses (e.g., lost wages and reduced spending). Indirect costs are thus incurred not only by people and firms subject to an outage, but also to people and firms outside of the affected area. For example, when a business forgoes paying an employee in downtown San Francisco, that employee will reduce household consumption and investment, which will adversely affect businesses in the greater Bay Area and California as a whole. The same logic applies to affected businesses, which will also reduce consumption and investments that benefit other businesses, including neighboring businesses in the target population. Additionally, outage costs associated with public expenditures (e.g., assistance programs, emergency services, loss of taxes), public goods (e.g., water treatment), and injury or loss of life can be considered a part of indirect costs. Considering the complexity of indirect cost estimation, these costs were not measured through the survey. We instead use a range of multipliers that is informed by the hazard loss estimation literature.

As discussed in Section 2, a reasonable multiplier that can be used in this study to estimate indirect costs for California businesses is between one half and two. Using these multipliers, Table 5-3 provides the aggregate indirect outage cost estimates by outage duration. The estimated indirect outage costs range from $62.9 million to $251.4 million for a 24-hour outage to between nearly $1.5 billion and over $5.8 billion for a 7-week outage.

Table 5-3: Aggregate Indirect Outage Cost Estimates by Outage Duration ($ Millions)

Outage Duration	Total Direct Outage Cost	Range of Total Indirect Outage Costs	
		Low (Direct Cost x 0.5)	High (Direct Cost x 2.0)
24 hours	$125.7	$62.9	$251.4
4 days	$407.4	$203.7	$814.8
3 weeks	$1,417.0	$708.5	$2,833.9
7 weeks	$2,922.6	$1,461.3	$5,845.2

6.1 Potential Social Disruption

As discussed in Section 2, a long duration outage in downtown San Francisco would cause social disruption and resulting costs from, among other things, government response to security and traffic control needs, private security, potential looting or vandalism, and disruption of transportation (BART, Muni, TransBay Terminal and Cruise Terminal). Additionally, as noted in Corwin and Miles (1978), there are many other non-quantified costs associated with social impacts, such as the cancellation of planned activities, changes in normal work and leisure routines, and the inconvenience of everyday life functions. As a result, the indirect cost estimate is likely to be toward the higher end of the range of estimates that is provided in this study.

ATTACHMENT 23

Review of Hazard Literature

Attachment 3

Review of Hazard Literature

Appendix B Literature Review

Calculating the losses from a long-term power outage involves estimating costs that are the immediate consequence of the outage, called *direct costs*, and costs provoked by the consequences of the outage, called *indirect costs*. In this appendix, we summarize basic conceptual and methodological aspects of estimating costs from long-duration outages. Section B.1 and Section B.2 compare the various methodologies for estimating direct and indirect costs, much of which draws from Adam Rose's 2004 article entitled, "Economic Principles, Issues, and Research Priorities in Hazard Loss Estimation," and Hallegatte and Przyluski's 2010 article entitled, "The Economics of Natural Disasters: Concepts and Methods." Then, Section B.3 reviews studies that estimate the cost of long duration power outages and Section B.4 reviews relevant studies on the estimated cost of natural disasters. Finally, this appendix concludes with Section B.5, which provides a list of referenced literature.

B.1 Estimating Direct Costs

Direct costs of outages are primarily attributed to commercial and industrial customers and consist of several components: lost output (business interruption costs), losses from damage to equipment and materials, payments to labor associated with making up lost output and costs associated with back-up generation. Additionally, direct costs are a net measure; savings to firms (for example, for unpaid wages) are subtracted from costs to arrive at a final value.

Survey methods are optimal for direct cost estimation. Methods that rely on scaling output losses from macreconomic variables (such as annual gross output), while simple to undertake, rely on fundamentally unrealistic assumptions. Similarly, methods that use estimates from prior case studies rely on conditions and assumptions that may have little bearing on the scenario and population under study. Approaches based on primary data collection, on the other hand, take into account assumptions and heterogeneity of customers. Surveys derive estimates directly from the firms—the agents in the best position to understand their firms and assess the likely costs of disruption. Surveys rely on scientific sampling techniques to ensure that answers obtained from surveys are representative of the customer population of interest, thereby enabling survey results to be scaled to the affected population. Although surveys ask respondents about hypothetical scenarios, and thus may be approximations at best, alternatives are much less accurate. Surveys of direct costs primarily focus on businesses and do not include the costs associated with government response or transportation disruption. In addition, residential direct costs may not be considered in a survey because these costs are so low relative to business direct costs that it is not cost-effective to conduct a formal survey of impacted households.

B.2 Estimating Indirect Costs

Indirect costs to commercial and industrial customers represent the chain reaction of economic losses stemming from direct costs: interactions between businesses (e.g., changes in quantities of inputs bought or outputs sold, changes in relative prices) and interactions between consumers and businesses (e.g., lost wages and reduced spending). Indirect costs are thus incurred not only by people and firms subject to an outage, but also to people and firms outside of the affected area. Additionally, outage costs associated with public expenditures (e.g., assistance programs, emergency services, loss of taxes), public goods (e.g., water treatment), injury or loss of life, and inconvenience to residents can be considered a part of indirect costs.

Measuring indirect costs is challenging for several reasons. Indirect losses cannot be readily ascertained through surveys like direct losses. Moreover, indirect effects are spatially dispersed; if a firm in San Francisco suspends operations, it may affect businesses elsewhere in the Bay Area, the United States, or the world. Also, indirect losses will vary substantially with the resiliency—the adaptive behaviors—of affected firms. As with direct costs, indirect costs should represent a net value, since some businesses stand to benefit in the case of an outage—whether by substituting adversely-affected competitors or responding to new demand. Any calculation of indirect costs, therefore, represents simply an order-of-magnitude approximation.

Because surveys may not be feasible with indirect costs, estimation of indirect costs has typically used one of several methods: input-output models, computational general equilibrium models, or macroeconometric models. In each approach, direct losses from business interruption are the negative shock input into the model. These direct losses can be estimated from surveys, but are more often derived from scaled macroeconomic indicators. Direct losses from physical damage are not included in the input to these models, since the models rely on flow measures of economic activity (e.g., output, income) rather than stock measures of asset values (e.g., replacement costs of capital).[8]

B.2.1 Input-output Models

Input-output (I/O) models are static, linear models of all purchases and sales between sectors of an economy, based on historical correlations between quantities of inputs and outputs from each sector used by every other sector. If outputs of particular sectors in particular areas experience a negative shock, such as from a power outage, the level of purchases and sales between sectors adjusts accordingly, rippling through all sectors in the economy. An I/O model therefore uses direct costs as an input, such as a net loss of revenue to firms, and calculates indirect losses relative to direct losses; the result is a multiplier that can be applied to direct loss estimates. The sum of direct costs and indirect costs is the total cost estimate. The advantage to I/O models is that they are fairly transparent and can be used relatively easily, given the simplifying assumptions involved. However, they remain allocative in the sense that they cannot represent strategic behavior—sectors simply reallocate quantities of inputs and outputs to adjust. The main disadvantages of I/O models include their inability to incorporate behavioral responses of firms, interdependencies between quantities and prices, and resource constraints.[9] As such, I/O models are better suited for short-duration disruptions.

B.2.2 Computational General Equilibrium Models

[8] In regional economic modeling, indirect costs are always caused by business interruption, not asset damage. For example, it is not the damage to a factory that matters to other businesses that supply its inputs or purchase its outputs, but rather the interruption of that factory's production. Therefore, damage to capital should generally not be used as an input to regional economic models. However, businesses must still make outlays to repair or replace damaged assets following an outage, representing a forced investment and thus a loss of welfare. The value of an asset is the discounted flow of net future returns from its operation; since the replacement cost of an asset is not likely to equal the lost output from that asset being out of service for a short duration, replacement costs may overstate the amount of output sacrificed through this forced investment. Nevertheless, it stands to reason that some amount of physical damages (perhaps amortized) could be included in the direct cost input to regional economic models. This possibility is beyond the scope of our review.

[9] Extensions and adaptation of I/O models exist to account for more realistic economy-wide interactions. However, a review of the various adjustments to and extensions of I/O models is beyond the scope of this review.

Computational general equilibrium (CGE) models are multi-market simulations that optimize behavior between consumers and firms in response to price signals, subject to economic account balances and resource constraints. If outputs of particular firms in particular areas experience a negative shock, such as from a power outage, prices adjust and stimulate behavioral responses in an iterative fashion until equilibrium is restored; indirect losses are calculated by the difference in overall output after the shock. By incorporating production and consumption functions and price and import elasticities, CGE models are fundamentally *adaptive*; they incorporate behavioral responses of firms, input substitution, increasing or decreasing-returns-to-scale, non-infinite supply elasticities and other assumptions. The main disadvantages of CGE models include their assumption that economies return to equilibrium, that all agents optimize under full information and that substitution occurs instantaneously. In addition, without incorporating the costs associated with these adaptive behaviors (i.e., the fuel cost of using a backup generator), the net cost reduction is not properly estimated. As such, CGE models are likely to represent an underestimate or lower-bound of indirect losses from a long-duration outage.

Note that CGE models do not yield an indirect cost multiplier like I/O models since they model non-linear relationships. Whereas indirect effects are a constant multiple of direct effects in an I/O model, indirect effects vary non-linearly with direct effects in a CGE model. Therefore, the effective indirect cost multiplier in a CGE model will depend on the actual value of direct costs.

B.2.3 Macroeconometric Models

Macroeconometric models are a set of statistically estimated simultaneous equations that represent the aggregate workings of an economy, with parameters based on (long) time series data. Indirect costs are predicted by running the simultaneous equations with and without an adjustment for direct costs in a future time period. The main advantage of macroeconometric models is that they can effectively separate out changes in an economy due to a negative shock from other secular changes in an economy. However, their main disadvantages are that the historical experience upon which these models are based is unlikely to be representative of future activity, particularly following a major disruption, and that data are often not available at sub-regional levels.

B.2.4 Further Considerations

Exogenous policy responses, such as government assistance and security programs, cannot be captured by these models. A long-duration outage, insofar as it resembles a major disruption of urban activity, is likely to include some amount of public expenditure as determined on an ad hoc, emergency basis. Also, non-market costs, such as inconvenience, injury or death, and pollution, often remain unaccounted for since they cannot easily be measured.

Finally, a difficulty in power outage cost assessment lies in the definition of the baseline scenario. This baseline may not be easy to define. Moreover, in cases where recovery does not lead to a return to the baseline scenario, there are permanent effects that are difficult to compare with a baseline scenario. For instance, a long-duration outage can lead to a permanent extinction of vulnerable economic activities in a region, whether because these activities are already threatened and cannot recover or because they can relocate. In that case, the disaster is not a temporary event, but a permanent negative shock for a region and it is more difficult to define the disaster cost. Also, recovery may increase productivity in the event that capital stock is replaced; this can lead to a final situation considered more desirable than the baseline scenario.

B.3 Studies of Long Duration Power Outages

FSC reviewed the literature on costs associated with major power outages.[10] We primarily focused on studies that estimated overall economic losses from outages in urban areas lasting a half day or longer. Furthermore, only studies of outages in the United States were examined. Most of the studies deal with actual outages; however, this literature review includes studies of hypothetical outages lasting longer than two weeks. In addition to information on the outage that each study examines and the method employed in each study, FSC has included an inflation-adjusted estimate of the economic losses overall and per capita in each study.

Estimates of outage costs vary substantially. Variation is due, in part, to the timing and duration of a given outage and the economic output of the affected area. Also, some studies attempt to estimate the costs from outages that occur in the course of natural disasters, whereas others focus on system disturbances alone. Ultimately, though, different methods of cost estimation reach significantly different results. The studies included in Table B-1 employ a variety of methods, ranging from back-of-the-envelope style estimates to surveys to regional economic modeling, often in combination. Moreover, the studies vary in the extent to which they capture direct, indirect or induced losses.

The ratio between direct and indirect costs (commonly known as the multiplier) ranges substantially. Early studies suggested indirect costs from power outages were substantial, perhaps more than five times direct costs. More recent studies have suggested indirect costs to be much lower, with some suggesting indirect costs as small as one quarter of direct costs, but these studies rely on theoretical models that have not been validated through primary data collection (i.e., a survey). For the purposes of understanding a long-duration outage in downtown San Francisco, it is reasonable to expect an indirect cost estimate between one-half and two times direct costs. However, for an important economic hub and urban area like downtown San Francisco, which has not been considered in prior studies, the indirect costs could be more than two times direct costs.

10 There are two major bodies of literature on outage costs that we chose to exclude from the present review. First, there is a substantial literature on the cost of unserved kWh (alternately called the value of lost load); these studies measure customers' valuation of power disruptions for the purposes of reliability planning for short-duration outages. Second, there is a literature on the annual cost of all power system disturbances; these studies estimate macroeconomic costs for the purposes of reliability planning and high-level policymaking.

Table B-1: Summary of Studies on Long Duration Power Outages

Study	Population Studied	Region Affected	Outage Duration	Outage Date	Hypothetical / Actual	Method	Population Affected	Total Cost Estimate (2011 $)*	Cost per Capita (2011 $)*		Notes
									Total	Per Day	
Corwin and Miles 1978	Non-residential	New York City	Up to 25 hours	Thursday, January 13, 1977	Actual	Reports from businesses and agencies	9 million	$1.3 billion	$144	$144	Much of cost from looting and arson, not representative of most outages
Rose and Lim 2002	Non-residential	Los Angeles (LADWP territory)	Up to 36 hours	Monday, January 17, 1994	Actual	I/O model with ex post resiliency adjustments	3.5 million	$8 - 158 million	$2 - 45	$1 - 30	Resiliency adjustments: electricity importance (-16%), production rescheduling (-84%) (may not be possible for a long duration outage), and time of day of usage (-94%); method is biased underestimate; population number from LADWP
Gordon et al 1998	Non-residential and commuters	Los Angeles County	Up to 36 hours	Monday, January 17, 1994	Actual	Survey and I/O model	9.1 million	$4.4 billion	$484	$323	Impacts: 51% impact zone, 20% rest of LA county, 29% region and world; population affected is LA County, so total impacts ($6.5 billion) have been scaled to it; additionally, 63% of cost is attributed to loss of utilities, so estimate is further scaled; method is biased overestimate; population number from Census
AUS Consultants 2001	Private sector	California	20 effective hours	June to September 2001	Hypothetical	Survey, macroeconomic measures, and I/O model	34.6 million	$31.2 billion	$900	$69	Rolling blackouts, so 20 hours is in 60-90 minute blocks over several months; method is biased overestimate; population number from Census

Study	Population Studied	Region Affected	Outage Duration	Outage Date	Hypothetical / Actual	Method	Population Affected	Total Cost Estimate (2011 $)*	Cost per Capita (2011 $)* Total	Cost per Capita (2011 $)* Per Day	Notes
Rose et al 2005	Non-residential	Los Angeles County	4x 1 hour	March 19-20 and May 7-8, 2001	Actual	PE and CGE model with ex post resiliency adjustments	9.6 million	$0.6 – 40.7 million	$0.06 - 4	$0.02 - 1	Short rolling blackouts with advance notice;* lost sales is the primary figure; range of estimates reflects no resilience versus full resilience options; CGE modeling of regional impact has ambiguities, difficult to know actual impact; population number from Census
Anderson Consulting 2003	Non-residential	Northeastern U.S.	Between 16 and 72 hours	Thursday, August 14, 2003	Actual	Macroeconomic measures and indirect effects multiplier	45 million	$5.5 - 10.1 billion	$122 - 224	$61 - 112	Population number from Wikipedia
ICF 2003	Non-residential	Northeastern U.S.	Between 16 and 72 hours	Thursday, August 14, 2003	Actual	Unserved kWh cost from prior studies	45 million	$8.3 - 12.6 billion	$184 - 280	$92 - 140	Population number from Wikipedia
Brattle Group 2003	Non-residential	Northeastern U.S.	Between 16 and 72 hours	Thursday, August 14, 2003	Actual	Unserved kWh cost from prior studies	45 million	$7.3 billion	$162	$81	Estimate is considered a lower bound; population number from Wikipedia
Ohio Manufacturers' Association (ref in ELCON 2004)	Manufacturing sector	Ohio	Between 16 and 72 hours	Thursday, August 14, 2003	Actual	Survey	11.4 million	$1.3 billion	$114	$57	Limited to impact on Ohio; Represents double the Anderson estimate for the state; population number from Census
Anderson et al 2007	General	Northeastern U.S.	Between 16 and 72 hours	Thursday, August 14, 2003	Actual	I/O model with inoperability	45 million	$8 billion	$178	$89	Population number from Wikipedia
National University System 2011	General	San Diego	Up to 13 hours	Thursday, September 08, 2011	Actual	Extrapolation from prior outages	2 million	$97 - 118 million	$49 - 59	$49 - 59	Estimation is considered a lower bound
Moore II et al 2005	General	Los Angeles & Orange Counties	One month	Summer mid-2000s	Hypothetical	Spatial I/O model	11.8 million	$14.4 billion	$1,220	$41	Relies on data from 1990s; population data from Census
Rose et al 2007	General	Los Angeles County	2 weeks	Summer mid-2000s	Hypothetical	CGE model with ex post resiliency adjustments	9.8 million	$3 - 14.2 billion	$306 - 1449	$22 - 104	Resiliency primarily from production rescheduling; population data from Census

* Values adjusted to 2011 dollars using CPI-U.

B.3.1 1977 New York City Outage

In July 1977, New York City experienced a 25-hour blackout that affected 9 million people and resulted in widespread criminal activity. Corwin and Miles' 1978 study of the blackout continues to be widely cited in the literature on the costs of major power outages. They constructed a summary of economic impacts by bringing together separate and independent reports of costs from businesses and business associations, governments, public service agencies, non-profit service organizations, insurers, and health institutions. Table B-2 presents the tabulation of these reports in nominal dollars. While Corwin and Miles disclaimed that their list was not comprehensive, the summation of reports resulted in an estimated outage cost of $345 million in nominal dollars. Additionally, Corwin and Miles discussed non-quantified costs associated with social impacts, such as the cancellation of planned activities, the alteration of traffic flows and the inconvenience of everyday life functions.

Table B-2: Corwin and Miles (1978) Tabulation of Costs for the 1977 NYC Blackout

Impacted Entities	Direct Costs (1977 $M)		Indirect Costs (1977 $M)	
Business	Food Spoilage	$1.0	Small Businesses	$155.4
	Wages Lost	$5.0	Emergency Aid (private)	$5.0
	Securities Industry	$15.0		
	Banking Industry	$13.0		
Government			Federal Assistance Programs	$11.5
			NY State Assistance Program	$1.0
Electric Utility	Restoration Costs	$10.0	New Capital Equipment	$65.0
	Overtime Payments	$2.0		
Insurance			Federal Crime Insurance	$3.5
			Fire Insurance	$19.5
			Private Property Insurance	$10.5
Public Health			Hospitals–overtime & emergency room	$1.5
Public Services	Transportation Authority Revenue Losses	$2.6	Vandalism	$0.2
	Overtime and Unearned Wages	$6.5	New Capital Equipment	$11.0
			Red Cross	$0.0
			Fire Department overtime	$0.5
			Police Department overtime	$4.4
			State Courts overtime	$0.1
			Prosecution and Correction	$1.1
Westchester County	Food Spoilage	$0.3		
	Public services overtime and damage	$0.2		
Total	**All Direct**	**$55.5**	**All Indirect**	**$290.2**

Corwin and Miles' primary methodological contribution was to study both impacts directly caused by an outage (e.g., business losses, lost wages) and costs incurred indirectly as a response to an outage (e.g., emergency services, assistance programs). Applying this method to downtown San Francisco would require, for example, interviewing government agencies and public service providers (e.g., SFMTA, SFPD) on the costs they would expect to incur from a long-duration outage. These entities may already have cost estimates associated with disaster planning.

B.3.2 1994 Northridge Earthquake Outage

On January 17, 1994, a magnitude 6.7 earthquake struck 20 miles northwest of downtown Los Angeles, causing a power outage in the LA Department of Water and Power service territory that was gradually restored over the course of 36 hours. Gordon et al. (1998) surveyed large businesses in the impact zone of the earthquake to solicit estimates of business interruption costs and understand what proportion experienced business interruption losses due to power outage. The estimates derived from the survey were then used as inputs into the Southern California Planning Model, an input-output regional economic model that adjusts the inputs and outputs of all sectors in response to a shock. In the paper, Gordon et al. elucidate the cost due to transportation problems by scaling the results of the I/O model according to the proportion of businesses reporting losses due to transportation problems. While the authors do not explicitly do this calculation in their own paper, we scaled the I/O model results similarly by the proportion of businesses reporting losses due to disruption of utility services (63%). The results are presented in Table B-3. In this approach, only 51% of losses are attributed to businesses within the impact zone; moreover, 29% of losses are attributed to businesses outside of LA County.

Table B-3: Gordon et al. (1998) Estimate of 1994 Losses Due to Outage

Area	Direct Losses (1994 $B)	Indirect and Induced Losses (1994 $B)	Total Losses (1994 $B)
Impact zone total	$1.97	$0.13	$2.10
Rest of Los Angeles City		$0.15	$0.15
Rest of Los Angeles County		$0.67	$0.67
Rest of region		$0.55	$0.55
Rest of world	$0.65		$0.65
Total	$2.62	$1.51	$4.12

Rose and Lim (2002) take a related approach to the outage following the Northridge earthquake. Like Gordon et al., Rose and Lim also use an I/O model, the Input–Output (I-O) Transactions Table for Los Angeles County, CA, to compute business losses in all sectors resulting from the outage. To compute the shock, Rose and Lim scaled annual gross output for each sector down to a single day and computed losses by the fraction of a day that a given sector's businesses had no power; this results in estimated losses of $88 million nominal dollars, which is substantially lower than the survey-based measurement of direct costs in Gordon et al. Rose and Lim then applied three adjustments cumulatively according to models of sector resiliency: adjustment according to the importance of electricity to operations, adjustment by production rescheduling and adjustment according to typical time of electricity use by each sector. The results of the initial I/O model results and adjustments are presented in Table B-4.

Table B-4: Rose and Lim (2002) Estimate of 1994 Losses Due to Outage

Sector	Base case	Electricity importance adjustment		Production shifting adjustment		Time of use adjustment	
	Output reduction (1994 $M)	Importance (%)	Output reduction (1994 $M)	Rate (%)	Output reduction (1994 $M)	Night/Day /Evening (%)	Output reduction (1994 $M)
Agriculture	0.4	50	0.2	75	0.1	20/60/20	0.0
Mining	0.7	90	0.6	99	n	30/40/30	0.0
Construction	5.6	40	2.2	95	0.1	10/80/10	0.0
Food processing	2.0	90	1.8	95	0.1	30/40/30	0.0
Nondurable manufacturing	5.6	98	5.5	95	0.3	30/40/30	0.1
Durable manufacturing	12.0	100	12.0	99	0.1	25/50/25	0.0
Petroleum refining	1.2	100	1.2	99	0.0	30/40/30	0.0
Transportation	2.4	30	0.7	30	0.5	25/50/25	0.2
Communication	1.9	90	1.7	40	1.0	25/50/25	0.3
Private Electric Utilities	0.0	80	0.0	75	0.0	30/40/30	0.0
Gas Utilities	1.7	80	1.4	75	0.4	30/40/30	0.1
Water Utilities	0.7	80	0.5	90	0.0	30/40/30	0.0
Wholesale Trade	4.0	90	3.6	99	0.0	30/80/30	0.0
Retail Trade	6.2	90	5.6	80	1.1	30/80/30	0.4
F.I.R.E.	15.5	90	14.0	90	1.4	5/90/5	0.5
Personal services	1.1	86	1.0	60	0.4	10/80/10	0.1
Business services	13.0	90	11.0	70	3.5	10/80/10	1.2
Entertainment	4.1	80	3.3	30	2.3	10/50/40	0.6
Health & social services	4.2	80	3.3	50	1.7	25/50/25	0.6
Education	0.9	80	0.7	99	0.0	5/80/15	0.0
Government	3.3	60	2.0	80	0.4	10/80/10	0.1
State/Local Electric utilities	1.4	80	1.2	75	0.3	30/40/30	0.1
Total	88.0		74.3		13.7		4.5

The adjustments that Rose and Lim identify deserve further attention. *Electricity importance* was defined as the percentage reduction in output caused by a 1% reduction in the availability of a utility lifeline service—effectively a measure of the relative importance of electricity to a sector's operation; using this adjustment reduces total losses by 16%. *Production rescheduling* rate refers to the ability of a sector to make up its production or sales at a later date; using this adjustment reduces total losses by an additional 69%. *Time of use adjustment* refers to the varying needs for electricity by a sector over a 24-hour period; using this adjustment reduces total losses further by an additional 10%. Thus, resiliency adjustments cumulatively reduce economic losses by 95%.

The contribution of both of these papers is to use input-output models to account for the linkages between sectors and pass the effects of a negative shock through a regional economy. Input-output models contain a static, linear model of all sales and purchases between all sectors in a regional economy in which parameters are often based on historical data. Other researchers have used the output of I/O models to devise shorthand multipliers for indirect effects from direct losses. For the purposes of a long-duration outage in San Francisco, indirect effects could be estimated using an I/O model encapsulating the Bay Area, California, the United States or even the world as a system.

Additionally, Rose and Lim's ex post resiliency adjustments to the results of I/O models provide a starting point for considering the ways in which businesses may adapt to the circumstances of a long-duration outage. I/O models do not allow for behavioral changes; yet, it is quite likely that a long-duration outage will induce businesses to take adaptive actions rather than simply suffer ongoing losses. The available adaptive actions will depend upon the nature of the business, the cost of adaptation, and the duration of the outage. For example, the time of use adjustment and production shifting adjustment used by Rose may not be applicable to a long duration (multiple weeks) outage. Some businesses may not be able to afford adaptive behaviors, such as relocation, and simply go out of business.

B.3.3 2003 Northeastern United States Outage

In August 2003, 45 million people in the northeastern United States and parts of Canada experienced a full outage for 16 hours, gradually recovering to full restoration of power over 72 hours in total. In the days following, several private consultancies released short studies estimating the economic costs of the blackout.

ICF Consulting (2003) released an estimate based on the ratio of cost per unserved kWh to price per kWh observed in Corwin and Miles. ICF calculated that outage costs per kWh in Corwin and Miles were 100 times the price of electricity per kWh. ICF then looked at the rate of recovery over the 72 hours of the blackout and calculated blackout costs at each period, based on calculated unserved kWh and price per kWh; to create an uncertainty range, ICF used 80 times the price of energy and 120 times the price of energy as lower and upper bounds to the estimate. Details of this calculation are presented in Table B-5.

Table B-5: ICF (2003) Calculation of 2003 Outage Costs

Period		Lost MW	Duration (Hrs)	Lost MWh	$/MWh	Cost of Blackout (2003 $)	
Start	End					Lower Bound	Upper Bound
8/14 - 4 PM	8/14 - 8 PM	61,800	4	247,200	$93	$1.8 Billion	$2.8 Billion
8/14 - 8PM	8/15 - 6 AM	30,900	10	309,000	$93	$2.3 Billion	$3.5 Billion
8/15 - 6 AM	8/15 - 10 AM	15,450	4	61,800	$93	$459.8 Million	$689.7 Million
8/15 - 10 AM	8/16 - 12 AM	13,200	14	184,800	$93	$1.4 Billion	$2.1 Billion
8/16 - 12 AM	8/16 - 10 AM	6,600	10	66,000	$93	$491 Million	$736.6 Million
8/16 - 10 AM	8/17 - 6 AM	2,000	20	40,000	$93	$297.6 Million	$446.4 Million

Period		Lost MW	Duration (Hrs)	Lost MWh	$/MWh	Cost of Blackout (2003 $)	
Start	End					Lower Bound	Upper Bound
8/17 - 6 AM	8/17 - 4 PM	1,000	10	10,000	$93	$74.4 Million	$111.6 Million
TOTAL			**72**	**918,800**		**$6.8 Billion**	**$10.3 Billion**

The Brattle Group (2003) released a paper with similar methods. Brattle made a simplifying assumption that half the interrupted load (30,900 MW) was offline for 4 hours and the other half offline for 8 hours; moreover, they used industry-wide averages for the affected customer mix. Brattle then calculated outage costs using cost per unserved kWh figures from previous surveys of residential and commercial customers. They arrive at an estimated $6 billion in nominal dollars.

Anderson Consulting (2003) took a different approach to Brattle and ICF, using macroeconomic measures to infer losses. Specifically, Anderson took the projected annual gross state product for each of the affected U.S. states in 2003, scaled it to a single day, and calculated the total earnings accruing to workers and investors based on the national average earnings share of output. These single-day earnings were then multiplied by fraction of output affected by the outage over the course of 72 hours to arrive at earnings losses during the full duration outage. Anderson then multiplied this value by 1.2 to account for indirect effects, with no source of this multiplier identified. To this, Anderson then added an estimate of losses due to food spoilage, power industry costs and costs to government to arrive at a total impact of $6.4 billion in nominal dollars. Table B-6 presents the tabulation of these costs. Anderson then constructs an uncertainty range by multiplying lost earnings figures by plus and minus 33% to produce lower and upper bounds.

Table B-6: Anderson Consulting (2003) Calculation of 2003 Outage Costs

States	Direct Effect, Lost Earnings (2003 $B)	Indirect Effect, Lost Earnings (2003 $B)	Spoiled Commodities (2003 $B)	Net Cost to Government (2003 $B)	Cost to Power Industry (2003 $B)	Total Economic Impact (2003 $B)
New York	$1.980	$0.198	$0.375	$0.033	$0.429	$3.015
Michigan	$0.653	$0.065	$0.124	$0.011	$0.141	$0.994
Ohio	$0.358	$0.036	$0.068	$0.006	$0.078	$0.545
New Jersey	$0.263	$0.026	$0.050	$0.004	$0.057	$0.400
Pennsylvania	$0.147	$0.015	$0.028	$0.002	$0.032	$0.223
Connecticut	$0.060	$0.006	$0.011	$0.001	$0.013	$0.091
Massachusetts	$0.003	$0.000	$0.001	$0.000	$0.001	$0.005
Vermont	$0.002	$0.000	$0.000	$0.000	$0.000	$0.003
All others	-	$0.347	-	-	$0.750	$1.097
Total	**$3.465**	**$0.693**	**$0.657**	**$0.058**	**$1.500**	**$6.373**

Interestingly, the Ohio Manufacturer's Association surveyed only firms in the manufacturing sector of Ohio to estimate costs to business from the 2003 blackout (ELCON, 2004). Based on survey responses of business interruption costs incurred by affected firms, OMA estimated that the cost to Ohio was $1.08 billion in nominal dollars. This figure is more than double the direct and indirect losses for Ohio estimated by Anderson Consulting.

Anderson et al. (2007) checked these prior estimates against an I/O model approach. Anderson et al. used the Regional Input-Output Multiplier System II, an I/O model, along with other macroeconomic indicators to approximate the impact of the blackout on the northeastern U.S. economy. Using the outage durations supplied by ICF, Anderson et al. calculated a direct loss of $2.12 billion in nominal dollars, based on the proportion of energy demand unmet over the course of the 3 days of the blackout and recovery. They then input this negative shock into their I/O model and calculate indirect costs of $4.41 billion, suggesting an indirect cost multiplier equal to 2 times direct costs. Anderson et al. concluded that the economic losses from the blackout totaled $6.53 billion in nominal dollars—a finding roughly in line with prior estimates.

Perhaps the greatest contribution these studies make is to demonstrate the use of back-of-the-envelope estimates to ascertain the magnitude of costs due to an outage. By scaling impacts from macroeconomic measures and previous surveys of costs per unserved kWh, as well as using multipliers for indirect effects, the magnitude of costs of a long-duration San Francisco outage may be quickly estimated—and may reasonably match results from a laborious modeling process. However, these methods contain many simplifying assumptions, and they may produce results very different than empirical work would show, such as demonstrated by the OMA survey.

B.3.4 2001 California Rolling Blackouts

Following efforts to deregulate its energy markets, California implemented rolling blackouts over six days in 2001 to avoid system-wide failure from supply shortages. On January 17–18, rolling blackouts were implemented only in PG&E's territory; on March 19–20 and May 7–8, rolling blackouts were implemented across all three investor-owned utilities in California. Rolling blackouts were implemented such that only a fraction of customers experienced an outage at any given time, with outages rotating across different groups of customers. While rolling blackouts occurred during several business hours on each of the 6 days, interruptions to any single customer typically lasted between 60 and 90 minutes.

AUS Consultants issued their study in May of 2001, during the ongoing supply shortages in California. The AUS study was fundamentally hypothetical in nature, as they sought to estimate costs associated with rolling blackouts over the summer to come. For this purpose, AUS assumed that rolling blackouts would culminate in 20 hours of outage over the course of the summer. AUS then surveyed commercial and industrial sector businesses across California about business interruption costs and behavior during prior rolling blackouts; results from the survey informed the estimated impacts of outages on business sectors overall, scaled to impact per hour of outage. AUS then calculated direct losses by multiplying losses per hour of outage by gross state product for each sector. AUS used multipliers for indirect losses derived from the Regional Input-Output Modeling System II, an I/O model built on regional data for 1997. They estimated that anticipated rolling blackouts would result in losses of $21.8 billion in nominal dollars. The tabulation of losses is shown in Table B-7.

Table B-7: AUS Consultants (2001) Estimate of 2001 Rolling Blackout Costs

Sector	RIMS II Multipliers			Losses (1996 $M)		
	Output	Earnings	Jobs	Direct	Indirect	Total
Agriculture, forest., fisheries	2.253	0.687	31.4	$181	$407	$588
Manufacturing				$1,216	$2,590	$3,805
Food & kindred products	2.16	0.45	15.5	$227	$490	$717
Paper products	1.842	0.427	12.4	$19	$35	$53
Chemicals/Petroleum	1.979	0.34	9	$245	$485	$729
Rubber & plastics	1.913	0.474	15.6	$13	$25	$38
Lumber & wood	2.085	0.545	19.2	$21	$45	$66
Stone, clay, glass	2.116	0.57	17.3	$54	$114	$168
Primary metals	1.962	0.466	13.3	$8	$16	$24
Fabricated metals	2.061	0.555	16.8	$30	$63	$93
Industrial machinery	2.243	0.597	15.2	$110	$248	$358
Electronic equipment	2.205	0.603	15.8	$335	$738	$1,073
Instruments and related	2.152	0.66	16.4	$103	$222	$325
Motor vehicles	2.016	0.444	12.9	$6	$12	$18
Other transport equip.	2.257	0.658	16.1	$31	$70	$101
Misc. manufacturing	2.196	0.591	21.4	$13	$29	$42
Electric, gas, & sanitary	2.135	0.382	9.5	$33	$70	$103
Wholesale trade	2.051	0.654	19.1	$525	$1,076	$1,600
Retail trade	2.102	0.688	30	$976	$2,051	$3,027
F.I.R.E.	2.142	0.587	17.5	$2,242	$4,804	$7,047
Services				$1,661	$3,934	$5,595
Personal services	2.333	0.79	40.3	$90	$209	$299
Business services	2.289	0.856	26.7	$888	$2,033	$2,921
Hotels/Amusement	2.604	0.85	31.5	$373	$972	$1,345
All other services	2.322	0.709	28.5	$310	$720	$1,030
Total Gross State Product				**$6,833**	**$14,932**	**$21,765**

Rose et al. (2005), on the other hand, examine the impact of the rolling blackouts on Los Angeles County after they occurred, representing an actual rather than hypothetical scenario. Rose et al. identified the geographic areas affected by each hour of each outage in SCE's service territory to estimate the direct business interruption costs to various sectors.[11] These results formed the input for an initial partial equilibrium model, which initially estimated direct losses within SCE's territory at $9.9

11 Because of the advance warning associated with rolling blackouts, Rose et al. suggest that this number signifies only lost sales and does not include material/labor costs or equipment damage.

million in nominal dollars. Rose et al. then reran the model with production functions and elasticities adjusted for resiliency behaviors associated with productivity and input substitution, which reduced losses by 88% to $1.2 million. An additional adjustment to account for production rescheduling of firms further diminished losses to $266,000—a 97% reduction from initial estimates of direct losses. Rose et al. then expanded the scope of the analysis to all of LA County and ran a computational general equilibrium model, which incorporated further resiliency options and calculated the indirect costs of the SCE outage scenario. Rose et al. found that indirect losses were equal to 74% of direct losses.

Unfortunately, the article as written appears to have logical inconsistencies and ambiguities that make tabulation of cost estimates difficult. Nevertheless, we present our understanding of the article in Table B-8.

Table B-8: Rose et al. (2005) Estimate of 2001 Rolling Blackout Costs

Area	PE Direct Losses (2001 $M)			GE Indirect Losses (2001 $M)			Total Losses (2001 $M)		
	Base case	Resiliency options included	Production resched. included	Base case	Resiliency options included	Production resched. included	Base case	Resiliency options included	Production resched. included
SCE Territory	$9.9	$1.2	$0.3	$7.4	$0.9	$0.2	$17.3	$2.1	$0.5
LA County	$18.4	$1.9	Not given	$13.7	$1.4	*	$32.1	$3.4	*

* Rose et al. do not give this number, stating that the multiplier varies, "because sectoral net GE effects are distributed differently than sectoral PE effects and because the CGE model is non-linear." Without the multiplier given, the numbers cannot be determined; however, it stands to reason that the indirect effects multiplier is in the same general range of this CGE model and other I/O models.

These studies both demonstrate how the effect of outages can be modeled through regional economies. AUS demonstrate that the parameters of sophisticated models and indirect effects multipliers they suggest can be combined with survey data to model overall costs to an economy. Rose et al. demonstrate that sophisticated models that allow for adaptive behaviors—likely in the case of the advance notice associated with 2001 60 to 90 minute rolling blackouts—can drastically reduce estimates of outage costs. As noted above, available adaptive behaviors will vary.

B.3.5 2011 San Diego Outage

In September 2011, San Diego Gas & Electric experienced a full system outage that recovered over the course of 13 hours. In the direct aftermath, National University System's Institute for Policy Research (2011) released a policy brief estimating the cost of the outage to lie between $97 million and $118 million. This figure represents the sum of three estimates: perishable food losses, government overtime and production losses. In all three cases, NUS extrapolated numbers from prior events (2003 Northeastern U.S. Blackout, local government response to firestorms, 1996 Western U.S. Power Outage) to arrive at estimates. The back-of-the-envelope nature and limited scope of costs taken into account make this study at best a rough, lower bound estimate.

B.3.6 Hypothetical Long-duration Los Angeles Outage

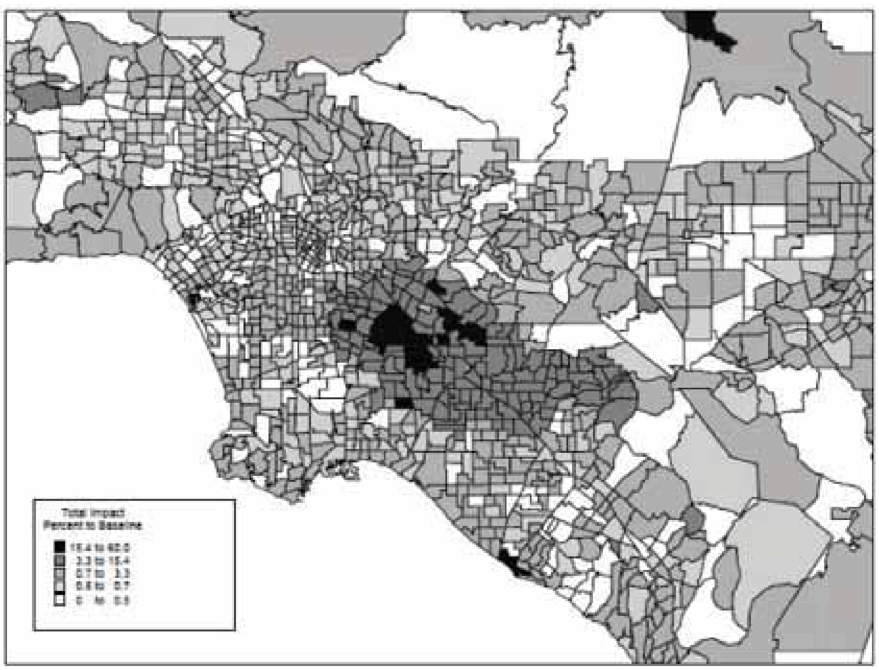
FSC examined two studies of hypothetical long-duration outages in the Los Angeles metropolitan area. Moore II et al. (2005) constructed a scenario of a one-month outage in Los Angeles and Orange Counties and used the Southern California Planning Model Version 2, an I/O model with spatial data, to predict the economic losses from such an outage. Moore II et al. scale annual gross output to a single month to represent the direct losses in the model; total costs are estimated to reach $12.1 billion in nominal dollars. The results of the I/O model are presented in Table B-9.

Table B-9: Moore II et al. (2005) Estimate of Losses from a Hypothetical One-month Outage

Loss Type	Losses (2005 $M)
Direct Losses	$7,412
Indirect Losses	$2,744
Induced Losses	$1,969
Travel Costs	$15
Total	**$12,140**

Moore II et al. used the spatial nature of their I/O model both to model impacts from altered transportation patterns and predicted the distribution of impacts geographically. Figure B-1 demonstrates the spatial results of the model, where economic losses are portrayed as a percent of baseline economic output in a given area.

Figure B-1: Geographic Distribution of Economic Losses from a Hypothetical One-month Outage



Rose et al. (2007) took a somewhat different approach to modeling the economic losses from a two-week outage in Los Angeles County. Rather than employ an I/O model, Rose et al. used a computational general equilibrium model to capture the indirect effects of their outage scenario, specifying production function for firms, consumption functions for households, expenditure functions for government, and income and price elasticities for households and government. The model incorporates inputs from the Impact Planning and Analysis database, which allows downscaling of macroeconomic indicators to the county level. Furthermore, several aspects of resiliency are applied to the model, including: interfuel substitution, adaptive electricity substitution (e.g., using physical labor in place of machinery), factor substitution, inventory drawdown, production rescheduling, alternative generation, and electricity importance. Results of the CGE model are presented in Table B-10. Rose et al. estimate that a two-week outage without resiliency leads to losses of $13.1 billion in nominal dollars; when production rescheduling, the most effective of resiliency options, is incorporated, losses reduce by 79% to $2.8 billion overall. However, it is important to note that these resiliency assumptions are based on a theoretical model and have not been verified through a survey. Indirect losses are roughly one quarter of direct losses.

Table B-10: Rose et al. (2007) Estimate of Economic Losses from Hypothetical Two-week Outage

Sector	Output baseline (2007 $M)	Direct losses (%)	Indirect losses (%)	Total losses (%)	Total losses (2007 $M)	Total losses adjusted for production rescheduling (2007 $M)
1. Agriculture	$1,398	-2.4	-7.3	-9.7	-$5	-$1
2. Mining	$2,589	-73.2	-1.6	-74.8	-$74	-$1
3. Construction	$28,770	-18.7	-29.9	-48.6	-$538	-$27
4. Food processing	$14,744	-56.5	-8.6	-65.1	-$369	-$18
5. Petroleum refining	$11,404	-29.7	-25.1	-54.8	-$240	-$2
6. Other nondurable mfg	$33,435	-71.2	-2.8	-73.9	-$951	-$48
7. Primary metals	$3,192	-30.1	-17.8	-48	-$59	-$1
8. Semiconductors	$1,133	-38.3	-7.8	-46	-$20	$0
9. Other durable mfg	$63,364	-73.1	-4.6	-77.7	-$1,894	-$19
10. Local private transportation	$1,039	0	-11.4	-11.4	-$5	-$4
11. Other transportation	$21,407	-5.2	-32.1	-37.2	-$306	-$214
12. Communications	$15,674	-23.3	-7.2	-30.6	-$184	-$111
13. Private electric utilities	$2,349	-99	0	-99	-$89	-$22
14. Gas utilities	$4,738	-22.9	-35.3	-58.2	-$106	-$27
15. Water utilities	$381	-55.5	-2.5	-57.9	-$8	-$1
16. Sanitary services	$1,149	-62.6	-1.6	-64.1	-$28	-$3
17. Wholesale trade	$35,676	-73	-0.2	-73.2	-$1,004	-$10
18. Retail trade	$27,761	-66.1	-8.5	-74.6	-$797	-$159
19. Real estate	$31,230	-73	-3.9	-76.8	-$923	-$92
20. Banking & credit	$19,759	-21.7	-11.2	-32.9	-$250	-$25
21. Security brokers	$8,153	-14.6	-15.4	-30	-$94	-$9
22. Insurance	$11,733	-66.6	-5.4	-72	-$325	-$33
23. Hotels & restaurants	$14,383	-43.3	-21.9	-65.2	-$361	-$144
24. Personal services	$4,301	-69.1	-2.2	-71.3	-$118	-$47
25. Business services	$59,026	-70	-3.1	-73.1	-$1,660	-$498
26. Computer services	$6,035	-11.7	-39.9	-51.6	-$120	-$72

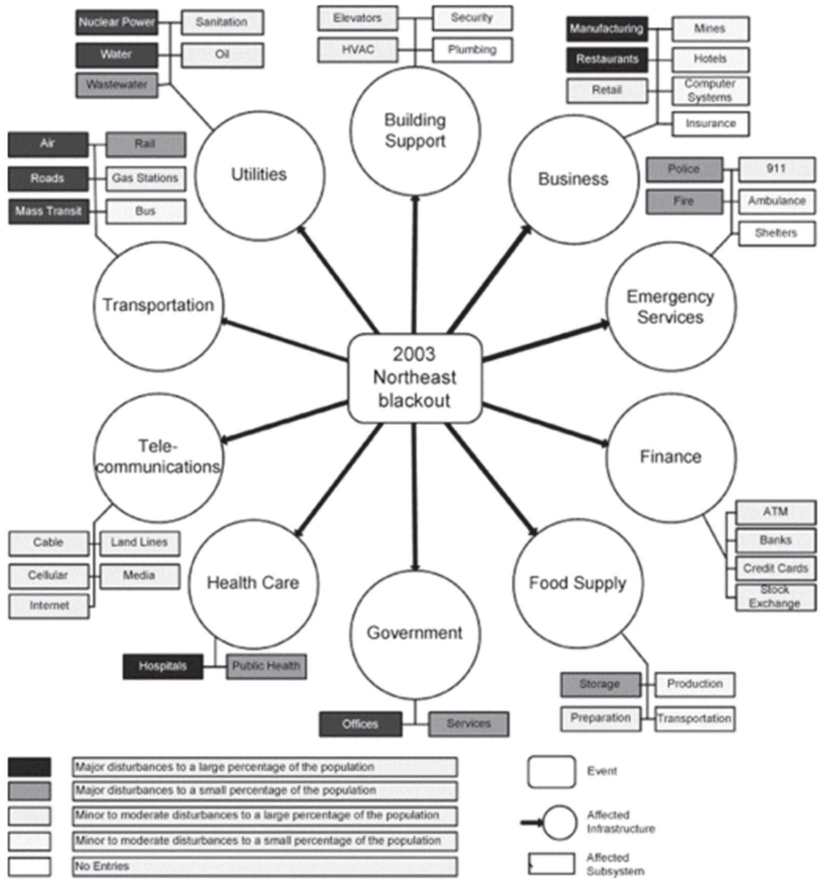
Sector	Output baseline (2007 $M)	Direct losses (%)	Indirect losses (%)	Total losses (%)	Total losses (2007 $M)	Total losses adjusted for production rescheduling (2007 $M)
27. Entertainment	$39,098	-57	-10.2	-67.1	-$1,010	-$707
28. Education	$5,015	-54.2	-31.2	-85.4	-$165	-$2
29. Health & social services	$30,138	-42.7	-32.2	-74.9	-$869	-$434
30. State & local electric utilities	$2,425	-99	0	-99	-$92	-$23
31. Local public transportation	$1,254	-9.1	-54.5	-63.5	-$31	-$21
32. Other government	$36,916	-5	-17.1	-22.1	-$314	-$63
Total	**$539,668**	**-47.9**	**-11.4**	**-59.3**	**-$13,010**	**-$2,839**

The main contribution of these studies is that they look at outages of long duration; their estimated costs thus serve as a guide to estimating the costs of a similarly long or longer duration outage in downtown San Francisco. In addition, Moore II et al., by using an I/O model with spatial data, illustrate graphically how areas that do not experience an outage can still be adversely affected. Rose et al. demonstrate how a CGE model, which allows for behavior change of firms and consumers using microeconomic principles, can allow for adaptive behavior when forecasting the impact of a negative shock. However, because this theoretical model has not been validated through primary data collection (i.e., a survey), it is unclear how realistic its assumptions are. A well-designed survey more accurately incorporates resiliency because it measures revenue losses after the respondent considers adaptive behaviors. However, those adaptive behaviors can be costly (i.e., the fuel cost of a backup generator), so it is important to measure these costs and factor them into a net estimate, which will be the most accurate measure of direct costs.

B.3.7 Issues Caused by Long-duration Outages

Long-duration outages create a set of challenges that shorter system disturbances rarely feature. Specifically, other systems that rely on electricity become compromised or inoperable, creating further difficulties. Brown et al. (2006) chart a number of infrastructure failure interdependencies during the 2003 U.S. Northeast blackout in Figure B-2; while not all of these failures are likely for the downtown San Francisco scenario, it is nevertheless illustrative of the impacts of a major outage.

Figure B-2: Infrastructure Failure Interdependencies from Power Outage (Brown et al., 2006)



At the outset of any major power outage, the set of costs is roughly the same: business interruption costs are incurred, labor costs associated with security and emergency services increase, transportation systems become congested, communications systems are interrupted and so on. Facilities may initiate alternative generation, and businesses may reschedule production. However, as an outage continues over the course of a single day, other costs are borne. Food spoilage and disposal not only imposes costs to businesses but can also cause a brief rise in related disease (for example, see Marx et al., 2006). Water service may become unavailable due to treatment equipment being out of service or offline pumps causing decreases in system pressure. Effluent from inactive sewage treatment equipment also poses threats to health and the local environment; during the Northeastern U.S. 2003 outage, at least 90 million gallons of untreated sewage spilled into local waterways (DePalma, 2006). Inoperable HVAC systems may cause inconvenience or, when coinciding with extreme temperatures, threats to health due to lack of heating or cooling. Elderly people may be particularly vulnerable due to reduced mobility and more fragile health. The combination of increasing emergency visits and power loss can degrade hospital operations (Klein et al., 2005). Overtime costs for public services increases substantially. The urban transportation system experiences severe congestion from ongoing lack of functioning traffic lights and other infrastructure; for example, during the Northeastern U.S. 2003 outage, congestion was severe, due to a combination of traffic light failure, electric train system shut down, and gasoline pump inoperability (Shaw, 2005). Similarly, communications systems can become overloaded, due to an increase in activity and/or communications equipment being out of service. Individuals cancel planned activities and may shift behavior to deal with lack of electricity. As residents use candles for lighting, incidences of fire increase substantially (for example, see SEMP 2006).

At a certain point, a long-duration outage comes to resemble a natural disaster. If an outage stretches to several days or longer, new costs are incurred: government assistance monies are spent, tourism declines, cancelled transactions result in lost taxes and so on. Alternative generation may not be possible for many facilities beyond several days; keeping hospitals and water treatment facilities operational becomes significantly more costly. Lack of working water, sanitation and HVAC makes residences difficult or impossible to live in. Continued transportation system challenges shift traffic patterns and slow delivery of goods. While costs associated with emergency services may decrease, security and public safety labor costs are likely to remain elevated. Businesses relocate on an emergency basis, or else shut down; individuals may relocate as well on a temporary basis. A torrent of litigation and insurance claims ensue. In the long run, insurance premia may rise.

Ultimately, an outage of duration longer than several weeks in a major downtown area would instigate an emergency response. In Auckland, New Zealand, a two-month outage in 1998 was partially mitigated by running cables from generators on industrial shipping boats into the local distribution system (see Newlove et al., 2003). While a full recovery is unlikely through such emergency measures, a long-duration outage in downtown San Francisco would almost surely invite similar measures to partially mitigate the outage. However, Embarcadero Substation serves over 27,000 customers in the downtown area, with a peak demand of more than 270 MW on a hot day and a normal peak demand of over 200 MW, and it is not evident how emergency measures would meet this demand.

B.4 Applicable Studies on Natural Disasters

Natural disasters often cause disruption to multiple, interlinked infrastructure systems. While there is a substantial literature on the costs associated with natural disasters, very few studies attempt to quantify the costs attributable specifically to the loss of electric power. In part, this is because the damage associated with the disaster may be difficult to disentangle from the costs caused by a power outage if a business' facility has experienced physical damage; in that case , the lack of electric service to the building may not be the binding constraint to resumption of business activity by the business or tenants. Further, the linkages between infrastructure systems often result in multiple failures; costs resulting from lack of power may be difficult to disentangle from lack of water and sewerage service (which may be caused by a lack of power or by physical damage).

B.4.1 Business Interruption Costs

The costs of natural disasters are generally enumerated as aggregate figures, derived from back-of-the-envelope estimates using macroeconomic figures. For example, in the aftermath of the 2011 Japanese earthquake and tsunami, several estimates from government and private sources estimated costs between $100 to $500 billion, primarily using macroeconomic indicators (Vervaeck and Daniell, 2011). Even when business interruption costs are estimated separately from physical damages, figures are rarely attributed to a particular cause. For example, Burton and Hicks (2005) used a spatial model with economic and hydrological factors to estimate aggregate costs of flooding from Hurricane Katrina. Although they reported business interruption losses (commercial revenue damages) separate from property damages and infrastructure damages (estimating that business interruption accounts for 3% of overall losses), they did not specify the cause of the business interruption.

Several studies have surveyed businesses on the causes of business interruption following a disaster. For example, Tierney (1996) surveyed businesses affected by the 1994 Northridge Earthquake on reasons for business closure, finding that 58.7% of respondents indicated “loss of electricity.” Similarly, Gordon et al. (1998) surveyed businesses affected by the 1994 Northridge Earthquake to estimate the proportion of business interruption attributable to specific causes; “interruption to utility services” was mentioned by 63% of respondents, coming in just behind “employees attending to personal matters” (73%) and “damage to place of business” (72%). Although Gordon et al. use their survey results to estimate economic losses attributable to specific causes, there are distinct shortcomings with this method, and it does not disentangle business interruption due to power outage from other disaster-related causes.

Wein and Rose (2008) attribute overall costs of a natural disaster to specific sources of business interruption. As part of a multi-disciplinary effort to model the physical and economic impacts of a hypothetical magnitude 7.8 earthquake in southern California, Wein and Rose separately modeled each shock from the earthquake, such as physical damage to buildings, disruption of power, disruption of transportation systems and so on. These negative shocks were then input into a regional I/O model to calculate indirect losses. Wein and Rose conclude that total losses attributable to power outages following the hypothetical earthquake amount to $7.4 billion, representing roughly 8% of total losses associated with the earthquake (see Table B-11). Direct losses make up $4.4 billion of total losses, suggesting a multiplier of 0.65 for indirect losses from lack of power. These results must be understood within the context of the assumed power outage scenario. In this study, the hypothetical earthquake is assumed to cause widespread power outages, but utilities are expected to restore electric service to a majority of interrupted customers within 24 hours and around 75% of customers within a couple of days. Therefore, the costs for a 3-week to 7-week power outage in San Francisco would comprise a substantially larger portion of the total losses associated with an earthquake and the multiplier would also be larger.

Table B-11: Wein and Rose (2008) Estimates of Hypothetical Earthquake Costs by Source

Sector	Damages (2008 $M)			Interruptions (2008 $M)					Total (2008 $M)
	Buildings	High-Rises	Secondary (Fires)	Power	Water	Gas	Transportation	Ports	
Agriculture	7	2	23	20	443	1	3	16	515
Construction	712	18	710	72	1,783	8	5	49	3,357
Food, Drugs & Chemicals	425	158	2,111	350	5,851	25	33	119	9,072
Mining & Metals/ Minerals Processing & Mft.	56	24	407	58	1,349	18	5	36	1,954
High Technology	23	8	174	20	463	1	2	22	712
Other Heavy Industry	232	48	1,249	127	3,639	9	12	126	5,442
Other Light	234	69	1,386	157	3,205	9	14	103	5,177

Sector	Damages (2008 $M)			Interruptions (2008 $M)					Total (2008 $M)
	Buildings	High-Rises	Secondary (Fires)	Power	Water	Gas	Transportation	Ports	
Industry									
Air Transportation	15	16	189	35	226	1	4	3	488
Rail Transportation	6	6	41	12	109	0	1	2	178
Water Transportation	3	3	29	5	38	0	1	11	90
Highway & Light Rail Transportation	76	83	716	158	1,248	4	35	18	2,340
Electric Utilities	42	35	108	101	708	5	5	14	1,016
Gas Utilities	34	39	99	73	1,021	89	5	21	1,382
Water Utilities	1	1	3	1	41	0	0	0	47
Wholesale Trade	380	83	825	288	2,470	12	24	49	4,131
Retail Trade	431	127	914	364	2,401	21	47	40	4,344
Banks & Financial Institutions	89	37	279	101	652	6	7	11	1,182
Professional & Technical Services	1,085	720	5,647	1,050	6,268	73	82	120	15,045
Education Services	149	25	442	182	980	4	13	10	1,806
Health Services	1,349	429	905	509	3,215	17	30	43	6,498
Entertainment & Recreation	739	131	1,788	750	5,684	26	66	46	9,232
Hotels	249	368	63	50	456	2	4	3	1,196
Other Services	367	80	613	466	1,819	15	42	41	3,442
Gov't & Non-NAICS	193	430	1,177	232	1,506	11	15	33	3,597
Real Estate	618	95	808	1,254	2,885	202	43	24	5,928
Owner-occupied dwellings	533	121	1,733	913	4,567	253	17	37	8,173
Total	**8,049**	**3,156**	**22,438**	**7,348**	**53,029**	**812**	**514**	**998**	**96,343**
(as % of Overall Costs)	***8.4%***	***3.3%***	***23.3%***	***7.6%***	***55.0%***	***0.8%***	***0.5%***	***1.0%***	

In most ways, regional economic modeling of power outages is virtually indistinguishable from regional economic modeling of natural disasters. What varies is not the method underlying each approach, but rather the direct losses that serve as inputs to each model. Hence, any I/O model or CGE model meant to model indirect costs from a natural disaster can be adapted to modeling indirect costs from the power outage underlying a natural disaster—presuming one can identify the separate direct losses of a power outage from a natural disaster and ensure parameters associated with energy supply are accurately specified. Although Wein and Rose are not explicit about their method for estimating direct costs from power outages in an earthquake, they suggest a particular scenario of power service recovery and appear to follow methods demonstrated in prior work (see Rose et al., 2007).

B.4.2 Loss of Electric Power

While the loss of electric power is a direct result of many natural disasters, it can also be a driver in the costs of recovery from a disaster and, over time, may become the binding constraint to recovery. Put another way, there are negative externalities in an extended power outage beyond the direct market value of the unserved power. Descriptive accounts of recovery efforts without reliable power have been published, but FSC is not aware of studies that quantify the costs of delayed power restoration to recovery. Kajitani and Tatano (2009) used surveys of business resilience to utility service interruptions in Japan to show that, in the event of simultaneous power, water, and gas outages, the restoration of electricity before other lifelines will best aid recovery. This remains the closest to an effort aimed at quantifying the impact of electricity outages on recovery duration.

B.4.3 Business Resiliency

Surveys of business resilience are rare, despite the increasing interest in the literature on hazard loss estimation. The Applied Technology Council (1991) ATC-25 modeled sector-wide average levels of importance for each lifeline service, basing their research on a mix of expert opinion and engineering models. Surveys by Webb et al. (1999) focused on disaster preparedness generally, capturing specific measures of back-up generation availability. Kajitani and Tatano (2009) demonstrated a method for surveying businesses in Aichi and Shizuoka, Japan, on several factors associated with resilience, primarily focusing production levels due to lifeline disruption (i.e., electricity, water, gas) and tolerable production stoppage durations. Table B-12 presents findings of Kajitani and Tatano on tolerable stoppage durations, defined as the length of time that can elapse without economic losses. However, short duration outage cost studies in the United States show that a majority of customers experience outage costs, even for a 5-minute power outage, so it is likely that these results are specific to Japan and are not applicable to San Francisco.

Table B-12: Kajitani & Tatano (2009) Survey of Tolerable Stoppages in Aichi and Shizuoka, Japan

Manufacturing		Non-Manufacturing	
Sector	Days	Sector	Days
Food	3.03	Construction	4.31
Apparel & Textile	6.43	Wholesale & Retail	3.42
Wood & Wooden Products	10.15	Financial & Insurance	2.68
Glass Stone Clay	11.59	Real Estate	9.09
Paper Pulp	6.09	Transportation	1.84
Chemicals	7	Communication	2.55
Refiner & Coal	4.6	Medical Services	2.85
Metal Products	5.82	Other Public Services	7.25
Steel	5.82	Business Services	6.24
Nonferrous	3.75	Personal Services	3.28
Genreal Machinery	8.02	Agriculture	3.71
Precision Machinery	8.15	Mining	3.5
Elec. & Electron	5.86		

Manufacturing		Non-Manufacturing	
Sector	**Days**	**Sector**	**Days**
Transport Eq	3.22		
Misc. Manufacturing	6.3		
Average	**6.39**	**Average**	**4.23**

B.4.4 Other Considerations

Webb et al. (1999) surveyed businesses pre-disaster in Memphis and post-disaster in Los Angeles and found that few businesses have made preparations or plans in the event of a disaster. About 15% of businesses owned a backup generator, and less than 10% of businesses had arrangements to relocate in the event of a disaster. Larger firms tended to have more preparation than smaller firms. This work provides an initial sense of the level of disaster preparedness we expect to find in our survey.

Webb et al. also found that most businesses recovered after the five major disasters under study, with a majority of businesses affected by disasters reported recovering to pre-disaster business conditions. However, this does not mean that the business did not experience substantially costs during the recovery. They found that business' financial condition prior to a disaster, firm size, and larger economic trends were a greater predictor of recovery outcomes than disaster planning, all else being equal. These findings suggest that direct costs are meaningful only insofar as they are portrayed relative to a business' current financial condition and in the context of that business' market. For example, businesses in wholesale and retail sectors have far worse outcomes following major disruptions than other businesses, due to competitiveness and high rates of failure and turnover that characterize those sectors (Tierney, 2007).

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ATTACHMENT 24

“Pacific Gas and Electric Co.’s 2012 Value of Service Study” 2012

Attachment 24

Pacific Gas & Electric Company's
2012 Value of Service Study

Nexant
Reimagine tomorrow.

FREEMAN, SULLIVAN & CO.
A MEMBER OF THE FSC GROUP

Pacific Gas & Electric Company's 2012 Value of Service Study

May 17, 2012

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Table of Contents

1 Executive Summary

Freeman, Sullivan & Co. (FSC) was retained by Pacific Gas & Electric Company (PG&E) to conduct its 2012 Value of Service (VOS) study – research to estimate the costs customers incur during power outages. This study was conducted as a result of a directive by the California Public Utilities Commission (CPUC) for PG&E to carry out a VOS study. This comprehensive research project was designed to collect detailed outage cost information from all 4 of PG&E's customer classes – residential, small & medium business (SMB), large business and agricultural. In this report, the methodology and results of the study are summarized. The primary objectives of the 2012 VOS study were to:

- Estimate 2012 outage costs by customer class and region;
- Determine how costs vary by outage timing for each customer class;
- Compare 2012 outage cost estimates by customer class to those of previous studies; and
- Understand the level of reliability that is considered acceptable within each customer class.

The VOS analyses are based on survey data collected in 4 separate surveys (one for each customer class) conducted during late 2011 and early 2012. The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated over the past 25 years by the Electric Power Research Institute (EPRI) and other parties.[1]

Although the basic methodology is similar to previous work, the 2012 PG&E VOS study featured several noteworthy methodological improvements. These methodological improvements include:

- **Dynamic survey instrument design:** In the 2012 survey instrument, each respondent was randomly assigned to 1 of 24 different outage onset times (for 24 hours of the day) and reported costs for a weekend scenario with a randomly assigned outage duration. This design produced the data necessary for understanding how outage costs vary across different times of the day and week, for outages from 5 minutes to 24 hours. This dynamic survey data was also able to produce an estimate of the average outage cost across all time periods, as opposed to focusing on an individual time period. In the 2005 PG&E VOS study and many other prior studies, outage scenarios were primarily limited to summer weekday afternoons, which was useful for generation planning, but not directly applicable to transmission and distribution planning.
- **Oversampling in Bay Area:** During the sample design process, FSC analyzed how aggregate economic output per unit of electricity use varied across PG&E's service territory. This analysis found that outage costs are likely to be significantly higher in the Bay Area than in other parts of PG&E's service territory. Therefore, the sample design had specific quotas for the number of Bay Area and non-Bay Area customers and included an oversampling of non-residential customers in the Bay Area. With this approach, the results were able to account for differences between Bay Area and non-Bay Area customers.
- **Optimized sample design:** The sample design took advantage of information from the 2005 PG&E VOS study to optimally define the number of usage strata and boundaries for the usage strata. Taking advantage of previous results allowed FSC to determine the sample stratification method that minimized the variance in the estimated outage cost, which maximized the precision of the 2012 estimates.
- **Improved customer damage functions:** Customer damage functions are statistical models that predict how outage costs vary across customers, outage duration and other outage characteristics. In the 2005 study, a Tobit regression model was used to estimate the

[1] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

customer damage functions. However, a 2009 meta-analysis by Lawrence Berkeley National Laboratory showed that a two-part econometric model is more appropriate for modeling outage cost data.[2] In this study, FSC applied the two-part econometric model to this dynamic survey data to develop estimates for how outage costs vary by time of day and week for each customer class.

- **Customized cost per unserved kWh estimates:** To develop the cost per unserved kWh estimates, it is necessary to produce a load ratio that estimates the relative amount of unserved electricity for each outage scenario and respondent. Previous studies would simply apply the load factor (ratio of average kW to peak kW) for each customer class because the outage scenarios were primarily focused on peaking periods. In this study, the cost per unserved kWh estimates were customized to each scenario (based on outage timing) and each respondent (based on rate profile).

With the methodological improvements in this study, the 2012 results can be directly applied to many different types of utility investments at the generation, transmission and distribution level.[3]

1.1 Response to Survey

Table 1-1 describes the total number of completed surveys by region and customer class. The total number of completed surveys varied by customer class and was roughly proportional to the size of the underlying populations. With over 1,000 completed surveys each, the relatively populous residential and SMB customer classes had the largest number of participants in the study. The smaller agricultural and large business segments had 538 and 210 respondents, respectively. With the oversampling of non-residential customers in the Bay Area, a majority of SMB and large business respondents were from that region. Considering that the non-Bay Area region has many more agricultural customers, the oversampling generated many more Bay Area respondents that there otherwise would have been, but still far fewer than in the non-Bay Area region.

Table 1-1:
Total Number of Completed Surveys by Region and Customer Class

Region	Residential	SMB	Large Business	Agricultural
Bay Area	491	637	119	125
Non-Bay Area	576	447	91	413
Overall	**1,067**	**1,084**	**210**	**538**

1.2 2012 Outage Cost Estimates

Table 1-2 provides the cost per outage event estimates by customer class. Cost per outage event is the average cost per customer resulting from each outage duration. Given the dynamic survey instrument design, these values represent the average outage cost across all time periods. For a 1-hour outage, large business customers experience the highest cost ($449,655) and residential customers experience the lowest cost ($11.89). Even though SMB and agricultural respondents had

[2] Sullivan, M.J., M. Mercurio and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[3] Sullivan, M.J. and J. Schellenberg (2011). *Evaluating Smart Grid Reliability Benefits for Illinois*. National Association of Regulatory Utility Commissioners.

roughly the same average usage, the SMB cost of $1,848.8 for a 1-hour outage is 4.1 times higher than the agricultural cost ($453.5). Between regions, the differences in cost per outage event are stark. Bay Area cost per event is higher than in the non-Bay Area region for every outage duration among residential, SMB and large business customers. For agricultural customers, Bay Area cost per event is higher than in the non-Bay Area region for all outage durations over 1 hour. This result underscores the importance of having segmented the sample among these two regions.

For large business customers in particular, a small subset of Bay Area customers with extremely high outage costs drives much of the difference between regions. These high outage costs must be understood within the context of their level of reliability. Many of these Bay Area large business customers are accustomed to a very high level of reliability and rarely experience sustained power interruptions, so even a 5-minute outage would impose extremely high costs. Considering that these customers are significantly less likely to experience transmission or distribution related power interruptions, it can be argued that their costs should be excluded from many transmission and distribution planning applications. Therefore, Appendix D provides the 2012 large business outage cost estimates by level of service reliability. For transmission and distribution planning applications, FSC recommends applying the results segmented by level of reliability as opposed to region.

Table 1-2:
2012 Cost per Outage Event Estimates by Region and Customer Class

Region	Outage Duration	Residential ($/Event)	SMB ($/Event)	Large Business ($/Event)	Agricultural ($/Event)
Bay Area	5 minutes	$8.18	$585.2	$761,784	$124.1
	1 hour	$13.22	$2,679.4	$861,359	$299.3
	4 hours	$19.59	$6,607.7	$1,073,743	$2,512.2
	8 hours	$26.63	$16,463.6	$1,080,310	$4,866.9
	24 hours	$37.83	$33,780.9	$2,252,293	$8,392.1
Non-Bay Area	5 minutes	$6.96	$159.0	$24,308	$147.5
	1 hour	$10.71	$973.9	$54,970	$461.6
	4 hours	$14.89	$2,761.1	$113,746	$1,201.5
	8 hours	$19.79	$4,435.0	$147,383	$2,496.6
	24 hours	$26.03	$8,514.5	$615,402	$5,763.9
All	5 minutes	$7.41	$379.8	$454,675	$146.1
	1 hour	$11.89	$1,848.8	$449,655	$453.5
	4 hours	$16.82	$4,774.3	$596,675	$1,230.7
	8 hours	$22.89	$10,568.7	$617,196	$2,549.4
	24 hours	$31.67	$21,339.4	$1,472,497	$5,842.4

Figure 1-1 shows cost per average kW by customer class. Cost per average kW is the cost per outage event normalized by average customer demand among respondents. This metric is useful for comparing outage costs across segments because it is normalized by customer demand. For a 1-hour outage, residential customers have the lowest cost per average kW ($14.86), followed by agricultural customers ($52.1) and SMB customers ($205.2). The relative order of cost per average kW for these

3 customer classes is consistent across all outage durations. Large business customers have the highest cost per average kW for outages of 5 minutes and 1 hour. For outages of 4 hours or more, large business cost per average kW is lower than that of the SMB segment. In fact, SMB customers experience the largest increase in costs as outage duration increases. From 5 minutes to 24 hours, SMB cost per average kW increases nearly $100 per hour, compared to around $30 per hour among large business and agricultural customers and a little over $1 per hour for residential customers. This result suggests that SMB customers have relatively few options for mitigating costs as outage duration increases.

Figure 1-1:
2012 Cost per Average kW Estimates by Customer Class

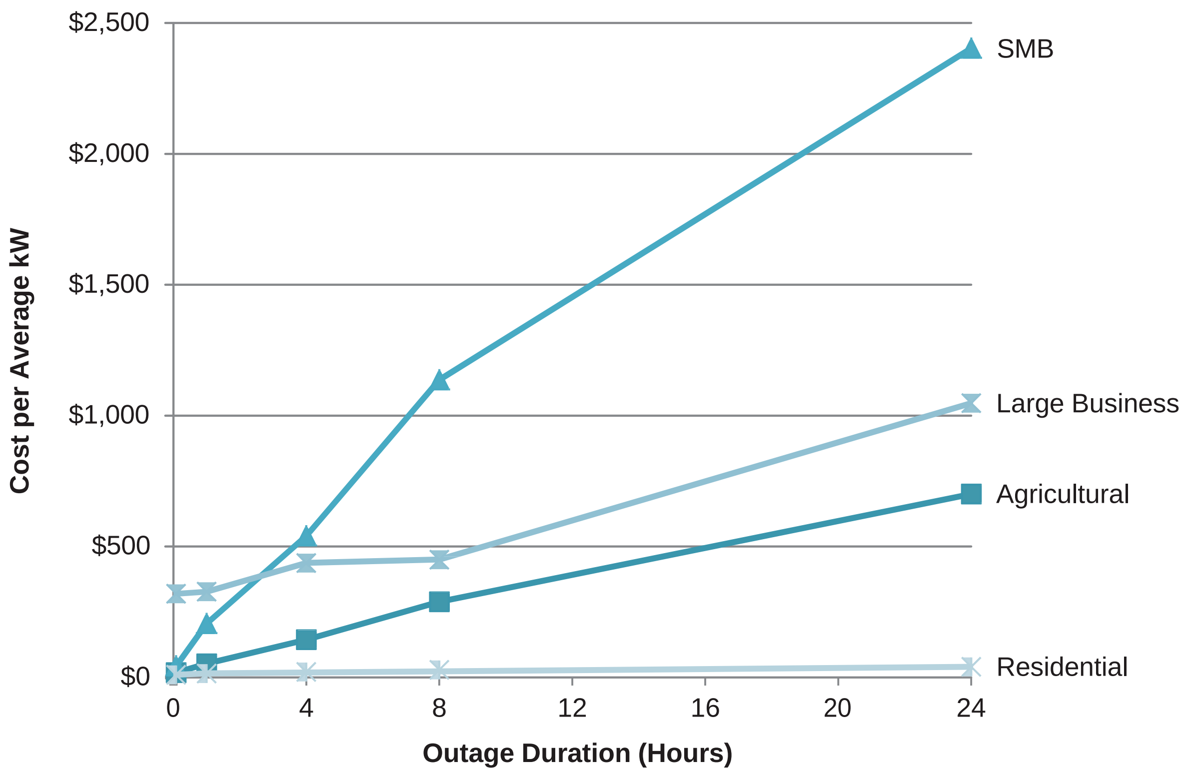


Table 1-3 summarizes cost per average kW by customer class, disaggregated by region. Between regions, the outage cost differences are equally stark when normalizing by respondent demand because average kW is similar in the two regions for each customer class. As in the cost per outage event estimates, Bay Area cost per average kW is higher than in the non-Bay Area region for every outage duration among residential, SMB and large business customers. For agricultural customers, Bay Area cost per average kW is higher than in the non-Bay Area region for all outage durations over 1 hour.

Table 1-3:
2012 Cost per Average kW Estimates by Region and Customer Class

Region	Outage Duration	Residential ($/kW)	SMB ($/kW)	Large Business ($/kW)	Agricultural ($/kW)
Bay Area	5 minutes	$11.86	$62.1	$547.5	$12.8
	1 hour	$18.62	$272.0	$624.7	$44.4
	4 hours	$27.59	$706.0	$774.6	$356.8
	8 hours	$37.51	$1,560.5	$771.0	$682.6
	24 hours	$54.04	$3,482.6	$1,663.5	$1,143.3
Non-Bay Area	5 minutes	$8.39	$19.8	$17.0	$18.2
	1 hour	$12.17	$121.9	$40.7	$52.5
	4 hours	$16.54	$339.2	$85.6	$138.1
	8 hours	$21.99	$557.9	$110.1	$281.8
	24 hours	$29.58	$1,073.7	$443.4	$686.2
All	5 minutes	$9.75	$43.3	$319.3	$18.1
	1 hour	$14.86	$205.2	$327.4	$52.1
	4 hours	$21.03	$540.1	$436.9	$143.9
	8 hours	$28.61	$1,136.4	$449.7	$288.7
	24 hours	$40.09	$2,403.1	$1,047.5	$700.5

Table 1-4 provides the cost per unserved kWh estimates by customer class. Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh for each outage scenario. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. At 5-minutes, cost per unserved kWh is at its maximum for each region and customer class because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases precipitously because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate. Between regions, the differences in cost per unserved kWh show the same trend as in the cost per outage event and cost per average kW estimates where the Bay Area cost is higher for all but the 5-minute and 1-hour agricultural estimates.

Cost per unserved kWh is also interesting because it directly provides an “apples-to-apples” comparison of how customers value electric service versus what they pay for electric service. For all 4 customer classes and all outage durations, customers place a substantially higher value on an unserved kWh than what they would have paid if that electricity had been delivered. Even a 24-hour SMB outage for which hundreds of kWh are unserved on average, SMB customers value lost electric service at $99.7 per unserved kWh. Residential customers experience an outage cost of $5.08 per unserved kWh for a 4-hour outage and $1.67 per kWh for a 24-hour outage, which are clearly lower than the other customer classes, but still substantially higher than what they pay per kWh.

Table 1-4:
2012 Cost per Unserved kWh Estimates by Region and Customer Class

Region	Outage Duration	Residential ($/kWh)	SMB ($/kWh)	Large Business ($/kWh)	Agricultural ($/kWh)
Bay Area	5 minutes	$136.33	$713.7	$6,486.6	$144.3
	1 hour	$18.89	$261.4	$609.7	$42.5
	4 hours	$6.73	$168.3	$189.9	$89.5
	8 hours	$4.56	$192.4	$94.8	$84.6
	24 hours	$2.24	$144.5	$69.1	$48.1
Non-Bay Area	5 minutes	$99.43	$227.2	$201.5	$207.8
	1 hour	$11.77	$114.7	$39.4	$50.7
	4 hours	$4.00	$79.3	$21.2	$34.2
	8 hours	$2.65	$66.5	$13.7	$35.0
	24 hours	$1.23	$44.5	$18.5	$28.2
All	5 minutes	$123.50	$493.3	$3,769.8	$205.7
	1 hour	$14.86	$195.6	$318.5	$50.3
	4 hours	$5.08	$127.5	$107.5	$35.6
	8 hours	$3.44	$138.4	$55.6	$35.9
	24 hours	$1.67	$99.7	$43.7	$28.8

1.3 Impact of Outage Timing

As a result of the dynamic survey design, the 2012 study provided useful information on how outage costs vary across different times of the day and week. For the residential and SMB analyses on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

With fewer observations in the large business and agricultural segments, onset times were aggregated into 2 key time periods because the analysis could not identify clear trends within the more granular time periods used for residential and SMB customers. The 2 key time periods for large business and agricultural customers were:

- Morning and Afternoon (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

These groups of onset times were further divided among weekdays and weekends for the residential, SMB and agricultural customer classes. In the large business analysis of the impact of outage timing, the onset times were not further divided by day of week because this variable did not have a significant effect for large business customers.

Figure 1-2 provides the weekday relative cost per outage event estimates and Figure 1-3 provides the weekend estimates, which were derived from the customer damage functions described in Appendix B. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each outage cost estimate in Section 1.2 (referred to as the “base value”). As shown in the figure, outage costs for SMB customers are the most sensitive to onset time, varying from 82.5% lower than the base value on a weekend evening to 85.5% higher on a weekday morning. SMB outages on weekday mornings have the highest percentage increase because these outages likely start and end during normal business hours, potentially disrupting an entire day of work. The only weekday SMB outages that have lower costs than the base value are those with an evening onset time because these outages begin after normal business hours and likely end before business resumes the next day. Although some SMB customers such as retail stores likely have higher costs on a weekend day, SMB is the only customer class that has lower relative outage costs for all weekend onset times. Considering that SMB outage costs vary substantially depending on the onset time, it is important that planning applications apply these relative values.

Figure 1-2:
Relative Cost per Outage Event Estimates by Onset Time and Customer Class – Weekdays

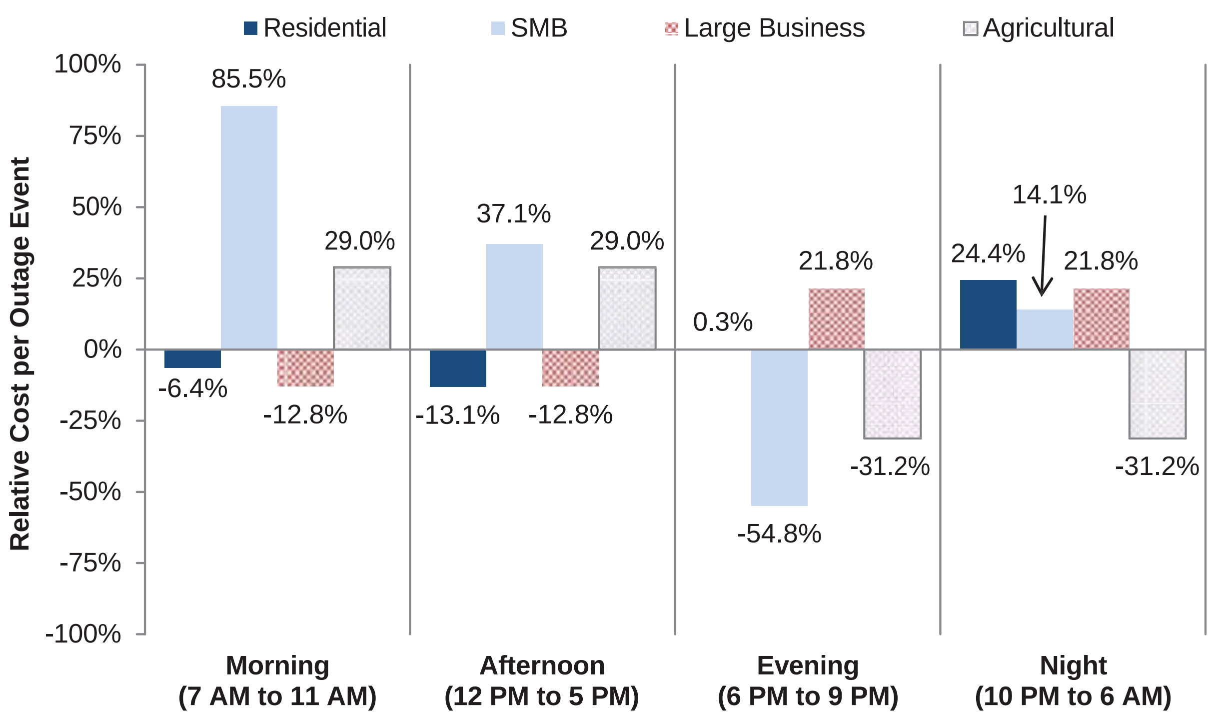
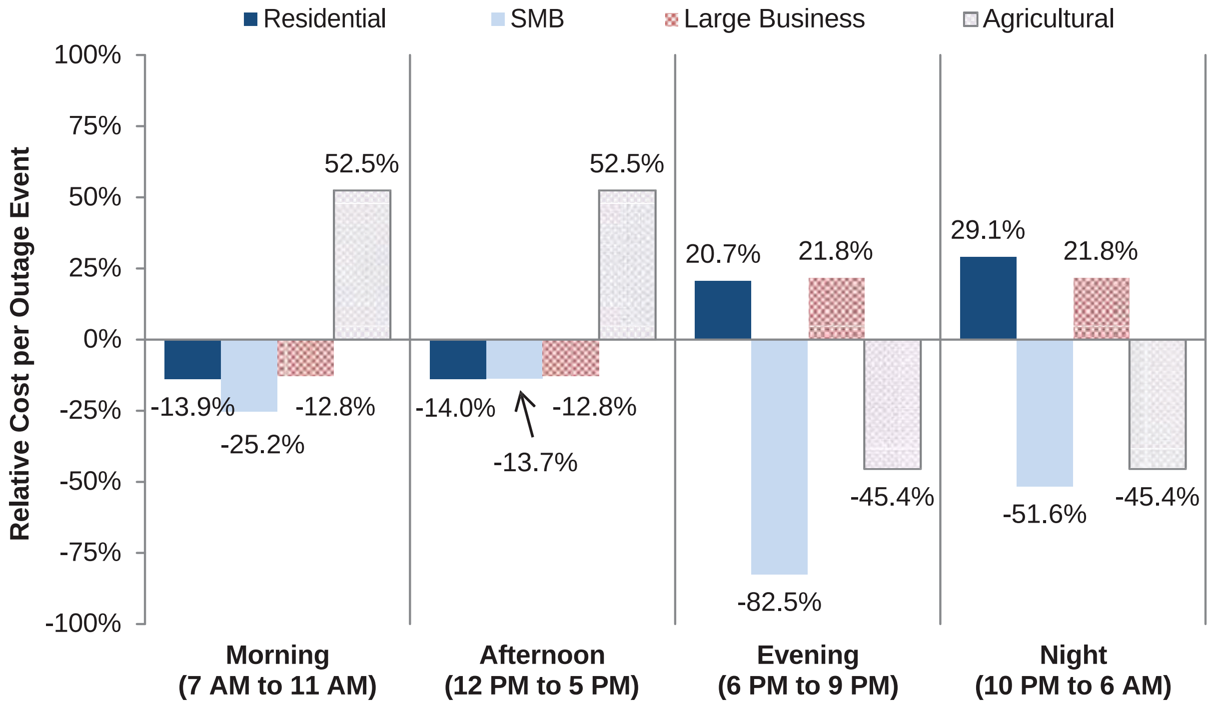


Figure 1-3:
Relative Cost per Outage Event Estimates by Onset Time and Customer Class – Weekends



Interestingly, residential and large business customers exhibit a similar trend, where outage costs vary moderately with lower costs during the morning and afternoon and higher costs during the evening and night throughout the week. Outage costs are higher during the evening and night for residential customers because they are more likely to be home at these times. For large business customers, considering that many operate 24 hours per day, 7 days per week, outages with different onset times likely have a similar impact on production, but the overall outage cost may be greater during the evening and night because outage response may require overtime or emergency staff.

Outage costs for agricultural customers vary more than those of residential and large business customers, but less than SMB outage costs. Agricultural outage costs during the morning and afternoon are higher than the base value on weekdays and weekends, which is not surprising considering that much agricultural work is conducted during daylight hours throughout the week.

1.4 Comparison to Previous Studies

PG&E previously carried out an outage cost study for all 4 customer classes in 2005. In addition, there was a large business study in 1989, an agricultural study in 1991 and residential and SMB in 1993. Table 1-5 compares the cost of a 4-hour, summer afternoon outage for each study year and customer class. The 1989-1993 and 2005 cost per outage event estimates were converted to 2012 dollars using the gross domestic product deflator, which was obtained from the U.S. Department of Commerce's Bureau of Economic Analysis. SMB and agricultural outage costs vary between study years, but these differences are not statistically significant. For residential customers, the difference between 2005 and 2012 is statistically significant and shows a 64.3% increase in reported outage cost since 2005. Although there seems to be a large increase in outage costs for residential customers, some of this difference is due to a change in the residential survey design that improved the accuracy of the estimates. After adjusting for this methodological difference, there is a smaller increase of 18.4% in reported outage cost for residential customers since 2005, which may be due to increased household sizes as a result of economic conditions. Even with these increases in outage costs in the 2012 study, all of the residential cost per event, average kW and unserved kWh estimates are lower than in the other customer classes, as shown above.

Between 1989 and 2005, there was a 53.3% increase in reported outage cost for large business customers, but this difference was not statistically significant. The difference between 2005 and 2012 is statistically significant and shows a 4-fold increase in reported outage cost for large business customers since 2005.[4] While it is possible that outage costs for large business customers have increased significantly since 2005, the results reported here must be used with caution. With the relatively small sample sizes for the large business segment and specific subset of customers with extremely high outage costs, the results for each large business study are subject to large statistical error because they are highly sensitive to the sample that is randomly selected. In the 2012 study, it seems that the random sample included a larger amount of these customers with extremely high outage costs. In addition, the 2012 study had lower large business response rates than those of the 1989 and 2005 studies, which may have led to non-response bias. Although the assessment presented in Appendix D did not find any observable factors (such as industry type) that led to non-response bias, there could have been unobservable factors that biased the results upward in light of the relatively low response rates in the 2012 study. Another possibility may be that these high-cost customers are more prevalent in PG&E's large business population than they were in the past, which may require further research.

Table 1-5:
Cost of a 4-Hour, Summer Afternoon Outage by Study Year and Customer Class

Study Year	Residential (2012$)	SMB (2012$)	Large Business (2012$)	Agricultural (2012$)
1989-1993	$8.37	$4,738.3	$73,948	$1,104.8
2005	$9.31	$3,884.4	$113,336	$1,945.1
2012	$15.30	$6,138.9	$460,263	$1,367.1

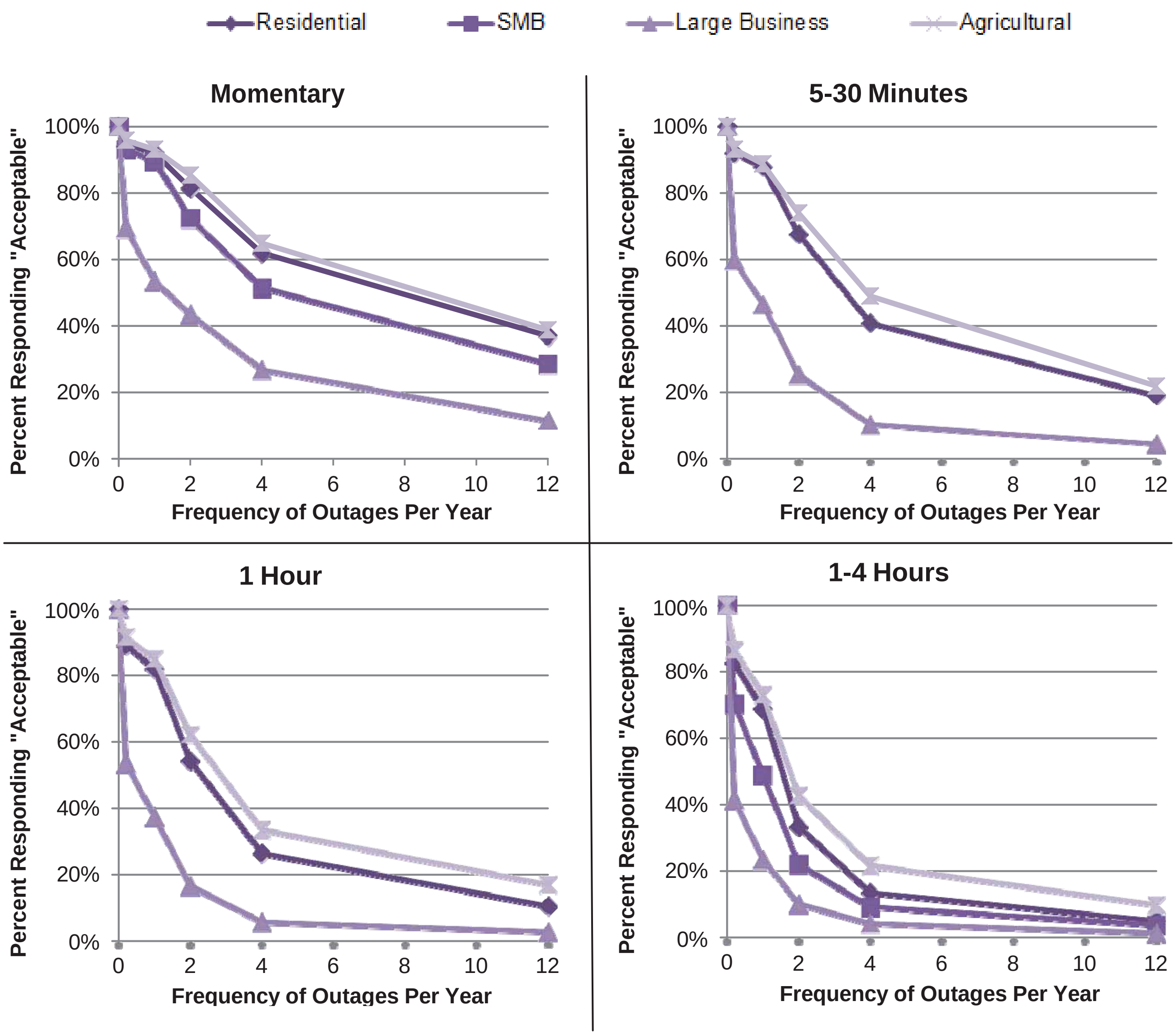
1.5 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 1-4 shows the percent of customers rating each combination of outage frequency and duration as acceptable. As expected, a customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Even though cost per unserved kWh for outages longer than 1 hour is lower for large business customers than it is for SMB customers, large business customers expect a substantially higher level of reliability. One outage of 1

[4] Note that statistical significance in this case implies that there was an increase in reported cost, but does not necessarily confirm that the magnitude of the increase was exactly 4-fold.

to 4 hours per year is acceptable to 23.6% of large business customers, compared to 49% of SMB customers. Agricultural customers expect the lowest level of reliability. One outage of 1 to 4 hours per year is acceptable to 73% of agricultural customers, compared to 68.8% of residential customers. Between regions, there are only slight differences in what level of reliability is considered acceptable for residential, SMB and agricultural customers, which is somewhat unexpected given the regional differences in outage costs. Large business was the only segment for which there is a substantial difference in the acceptable level of service reliability by region. Bay Area large business customers expect a very high level of service reliability.

Figure 1-4:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable by Customer Class



To determine what percent of customers receives service that they consider acceptable, the acceptable level of service reliability questions were compared with the number of outages customers reported experiencing over the past 12 months. Table 1-6 provides the results of this analysis by outage duration and customer class for the survey in 2005 and 2012. In the 2012 study, up to 87% of residential and 81% of SMB customers reported that they receive service that they say is acceptable. Across all outage durations, these results are very similar to 2005 for residential and SMB customers. Large business and agricultural customers were less likely to receive service they say is acceptable, and as in the 2005 study, momentary outages for large business customers are the type of outage that most likely leads to unacceptable service.

Table 1-6:
Percent of Customers Receiving Service Rated as Acceptable by Study Year and Customer Class

Outage Duration	Residential		SMB		Large Business		Agricultural	
	2005	2012	2005	2012	2005	2012	2005	2012
Momentary	89%	91%	88%	87%	70%	68%	88%	86%
5-30 Minutes	95%	94%	-	-	86%	84%	91%	90%
Up to 1 Hour	-	-	83%	85%	-	-	-	-
1 Hour	94%	95%	-	-	92%	81%	92%	87%
1-4 Hours	85%	87%	82%	81%	78%	73%	83%	76%

2 Introduction

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- Compare 2012 outage cost estimates by customer class to those of previous studies; and
- Understand the level of reliability that is considered acceptable within each customer class.

Since VOS cannot be measured directly, it is estimated from outage cost surveys of utility customers. These cost estimates can be used to assess the cost-effectiveness of investments in generation, transmission and distribution systems and to strategically compare alternative investments in order to determine which provides the most combined benefits to the utility and its customers. This comprehensive approach to valuing reliability, commonly known as "value-based reliability planning," has been a well-established theoretical concept in the utility industry for the past 30 years.[5] With the methodological improvements in this study, the 2012 results can be directly applied to many different types of utility investments at the generation, transmission and distribution level.

2.1 Study Methodology

The objectives above were addressed in this study by conducting 4 separate outage cost surveys (one for each customer class) during late 2011 and early 2012. This survey methodology has been implemented by many electric utilities throughout the United States over the past 25 years. This study and the prior studies employed a common survey methodology, including sample designs, measurement protocols, survey instruments and operating procedures. This methodology is described in detail in EPRI's Outage Cost Estimation Guidebook.[6] The results of 28 prior studies are part of a meta-analysis of nationwide outage costs that is summarized in a 2009 report by Lawrence Berkeley National Laboratory (LBNL).[7]

Although the basic methodology is similar to previous work, the 2012 PG&E VOS study featured several noteworthy methodological improvements. These methodological improvements include:

- **Dynamic survey instrument design:** In the 2012 survey instrument, each respondent was randomly assigned to one of 24 different outage onset times (for 24 hours of the day) and reported costs for a weekend scenario with a randomly assigned outage duration. This design

[5] For an early paper on value-based reliability planning, see: Munasinghe, M. (1981). "Optimal Electricity Supply, Reliability, Pricing and System Planning." Energy Economics, 3: 140-152.

[6] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

[7] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

produced the data necessary for understanding how outage costs vary across different times of the day and week, for outages from 5 minutes to 24 hours. This dynamic survey data was also able to produce an estimate of the average outage cost across all time periods, as opposed to focusing on an individual time period. In the 2005 PG&E VOS study and many other prior studies, outage scenarios were primarily limited to summer weekday afternoons, which was useful for generation planning, but not directly applicable to transmission and distribution planning.

- **Oversampling in Bay Area:** During the sample design process, FSC analyzed how aggregate economic output per unit of electricity use varied across PG&E's service territory. This analysis found that outage costs are likely to be significantly higher in the Bay Area than in other parts of PG&E's service territory. Therefore, the sample design had specific quotas for the number of Bay Area and non-Bay Area customers and included an oversampling of non-residential customers in the Bay Area. With this approach, the results were able to account for differences between Bay Area and non-Bay Area customers.
- **Optimized sample design:** The sample design took advantage of information from the 2005 PG&E VOS study to optimally define the number of usage strata and boundaries for the usage strata. Taking advantage of previous results allowed FSC to determine the sample stratification method that minimized the variance in the estimated outage cost, which maximized the precision of the 2012 estimates.
- **Improved customer damage functions:** Customer damage functions are statistical models that predict how outage costs vary across customers, outage duration and other outage characteristics. In the 2005 study, a Tobit regression model was used to estimate the customer damage functions. However, the 2009 meta-analysis for LBNL showed that a two-part econometric model is more appropriate for modeling outage cost data. In this study, FSC applied the two-part econometric model to this dynamic survey data to develop estimates for how outage costs vary by time of day and week for each customer class.
- **Customized cost per unserved kWh estimates:** To develop the cost per unserved kWh estimates, it is necessary to produce a load ratio that estimates the relative amount of unserved electricity for each outage scenario and respondent. Previous studies would simply apply the load factor (ratio of average kW to peak kW) for each customer class because the outage scenarios were primarily focused on peaking periods. In this study, the cost per unserved kWh estimates were customized to each scenario (based on outage timing) and each respondent (based on rate profile).

2.2 Economic Value of Service Reliability

The purpose of VOS research is to measure the economic value of service reliability, using information regarding outage costs as a proxy. Under the general theory of welfare economics, the economic value of service reliability is equal to the economic losses that customers experience as a result of service interruptions. The history of efforts to measure customer outage costs goes back several decades. In that time, several approaches have been used. These include:

- Scaled macro-economic indicators (i.e., gross domestic product, wages, etc.);
- Market-based indicators (e.g., incremental value of reliability derived from studies of price–elasticity of demand for service offered under non-firm rates); and
- Survey-based indicators (i.e., cost estimates obtained from surveys of representative samples of utility customers).

The most widely used approach to estimating customer outage costs is through analysis of data collected via customer surveys. In a customer outage cost survey, a representative sample of customers is asked to estimate the costs they would experience given a number of hypothetical outage scenarios. In these hypothetical outage scenarios, key characteristics of the outages described in these scenarios are varied systematically in order to measure differential effects of service outage events with various different characteristics. A variety of statistical techniques are then used to identify and describe the relationships between customer economic losses and outage attributes.

Survey-based methods are generally preferred over the other measurement protocols because they can be used to obtain outage costs for a wide variety of reliability conditions not observable using the other techniques. As in 2005, these methods were selected for use in the 2012 PG&E VOS study.

2.3 Valuation Methods

Two basic valuation methods are used to measure outage costs in the surveys – direct cost measurement and willingness-to-pay (WTP). Direct cost measurement techniques involve asking customers to estimate the direct costs they will experience during a service outage. WTP measurement techniques involve measuring the amount customers would be willing to pay to avoid experiencing the outage. In both approaches, the surveys ask respondents to provide these estimates for a number of outage scenarios, which vary in terms of the characteristics of the event.

2.3.1 Direct Cost Measurement

For non-residential customers (SMB, large business and agricultural), direct cost measurement was used in this study because their outage costs are more tangible and much less difficult to estimate directly. At its most general level, the direct cost of an outage is defined as follows:

$$\begin{aligned} \mathit{Direct\,Cost} &= \mathit{Value\ of\ Lost\ Production} + \mathit{Outage\ Related\ Costs} \\ &\quad - \mathit{Outage\,Related\,Savings} \end{aligned}$$

The *Value of Lost Production* is the amount of revenue the surveyed business would have generated in the absence of the outage minus the amount of revenue it was able to generate given that the outage occurred. It is their net loss in the economic value of production after their ability to make up for lost production has been taken into account. It includes the entire cost of making or selling the product as well as any profit that could have been made on the production.

Outage Related Costs are additional production costs directly incurred because of the outage. These costs include:

- Labor costs to make up any lost production (which can be made up);
- Labor costs to restart the production process;
- Material costs to restart the production process;
- Costs resulting from damage to input feed stocks;
- Costs of re-processing materials (if any); and
- Cost to operate backup generation equipment.

Outage Related Savings are production cost savings resulting from the outage. When production or sales cannot take place, there are economic savings resulting from the fact that inputs to the production or sales process cannot be used. For example, during the time electric power is interrupted, the enterprise cannot consume electricity and thus will experience a savings on their electric bill. In many cases, savings resulting from outages are small and do not significantly affect outage cost calculations. However, for manufacturing enterprises where energy and feedstock costs account for a significant fraction of production cost, these savings may be quite significant and must be measured and subtracted from the other cost components to ensure outage costs are not double counted. These savings include:

- Savings from unpaid wages during the outage (if any);
- Savings from the cost of raw materials not used because of the outage;
- Savings from the cost of fuel not used; and
- Scrap value of any damaged materials.

In measuring outage costs, only the incremental losses resulting from unreliability are included in the calculations. Incremental losses include only those costs described above and beyond the normal costs of production. If the customer is able to make up some percentage of their production loss at a later date (e.g., by running the production facility during times when it would normally be idle), the outage cost does not include the full value of the production loss. Rather, it is calculated as the value of production not made up plus the cost of additional labor and materials required to make up the share of production eventually recovered.

2.3.2 Willingness-to-Pay Approach

Cost estimates for the residential segment are based on a WTP question because residential customers do not experience many directly measureable costs during an outage. Considering that most of the outage cost for residential customers is a result of inconvenience or hassle, WTP is a better representation of their underlying costs. The WTP approach to outage cost estimation is quite different than the direct cost measurement approach. Rather than asking what an outage would cost the customer, the WTP approach asks how much the customer would pay to avoid its occurrence. This technique employs the concept of compensating valuation – customers are asked to estimate the economic value that would leave their welfare unchanged compared to a situation in which no outage occurred. This approach is especially useful when intangible costs are present, which by their nature, are difficult to estimate using the direct cost measurement approach.

2.4 Report Organization

The remainder of this report proceeds as follows:

- **Section 3 – Survey Methodology:** This section covers the survey methodology, including details on the survey implementation approach by customer class, survey instrument design, sample design and data collection procedures for each customer class.
- **Section 4 – Outage Cost Estimation Methodology**: The results of this study focus on the following 3 key metrics – cost per outage event, cost per average kW and cost per unserved kWh. This section on the outage cost estimation methodology explains what each of these 3 key metrics represents, how they are calculated from the survey data and how they are related to each other.
- **Sections 5 through 8 – Results**: These 4 sections provide the results for each customer class, beginning with the 3 key metrics defined in Section 4 for the service territory as a whole and disaggregated by region. Comparisons of outage costs in the two regions are discussed and confidence intervals for the estimates are provided. Then, each section provides results on how outage costs vary by the time of day and week for each customer class. This

discussion is followed by a comparison of the 2012 outage cost estimates to those of previous studies. Finally, each section concludes with results related to the level of reliability that each customer class considers acceptable.

- **Appendix A – Sampling Strategy Determination:** This appendix provides more details on the sample design, specifically focusing on how the final sampling strategy was determined for each customer class.
- **Appendix B – Customer Damage Functions:** This appendix details the customer damage functions, which are econometric models that predict how outage costs vary across customers, outage duration and other outage characteristics. For example, these models were used to develop the results in Sections 5 through 8 related to how outage costs vary by the time of day and week for each customer class.
- **Appendix C – Assessment of Non-response Bias:** In this appendix, a systematic assessment of non-response bias in the survey is provided.
- **Appendix D – 2012 Large Business Outage Cost Estimates by Level of Service Reliability:** Many large business customers are accustomed to a very high level of reliability and rarely experience sustained power interruptions. Therefore, this appendix provides the large business outage cost estimates by level of service reliability. For distribution planning applications, FSC recommends using the outage cost estimates associated with large business customers that have experienced one or more sustained outages in the past year.
- **Appendices E through H – Survey Instruments:** These 4 appendices include the survey instruments for each customer class.

3 Survey Methodology

Table 3-1 provides an overview of the 2012 VOS survey implementation approach by customer class. Residential customers were recruited with a letter that encouraged them to go online to complete the survey (the letter included a link to the online survey along with a unique access code specific to each customer). If a residential customer did not complete the survey online, a paper copy was sent. SMB and agricultural customers were recruited by telephone and were asked if they preferred to fill out the paper survey or go online to complete the survey. If a customer preferred to fill out the paper survey, it was sent to them by mail. If a customer preferred to go online to complete the survey, a link to the online survey and a unique access code specific to each customer were provided in an email. Large business customers were recruited by telephone and received an in-person interview.

Although all survey instruments included variations of willingness-to-pay (WTP) and direct cost questions, the results in Sections 5 through 8 are based on the valuation method listed in Table 3-1. Cost estimates for the residential segment are based on a WTP question because residential customers do not experience many directly measureable costs during an outage. Considering that most of the outage cost for residential customers is a result of inconvenience or hassle, WTP is a better representation of their underlying costs. For SMB, large business customers and agricultural customers, direct cost measurement is the preferred valuation method because their outage costs are more tangible and much less difficult to estimate directly.

Table 3-1:
2012 VOS Survey Implementation Approach by Customer Class

Customer Class	Sample Design Target	Recruitment Method	Data Collection Approach	Valuation Method	Incentive Provided
Residential	1,000	Letter	Mail/Internet Survey	WTP	Two $2 bills
SMB	1,000	Telephone	Mail/Internet Survey	Direct Cost	$50
Large Business	190	Telephone	In-person Interview	Direct Cost	$50
Agricultural	500	Telephone	Mail/Internet Survey	Direct Cost	$150

3.1 Survey Instrument Design

This discussion of the survey instrument design focuses on the outage scenarios, which were designed the same for all segments. The survey instruments are included as appendices in case more detail is required on other aspects of the survey.

Considering that most customers rarely experience sustained power interruptions, an outage cost survey presents the respondent with hypothetical outage scenarios that are specific to a certain time period. As stated in Section 2, one of the objectives of the study was to compare the 2012 outage cost estimates with those of previous studies. As such, the first outage scenario for each customer class was the same as in the 2005 study. This outage scenario was the 4-hour, summer weekday scenario with a 3 PM onset time and no advance warning. Each results section contains a comparison to previous studies that was based on the responses to this outage scenario.

Another key objective of this study was to estimate the average outage cost across all time periods. In the 2005 study, outage scenarios were primarily limited to summer weekday afternoons. Outage cost estimates for this time period are useful for generation planning, but not transmission and distribution planning for which the power interruptions of interest occur at all times. In fact, outages are distributed throughout the day for all customer classes. As shown in Figure 3-1, there is no single hour for any customer class that accounts for more than 6.5% of outages or less than 2% of outages. Instead of having a study that produces results specifically for one time period, the outage scenarios in the 2012 VOS study were designed to capture information across all time periods. This objective was accomplished by randomizing the outage scenarios in proportion to the distribution of onset times in Figure 3-1. As a result, the outage cost estimates provided in Sections 4 through 8 are representative of the average outage cost across all time periods as opposed to just one time period.

Figure 3-1:
Distribution of Outages by Onset Time and Customer Class (2008-2010)

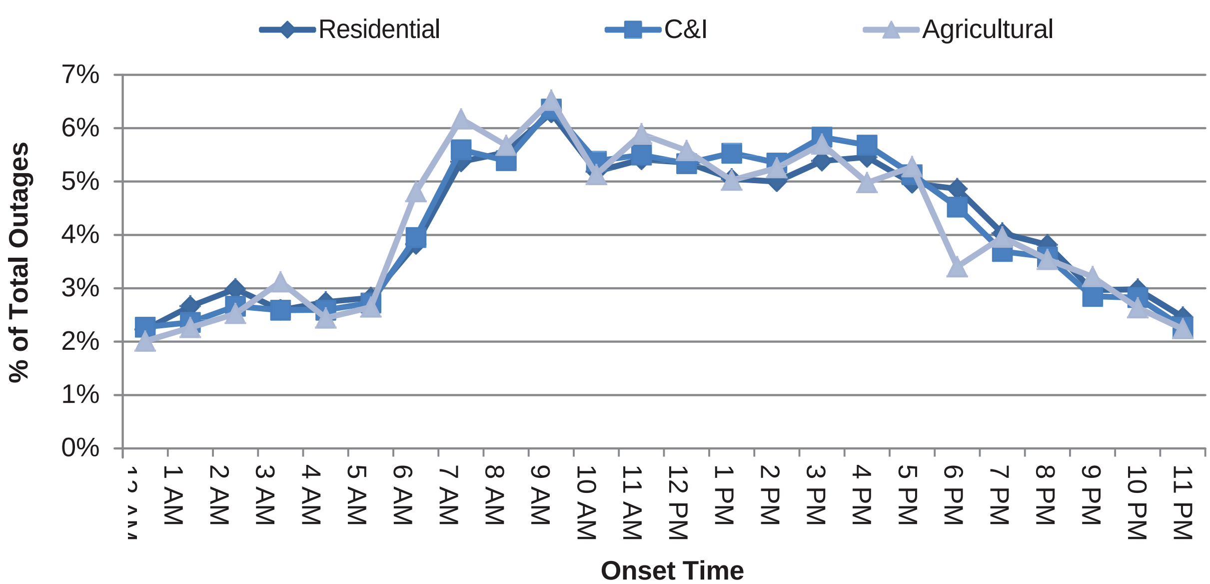


Table 3-2 provides an example set of outage scenarios. As discussed above, scenario A was the same for all respondents so that this study could be compared with the 2005 study. In accordance with Figure 3-1, this onset time of 11 AM for scenarios B through F was assigned to approximately 5.5% of respondents. Each respondent was assigned the same onset time for scenarios B through F in order to minimize respondent burden. An alternative was to randomize the onset time for every scenario and respondent, but that would likely lead to confusion and the survey would be more difficult to complete. To be consistent with scenario A, scenarios B through F were described to occur during the summer and did not include advance warning. Outage costs for the average customer do not vary substantially throughout the year, especially in California,[8] so the season was kept consistent with scenario A even though these estimates can be applied throughout the year. Advance warning was

[8] This conclusion was reached by using estimates from the Department of Energy's Interruption Cost Estimate Calculator, which can be found at ICECalculator.com. Note that this calculator does not report agricultural outage costs separately, so costs may vary throughout the year specifically for agricultural customers. For the average customer overall, the seasonal variation was not substantial.

not included for any of the scenarios because it is rarely provided for distribution or transmission related power interruptions. Scenario F was always the single weekend scenario, which provided very useful information on how outage costs are affected by timing during the week. Finally, each set of scenarios always included durations of 5 minutes, 1 hour, 4 hours, 8 hours and 24 hours. In this example set of outage scenarios, the 1-hour duration was randomly assigned to the weekend outage scenario F, which was not always the case. In fact, there were 120 different, randomly assigned versions of the survey (5 possible durations for the weekend scenario X 24 possible hours for the onset times).

Table 3-2:
Example Set of Outage Scenarios

Scenario	Season	Time of Week	Onset Time	Warning	Duration
A	Summer	Weekday	3:00 PM	No	4 hours
B	Summer	Weekday	11:00 AM	No	4 hours
C	Summer	Weekday	11:00 AM	No	5 minutes
D	Summer	Weekday	11:00 AM	No	8 hours
E	Summer	Weekday	11:00 AM	No	24 hours
F	Summer	Weekend	11:00 AM	No	1 hour

3.2 Sample Design

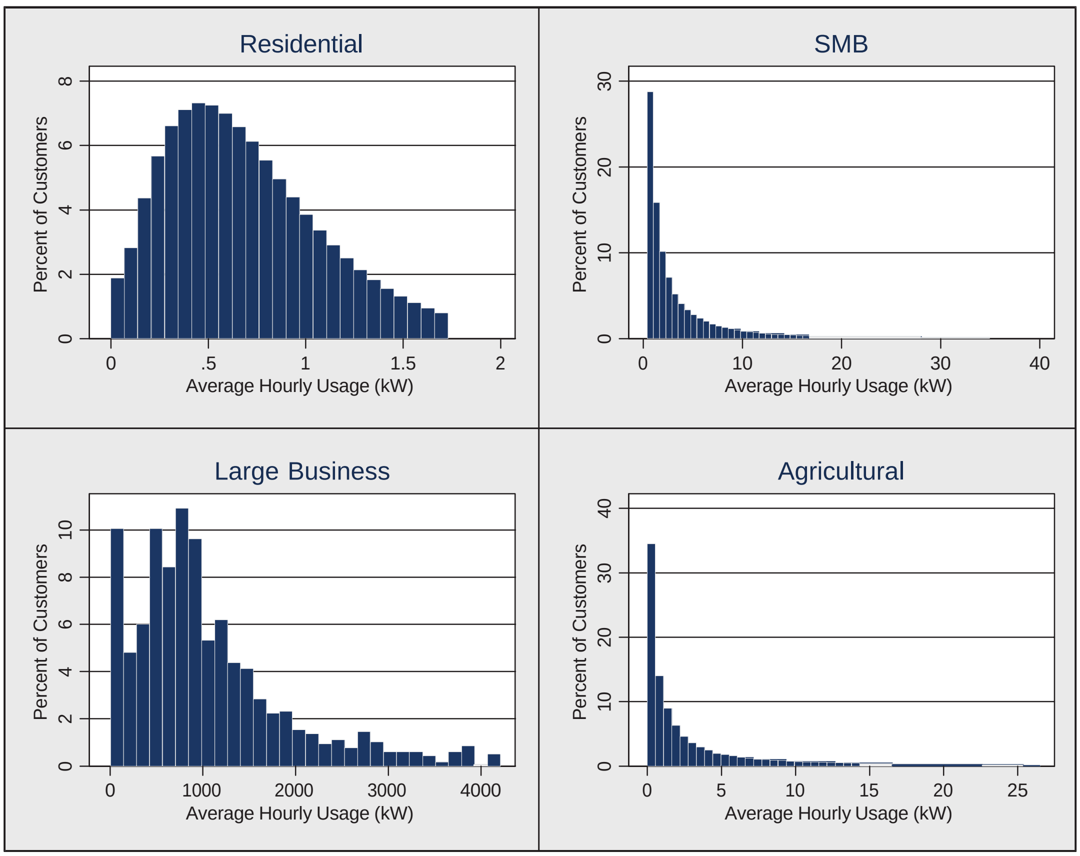
The study aimed for the following amount of completed surveys for each customer class:

- 1,000 residential customers;
- 1,000 SMB customers;
- 190 large business customers; and
- 500 agricultural customers.

Before detailing the sample design methodology and how these sample points were distributed among usage categories and region, it is important to note that a "customer" refers to a premise in the three non-residential segments, not an individual account. When SMB, large business and agricultural customers complete an outage cost survey, they provide answers for the premise associated with all of their accounts at a certain address. Many of these premises only have one account at that address, in which case the premise-level estimates and account-level estimates are identical. However, there are some non-residential premises that have multiple accounts for the same business, in which case the respondent is rarely able to provide the cost estimates for an individual account within that premise. Therefore, usage and customer contact information were aggregated across all of the accounts associated with each business at each premise, and then the customers were sampled. For the residential segment, a "customer" refers to an individual account because it is rare that a residential customer has multiple accounts at a single address.

The sample design methodology was determined using the approach described in Appendix A. This approach to determining the sample design was a substantial improvement on previous studies because it took advantage of information from the 2005 PG&E VOS study to optimally define the number of usage strata and boundaries for the usage strata. This sampling approach is necessary because the distribution of usage per customer is highly skewed. As shown in Figure 3-2, the vast majority of customers is clustered towards the lower end of the usage distribution for each customer class and there is a "long tail" of high usage customers towards the upper end of the distribution. Considering that usage is a proxy for outage costs, an objective of the sample design methodology was to ensure that a sufficient amount of high usage customers was included in the sample. A simple random sample would not accomplish this objective because high usage customers would have a very low probability of being selected for the sample considering that they account for a small percentage of each segment.

Figure 3-2:
Distribution of Average Hourly Usage by Customer Class
(Top 5th Percentile for Each Customer Class Omitted)



3.2.1 Regional Considerations

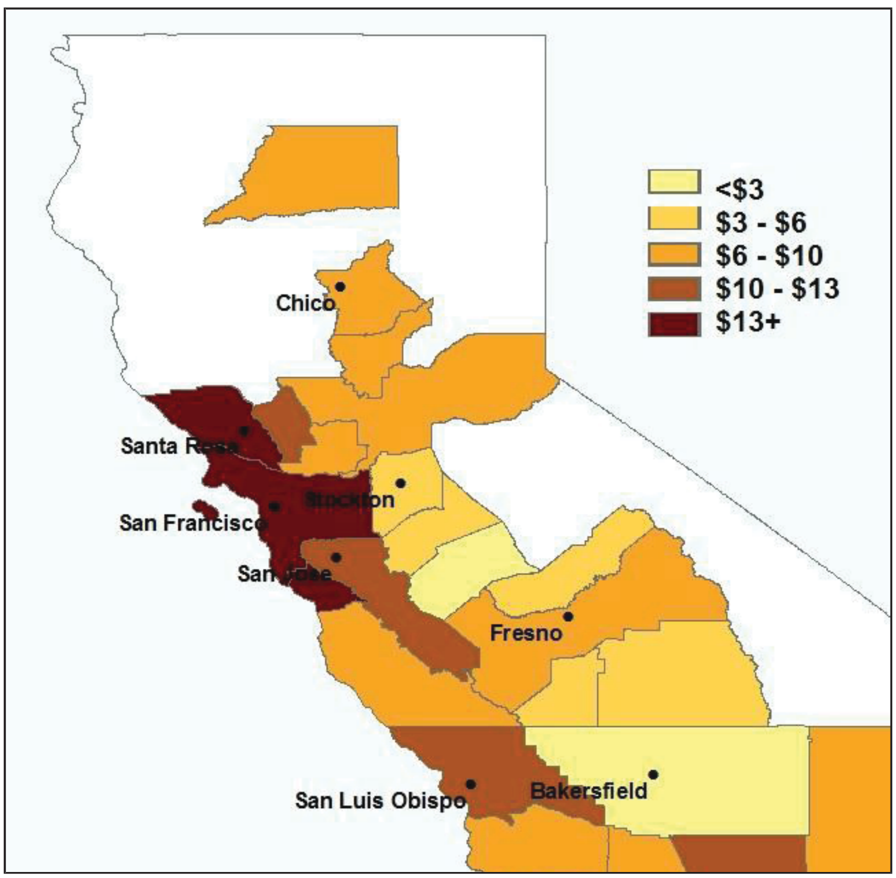
In addition to estimating outage costs at the system level, there is value in determining outage costs for non-residential customers within certain areas of PG&E's service territory with high outage costs. In order to identify areas with high outage costs, FSC analyzed gross domestic product (GDP) per non-residential kWh for each metropolitan statistical area (MSA)[9] in PG&E's service territory. Although

[9] MSAs are the smallest geographic unit for which the U.S. Department of Commerce provides GDP information. In PG&E's service territory, each MSA is made up of a contiguous grouping of one to five counties. Some of PG&E's service territory is not assigned to an MSA because areas with relatively low population density are not assigned to an MSA.

GDP per kWh tends to substantially underestimate outage costs, it serves as a good proxy for the geographic variation of non-residential outage costs normalized by usage. Residential customers were not included in this analysis because a good proxy for geographic variation has not been identified and their outage costs are substantially lower and less variable.

Figure 3-3 provides a map of GDP per non-residential kWh for each MSA in PG&E's service territory. GDP per non-residential kWh varies greatly from $2.4 in the Bakersfield-Delano MSA to $15.3 in the San Francisco-Oakland-Fremont MSA. In general, there are extreme differences between the Bay Area and the remaining MSAs in PG&E's service territory. Among the MSAs comprising the 9 Bay Area counties,[10] GDP per non-residential kWh is $13.9 and no lower than $11.1. Outside the Bay Area, GDP per non-residential kWh does not exceed $10.9 and is $4.7 overall, *one-third* that of the Bay Area. Therefore, the sample design had specific quotas for the number of Bay Area and non-Bay Area customers in each usage category and included an oversampling of 200 SMB, 40 large business and 100 agricultural customers in the Bay Area.[11] With this approach, the results were able to account for differences between Bay Area and non-Bay Area customers.

Figure 3-3:
GDP per Non-Residential kWh for Each
Metropolitan Statistical Area in PG&E's Service Territory



10 San Francisco, San Mateo, Santa Clara, Alameda, Contra Costa, Marin, Santa Cruz, Sonoma and Napa

11 For the purposes of this study, the Bay Area region included the following 8 PG&E divisions: San Francisco, Peninsula, De Anza, San Jose, Mission, East Bay, Diablo and North Bay. The non-Bay Area region included all other divisions.

3.2.2 Residential Customers

Table 3-3 summarizes the sample design for residential customers, which had 4 usage categories. The population of residential customers is divided roughly evenly by region. The non-Bay Area region accounted for a larger portion of the sample because this region has a relatively higher percentage of customers in the larger usage categories for which the Neyman allocation required a relatively large sample size. In addition, the sample design for the residential segment did not include oversampling for customers in the Bay Area. The smallest usage category (0 to 1.7 average kW) had the highest sample design target, and the rest of the sample was distributed roughly evenly between the remaining 3 usage categories. As expected by the sample design methodology, the largest customers accounted for a high proportion of the sample design target relative to their percentage of the population. Across regions, the largest usage category (4.8 to 10 average kW) comprised 0.2% of the population, but 9.3% of the sample. This sample design ensured that the study included a sufficient amount of high usage customers that were likely to have higher and more variable outage costs.

Table 3-3:
Sample Design Summary – Residential

Region	Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
Bay Area	0 to 1.7	2,054,448	49.0%	374	37.4%
	1.7 to 2.7	52,636	1.3%	28	2.8%
	2.7 to 4.8	10,732	0.3%	27	2.7%
	4.8 to 10	2,263	0.1%	25	2.5%
	Bay Area Overall	*2,120,079*	*50.5%*	*454*	*45.4%*
Non-Bay Area	0 to 1.7	1,907,383	45.5%	343	34.3%
	1.7 to 2.7	135,229	3.2%	73	7.3%
	2.7 to 4.8	27,460	0.7%	62	6.2%
	4.8 to 10	5,948	0.1%	68	6.8%
	Non-Bay Area Overall	*2,076,020*	*49.5%*	*546*	*54.6%*
Overall		**4,196,099**	**100%**	**1,000**	**100%**

3.2.3 Small & Medium Business Customers

Table 3-4 summarizes the sample design for SMB customers, which had 5 usage categories. Although the non-Bay Area region accounted for a larger percentage of the population, 58.8% of the sample was allocated to the Bay Area because the sample design included an oversampling of 200 SMB customers in the Bay Area. As expected by the sample design methodology, the largest customers accounted for a high proportion of the sample design target relative to their percentage of the population. Across regions, the largest usage category (222 to 884 average kW) comprised 2.4% of the population, but 18.5% of the sample. This sample design ensured that the study included a sufficient amount of high usage customers that were likely to have higher and more variable outage costs.

Table 3-4:
Sample Design Summary – SMB

Region	Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
Bay Area	0 to 4	72,700	20.1%	140	14.0%
	4 to 13	44,431	12.3%	93	9.3%
	13 to 46	30,790	8.5%	113	11.3%
	46 to 222	14,034	3.9%	120	12.0%
	222 to 884	4,904	1.4%	122	12.2%
	Bay Area Overall	*166,859*	*46.2%*	*588*	*58.8%*
Non-Bay Area	0 to 4	95,231	26.4%	122	12.2%
	4 to 13	49,670	13.8%	68	6.8%
	13 to 46	31,331	8.7%	78	7.8%
	46 to 222	14,010	3.9%	81	8.1%
	222 to 884	3,749	1.0%	63	6.3%
	Non-Bay Area Overall	*193,991*	*53.8%*	*412*	*41.2%*
Overall		**360,850**	**100%**	**1,000**	**100%**

3.2.4 Large Business Customers

Table 3-5 summarizes the sample design for large business customers, which had 4 usage categories. Although the population of large business customers is divided roughly evenly by region, 61.6% of the sample was allocated to the Bay Area because the sample design included an oversampling of 40 large business customers in the Bay Area. As expected by the sample design methodology, the largest customers accounted for a high proportion of the sample design target relative to their percentage of the population. Across regions, the largest usage category (2,981 to 65,791 average kW) comprised 9% of the population, but 36.9% of the sample. This sample design ensured that the study included a sufficient amount of high usage customers that were likely to have higher and more variable outage costs.

Table 3-5:
Sample Design Summary – Large Business

Region	Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
Bay Area	0 to 600	145	11.8%	25	13.2%
	600 to 1,268	295	24.1%	26	13.7%
	1,268 to 2,981	134	10.9%	21	11.1%
	2,981 to 65,791	56	4.6%	45	23.7%
	Bay Area Overall	*630*	*51.4%*	*117*	*61.6%*

Region	Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
Non-Bay Area	0 to 600	241	19.7%	28	14.7%
	600 to 1,268	157	12.8%	6	3.2%
	1,268 to 2,981	143	11.7%	14	7.4%
	2,981 to 65,791	54	4.4%	25	13.2%
	Non-Bay Area Overall	*595*	*48.6%*	*73*	*38.4%*
Overall		**1,225**	**100%**	**190**	**100%**

3.2.5 Agricultural Customers

Table 3-6 summarizes the sample design for agricultural customers, which had 3 usage categories. The non-Bay Area region accounted for the vast majority of agricultural customers in the population. Nonetheless, 23% of the sample was allocated to the Bay Area because the sample design included an oversampling of 100 agricultural customers in the Bay Area. Without this oversampling, it would not have been possible to reliably estimate agricultural outage costs separately for the Bay Area. In addition, considering that outage costs were higher and more variable in the Bay Area, this oversampling improved the precision of the estimates for the agricultural segment as a whole.

Table 3-6:
Sample Design Summary – Agricultural

Region	Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
Bay Area	0 to 0.5	1,469	1.9%	39	7.8%
	0.5 to 6.2	1,714	2.2%	43	8.6%
	6.2 to 5,511	280	0.4%	33	6.6%
	Bay Area Overall	*3,463*	*4.5%*	*115*	*23.0%*
Non-Bay Area	0 to 0.5	22,939	29.9%	123	24.6%
	0.5 to 6.2	34,427	44.9%	143	28.6%
	6.2 to 5,511	15,916	20.7%	119	23.8%
	Non-Bay Area Overall	*73,282*	*95.5%*	*385*	*77.0%*
Overall		**76,745**	**100%**	**500**	**100%**

3.3 Data Collection Procedures

This section summarizes the data collection procedures for each customer class.

3.3.1 Residential Customers

The residential survey was carried out by mail (with the ability to respond online if a respondent desired to do so). It was distributed to the target respondents in two waves. In the first wave, respondents received a cover letter on PG&E stationery explaining the purpose of the study and requesting their participation. An incentive of two $2 bills was mailed with the initial letter to all target respondents. This letter also contained a URL and respondent ID number so that respondents could complete the survey online. Two weeks after the first wave was mailed, respondents who did not complete the online survey received a reminder letter with a paper copy of the survey. The letters and survey packet included an 800 number that respondents could call to verify the legitimacy of the survey and ask any questions they had.

3.3.2 Small & Medium Business Customers

SMB customers were first recruited by telephone to ensure that FSC identified the appropriate individuals for answering questions related to energy and outage issues for that company; and to secure a verbal agreement from them to complete the survey. Telephone interviewers explained the purpose of the survey and indicated that an incentive was to be provided to thank the respondent for their time. The individuals were then sent an email containing an individualized survey link or had the survey package mailed or faxed to them containing:

- Additional explanation of the purpose of the research;
- Clear and easy-to-understand instructions for completing the survey questions;
- A telephone number they could call if they had questions about the research or wished to verify its authenticity;
- The survey booklet (or a link in the email to compete the survey online); and
- Return envelope with pre-paid postage (for the paper survey option).

One week after the survey link was emailed or the survey was faxed, respondents were given a reminder call. Customers who requested regular mail received their reminder calls in about 2 weeks. About 10 days after the reminder calls were made to the email recipients, the email was re-sent to anyone who hadn't completed it. If the survey was still not completed within 10 days, it was assumed that the customer would not complete the survey and they were not contacted again. An incentive of $50 was mailed to respondents who completed the survey form.

3.3.3 Large Business Customers

For large business customers, an experienced telephone recruiter first located and recruited an appropriate representative at each of the sampled premises. The target respondent was usually a plant manager or plant engineering manager – someone who was highly familiar with the cost structure of the enterprise. The recruiter first identified the target respondent by calling the phone number of the company representative in PG&E's customer database. Once the target respondent was identified and agreed to participate, a scheduler called back within the following two days to set up an appointment with the field interviewer. Once the appointment was scheduled, FSC emailed them a confirmation along with a written description of the study and an explanation of the information they were being asked to provide. The interview was scheduled at the convenience of the customer. A financial incentive of $150 was offered for completion of the information. On the agreed upon date, FSC's field interviewer visited the sampled site and conducted the in-person interview.

3.3.4 Agricultural Customers

The data collection procedures for agricultural customers were the same as in the SMB segment.

4 Outage Cost Estimation Methodology

The results sections for each customer class (Sections 5 through 8) primarily focus on the following three outage cost metrics:

- Cost per Outage Event;
- Cost per Average kW; and
- Cost per Unserved kWh.

Before presenting the results, it is important to understand how each of these metrics was derived. This section begins with a description of the cost per outage event estimate because it came directly from the survey responses and the other cost metrics were derived from this one.

Cost per outage event is the average cost per customer resulting from each outage duration. It was derived by simply calculating a weighted average of the values that the respondent provided on the survey. Each scenario on the survey focused on a specific outage event and then asked the respondent to provide the cost estimate. The respondent was basically providing the cost per outage event estimate. Before calculating the weighted average of these estimates, the top 0.5% of values normalized by usage was dropped from the analysis. These outliers were dropped because respondents may erroneously provide unrealistically high estimates when taking an outage cost survey, as a result of human error or misunderstanding of the question. After dropping outliers, cost per outage event was derived as an average of the customer responses, weighted by region and usage category for each segment.

Cost per average kW is the average cost per outage event normalized by average customer demand. This metric is useful for comparing outage costs across segments because it is normalized by customer demand. Cost per average kW was derived by dividing average cost per outage event by the weighted average customer demand among respondents for each outage duration by customer class. It is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each outage duration and customer class, average cost per event was first calculated using the steps above and then divided by the average demand among respondents. The average demand for each respondent was calculated as the annual kWh usage divided by 8,760 hours in the year, as shown in the following equation:

$$Average\,Demand = \left(\frac{Annual\ kWh\ usage}{8{,}760}\right)$$

As in the cost per outage event average calculation, the average customer demand (the denominator of the ratio) was weighted by region and usage category for each segment.

Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh for each outage scenario. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. As in the cost per average kW calculation, cost per unserved kWh is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each duration and customer class, average cost per event was first calculated using the steps above and then divided by the expected unserved kWh. The expected unserved kWh is the estimated quantity of electricity that would have been consumed if an outage had not occurred. Because the outage scenarios in this study occur during various times of the day and week, the average customer demand from the denominator of the cost per average kW calculation could not simply be multiplied by the number of unserved hours in order to develop the expected unserved kWh estimate. Average customer demand had to be adjusted by a load ratio specific to the time of day and week for each outage scenario and then multiplied by the number of unserved hours, as shown in the following equation:

$$Expected\,Unserved\,kWh = Average\,Demand\ x\ Load\,Ratio\ x\ Unserved\,Hours$$

The load ratios in this study are the ratio of expected kW (during a specific time interval for a given customer) to average kW. These ratios were assigned to each respondent based on their rate profile and the outage scenario. FSC used 3 years of aggregate hourly load profile data for each PG&E rate profile to develop the average load ratio of each weekday hour and weekend hour for a given customer. These hourly load ratios for each customer were used to calculate the load ratio appropriate to the timing and duration of each outage scenario. For example, a 4-hour outage starting at 3 PM on a weekday would use the average load ratio of weekday hours from 3 PM to 7 PM. A respondent's average demand was then multiplied by the load ratio to estimate the expected demand throughout the course of each outage scenario. This expected demand was then multiplied by the number of unserved hours associated with each outage scenario to estimate the expected amount of unserved kWh for each outage scenario. Finally, cost per outage event was divided by the expected unserved kWh to develop the cost per unserved kWh estimate.

Figure 4-1 shows the average hourly load ratios by customer class for weekday outage scenarios and Figure 4-2 for weekend outage scenarios. These figures provide an understanding of how the average kW values were adjusted to develop the expected unserved kWh specific to each outage scenario. Residential customers generally have below average demand on weekdays until 3 PM and then peak at around 1.4 times average kW from 7 PM to 9 PM. On weekends, residential load is well above average demand starting at around 9 AM and the peak timing and magnitude is similar to weekdays. SMB customer load peaks at over 1.4 times average kW between 10 AM to 4 PM on weekdays. On weekends, SMB customers are below average demand throughout the day. Large business and agricultural customers have much flatter load profiles, staying between 0.8 and 1.2 times average kW throughout the day and week. Although there are multiple rate profiles within each customer class that are not shown in the figures, these average hourly load ratios by customer class provide a general idea of how average kW was adjusted for the expected unserved kWh estimates.

Figure 4-1:
Average Hourly Load Ratios (Hourly kW/Average kW)
by Customer Class for Weekday Outage Scenarios

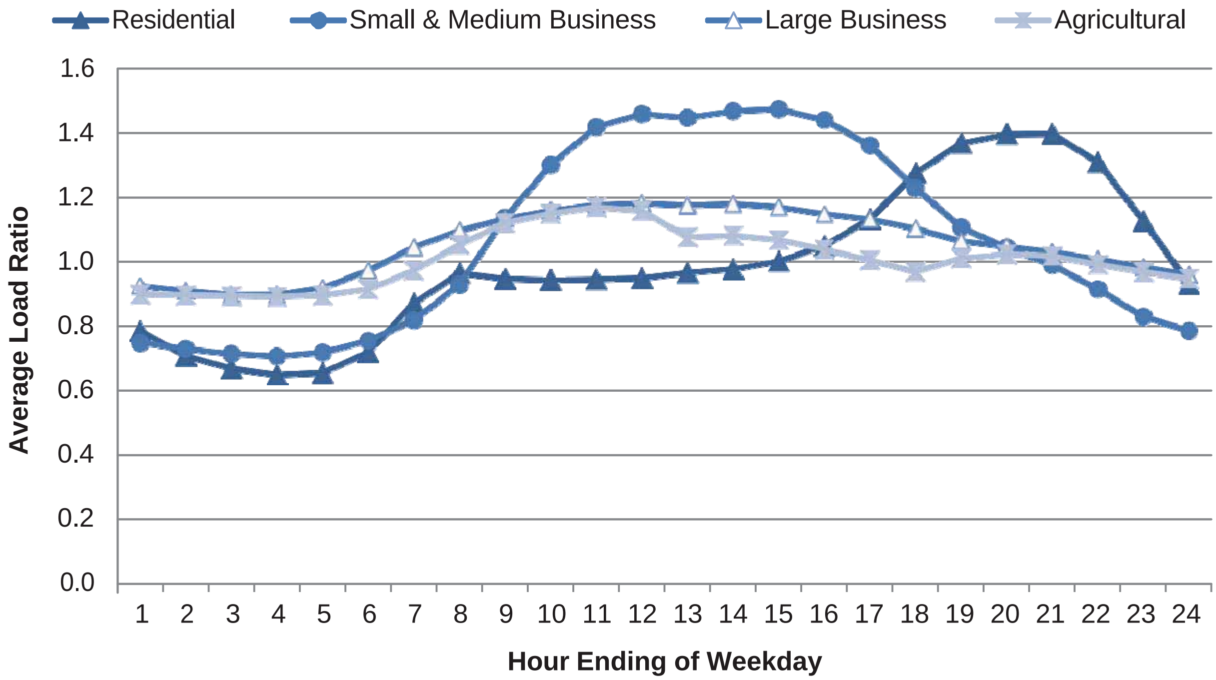
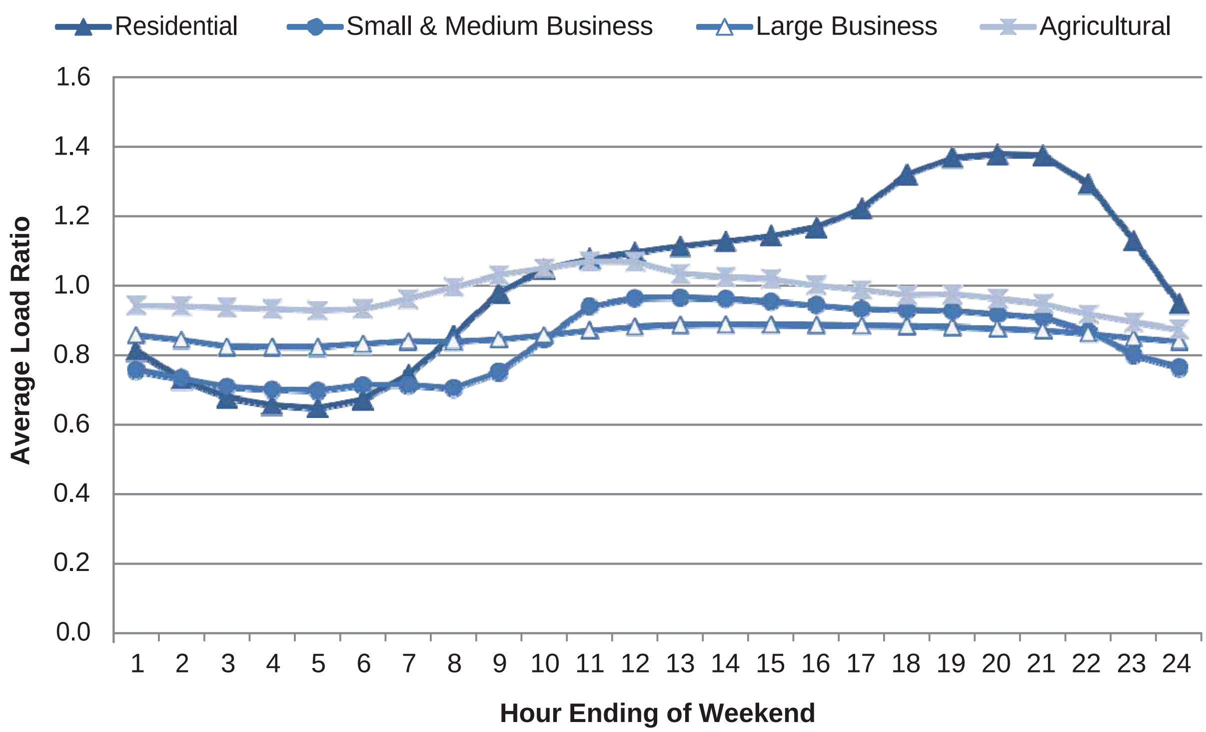


Figure 4-2:
Average Hourly Load Ratios (Hourly kW/Average kW)
by Customer Class for Weekend Outage Scenarios



5 Residential Results

This section summarizes the results for residential customers.

5.1 Response to Survey

Table 5-1 summarizes the survey response for residential customers. With 1,067 total completed surveys, customer response was above the overall sample design target of 1,000. Overall, the survey had a 28.7% response rate that was nearly equal across regions. Among the first 3 usage categories, the response rate was relatively constant by region, varying moderately from 24.0% to 32.7%. High usage residential customers in the 4.8 to 10 average kW category were less likely to respond to the survey and had a response rate below 20% within each region. However, non-response bias among high usage residential customers is not a significant concern for the outage cost estimates because usage category is factored into the stratification weights in the analysis. Appendix C provides a more detailed assessment of the potential sources of non-response bias among residential customers.

Table 5-1:
Customer Survey Response Summary – Residential

Region	Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
Bay Area	0 to 1.7	2,054,448	374	1,275	392	30.7%
	1.7 to 2.7	52,636	28	104	28	26.9%
	2.7 to 4.8	10,732	27	130	34	26.2%
	4.8 to 10	2,263	25	188	37	19.7%
	Bay Area Overall	*2,120,079*	*454*	*1,697*	*491*	*28.9%*
Non-Bay Area	0 to 1.7	1,907,383	343	1,142	362	31.7%
	1.7 to 2.7	135,229	73	248	81	32.7%
	2.7 to 4.8	27,460	62	267	64	24.0%
	4.8 to 10	5,948	68	362	69	19.1%
	Non-Bay Area Overall	*2,076,020*	*546*	*2,019*	*576*	*28.5%*
Overall		**4,196,099**	**1,000**	**3,716**	**1,067**	**28.7%**

Before presenting the outage cost estimates, it is important to summarize the prevalence of invalid responses. This summary is only provided for the residential segment because its cost estimates are derived from a WTP question. Some respondents are confused by WTP questions or end up answering a question that is quite different from the one that is being asked. For example, customers sometimes react to questions about WTP by redefining the question so that it relates to their ability to pay, their satisfaction with service or whether they think they are being fairly charged for the service they are receiving. Such responses do not accurately reflect the cost of an outage for a customer, so they were removed from the analysis.

To identify these responses, the survey included a follow-up question for respondents that indicated a WTP value of $0. If the respondent verified that WTP was $0 because the outage scenario would not in fact result in any noticeable costs, the $0 response was confirmed as valid and included in the cost estimate calculations. However, if the respondent indicated that there was some other reason that WTP was $0, the response was deemed invalid and not included in the cost estimate calculations. Table 5-2 summarizes the prevalence of invalid responses by outage duration in the residential survey. The percentage of responses deemed invalid varied from 15.7% for an 8-hour outage to 26.0% for a 5-minute outage. This explains why the results below are based on a number of observations that is less than what would be expected from a study with 1,067 responses.

Table 5-2:
Summary of Invalid Responses – Residential

Outage Duration	Total Responses	Invalid Responses		Valid Responses
		N	%	
5 minutes	1,057	275	26.0%	782
1 hour	1,053	223	21.2%	830
4 hours	1,051	187	17.8%	864
8 hours	1,051	165	15.7%	886
24 hours	1,045	166	15.9%	879

5.2 2012 Outage Cost Estimates

Figure 5-1 and Table 5-3 provide the residential cost per outage event estimates. For a 1-hour outage, residential customers experience a cost of $11.89. Residential cost per outage event increases to $22.89 at 8 hours and $31.67 for a 24-hour outage. Bay Area residential customers report higher costs than non-Bay Area customers for all outage durations. At 5 minutes, Bay Area residential cost per outage event is 17.5% higher. The percentage difference between regions increases with duration and at 24 hours, Bay Area residential cost per outage event is 45.3% higher. This result suggests that outages have a relatively higher incremental impact in the Bay Area as duration increases.

Figure 5-1:
2012 Cost per Outage Event Estimates by Region – Residential

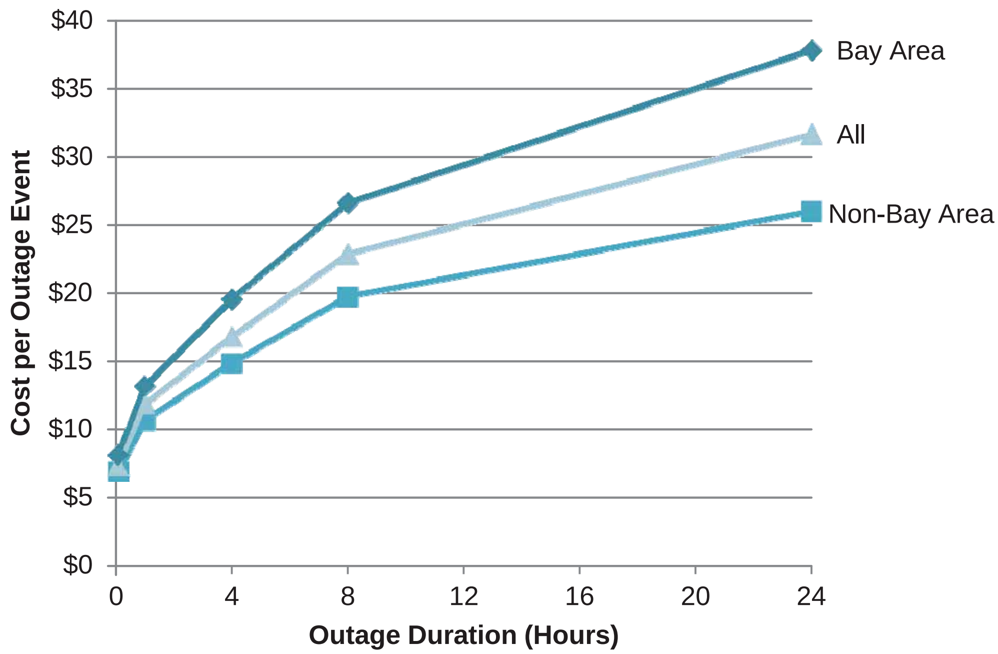


Table 5-3:
2012 Cost per Outage Event Estimates by Region – Residential

Region	Outage Duration	N	Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	362	$8.18	$5.19	$11.16
	1 hour	379	$13.22	$9.18	$17.26
	4 hours	403	$19.59	$15.27	$23.90
	8 hours	407	$26.63	$21.43	$31.83
	24 hours	406	$37.83	$31.73	$43.94
Non-Bay Area	5 minutes	417	$6.96	$4.88	$9.04
	1 hour	447	$10.71	$7.78	$13.64
	4 hours	457	$14.89	$11.59	$18.19
	8 hours	475	$19.79	$16.04	$23.55
	24 hours	469	$26.03	$21.93	$30.12
All	5 minutes	779	$7.41	$5.65	$9.18
	1 hour	826	$11.89	$9.44	$14.33
	4 hours	860	$16.82	$14.19	$19.46
	8 hours	882	$22.89	$19.69	$26.10
	24 hours	875	$31.67	$27.92	$35.42

Table 5-4 summarizes residential cost per average kW. For a 1-hour outage, residential customers experience a cost of $14.86 per average kW. The cost per average kW estimates are roughly 25% higher than the cost per outage event estimates because average demand for residential respondents was around 0.8 kW. Considering that Bay Area residential respondents had relatively low average demand, the difference with non-Bay Area customers is even greater when normalized by average kW. At 5 minutes, Bay Area residential cost per average kW is 41.4% higher. The percentage difference between regions increases with duration and at 24 hours, Bay Area residential cost per outage event is 82.7% higher.

Table 5-4:
2012 Cost per Average kW Estimates by Region – Residential

Region	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	362	$11.86	$7.52	$16.17
	1 hour	379	$18.62	$12.93	$24.31
	4 hours	403	$27.59	$21.51	$33.66
	8 hours	407	$37.51	$30.18	$44.83
	24 hours	406	$54.04	$45.33	$62.77
Non-Bay Area	5 minutes	417	$8.39	$5.88	$10.89
	1 hour	447	$12.17	$8.84	$15.50
	4 hours	457	$16.54	$12.88	$20.21
	8 hours	475	$21.99	$17.82	$26.17
	24 hours	469	$29.58	$24.92	$34.23
All	5 minutes	779	$9.75	$7.43	$12.08
	1 hour	826	$14.86	$11.80	$17.91
	4 hours	860	$21.03	$17.74	$24.33
	8 hours	882	$28.61	$24.61	$32.63
	24 hours	875	$40.09	$35.34	$44.84

Table 5-5 provides the residential cost per unserved kWh estimates. For a 1-hour outage, residential customers experience a cost of $14.86 per unserved kWh, which is equivalent to the cost per average kW estimate because the expected amount of unserved kWh is also around 0.8 at 1 hour. At 5-minutes, the systemwide estimate is over $123 because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases precipitously because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Table 5-5:
2012 Cost per Unserved kWh Estimates by Region – Residential

Region	Outage Duration	N	Cost per Unserved kWh	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	362	$136.33	$86.50	$186.00
	1 hour	379	$18.89	$13.11	$24.66
	4 hours	403	$6.73	$5.25	$8.21
	8 hours	407	$4.56	$3.67	$5.45
	24 hours	406	$2.24	$1.88	$2.60
Non-Bay Area	5 minutes	417	$99.43	$69.71	$129.14
	1 hour	447	$11.77	$8.55	$14.99
	4 hours	457	$4.00	$3.12	$4.89
	8 hours	475	$2.65	$2.15	$3.15
	24 hours	469	$1.23	$1.04	$1.43
All	5 minutes	779	$123.50	$94.17	$153.00
	1 hour	826	$14.86	$11.80	$17.91
	4 hours	860	$5.08	$4.29	$5.88
	8 hours	882	$3.44	$2.96	$3.92
	24 hours	875	$1.67	$1.47	$1.86

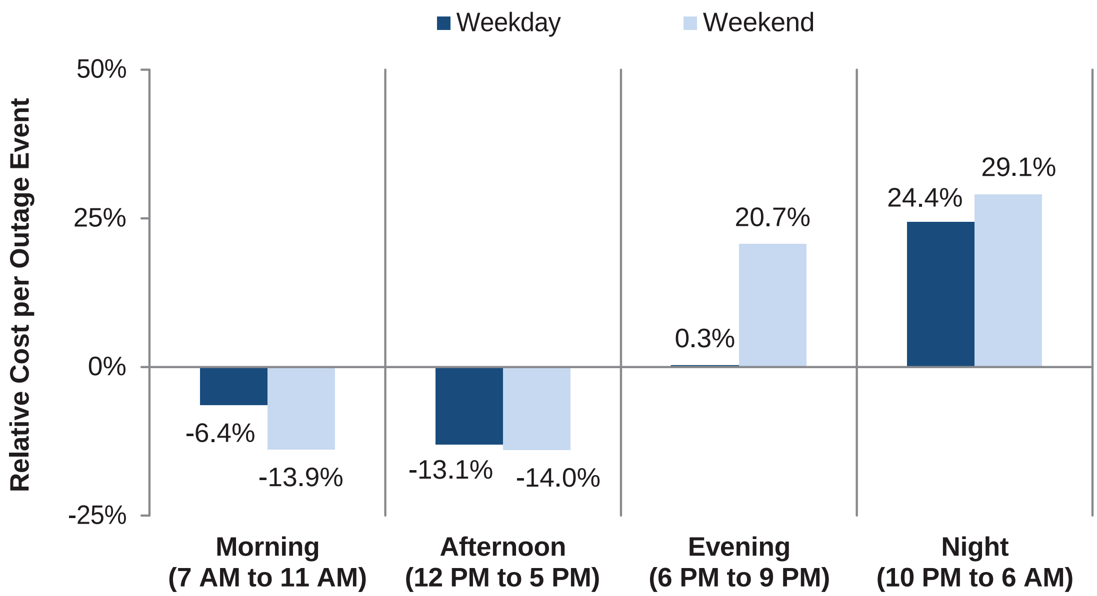
5.3 Impact of Outage Timing

For the residential analysis on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 5-2 provides the relative cost per outage event estimates, which were derived from the residential customer damage functions described in Appendix B. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each residential outage cost estimate in Section 5.2 (referred to as the "base value"). As shown in the figure, outage costs for residential customers are somewhat sensitive to onset time, varying from 14% lower than the base value on a weekend afternoon to 29.1% higher on a weekend night. Residential customers also experience relatively high outage costs during weekday nights. Outage costs with onset times in the daytime (morning and afternoon) are lower than the base value. This result is not surprising for daytime on weekdays because fewer people are at home during that time period. It is not as clear why outage costs would be relatively low during daytime on weekends though. Perhaps residential customers are less concerned about a daytime outage because it does not leave them in the dark, which may lead to perceived safety issues or the inconvenience of lighting candles or retrieving flashlights.

Figure 5-2:
Relative Cost per Outage Event Estimates by Day of Week and Onset Time – Residential



5.4 Comparison to Previous Studies

PG&E previously carried out a residential outage cost study in 1993 and 2005. Table 5-6 compares the cost of a 4-hour, summer afternoon outage for each study year. The 1993 and 2005 cost per outage event estimates were converted to 2012 dollars using the gross domestic product deflator, which was obtained from the U.S. Department of Commerce's Bureau of Economic Analysis. Between 1993 and 2005, there was a small increase in reported outage cost for residential customers, but this difference was not statistically significant. The difference between 2005 and 2012 is statistically significant and shows a 64.3% increase in reported outage cost for residential customers since 2005. Although there seems to be an upward trend in outage costs, much of this difference is due to a change in the survey design. In 2005, the highest possible cost estimate for residential customers was $50 because the survey only included outage scenarios up to 8 hours. In the 2012 study, the highest possible cost estimate for residential customers was increased to $200 because the survey included outage scenarios up to 24 hours. This change in the survey design allowed respondents to provide cost estimates in excess of $50 for the 4-hour, summer afternoon outage as well. When given this option, many residential respondents reported outage costs between $50 and $200. Therefore, the 2012 study is a better measure of outage costs for residential customers because the cost estimates are no longer truncated at $50 – a threshold that now seems too low in light of some of the high reported outage costs in the 2012 study. Even with this increase in outage costs in the 2012 study, all of the residential cost per event, average kW and unserved kWh estimates are lower than in the other customer classes.

To adjust for methodological differences, the adjusted 2012 value is provided in Table 5-6 so that an "apples-to-apples" comparison can be made with previous studies. To estimate this value, FSC truncated the 2012 survey data at $50 (adjusted for inflation) before summarizing the results. This adjusted 2012 value is simply provided for comparison to the previous studies and is not recommended for use in planning applications. Using this value in the comparison, there is a smaller increase of 18.4% in reported outage cost for residential customers since 2005. This difference is statistically significant, which suggests that residential outage costs have increased since 2005. This increase may be due to increased household sizes as a result of economic conditions.

Table 5-6:
Cost of a 4-Hour, Summer Afternoon Outage by Study Year – Residential

Study Year	N	Cost per Outage Event (2012$)	95% Confidence Interval	
			Lower Bound	Upper Bound
1993	560	$8.37	$7.35	$9.41
2005	909	$9.31	$8.49	$10.13
2012	858	$15.30	$13.27	$17.33
2012 Adjusted *	858	$11.02	$9.94	$12.09

* This value truncates the 2012 survey data to adjust for methodological differences between the 2005 and 2012 studies. It is simply provided for comparison to the previous studies and is not recommended for use in planning applications.

5.5 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 5-3 shows the percent of residential customers rating each combination of outage frequency and duration as acceptable. As expected, a residential customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Residential customers are willing to accept a relatively high frequency of short-duration outages. Over 60% of residential customers report that 4 momentary outages per year or 2 outages of 5 to 30 minutes per year are acceptable. One outage of 1 to 4 hours per year is acceptable to 68.8% of residential customers.

Figure 5-3:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – Residential

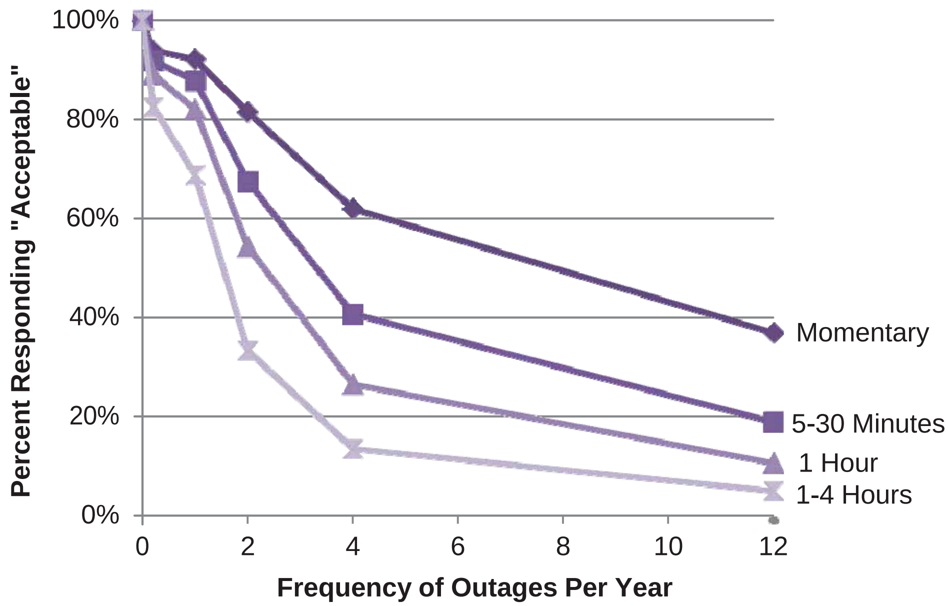


Table 5-7 shows the percent of residential customers rating each combination of outage frequency and duration as acceptable, disaggregated by region. In general, Bay Area residential customers expect a slightly higher level of reliability.

Table 5-7:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable by Region – Residential

Region	Frequency of Outages per Year	Outage Duration			
		Momentary	5-30 Minutes	1 Hour	1-4 Hours
Bay Area	Once every 5 years	94.8%	93.0%	88.4%	81.1%
	1	91.4%	87.3%	79.5%	65.1%
	2	80.0%	64.4%	50.6%	29.3%
	4	60.3%	38.6%	25.1%	14.7%
	12	36.2%	16.7%	9.7%	4.6%
	52	17.7%	6.6%	5.2%	2.4%
Non-Bay Area	Once every 5 years	93.0%	90.7%	89.9%	84.0%
	1	92.7%	88.3%	84.4%	72.8%
	2	82.8%	70.6%	57.9%	37.2%
	4	63.5%	43.3%	28.3%	12.2%
	12	37.8%	21.3%	11.7%	5.6%
	52	20.6%	9.7%	6.1%	3.4%

Region	Frequency of Outages per Year	Outage Duration			
		Momentary	5-30 Minutes	1 Hour	1-4 Hours
All	Once every 5 years	93.9%	91.9%	89.1%	82.5%
	1	92.1%	87.8%	82.0%	68.8%
	2	81.5%	67.5%	54.3%	33.4%
	4	62.0%	40.8%	26.6%	13.6%
	12	37.0%	19.0%	10.7%	5.1%
	52	19.1%	8.1%	5.6%	2.8%

To determine what percent of residential customers receives service that they consider acceptable, the acceptable level of service reliability questions were compared with the number of outages customers reported experiencing over the past 12 months. Table 5-8 provides the results of this analysis by outage duration for the residential survey in 2005 and 2012. In the 2012 study, up to 87% of residential customers reported that they receive service that they say is acceptable. Across all outage durations, these results are very similar to 2005.

Table 5-8:
Percent of Customers Receiving Service Rated as Acceptable by Study Year – Residential

Outage Duration	2005	2012
Momentary	89%	91%
5-30 Minutes	95%	94%
1 Hour	94%	95%
1-4 Hours	85%	87%

Table 5-9 shows how 2 additional measures of satisfaction with service reliability have changed by study year for residential customers. On a 5-point scale, with 1 as “Very Low” and 5 as “Very High,” residential customers report a 1.86 average rating for the number of power outages they experience. On a 5-point scale, with 1 as “Very Dissatisfied” and 5 as “Very Satisfied,” residential customers report a 3.97 average rating of their satisfaction with the level of service reliability they receive from PG&E. Both of these measures are very similar to the results of the 2005 study.

Table 5-9:
Satisfaction with Service Reliability by Study Year – Residential

Question	Study Year		
	1993	2005	2012
Do you feel the number of power outages your residence experiences is … (5-point scale, 1 for “Very Low” to 5 for “Very High”)	2.44	1.88	1.86
How satisfied are you with the reliability of the electrical service you receive from PG&E? (5-point scale, 1 for “Very Dissatisfied" to 5 for “Very Satisfied”)	3.94	3.98	3.97

6 Small & Medium Business Results

This section summarizes the results for SMB customers.

6.1 Response to Survey

Table 6-1 summarizes the survey response for SMB customers. With 1,084 total completed surveys, customer response was above the overall sample design target of 1,000. Overall, the survey had a 20.7% response rate that was slightly lower in the Bay Area than non-Bay Area region. The response rate was relatively constant across region and usage category, varying moderately from 17.4% to 24.7%. Low usage SMB customers with average demand below 4 kW were more likely to respond to the survey and had a response rate above 23% within each region. However, non-response bias among higher usage residential customers is not a significant concern for the results because usage category is factored into the stratification weights in the analysis. Appendix C provides a more detailed assessment of the potential sources of non-response bias among SMB customers.

Table 6-1:
Customer Survey Response Summary – SMB

Region	Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
Bay Area	0 to 4	72,700	140	685	158	23.1%
	4 to 13	44,431	93	494	96	19.4%
	13 to 46	30,790	113	574	117	20.4%
	46 to 222	14,034	120	736	128	17.4%
	222 to 884	4,904	122	696	138	19.8%
	Bay Area Overall	*166,859*	*588*	*3,185*	*637*	*20.0%*
Non-Bay Area	0 to 4	95,231	122	533	131	24.6%
	4 to 13	49,670	68	359	71	19.8%
	13 to 46	31,331	78	340	84	24.7%
	46 to 222	14,010	81	452	90	19.9%
	222 to 884	3,749	63	375	71	18.9%
	Non-Bay Area Overall	*193,991*	*412*	*2,059*	*447*	*21.7%*
Overall		**360,850**	**1,000**	**5,244**	**1,084**	**20.7%**

6.2 2012 Outage Cost Estimates

Figure 6-1 and Table 6-2 provide the SMB cost per outage event estimates. For a 1-hour outage, SMB customers experience a cost of $1,848.8. SMB cost per outage event increases to $10,568.7 at 8 hours and $21,339.4 for a 24-hour outage. The percentage difference between Bay Area and non-Bay Area SMB cost per outage event is substantially greater than in the residential segment. Across all outage durations, Bay Area SMB customers report 2.4 to 4 times higher costs than non-Bay Area customers.

Figure 6-1:
2012 Cost per Outage Event Estimates by Region – SMB

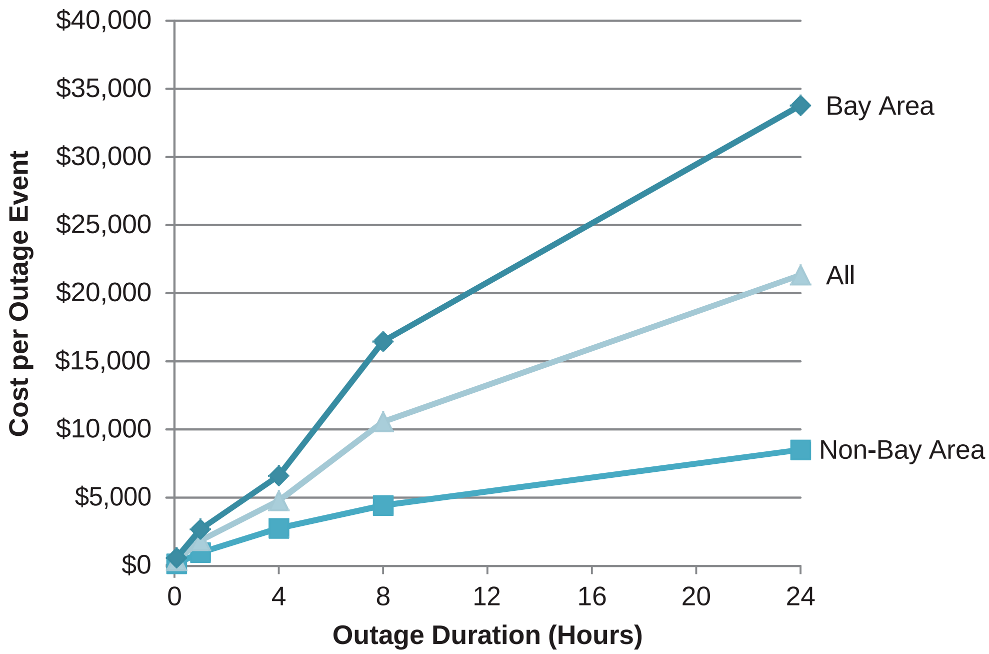


Table 6-2:
2012 Cost per Outage Event Estimates by Region – SMB

Region	Outage Duration	N	Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	631	$585.2	$277.3	$893.2
	1 hour	629	$2,679.4	$1,431.3	$3,927.5
	4 hours	630	$6,607.7	$4,275.2	$8,940.2
	8 hours	630	$16,463.6	$7,286.9	$25,640.2
	24 hours	629	$33,780.9	$13,473.5	$54,088.2
Non-Bay Area	5 minutes	445	$159.0	$103.7	$214.3
	1 hour	442	$973.9	$476.7	$1,471.1
	4 hours	442	$2,761.1	$1,559.0	$3,963.2
	8 hours	445	$4,435.0	$2,611.2	$6,258.7
	24 hours	444	$8,514.5	$4,551.8	$12,477.1
All	5 minutes	1076	$379.8	$223.9	$535.8
	1 hour	1071	$1,848.8	$1,186.3	$2,511.3
	4 hours	1072	$4,774.3	$3,445.6	$6,103.0
	8 hours	1075	$10,568.7	$5,921.4	$15,216.0
	24 hours	1073	$21,339.4	$10,976.6	$31,702.2

Table 6-3 summarizes SMB cost per average kW. For a 1-hour outage, SMB customers experience a cost of $205.2 per average kW. The cost per average kW estimates are substantially lower than the cost per outage event estimates because average demand for SMB respondents was around 9 kW. Considering that Bay Area SMB respondents had slightly higher average demand, the difference with non-Bay Area customers is lower when normalized by average kW. Nonetheless, Bay Area SMB customers report 2.1 to 3.2 times higher cost per average kW than non-Bay Area customers.

Table 6-3:
2012 Cost per Average kW Estimates by Region – SMB

Region	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	631	$62.1	$29.4	$94.7
	1 hour	629	$272.0	$145.3	$398.7
	4 hours	630	$706.0	$456.8	$955.1
	8 hours	630	$1,560.5	$690.7	$2,430.3
	24 hours	629	$3,482.6	$1,389.0	$5,576.1
Non-Bay Area	5 minutes	445	$19.8	$12.9	$26.7
	1 hour	442	$121.9	$59.7	$184.1
	4 hours	442	$339.2	$191.5	$486.9
	8 hours	445	$557.9	$328.5	$787.3
	24 hours	444	$1,073.7	$574.0	$1,573.4
All	5 minutes	1076	$43.3	$25.5	$61.0
	1 hour	1071	$205.2	$131.7	$278.7
	4 hours	1072	$540.1	$389.8	$690.4
	8 hours	1075	$1,136.4	$636.7	$1,636.1
	24 hours	1073	$2,403.1	$1,236.1	$3,570.1

Table 6-4 provides the SMB cost per unserved kWh estimates. For a 1-hour outage, SMB customers experience a cost of $195.6 per unserved kWh, which is similar to the cost per average kW estimate because the expected amount of unserved kWh is also around 9 at 1 hour. At 5-minutes, the systemwide estimate is over $490 because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases precipitously because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Table 6-4:
2012 Cost per Unserved kWh Estimates by Region – SMB

Region	Outage Duration	N	Cost per Unserved kWh	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	631	$713.7	$338.2	$1,089.2
	1 hour	629	$261.4	$139.6	$383.2
	4 hours	630	$168.3	$108.9	$227.7
	8 hours	630	$192.4	$85.2	$299.7
	24 hours	629	$144.5	$57.6	$231.3
Non-Bay Area	5 minutes	445	$227.2	$148.2	$306.2
	1 hour	442	$114.7	$56.1	$173.3
	4 hours	442	$79.3	$44.7	$113.8
	8 hours	445	$66.5	$39.1	$93.8
	24 hours	444	$44.5	$23.8	$65.3
All	5 minutes	1076	$493.3	$290.7	$695.8
	1 hour	1071	$195.6	$125.5	$265.7
	4 hours	1072	$127.5	$92.0	$163.0
	8 hours	1075	$138.4	$77.5	$199.2
	24 hours	1073	$99.7	$51.3	$148.1

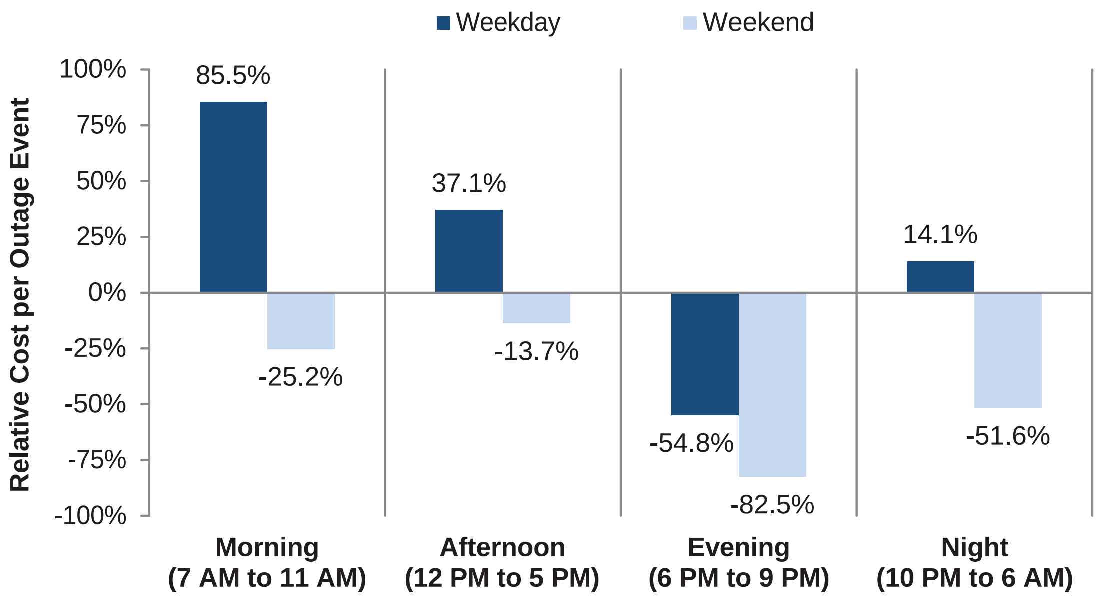
6.3 Impact of Outage Timing

For the SMB analysis on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 6-2 provides the relative cost per outage event estimates, which were derived from the SMB customer damage functions described in Appendix B. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each SMB outage cost estimate in Section 6.2 (referred to as the "base value"). As shown in the figure, outage costs for SMB customers are highly sensitive to onset time, varying from 82.5% lower than the base value on a weekend evening to 85.5% higher on a weekday morning. The only weekday outages that have lower costs than the base value are those with an evening onset time because these outages begin after normal business hours and likely end before business resumes the next day. Outages with a weekday morning onset time have the highest cost because these outages likely start and end during normal business hours, potentially disrupting an entire day of work. Although some SMB customers such as retail stores likely have higher costs on a weekend day, the overall trend shows that outage costs are lower than the base value for all weekend onset times. Considering that SMB outage costs vary substantially depending on the onset time, it is important that planning applications apply these relative values.

Figure 6-2:
Relative Cost per Outage Event Estimates by Day of Week and Onset Time – SMB



6.4 Comparison to Previous Studies

PG&E previously carried out an SMB outage cost study in 1993 and 2005. Table 6-5 compares the cost of a 4-hour, summer afternoon outage for each study year. The 1993 and 2005 cost per outage event estimates were converted to 2012 dollars using the gross domestic product deflator, which was obtained from the U.S. Department of Commerce's Bureau of Economic Analysis. Between 1993 and 2005, there was a decrease in reported outage cost for SMB customers, but this difference was not statistically significant. The difference between 2005 and 2012 is also not statistically significant, even though there is a 58% increase in average cost per outage event. Given the underlying high variability of reported outage costs from customer to customer, large differences in average values are required to detect a statistically significant difference. In this case, the results are inconclusive.

Table 6-5:
Cost of a 4-Hour, Summer Afternoon Outage by Study Year – SMB

Year		Cost per (2012$)	95% Confidence Interval	
			Lower Bound	Upper Bound
1993	684	$4,738.3	$2,651.6	$6,825.0
2005	784	$3,884.4	$3,045.0	$4,722.7
2012	1074	$6,138.9	$3,541.9	$8,735.8

6.5 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 6-3 shows the percent of SMB customers rating each combination of outage frequency and duration as acceptable. As expected, an SMB customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. SMB customers are willing to accept a relatively high frequency of short-duration outages. A majority of SMB customers reports that 4 momentary outages per year is acceptable. One outage of 1 to 4 hours per year is acceptable to 49% of SMB customers.

Figure 6-3:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – SMB

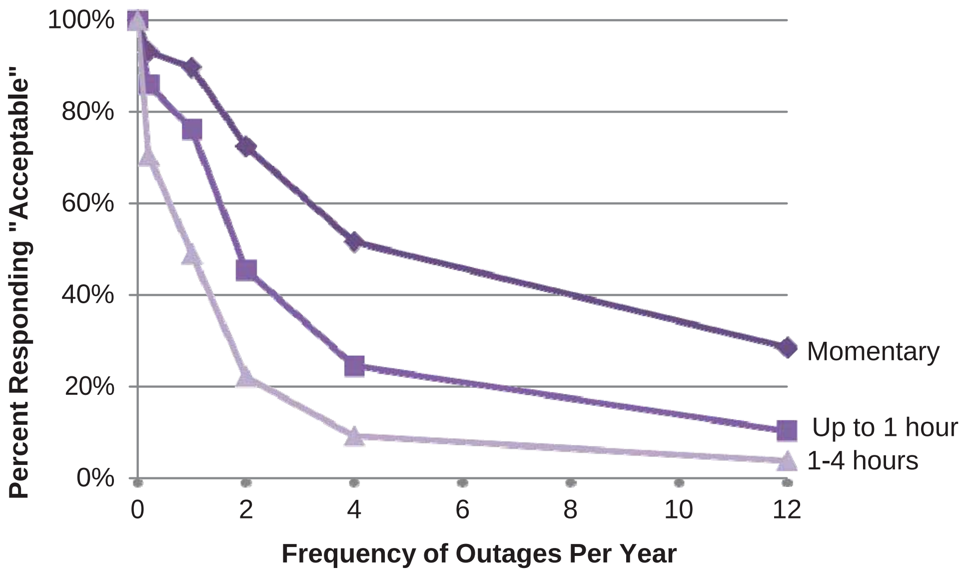


Table 6-6 shows the percent of SMB customers rating each combination of outage frequency and duration as acceptable, disaggregated by region. In general, Bay Area SMB customers expect a slightly higher level of reliability.

Table 6-6:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable by Region – SMB

Region	Frequency of Outages per Year	Outage Duration		
		Momentary	Up to 1 Hour	1-4 Hours
Bay Area	Once every 5 years	92.6%	84.7%	68.5%
	1	88.6%	73.2%	43.2%
	2	67.4%	40.0%	16.7%
	4	46.4%	22.0%	8.1%
	12	24.9%	10.5%	3.8%
	52	14.9%	5.6%	1.8%

Region	Frequency of Outages per Year	Outage Duration Momentary	Up to 1 Hour	1-4 Hours
Non-Bay Area	Once every 5 years	93.5%	86.9%	71.8%
	1	90.2%	78.3%	53.8%
	2	76.5%	49.9%	26.9%
	4	55.6%	26.6%	10.2%
	12	31.4%	10.4%	4.1%
	52	17.4%	5.1%	2.9%
All	Once every 5 years	93.1%	85.9%	70.4%
	1	89.6%	76.1%	49.0%
	2	72.4%	45.5%	22.2%
	4	51.6%	24.6%	9.3%
	12	28.6%	10.4%	3.9%
	52	16.3%	5.3%	2.5%

To determine what percent of SMB customers receives service that they consider acceptable, the acceptable level of service reliability questions were compared with the number of outages customers reported experiencing over the past 12 months. Table 6-7 provides the results of this analysis by outage duration for the SMB survey in 2005 and 2012. In the 2012 study, up to 81% of SMB customers reported that they receive service that they say is acceptable. Across all outage durations, these results are very similar to 2005.

Table 6-7:
Percent of Customers Receiving Service Rated as Acceptable by Study Year – SMB

Outage Duration	2005	2012
Momentary	88%	87%
Up to 1 Hour	83%	85%
1-4 Hours	82%	81%

7 Large Business Results

This section summarizes the results for large business customers.

7.1 Response to Survey

Table 7-1 summarizes the survey response for large business customers. With 210 total completed surveys, customer response was above the overall sample design target of 190. Overall, the survey had a 32.1% response rate that was relatively higher in the Bay Area. In both regions, the response rate increased as usage increased. Bay Area customers in the largest usage category provided a 61.2% response rate, which was substantially higher than any other category. Considering that usage category and region are factored into the stratifications weights in the analysis, non-response bias among these categories is not a significant concern. Appendix C provides a more detailed assessment of the potential sources of non-response bias among large business customers.

Table 7-1:
Customer Survey Response Summary – Large Business

Region	Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
Bay Area	0 to 600	145	25	101	27	26.7%
	600 to 1,268	295	26	96	30	31.3%
	1,268 to 2,981	134	21	91	32	35.2%
	2,981 to 65,791	56	45	49	30	61.2%
	Bay Area Overall	*630*	*117*	*337*	*119*	*35.3%*
Non-Bay Area	0 to 600	241	28	122	29	23.8%
	600 to 1,268	157	6	28	7	25.0%
	1,268 to 2,981	143	14	115	37	32.2%
	2,981 to 65,791	54	25	53	18	34.0%
	Non-Bay Area Overall	*595*	*73*	*318*	*91*	*28.6%*
Overall		**1,225**	**190**	**655**	**210**	**32.1%**

7.2 2012 Outage Cost Estimates

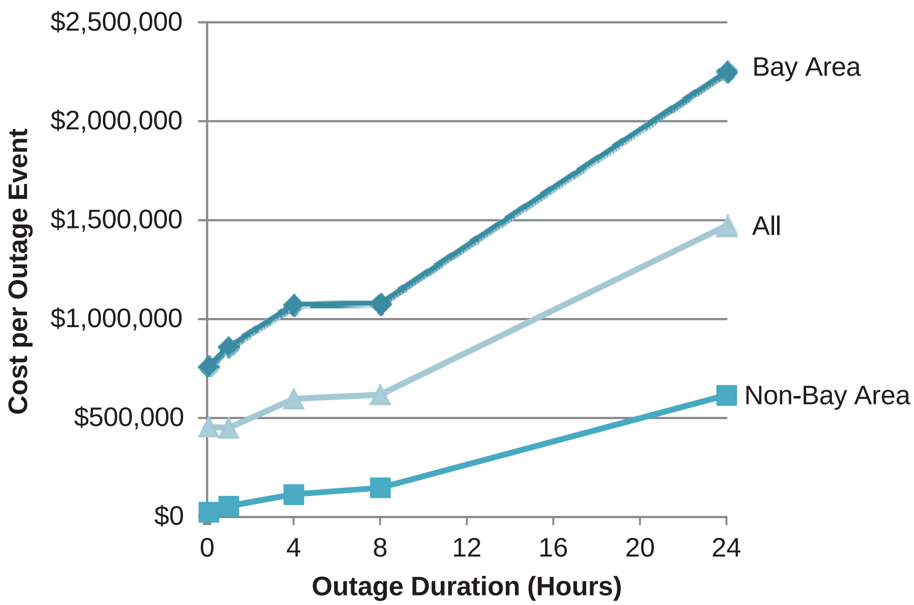
Figure 7-1 and Table 7-2 provide the large business cost per outage event estimates. For a 1-hour outage, large business customers experience a cost of $449,655. Large business cost per outage event increases to $617,196 at 8 hours and $1,472,497 for a 24-hour outage. The confidence intervals for these estimates are quite wide because the large business segment had a smaller sample size and much more variable outage cost estimates from customer to customer. The variability of outage costs was particularly high in the Bay Area, which had a subset of large business customers with extremely high costs, even for a 5-minute outage. This subset of Bay Area customers drives much of the difference between regions, but because of the wide confidence intervals as a result of the relatively small sample size and high variability in outage costs, the regional differences are not statistically significant.

The extremely high outage costs for some of the large business customers in the Bay Area must be understood within the context of their level of reliability. Many of these Bay Area large business customers are accustomed to a very high level of reliability and rarely experience sustained power interruptions, so even a 5-minute outage would impose extremely high costs. Considering that these customers are significantly less likely to experience transmission or distribution related power interruptions, it can be argued that their costs should be excluded from many transmission and distribution planning applications. Therefore, Appendix D provides the 2012 large business outage cost estimates by level of service reliability. For transmission and distribution planning applications, FSC recommends applying the results segmented by level of reliability as opposed to region.[12] This segmentation of the analysis should be carried out as follows:

- If a planning analysis focuses on a circuit or transmission line that has performed badly in the past, which is often the focus of these types of planning analyses, FSC recommends applying the outage cost estimates associated with large business customers that have experienced a sustained outage in the past year.
- If a planning analysis focuses on a circuit or transmission line that has performed well in the past, FSC recommends applying the outage cost estimates associated with large business customers that have not experienced a sustained outage in the past year.

For generation planning, FSC recommends applying the outage cost estimates for all large business customers because supply shortages usually have a similar impact on all customers systemwide.

Figure 7-1:
2012 Cost per Outage Event Estimates by Region – Large Business



12 Another option is to apply to results segmented by level of reliability *and* region, but with the relatively small sample sizes in the large business segment, it is not recommended to divide the results into such granular categories.

Table 7-2:
2012 Cost per Outage Event Estimates by Region – Large Business

Region	Outage Duration	N	Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	119	$761,784	-$90,608	$1,614,177
	1 hour	119	$861,359	$25,312	$1,697,407
	4 hours	120	$1,073,743	$223,315	$1,924,171
	8 hours	120	$1,080,310	$283,933	$1,876,688
	24 hours	120	$2,252,293	$802,979	$3,701,606
Non-Bay Area	5 minutes	90	$24,308	$10,812	$37,804
	1 hour	90	$54,970	$28,648	$81,292
	4 hours	90	$113,746	$52,625	$174,868
	8 hours	90	$147,383	$82,122	$212,644
	24 hours	90	$615,402	$184,438	$1,046,366
All	5 minutes	209	$454,675	-$54,092	$963,442
	1 hour	209	$449,655	$51,936	$847,375
	4 hours	210	$596,675	$178,277	$1,015,072
	8 hours	210	$617,196	$231,787	$1,002,605
	24 hours	210	$1,472,497	$682,564	$2,262,429

Table 7-3 summarizes large business cost per average kW. For a 1-hour outage, large business customers experience a cost of $327.4 per average kW. The percentage difference between Bay Area and non-Bay Area large business cost per average kW is substantially greater than in any other segment. For a 5-minute outage, Bay Area cost per average kW is 32 times higher than in the non-Bay Area. The percentage difference decreases as duration increases and at 24 hours, Bay Area cost per average kW is 3.8 times higher than in the non-Bay Area.

Table 7-3:
2012 Cost per Average kW Estimates by Region – Large Business

Region	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	119	$547.5	-$65.1	$1,160.2
	1 hour	119	$624.7	$18.4	$1,231.0
	4 hours	120	$774.6	$161.1	$1,388.2
	8 hours	120	$771.0	$202.6	$1,339.4
	24 hours	120	$1,663.5	$593.1	$2,734.0
Non-Bay Area	5 minutes	90	$17.0	$7.6	$26.5
	1 hour	90	$40.7	$21.2	$60.2
	4 hours	90	$85.6	$39.6	$131.6
	8 hours	90	$110.1	$61.4	$158.9
	24 hours	90	$443.4	$132.9	$753.9

Region	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
All	5 minutes	209	$319.3	-$38.0	$676.5
	1 hour	209	$327.4	$37.8	$617.0
	4 hours	210	$436.9	$130.5	$743.2
	8 hours	210	$449.7	$168.9	$730.6
	24 hours	210	$1,047.5	$485.6	$1,609.5

Table 7-4 provides the large business cost per unserved kWh estimates. For a 1-hour outage, large business customers experience a cost of $318.5 per unserved kWh. At 5-minutes, the systemwide estimate is nearly $3,770 because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. In addition, many of the Bay Area large business customers have extremely high costs, even for a 5-minute outage, because they are accustomed to a very high level of reliability and rarely experience sustained power interruptions, as discussed above. As duration increases, cost per unserved kWh decreases precipitously because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate. In fact, many of the high-cost large business customers have the same or very similar costs for a 5-minute outage and a 24-hour outage.

Table 7-4:
2012 Cost per Unserved kWh Estimates by Region – Large Business

Region	Outage Duration	N	Cost per Unserved kWh	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	119	$6,486.6	-$771.5	$13,744.7
	1 hour	119	$609.7	$17.9	$1,201.4
	4 hours	120	$189.9	$39.5	$340.4
	8 hours	120	$94.8	$24.9	$164.7
	24 hours	120	$69.1	$24.6	$113.5
Non-Bay Area	5 minutes	90	$201.5	$89.6	$313.3
	1 hour	90	$39.4	$20.5	$58.3
	4 hours	90	$21.2	$9.8	$32.6
	8 hours	90	$13.7	$7.6	$19.8
	24 hours	90	$18.5	$5.6	$31.5
All	5 minutes	209	$3,769.8	-$448.5	$7,988.1
	1 hour	209	$318.5	$36.8	$600.2
	4 hours	210	$107.5	$32.1	$182.8
	8 hours	210	$55.6	$20.9	$90.4
	24 hours	210	$43.7	$20.3	$67.2

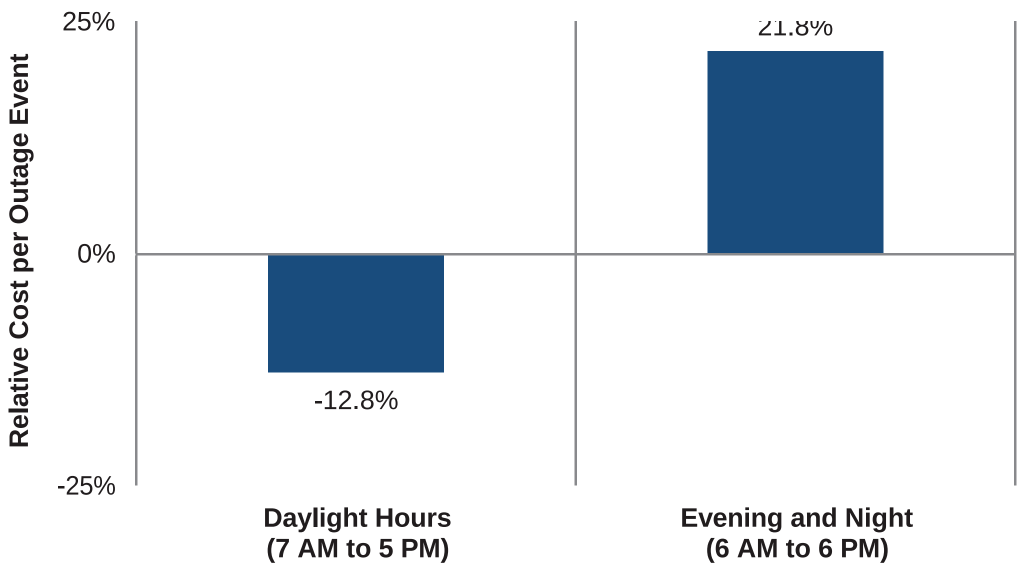
7.3 Impact of Outage Timing

For the large business analysis on the impact of outage timing, onset times were aggregated into 2 key time periods with distinct cost per outage event. These time periods were:

- Daylight Hours (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

Figure 7-2 provides the relative cost per outage event estimates, which were derived from the large business customer damage functions described in Appendix B. Unlike the other 3 customer segments, the onset times were not further divided by day of week because this variable did not have a significant effect for large business customers. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each large business outage cost estimate in Section 7.2 (referred to as the "base value"). As shown in the figure, outage costs for large business customers are somewhat sensitive to onset time, varying moderately from 12.8% lower than the base value during daylight hours to 21.8% higher during the evening and night. Considering that many large business customers operate 24 hours per day, 7 days per week, outages with different onset times likely have a similar impact on production. Even though the impact on production is similar, the overall outage cost may be greater during the evening and night because outage response may require overtime or emergency staff.

Figure 7-2:
Relative Cost per Outage Event Estimates by Onset Time – Large Business



7.4 Comparison to Previous Studies

PG&E previously carried out a large business outage cost study in 1989 and 2005. Table 7-5 compares the cost of a 4-hour, summer afternoon outage for each study year. The 1989 and 2005 cost per outage event estimates were converted to 2012 dollars using the gross domestic product deflator, which was obtained from the U.S. Department of Commerce's Bureau of Economic Analysis.

Between 1989 and 2005, there was a 53.3% increase in reported outage cost for large business customers, but this difference was not statistically significant. The difference between 2005 and 2012 is statistically significant and shows a 4-fold increase in reported outage cost for large business customers since 2005.[13]

While it is possible that outage costs for large business customers have increased significantly since 2005, the results reported here must be used with caution. With the relatively small sample sizes for the large business segment and specific subset of customers with extremely high outage costs, the results for each large business study are subject to large statistical error because they are highly sensitive to the sample that is randomly selected. In the 2012 study, it seems that the random sample included a larger amount of these customers with extremely high outage costs. In addition, the 2012 study had lower large business response rates than those of the 1989 and 2005 studies, which may have led to non-response bias. Although the assessment presented in Appendix D did not find any observable factors (such as industry type) that led to non-response bias, there could have been unobservable factors that biased the results upward in light of the relatively low response rates in the 2012 study. Another possibility may be that these high-cost customers are more prevalent in PG&E's large business population than they were in the past, which may require further research.

Table 7-5:
Cost of a 4-Hour, Summer Afternoon Outage by Study Year – Large Business

Year		Cost per (2012$)	95% Confidence Interval	
			Lower Bound	Upper Bound
1989	372	$73,948	$53,045	$94,852
2005	143	$113,336	$69,959	$156,714
2012	210	$460,263	$131,708	$788,819

7.5 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 7-3 shows the percent of large business customers rating each combination of outage frequency and duration as acceptable. As expected, a large business customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Even though cost per unserved kWh for outages longer than 1 hour is lower for large business customers than it is for SMB customers, large business customers expect a substantially higher level of reliability. One outage of 1 to 4 hours per year is acceptable to 23.6% of large business customers, compared to 49% of SMB customers. A single sustained outage more than 5 minutes per year is considered unacceptable for a majority of large business customers. Two momentary outages is considered unacceptable by the majority.

[13] Note that statistical significance in this case implies that there was an increase in reported cost, but does not necessarily confirm that the magnitude of the increase was exactly 4-fold.

Figure 7-3:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable – Large Business

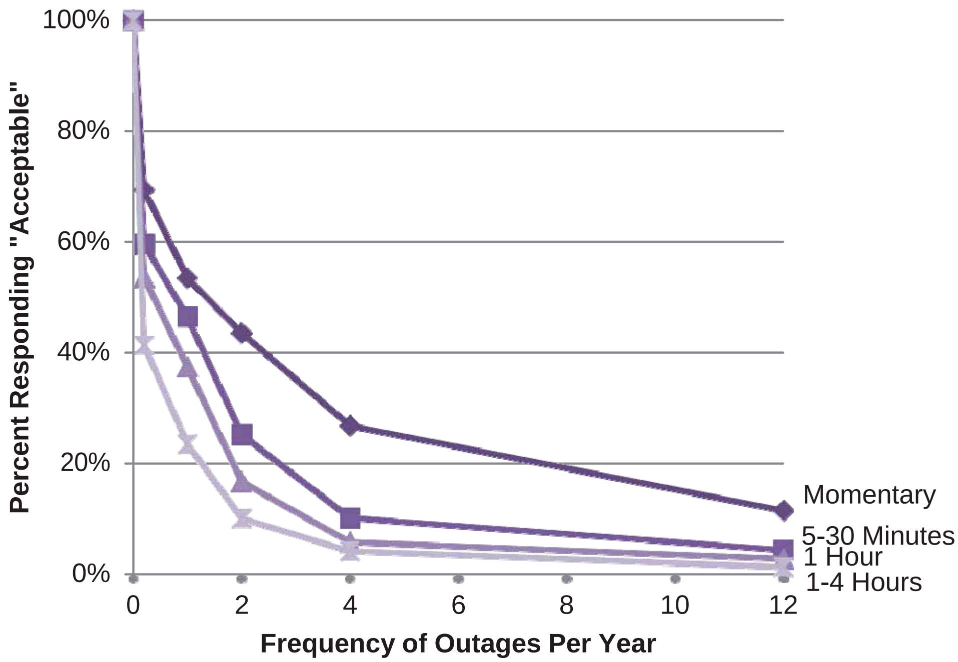


Table 7-6 shows the percent of large business customers rating each combination of outage frequency and duration as acceptable, disaggregated by region. This is the only segment for which there is a substantial difference in the acceptable level of service reliability by region. Bay Area large business customers expect a very high level of service reliability. Over 40% of Bay Area large business customers report that a single momentary outage every 5 years is unacceptable, compared to 23.6% in the non-Bay Area region. For outages between 5 minutes and 30 minutes, only 35.3% of Bay Area large business customers find it acceptable once per year, compared to 53.7% in the non-Bay Area region. As outage frequency and duration increase, the regional differences are not as large.

Table 7-6:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable by Region – Large Business

Region	Frequency of Outages per Year	Outage Duration			
		Momentary	5-30 Minutes	1 Hour	1-4 Hours
Bay Area	Once every 5 years	59.4%	50.3%	45.1%	33.0%
	1	41.2%	35.3%	31.4%	20.4%
	2	29.5%	18.8%	15.9%	12.4%
	4	15.9%	8.6%	5.3%	4.1%
	12	7.6%	3.4%	3.4%	1.1%
	52	4.6%	3.4%	1.1%	1.8%

Region	Frequency of Outages per Year	Outage Duration			
		Momentary	5-30 Minutes	1 Hour	1-4 Hours
Non-Bay Area	Once every 5 years	76.4%	62.4%	55.8%	47.0%
	1	60.5%	53.7%	41.6%	25.3%
	2	54.0%	28.1%	15.9%	7.4%
	4	32.2%	10.8%	6.2%	4.0%
	12	13.7%	5.1%	2.3%	1.7%
	52	2.2%	0.0%	0.0%	0.0%
All	Once every 5 years	69.4%	59.6%	53.6%	41.4%
	1	53.5%	46.5%	37.5%	23.6%
	2	43.6%	25.3%	16.8%	10.2%
	4	26.9%	10.3%	5.9%	4.3%
	12	11.6%	4.5%	2.9%	1.4%
	52	3.4%	1.6%	0.4%	0.8%

To determine what percent of large business customers receives service that they consider acceptable, the acceptable level of service reliability questions were compared with the number of outages customers reported experiencing over the past 12 months. Table 7-7 provides the results of this analysis by outage duration for the large business survey in 2005 and 2012. In the 2012 study, up to 68% of large business customers reported that they receive service that they say is acceptable. As in the 2005 study, momentary outages for large business customers are the outage duration that most likely leads to unacceptable service.

Table 7-7:
Percent of Customers Receiving Service Rated as Acceptable by Study Year – Large Business

Outage Duration	2005	2012
Momentary	70%	68%
5-30 Minutes	86%	84%
1 Hour	92%	81%
1-4 Hours	78%	73%

8 Agricultural Results

This section summarizes the results for agricultural customers.

8.1 Response to Survey

Table 8-1 summarizes the survey response for agricultural customers. With 538 total completed surveys, customer response was above the overall sample design target of 500. Overall, the survey had a 15.4% response rate that was slightly higher in the Bay Area than non-Bay Area. The response rate was relatively constant across region and usage category, varying moderately from 13.6% to 20%. Considering that the 2 key observable factors of interest in this study – usage and region – did not substantially affect the likelihood that a customer responded to the survey, non-response bias is not a significant concern for the agricultural customer results. Nonetheless, Appendix C provides a more detailed assessment of the potential sources of non-response bias among agricultural customers.

Table 8-1:
Customer Survey Response Summary – Agricultural

Region	Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
Bay Area	0 to 0.5	1,469	39	276	46	16.7%
	0.5 to 6.2	1,714	43	332	45	13.6%
	6.2 to 5,511	280	33	170	34	20.0%
	Bay Area Overall	*3,463*	*115*	*778*	*125*	*16.1%*
Non-Bay Area	0 to 0.5	22,939	123	804	127	15.8%
	0.5 to 6.2	34,427	143	1,047	159	15.2%
	6.2 to 5,511	15,916	119	859	127	14.8%
	Non-Bay Area Overall	*73,282*	*385*	*2,710*	*413*	*15.2%*
Overall		**76,745**	**500**	**3,488**	**538**	**15.4%**

8.2 2012 Outage Cost Estimates

Figure 8-1 and Table 8-2 provide the agricultural cost per outage event estimates. For a 1-hour outage, agricultural customers experience a cost of $453.5. Agricultural cost per outage event increases to $2,549 at 8 hours and $5,842 for a 24-hour outage. Since over 95% of agricultural customers are outside of the Bay Area, the outage cost estimates for all customers closely match those of non-Bay Area agricultural customers. Bay Area agricultural customers report higher costs than non-Bay Area customers for outages of 4 hours or longer and lower costs than non-Bay Area customers for outages of 5 minutes and 1 hour.

Figure 8-1:
2012 Cost per Outage Event Estimates by Region – Agricultural

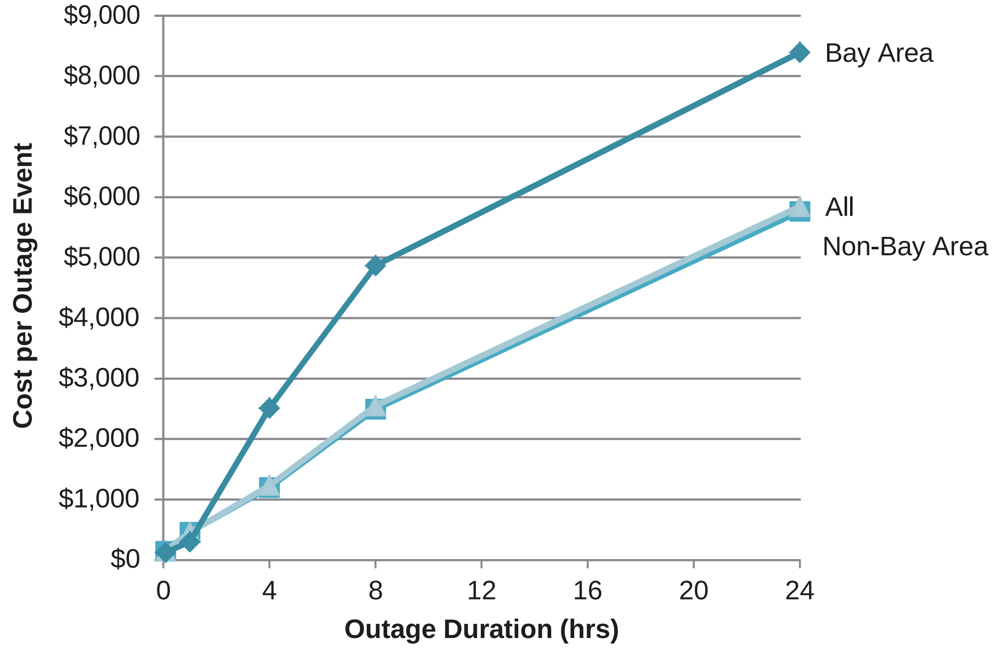


Table 8-2:
2012 Cost per Outage Event Estimates by Region – Agricultural

Region	Outage Duration	N	Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	106	$124.1	$0.2	$248.1
	1 hour	104	$299.3	$156.6	$442.1
	4 hours	101	$2,512.2	-$72.9	$5,097.3
	8 hours	100	$4,866.9	$1,343.6	$8,390.2
	24 hours	97	$8,392.1	$3,467.0	$13,317.1
Non-Bay Area	5 minutes	345	$147.5	$82.8	$212.2
	1 hour	337	$461.6	$207.2	$715.9
	4 hours	324	$1,201.5	$756.0	$1,646.9
	8 hours	324	$2,496.6	$1,644.8	$3,348.4
	24 hours	322	$5,763.9	$3,180.1	$8,347.7
All	5 minutes	451	$146.1	$84.5	$207.7
	1 hour	441	$453.5	$212.6	$694.5
	4 hours	425	$1,230.7	$802.9	$1,658.4
	8 hours	424	$2,549.4	$1,721.7	$3,377.2
	24 hours	419	$5,842.4	$3,289.2	$8,395.6

Table 8-3 summarizes agricultural cost per average kW. For a 1-hour outage, agricultural customers experience a cost of $52.1 per average kW. The cost per average kW estimates are substantially lower than the cost per outage event estimates because average demand for agricultural respondents was around 8.5 kW. As in the cost per outage event estimates, Bay Area agricultural customers report higher costs than non-Bay Area customers for outages of 4 hours or longer and lower costs than non-Bay Area customers for outages of 5 minutes and 1 hour.

Table 8-3:
2012 Cost per Average kW Estimates by Region – Agricultural

Region	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	106	$12.8	$0.0	$25.5
	1 hour	104	$44.4	$23.2	$65.6
	4 hours	101	$356.8	-$10.3	$724.0
	8 hours	100	$682.6	$188.4	$1,176.7
	24 hours	97	$1,143.3	$472.3	$1,814.3
Non-Bay Area	5 minutes	345	$18.2	$10.2	$26.2
	1 hour	337	$52.5	$23.6	$81.4
	4 hours	324	$138.1	$86.9	$189.3
	8 hours	324	$281.8	$185.6	$377.9
	24 hours	322	$686.2	$378.6	$993.8
All	5 minutes	451	$18.1	$10.5	$25.7
	1 hour	441	$52.1	$24.4	$79.8
	4 hours	425	$143.9	$93.9	$194.0
	8 hours	424	$288.7	$195.0	$382.5
	24 hours	419	$700.5	$394.4	$1,006.7

Table 8-4 provides the agricultural cost per unserved kWh estimates. For a 1-hour outage, agricultural customers experience a cost of $50.3 per unserved kWh, which is similar to the cost per average kW estimate because the expected amount of unserved kWh is also around 8.5 at 1 hour. Agricultural cost per unserved kWh is substantially lower than in the SMB segment. Even though agricultural and SMB respondents had roughly equivalent average usage, agricultural cost per unserved kWh is 58.3% lower at 5 minutes and 71% to 74% lower for outages lasting an hour or more. Agricultural customers clearly place a lower value on lost load than SMB customers of a similar size.

Table 8-4:
2012 Cost per Unserved kWh Estimates by Region – Agricultural

Region	Outage Duration	N	Cost per Unserved kWh	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	106	$144.3	$0.2	$288.4
	1 hour	104	$42.5	$22.2	$62.8
	4 hours	101	$89.5	-$2.6	$181.7
	8 hours	100	$84.6	$23.4	$145.8
	24 hours	97	$48.1	$19.9	$76.3
Non-Bay Area	5 minutes	345	$207.8	$116.6	$298.9
	1 hour	337	$50.7	$22.8	$78.7
	4 hours	324	$34.2	$21.5	$46.9
	8 hours	324	$35.0	$23.1	$47.0
	24 hours	322	$28.2	$15.5	$40.8
All	5 minutes	451	$205.7	$118.9	$292.5
	1 hour	441	$50.3	$23.6	$77.0
	4 hours	425	$35.6	$23.2	$48.0
	8 hours	424	$35.9	$24.3	$47.6
	24 hours	419	$28.8	$16.2	$41.4

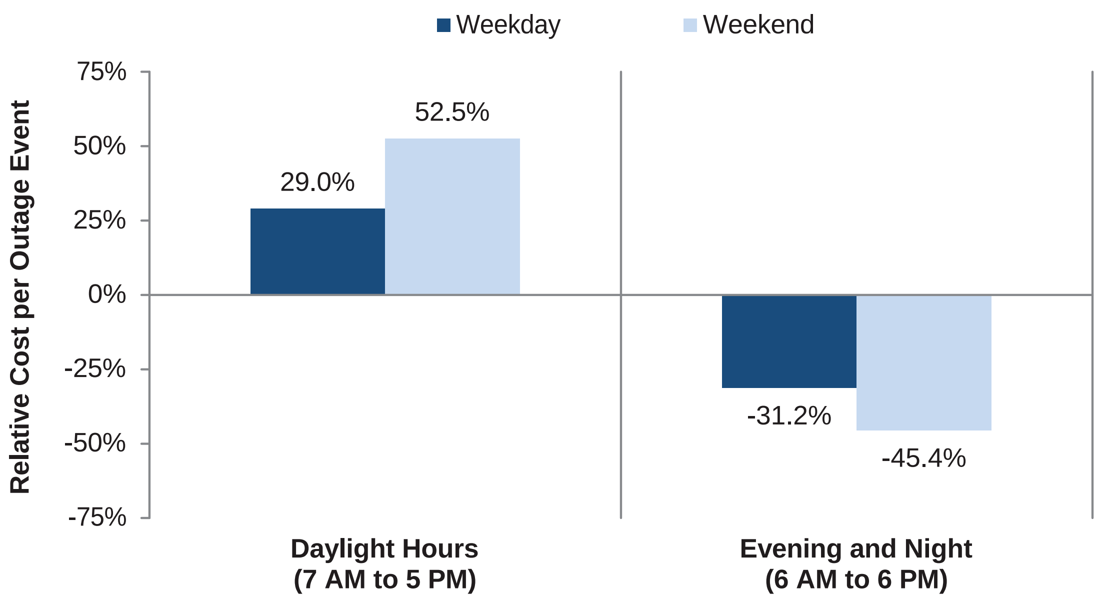
8.3 Impact of Outage Timing

For the agricultural analysis on the impact of outage timing, onset times were aggregated into 2 key time periods with distinct cost per outage event. These time periods were:

- Daylight Hours (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

Figure 8-2 provides the relative cost per outage event estimates, which were derived from the agricultural customer damage functions described in Appendix B. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each agricultural outage cost estimate in Section 8.2 (referred to as the "base value"). As shown in the figure, outage costs for agricultural customers are sensitive to onset time, varying from 45.4% lower than the base value on a weekend evening/night to 52.5% higher on a weekend during daylight hours. Outages during daylight hours on weekdays are also higher than the base value, which is not surprising considering that much agricultural work is conducted during daylight hours. Considering that agricultural outage costs vary depending on the onset time, it is important that planning applications apply these relative values.

Figure 8-2:
Relative Cost per Outage Event Estimates by Day of Week and Onset Time – Agricultural



8.4 Comparison to Previous Studies

PG&E previously carried out an agricultural outage cost study in 1991 and 2005. Table 8-5 compares the cost of a 4-hour, summer afternoon outage for each study year. The 1991 and 2005 cost per outage event estimates were converted to 2012 dollars using the gross domestic product deflator, which was obtained from the U.S. Department of Commerce's Bureau of Economic Analysis. Between 1991 and 2005, there was an increase in reported outage cost for agricultural customers, but this difference was not statistically significant. The difference between 2005 and 2012 is also not statistically significant, even though there is a 29.7% decrease in average cost per outage event. Given the relatively small sample sizes for agricultural customers, large differences in average values are required to detect a statistically significant difference. In this case, the results are inconclusive and the changes in outage cost likely represent random sampling variation between studies.

Table 8-5:
Cost of a 4-Hour, Summer Afternoon Outage by Study Year – Agricultural

Year		Cost per (2012$)	95% Confidence Interval	
			Lower Bound	Upper Bound
1991	803	$1,104.8	$809.3	$1,400.4
2005	380	$1,945.1	$1,023.5	$2,866.7
2012	434	$1,367.1	$907.7	$1,826.5

8.5 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 8-3 shows the percent of agricultural customers rating each combination of outage frequency and duration as acceptable. As expected, an agricultural customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Compared to the other customer classes, agricultural customers expect the lowest level of reliability. Approximately half of agricultural customers report that 4 outages of 5 minutes to 30 minutes per year is acceptable. One outage of 1 to 4 hours per year is acceptable to 73% of agricultural customers, compared to 49% of SMB customers and 68.8% of residential customers.

Figure 8-3:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – Agricultural

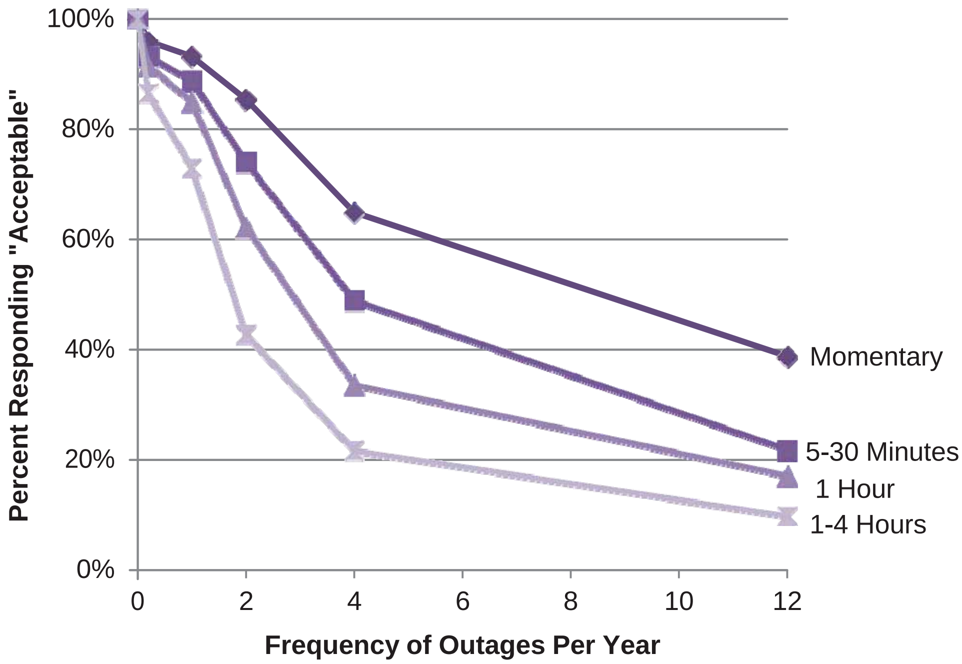


Table 8-6 shows the percent of agricultural customers rating each combination of outage frequency and duration as acceptable, disaggregated by region. In general, non-Bay Area agricultural customers expect a slightly higher level of reliability.

Table 8-6:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable by Region – Agricultural

Region	Frequency of Outages per Year	Outage Duration			
		Momentary	5-30 Minutes	1 Hour	1-4 Hours
Bay Area	Once every 5 years	94.8%	92.0%	87.2%	82.8%
	1	92.7%	88.0%	82.9%	70.5%
	2	87.0%	73.2%	58.1%	36.9%
	4	66.7%	49.0%	36.5%	21.7%
	12	37.8%	24.4%	17.1%	7.0%
	52	17.7%	7.9%	7.1%	3.8%
Non-Bay Area	Once every 5 years	95.9%	93.3%	91.7%	86.6%
	1	93.2%	88.8%	85.2%	73.1%
	2	85.3%	74.1%	62.3%	43.1%
	4	64.9%	49.1%	33.5%	21.8%
	12	38.9%	21.9%	17.3%	10.0%
	52	17.6%	13.2%	9.7%	6.0%
All	Once every 5 years	95.9%	93.2%	91.5%	86.5%
	1	93.2%	88.8%	85.0%	73.0%
	2	85.4%	74.0%	62.2%	42.8%
	4	64.9%	49.0%	33.7%	21.8%
	12	38.8%	21.9%	17.2%	9.9%
	52	17.5%	12.9%	9.6%	5.9%

To determine what percent of agricultural customers receives service that they consider acceptable, the acceptable level of service reliability questions were compared with the number of outages customers reported experiencing over the past 12 months. Table 8-7 provides the results of this analysis by outage duration for the agricultural survey in 2005 and 2012. In the 2012 study, up to 76% of agricultural customers reported that they receive service that they say is acceptable. As in the 2005 study, outages of 1 to 4 hours for agricultural customers are the outage duration that most likely leads to unacceptable service.

Table 8-7:
Percent of Customers Receiving Service Rated as Acceptable by Study Year – Agricultural

Outage Duration	2005	2012
Momentary	88%	86%
5-30 Minutes	91%	90%
1 Hour	92%	87%
1-4 Hours	83%	76%

ATTACHMENT 25

"Restoration and Impacts From The September 8, 2011 San Diego Power Outage, Scott B. Miles, Hannah Gallagher, and Charles J. Huxford (Feb. 29, 2012)

Attachment 25

Restoration and Impacts From the September 8, 2011
San Diego Power Outage

Natural Hazards Review
Restoration and Impacts From The September 8, 2011 San Diego Power Outage
--Manuscript Draft--

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Abstract:	This case study presents post-event reconnaissance research of the September 8, 2011 power outage that left San Diego County, CA without electricity for up to 12 hours. The blackout also affected additional parts of California, as well as Arizona and Mexico. This work focuses only on San Diego County, which was the largest and most densely populated local jurisdiction impacted. The objective of this case study research is to understand the ways in which the outage, restoration, and impacts suggest changes in policies, practices, and research for community disaster resilience related to widespread power loss and cascading impacts to other lifeline infrastructure. This study reveals several issues related to restoration decision-making and communication to critical customers related. Restoration did not occur and was not communicated in such a way to avoid impacts to dependent critical infrastructure or reflect state restoration criteria. Insight from this research suggests several state and federal policy reforms, such as improved energy reliability standards for wastewater facilities. Lastly, this events supports the notion that infrastructure must be explicitly conceptualized as socio-technical systems so that social and organizational biases can be avoided through better institutionalized decision and communication processes.
Suggested Reviewers:	Dorothy Reed, Ph.D. Professor, University of Washington reed@u.washington.edu Expert in power outage from wind hazards and electric network restoration.
	Raymond Murphy, Ph.D. Professor Emeritus, University of Ottawa rmurphy@uOttawa.ca sociologist of disasters who has published on social issues around wind storms and power outages.
	Massoud Amin, D.Sc. Professor Emeritus, University of Minnesota amin@umn.edu Critical infrastructure protection expert with several publications on power outages and the vulnerability of the US grid.

Opposed Reviewers:	

WESTERN
WASHINGTON UNIVERSITY

February 29, 2012

Dear Editors,

Please find attached our manuscript entitled "Restoration and Impacts From The September 8, 2011 San Diego Power Outage" for review and potential publication in Natural Hazards Review as a case study. While the topic of this manuscript is not natural hazard related, I believe that it is of considerable value to NHR's readership because power outage and restoration is one of the most fundamental factors effecting disaster impacts and recovery. The work described in this paper was funded by a Natural Hazards Center Quick Response Grant, as well as a grant from the NSF CMMI program. The co-authors of this manuscript are student research assistants - an undergraduate and a master's student.

Please do not hesitate to contact me with any questions or requests. Thank you for your time and consideration.

Sincerely,

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Restoration and Impacts From The September 8, 2011 San Diego Power Outage

Scott B. Miles[1], Hannah Gallagher[2], and Charles J. Huxford[3]

Abstract

This case study presents post-event reconnaissance research of the September 8, 2011 power outage that left San Diego County, CA without electricity for up to 12 hours. The blackout also affected additional parts of California, as well as Arizona and Mexico. This work focuses only on San Diego County, which was the largest and most densely populated local jurisdiction impacted. The objective of this case study research is to understand the ways in which the outage, restoration, and impacts suggest changes in policies, practices, and research for community disaster resilience related to widespread power loss and cascading impacts to other lifeline infrastructure. This study reveals several issues related to restoration decision-making and communication to critical customers related. Restoration did not occur and was not communicated in such a way to avoid impacts to dependent critical infrastructure or reflect state restoration criteria. Insight from this research suggests several state and federal policy reforms, such as improved energy reliability standards for wastewater facilities. Lastly, this events supports the notion that infrastructure must be explicitly conceptualized as socio-technical systems so that social and organizational biases can be avoided through better institutionalized decision and communication processes.

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Introduction

This case study presents post-event reconnaissance research of the September 8, 2011 power outage that left San Diego County, CA without electricity for up to 12 hours. The blackout also affected additional parts of California, as well as Arizona and Mexico. This work focuses only on San Diego County, which was the largest and most densely populated local jurisdiction impacted. The power outage affected San Diego Gas & Electric's (SDG&E) entire service area. SDG&E provides electrical service to about 3.5 million people through 1.4 million electric meters—all of whom lost power. SDG&E was responsible for power restoration within their service area, which spans 4,100 square miles of Orange and San Diego Counties.

The objectives of this case study research are threefold. First is to document and analyze the organizational and socio-economic impacts of the outage, as well as lifeline infrastructure interdependence impacts. Second is to characterize the differential impacts and restoration outcomes related to organizational and inter-organizational responses by SDG&E, government agencies, and to a lesser extent the private sector. Third is to provide policy and planning recommendations for increased community disaster resilience with respect to large-scale power outages related to human error, technology failure, and fast-onset hazard events such as earthquakes and terrorism. The research employed a mixed-method approach to data collection and analysis. The remainder of this paper is comprised of sections describing a brief background literature review, the study's data collection strategy, an overview of the outage, the lifeline impacts of the outage, the socio-economic impacts, and conclusions.

Data Collection Strategy

For this exploratory research we used a mixed-methods approach to develop our data collection strategy. We gathered data with respect to two variables: 1) service loss and restoration and 2) differential socio-economic impacts. Collected data included interview transcripts, content from news and social media, and government documents and databases. We identified representatives from SDG&E customers to interview, specifically public agencies, hospitals, schools, and businesses.

Initially we planned to conduct interviews with SDG&E personnel. However, after a short phone interview and a few emails, SDG&E declined to be interviewed further or provide information of any kind, citing an ongoing federal, state, and private investigations of the company related to their role in and response to the outage. While we were not able to collect data directly from SDG&E representatives, we were able to collect SDG&E data through indirect sources. These include public statements available through media sources, regulatory data (SDG&E, 2012a), and data from SDG&E logged into the County of San Diego Office of Emergency Services's (OES) WebEOC system. SDG&E is required by the federal government to provide a variety of data and information on their Web site (SDG&E, 2012b), including dynamic load profiles (SDG&E, 2012a), which were particularly useful for this study.

SDG&E used Twitter exclusively for social media-based public relations and, in part, as a means of communicating with public agencies. SDG&E used Twitter to provide advice on what to do during the power outage and also to announce when regions of their service area had been restored., We obtained a dataset of all the Twitter posts from SDG&E during the power outage, including the post text and timestamp. The dataset was created using the system of Butts et al. (2011).

Outage and Restoration

According to the California Public Utilities Commission, the power outage began at the 500kV North Gila substation in Arizona (CPUC, 2011). At 3:27:39pm on September 8, 2011 the substation went off line. Eleven seconds later all of the power was out in San Diego County. With the substation off line there was a loss of power on the Southwest Powerlink (SWPL) transmission line, which runs into San Diego County across the southeast border. Because of the loss in current on the SWPL there was increased current on the Path 44 transmission line that enters San Diego County from the northwest. With the SWPL offline, Yuma, Arizona, Imperial Valley, California, Baja Norte, Mexico, and San Diego were wholly dependent on Path 44. This exceeded the safety setting of Path 44 and, in turn, shut down the San Onfre Nuclear Generation Station (SONGS) switchyard. This stopped the current into San Diego County from the northeast (Path 44) and the southeast (SWPL). Local generation in San Diego County could not meet demand and was disconnected to prevent damage as well.

All of San Diego County is within SDG&E's service area and so restoration within the jurisdiction was conducted by SDG&E (SDG&E, 2011b). According to public information from SDG&E, as well as various public testimonies (e..g, California Legislature, 2011; California State Assembly, 2011; City of San Diego, 2011), the first instance of restoration occurred around 8 p.m. on September 8. According to the same sources, all but a few isolated customers were restored in about 12 hours—no later than about 3:30 a.m. on September 9, 2011.

Figure 1 shows two different types of recovery curves—one based on the number of customers restored and one calculated from SDG&E dynamic load profiles. The fraction of total customers restored over time is derived from OES logs. In addition, the figure shows the dynamic load profile of the SDG&E service area by economic sector. The load profile data shown starts at Hour 20 (or 8 p.m. on September 8) and ends at Hour 48 (or 12 a.m. on September 9). The load profile data are normalized using the load profile data for the same two days of the week for the week before (September 1 and 2). Thus, a value of one indicates the load is back to the "normal" load compared to the week before—that is, the load has recovered. (The load from the prior week was compared to other past weeks and found to be representative.)

We were able to assemble a spatio-temporal database using Twitter data developed with the system of Butts et al. (2011), which include the post text and timestamp. With this data, we noted the timestamp either for when SDG&E posted that a community had been restored or the last instance the community was referred to. Figure 1 then plots the estimated time between the first instance of restoration and when each community mentioned by SDG&E was restored. Figure 2a presents the same information in map form, but this case it is expressed as the estimated time that the power was out for each community. Unfortunately, SDG&E did not provide updates on Twitter for all communities within San Diego County; it's not clear why.

Public statements by SDG&E, interviews with an OES representative, as well as a CPUC (2011), indicate the technical requirements of restoring the system meant that power along Path 44 and SWPL had to be restored first at the SONGS and North Gila substations, respectively. Once SONGS and North Gila substations were back online, in general, SDG&E reportedly restored power toward the middle of the county while taking into account the ease or technical need to restore specific circuits. In other words, the restoration was primarily circuit-based, rather than substation-based or community-based. Restoration to specific customers occurred in groups based on when each circuit in the distribution substation was restored, as well as when a distribution transformer near the customer location was repaired, if damaged.

Based on Figures 1 and 2a, it does not appear that restoration occurred starting in the southwest with the North Gila substation and then, soon after, the northwest with the SONGS substation, progressing inwards to the central part of the county. For example, Fallbrook (Polygon 10 in Figure 2a) is located near the SONGS substation in the north, but was restored well after Torrey Pines (polygon 38, which is along the central part of the coast much farther away from SONGS or North Gila. Lemon Grove (Polygon 17) was restored well before Chula Vista (Polygon 4) and National City (Polygon 25), even though these municipalities are close together in the southern-most part of the county. The first two municipalities with restored power were Escondido and San Marcos according to updates from SDG&E logged into San Diego County's WebEOC. These municipalities are in the central part of the county.

There is no legal requirement in California for a particular sequence or pattern of electric system restoration. That said, the California Public Utilities Commission has adopted General Order No. 166 that sets out "the standards [that] will facilitate the Commission's investigations into the reasonableness of the utility's response to emergencies and major outages." CPUC sœets out an expectation that a utility consider more than technical decision criteria in restoring electricity. CPUC states the expected priority of restoration for both essential and general customers as the following:

> Essential [c]ustomers … [are] [c]ustomers requiring electric service to provide essential public health and safety services. … The plan shall include guidelines for setting priorities for service restoration. In general, the utility shall set priorities so that service is restored first to critical and essential customers, and so that the largest number of customers receive service in the shortest amount of time.

Figure 2b presents a map of the population of each community in the Twitter restoration database to help give insight into whether SDG&E's approached resulted in restoration to the largest number of customers in the shortest amount of time. Of the mapped communities, the largest populations are located in Carlsbad (Polygon 3 in Figure 2b), Chula Vista (Polygon 4), El Cajon (Polygon 7), Escondido (Polygon 9), and Oceanside (Polygon 27). Carlsbad, El Cajon, Escondido, and Oceanside were among the first group of communities that SDG&E announced were restored (Figure 1 and Figure 2a). Chula Vista was among the last group of communities that SDG&E announced had been restored. Chula Vista is not only the second largest community in the San Diego County, it has the largest Hispanic population. It is important to note that restoration cannot be specifically community-based; it must be circuit based. Each substation has multiple circuits, which are restored individually. One circuit may provide electricity to more than one community.

To provide some insight regarding SDG&E restoring power to essential customers, Figure 2 shows the location of all hospitals in San Diego County. There are multiple hospitals in communities that had relatively long outage times, for example in Chula Vista (Polygon 4). , The first circuit restored in Chula Vista was at about 12:30am on September 9, 2011 according to the updates on individual circuit restoration times logged by SDG&E into OES's WebEOC. In other words the hospitals in Chula Vista had to rely on backup power for longer than any other hospital – over four hours after the first circuits were restored in the county.

Lifeline Impacts

The San Diego power outage caused disruptions to other dependent lifeline infrastructure. Some infrastructure types were more impacted than others. The outage's impacts on such a large range of lifelines posed significant challenges to all decision makers and residents.

Communication Impacts

Communication networks including emergency communications, telephone, cellular, Internet, and cable service were overwhelmed in the first 30-60 minutes after the blackout. While some communication systems had backup power, there were several instances where either backup power did not work properly or was insufficient to handle the necessary load. For example, the city manager of El Cajon said the city experienced outages of their emergency communications system because of insufficient relay capacity. As a result, police, fire and emergency management had difficulty communicating in some instances. In these instances, cellular SMS (text messaging) services were used. As a result of communication disruptions and initial miscommunications, agencies sent representatives to other agencies in order to gain or communicate critical information. As an example San Diego County Health and Human Services Agency (HHSA) Division of Public Health Services (PHS) sent someone to City of San Diego Public Utilities (PU) to clear up a miscommunication about required beach closures.

While sources indicated that cellular towers have battery backup for 8 to 72 hours, service was limited, if available at all, throughout the 12-hour duration of the outage. Study participants regularly indicated that certain providers were more reliable than others, particularly related to cellular service. SMS service on cellular networks worked fairly consistently while voice and data services performed poorly. Calls and texts from friends and co-workers about power service and restoration were frequently stated as the best source for information. Many of those that had smartphones and could access their cellular data services used social media to disseminate and find information about the outage until their batteries ran down. Ninety percent of Time Warner Cable Company's customers lost service immediately. Thus, most of the public, including those with only broadcast service, could not access emergency information from local and national television sources, even though local news covered the outage extensively.

The 9-1-1-call volume immediately after the outage was three times higher than typical volumes, exceeding surge capacity. The majority of 9-1-1 calls were related to elevators that had stopped working, residents' dependent on home medical systems, traffic issues, and general questions about the power outage. OES in collaboration with SDG&E issued about 500,000 reverse-9-1-1 calls to the public, particularly those with special medical needs, using AlertSanDiego – a regional public notification system. AlertSanDiego was thought to be relatively ineffective by OES because the phone number database is primarily of landline numbers. OES is currently making a concerted effort to get the public to register their cellular phone numbers and has been advocating for years for homes to have at least one non-cordless phone. The AlertSanDiego system was also used to notify residents and businesses that were in a boil water advisory zone (see water section below).

Transportation Impacts

The power outage had significant impacts on transportation. San Diego's light rail system went down. San Diego International Airport remained open during the blackout, though outbound flights were not permitted, and some inbound flights were delayed or diverted. Backup power supplied about 25% of their operations, prioritized with respect to life-safety and evacuation purposes.

The most critical impact was to traffic and freeway onramp signals, which have little or in most cases, no battery backup. Signals were either off or had reverted to flashing red. Signal outages in combination with higher than normal traffic volumes led to major delays, particularly along routes to freeway onramps. Study participants estimated a normal 15-minute commute took 2 to 3 hours during the power outage. Traffic began to clear approximately 3 hours after the initial outage. However, traffic signal operations were impaired and unreliable for about two weeks after the event. Traffic delays were exacerbated in downtown San Diego because rail-crossing arms were stuck in the down position. All public schools in the county were closed the following day, Friday, September 9, primarily due to inoperable traffic signals. One reason that San Diego County Office of Education (SDCOE) said they made the decision to close all schools in the county was to ensure the safety of the children with respect to traffic accidents. Many study participants noted traffic issues could have been avoided if more traffic signals had backup power.

OES had difficulties getting emergency personnel and county officials from their downtown administrative offices to the county's new EOC located several miles to the north. The California Department of Transportation (Cal Trans) traffic management system was impaired because of inoperable cameras. Cal Trans used information from media reports in cases where they did not have camera information. In addition, traffic delays also led to difficulties delivering generators to critical facilities.

Fuel Impacts

The outage severely impacted access to fuel service. The former director of OES observed that the most significant impact was on the ability of consumers, repair crews, and law enforcement to access gasoline. Without electricity, gas pumps were inoperable. For the most part, agencies reported being able to operate their own fueling locations for first responder vehicles using manual pumps. Almost all of the roughly 1000 retail gasoline stations in San Diego County, which account for about $150 million of payroll in the county, were closed during the outage. Clearly there was an economic impact associated with gas station and convenience store closures, but no estimate has been done to our knowledge. Access to natural gas by consumers was also hampered as a result of the outage, for similar reasons. The natural gas company Kindermorgan said they did not have backup generators and noted that it could take 24-36 hours to have large generators delivered and installed. This means that longer outages in the San Diego region will result in a significant natural gas shortage.

Potable Water Impacts

In areas that rely on wells for potable water, the loss of power impacted access to potable water in some cases. Seventeen of 166 small water systems in rural unincorporated San Diego County experienced low water pressure. These respective systems serve relatively small populations. Department of Environmental Health (DEH) used a callback system to determine which water networks lost pressure. It took almost two weeks to clear all of the issued boil water orders. Within the City of San Diego, 13 small areas experienced reduced water pressure, but there were no reports of contamination. For the most part, these communities lack the ability and resources to monitor the water pressure of their own system. Boil water advisories were issued for these areas and lifted by September 11. The city has 17 generators to dispatch to their 49 pump stations in the case of emergency. In this case, the city dispatched generators to five of the boil-water advisory areas before SDG&E was able to restore power.

A boil-water advisory was issued in areas with low pressure in case there was contamination from backflow. According to DEH, this was done as a precaution; no instances of contamination were reported. Boil-water advisories were issued for these areas and lifted by September 11. There was a lot of confusion among residents and businesses about the boil water advisory. Many were unaware of the advisory, initially including PHS officials we spoke with because of impaired access to public information. While others who knew about the boil water advisory didn't have means to boil water because of the lack of electricity. DEH gave restaurants three options under which they could operate if they were within one of the boil water areas: close, sell only pre-packaged food, and serve under limited conditions. In large part, businesses were aware of these options before the outage occurred from pre-event educational guidance provided by the department.

Wastewater Impacts

PU operates and maintains 82 pumps stations as part of their wastewater system. The outage led to failures, which caused sewage spills, at two pumps stations at Los Penosquitos lagoon near Torrey Pines State Park (Pump Station 64) and South Bay (Pump

Station 1), respectively. This led to the closure of ten miles of shoreline in the county. Closures and warnings were posted at beaches from the Scripps Pier in La Jolla north to Solana Beach about six hours after the spills started. The delay was caused by miscommunication between agencies, including PU and DEH. About 3.6 million gallons of sewage was also spilled into the Tijuana River in Mexico as a result of power loss outside of San Diego. All beaches and parks in San Diego were reopened by September 14th.

Power was restored to the pumps in approximately five hours and before SDG&E could deliver mobile generators. PU has requested in the past that SDG&E prioritize restoration of circuits feeding their critical facilities. A PU representative noted that nearby residential areas were restored before their facilities. Of the 82 pump stations operated by City of San Diego, 54 have backup generators. One has dual natural gas powered pumps. Five, including Pump Stations 1 and 64, have dual electrical feeds from separate SDG&E substations, which is in accordance with EPA standards for energy reliability. The option of dual feeds to satisfy EPA reliability standards does not consider a system-wide power outage such as the one that occurred on September 8th or as a result of a significant earthquake. PU had studied the feasibility of backup generators prior to the outage but found the costs to outweigh the benefits. Currently, the San Diego City Council is looking at funding for backup generators at Pump Stations 1, 64, and others.

Approximately 2.6 million gallons of sewage were spilled into Los Penosquitos lagoon and is considered to be the biggest sewage spill in the county over the past decade. A local environmental group, San Diego Coastkeeper, reported fish kills as a result of the spill (San Diego Coastkeeper, 2011). San Diego Coastkeeper also reported elevated fecal coliform and reduced dissolved oxygen levels for at least a week after the outage. PU pumped 15 million gallons of contaminated water from the lagoon into San Diego Bay over two weeks as part of clean up efforts. Over 900,000 gallons of sewage were spilled from Pump Station 1 at South Bay into the Sweetwater River and, ultimately, the bay.

Socio-Economic Impacts

Although the September 8th power outage was brief and the direct economic loss small, the event had distinct and varied social and economic impacts that can provide lessons for future disaster preparedness, response, and recovery efforts. Among the impacts documented are economic impacts, impacts to schools, to health care services, and social services. These impacts are described below.

Economic Impacts

The economic impacts of the power outage varied with respect to government, households, and businesses. The general public was impacted because ATMs did not have power to operate. Government largely was impacted by overtime costs related to increased hours for police, fire and other critical personnel, with some productivity loss. Many households threw out perishable food as a result of public information regarding food spoilage originating from SDG&E. Also, those that work at businesses typically open during the period of the outage likely lost wages. Businesses could have suffered from all three types of impacts: overtime costs, lost productivity, and lost inventory in the form of perishable food. Businesses typically open in the evening or those that operate 24 hours a day were forced to close in most cases. Many bars and restaurants were expecting higher than normal revenue the evening of September 8, 2011 because it was opening night of the National Football League. Many business sectors were not severely impacted by the outage because it occurred in the late afternoon and the majority of the restoration was complete by early the following morning.

The National University System Institute for Policy Research (NUSIPR) calculated the direct economic loss of the outage to be between $97 and $118 million. According to the president of NUSIPR, the calculation underestimates actual losses. Their estimate includes $12 to $18 million for food spoilage, $10 to $20 million for government overtime, and about $70 million for lost productivity (NUSIPR, 2011). These three estimates were based on estimates for the 2003 Northeast United States blackout, 2003 and 2007 San Diego wildfires, and 1996 San Diego brownouts, respectively. The original estimates were adjusted for various factors, such as population difference, to arrive at the estimates for this event. The NUSIPR estimate is not specific to this outage. As a result the estimate ignores several sources of direct and indirect losses associated with the outage, such as millions of dollars of losses suffered by medical care facilities (discussed below) and issues with childcare for the day that schools were closed.

Of particular note were food service businesses, including restaurants, bars, grocery stores, cold storage and processing, which unlike most other businesses, might have thrown out perishable food. According to DEH, there are over 12,000 businesses accounting for over 30,000 inspections per year. If each of those businesses discarded only $1000 of food, the total loss would double the NUSIPR estimate. The majority of these businesses are small and locally owned. The Food and Drug Administration guidelines state in the event of a power outage, refrigerated food can be kept up to four hours if the fridge is not opened. Thus, many restaurants chose to throw away, discount or give away perishables to avoid liability of serving spoiled food. SDG&E also made several public statements that restoration might take several days, which may have prompted businesses to throw out frozen food. Emergency backup generators to maintain typical restaurant service can cost as much as $20,000. This seems like a large expense for most restaurants and bars, but one downtown bar owner estimated their losses to be between $15,000 and $20,000 not considering discarded food. Many bars and restaurants with backup generators unsurprisingly saw an increase in business and garnered attention by the news media, citing that many residents celebrated the outage at these establishments.

School Impacts

In response to the outage, SDCOE closed all schools in the 42 districts of San Diego County on September 9 – the day after the outage. The SDCOE public information officer said that for the most part, schools in the area experienced little logistical trouble on the first day of the outage, with students able to get home because of the timing of the outage. At 8pm on September 8, the public announcement to close was made. Schools were closed in part for safety concerns related to traffic signal outages and the impact on bussing, as well as to avoid uncertainty the of whether power would be back on the next day. SDCOE said that SDG&E's restoration approach was a factor in their decision to keep schools closed the next day. SDG&E indicated they could not prioritize the restoration of some schools so they could prioritize other areas. In addition, SDG&E communicated to SDCOE that restoration of schools en masse would lead to a large spike in load that would make stabilizing the electrical network difficult and result in a prolonged outage. To avoid a small budget loss, some school districts petitioned the California Department of Education that the lost day not be considered in calculation of average daily attendance money because it was due to an emergency.

The conflict between SDCOE and SDG&E with respect to restoration priority has roots prior to the September 8th, 2011 power outage. In 2007, SDG&E was sued for its response to the wildfires that swept the area. In response, SDG&E developed a plan to avert similar disasters. The plan, referred to commonly as the "shutoff plan," involved preemptively powering down certain circuits of their network if they deemed a hazard in the area an imminent threat to their system. This plan was widely critiqued by elected officials, agency representatives, and advocacy groups. One particular critique related to SDG&E not involving various agencies and organizations including SDCOE, water utilities, major health care providers and disability rights organizations in the development of the plan. Additionally, SDCOE opposed the plan because SDG&E refused to guarantee they would give prior notification of a shutoff, which would pose a danger to students and result in a loss of average daily attendance money. The California Public Utilities Commission ultimately rejected SDG&E's proposed shutoff plan. However, agencies and organizations that originally critiqued the plan, including SDCOE, are currently negotiating with SDG&E to allow input on pre-event planning, as well as post-event restoration.

Health Care and Social Services Impacts

There were no deaths or significant injuries reported as a result of the outage. There were several cases of various health care facilities transporting patients to other facilities for precautionary reasons or because of generator malfunctions, including at one large nursing home. There were also instances where homebound residents using electric medical devices were transported to nearby health care facilities. Because these devices typically have at least six hours of battery backup, these instances were relatively rare. SDG&E maintains a list of about 14,000 people who require power for medical devices so they or OES can make contact and inquire whether there is a medical emergency requiring assistance.

California law requires hospitals to have emergency power that restores electricity within 10 seconds of an outage, as well fuel to run generators for at least 24 hours. Two hospitals experienced backup generator malfunctions: Sharp Memorial Hospital in Kearney Mesa and Scripps Mercy Hospital in Chula Vista. While Sharp Memorial was never entirely without power, Scripps Mercy was without power for 90 minutes until they brought in mobile emergency backup, according to the administrative director of disaster preparedness for Scripps Health. The permanent backup generator failed to work because of a fuel pump problem. Scripps, like other health care facilities, is not permitted to test their generators for more than 96 hours per year because of California Air Resources Board regulations (ARB, 2012). The Scripps disaster preparedness director observed that, as a result of the regulations, the generator might not have been run long enough to catch the fuel pump problem during testing the week prior to the outage. Even so, the entire facility was eventually evacuated in coordination with San Diego County. Many of the medical equipment within Scripps Mercy have battery backup that lasted for all or most of the outage. Scripps Mercy had to cancel surgeries, exams, diagnostics, and close clinics serving more than 900,000 customers. Direct losses for Scripps Mercy were estimated to in the range of $5 million, including lost revenue and perishable medication that had to be discarded—the value of which is estimated to be in the millions of dollars.

The CalFresh program issues nearly $30 million in food stamp benefits to about 200,000 low-income residents of San Diego County every month. The HHSA Division of Strategy Planning and Operational Support (SPOS) manages the CalFresh program within the county. The power outage occurred near the beginning of the month when recipients typically use much of their benefits to purchase food. As a result, the county offered to reimburse recipients up to one month of benefits to replace discarded food if they applied within 10 days of the outage. The value of the reimbursement could be in the thousands of dollars for a large family. Recipients could apply in person for benefit replacements at 10 county family resource centers using forms available in English and Spanish. It is unclear how many recipients knew they could receive replacement benefits, but it is clear that only a portion of those eligible applied for replacement. According to SPOS, the Iraqi population applied for replacement benefits at the highest rate of all replacement applicants. In one instance, nearly 600 Iraqi recipients showed up simultaneously at the El Cajon family resource center. East San Diego County has experienced a large influx of Iraqi refugees – over 13,000 since 2005. As a counter example, the Somali population, which is of similar size, had a replacement application rate of about 2%. In general, San Diego's food stamp participation rate for eligible residents has been among the lowest of urban centers in the country due to lack of awareness of eligibility rules.

Conclusion

The San Diego power outage of September 8, 2011 highlights the vulnerability of our country's electric infrastructure and the potential for major outages in the future. This vulnerability and potential for disaster is increasing even in the context of growing attempts to strengthen regulations to increase its resilience. The relevance of this study for responding to and recovering from large-scale power outages will increase in the immediate future, as we deal with more similar events and their technological, social, and economic impacts. In comparison to other outage events, such as the larger 2003 blackout in the northeast United States, disaster researchers can develop knowledge to fill gaps in our understanding of promoting community resilience to electric infrastructure disruption. Beyond lessons specific to large power outages, this study exposes gaps related to San Diego's disaster resilience, the resilience of other areas, and our basic understanding of socio-technical systems resilience and our ability to utilize this knowledge.

San Diego Disaster Resilience

Specific to San Diego, the State of California, and organizations such as SDG&E and San Diego County, there are clear lessons to be learned. Further, questions have been raised that are unlikely to be answered by the investigations of SDG&E. In essence, the event serves as a county-scale disaster simulation with widespread participation of stakeholders.

The event points to several areas of increased public awareness. Residents can be reminded what are appropriate 9-1-1 calls in the event of disasters and that sheltering in place facilitates emergency response after a similar outage and, more importantly, an earthquake. The county could better raise awareness of the eligibility and process for replacing CalFresh food stamp benefits after disasters. This will require ethnically specific approaches, such as increasing the number of languages available for CalFresh applications and educational materials.

Looking at the public information provided by SDG&E, it is not clear if they approached the restoration in the way they claimed. Based on this work, SDG&E's restoration of Chula Vista did not reasonably follow State of California standards for prioritizing hospitals and large populations centers. Customers in their service areas—whether governments, businesses, or households—would undoubtedly benefit from having better pre- and post-event knowledge of (if not involvement in shaping) SDG&E's restoration process, including prioritization criteria and restoration sequence.

Backup power is central to the lessons learned from the power outage. Local businesses, governments, and critical facilities have been and should be compelled to reconsider their stances on planning for and investing in power continuity. Some businesses, particularly food services, may now perceive the benefits of backup generators to outweigh the costs. Public pressure may be applied to governments for increased energy assurance. For example, the City of San Diego, at the time of this writing, is planning on spending $11 million on permanent backup generators to prevent future disaster-related sewage spills (Lee, 2012). State and local governments might consider implementing or improving policies to promote electrical continuity for households and businesses during disasters. This could range from providing technical resources for calculating cost-benefit and determining necessary generator sizes to subsidizing or incentivizing the purchase of backup generators. There is also opportunity for improving plans and agreements to deliver mobile generators during disasters.

In general, federal or state regulations could be improved, put in place, or enforced to ensure power restoration considers community-based goals such as health care, environmental quality, small businesses performance, and rural communities. The former director of OES suggested that San Diego County require large-scale disaster exercises that focus on infrastructure interdependence so these goals can be evaluated. The Environmental Protection Agency should revise energy reliability standards to require backup power in areas where large-scale outages are likely to result from natural hazards. Similarly, the State of California should review current air quality regulations related to backup generator to ensure adequate testing is permitted. Lastly, the state should continue to consider the issue of whether power companies are required to consult certain critical organizations or agencies, such as SDCOE and PU, in planning for and responding to power outages.

Community Disaster Resilience

San Diego had extensive disaster experience even before the September 8, 2011 power outage. Within five years, the county experienced two extreme wildfires. The San Diego area has participated in multiple statewide Great California Shakeout drills—an exercise that, until recently, was unique to California. Even so, the outage exposed significant obstacles for San Diego to successfully recovery from future disasters, considering the relatively limited impact of the power outage.

The limited impacts of the power outage emphasized significant effects that could be overlooked in larger disasters. Environmental impacts, such as sewage spills, are one example. While certainly an issue in all extended power outages, food spoilage was of note in this case because of fewer impacts than would be the expected in a larger-scale natural disaster. The loss to small businesses, however, is not discountable and should be considered in business continuity planning for food-related businesses.

Current emergency preparedness campaigns and disaster drills tend to focus at least somewhat on communication and use of information sources. Even so, this event illustrates a need for more research with respect to awareness of and the role of social media. For disaster preparedness education, such as the use of disaster kits, does infrastructure service disruptions provide a useful frame for the public? Does the potential loss of daily utilities give the public a better understanding of what they need to prepare to be without? Many stakeholders of the San Diego outage felt, figuratively, in the dark with respect to SDG&E's restoration effort as it pertained to their particular situations. This could be ameliorated through improved public information protocols, awareness of restoration protocols, and stakeholder involvement in the development of these protocols, such as through increased participation of lifeline agencies and organizations in disaster exercises. Social media was extensively used after the San Diego power outage and universally praised for its role. This points to the importance of related research, such as done by Butts et al. (2011). Social media has not been deeply researched in the context of socio-technical or infrastructure interdependencies. For example, at what duration of power outage does agency and organizational reliance on social media become potentially counter to resilience? What are the current and normative practices of social media with respect to ethnic and resource-deprived populations?

The outage provides several policy lessons relevant to community resilience to larger and more complex disasters. The EPA could revise their energy reliability standard to require backup power in areas where large-scale outages are likely as the result of natural hazards. State and local governments should also consider improving policies and their enforcement to promote electricity continuity during disasters. This could range from providing technical resources for calculating cost-benefit and determining necessary generator sizes, to subsidizing or incentivizing the purchase of backup generators. There is opportunity for improving plans and agreements for the delivery of mobile generators during disasters. Any difficulty experienced during the power outage will be increased when transportation is more severely impacted. Federal or state regulations can be improved, put in place, or enforced to ensure power restoration considers community-based goals, such as related to health care, environmental quality, small businesses performance, and rural communities.

Socio-Technical Systems Resilience

As described above, the San Diego power outage reveals possibilities for San Diego and other areas to learn lessons for improving resilience to the increasing number of power outages, as well as instances of widespread infrastructure disruptions. Events like this can help politicians and the public to see inside the black box of infrastructure technology and utility services. In other words, infrastructure disruption results in people seeing what they did not see in front of them previously because it is so deeply embedded in their daily lives. Additional research and the dissemination of its results can help people and communities who haven't experienced major disruptions first hand to see into the black box through systematic analysis and narrative. This research can help illuminate the repercussions of politically and economically ignoring infrastructure operations and maintenance.

The outage of course had an extremely localized initial disruption associated with a relatively well-defined set of political and organizational actors. These characteristics serve to isolate the cascading effects of a particular lifeline's disruption. Compared to a major hazard-induced disaster, disaster researchers have, in effect, a chance to control for the simultaneous lifeline disruptions of a natural hazard event, as well as the more diffuse social context of response and recovery. This ability to control, as best as disaster research possibly can, has great value for creating much-needed fundamental knowledge about socio-technical systems resilience. In turn, this knowledge will help to improve practices and modeling to support better response and restoration decisions with respect to socio-technical goals rather than merely technical goals.

The San Diego event also provides an opportunity to advance inter-disciplinary knowledge of the relationship between infrastructure and community resilience. It should be evident through this and other studies, that the vulnerability and restoration of electric and other infrastructure is not a purely technical issue. SDG&E's restoration approach demonstrates either that they were unable or unwilling to follow state decision criteria for restoration. More troubling is it appears that this was most evident in Chula Vista, which has the highest Hispanic population in the county. At this point it is impossible why restoration occurred this way. Likely it was a combination of explicit and implicit decisions resulting in intended and unintended outcome. Electricity is generated and delivered with arguably the most complex technical systems in existence. The technical complexity is increases several magnitudes with the addition of organizational culture, government regulations, public-private relationships, communication difficulties, resource constraints, and institutionalized biases.

It follows that it is impossible to increase resilience – reduce loss and facilitate recovery solely technical or engineering means. This case study points to the potential value of adopting explicitly socio-technical frameworks, such as provided by urban political ecology and the social studies of science and technology (Coutard and Guy, 2007; Graham and Marvin, 2001. Similarly supported is the further research into the development and applications of methods that facilitate socio-technical simulation, such as agent-based modeling (Miles and Chang, 2011; Miles and Chang, 2006).

Acknowledgements

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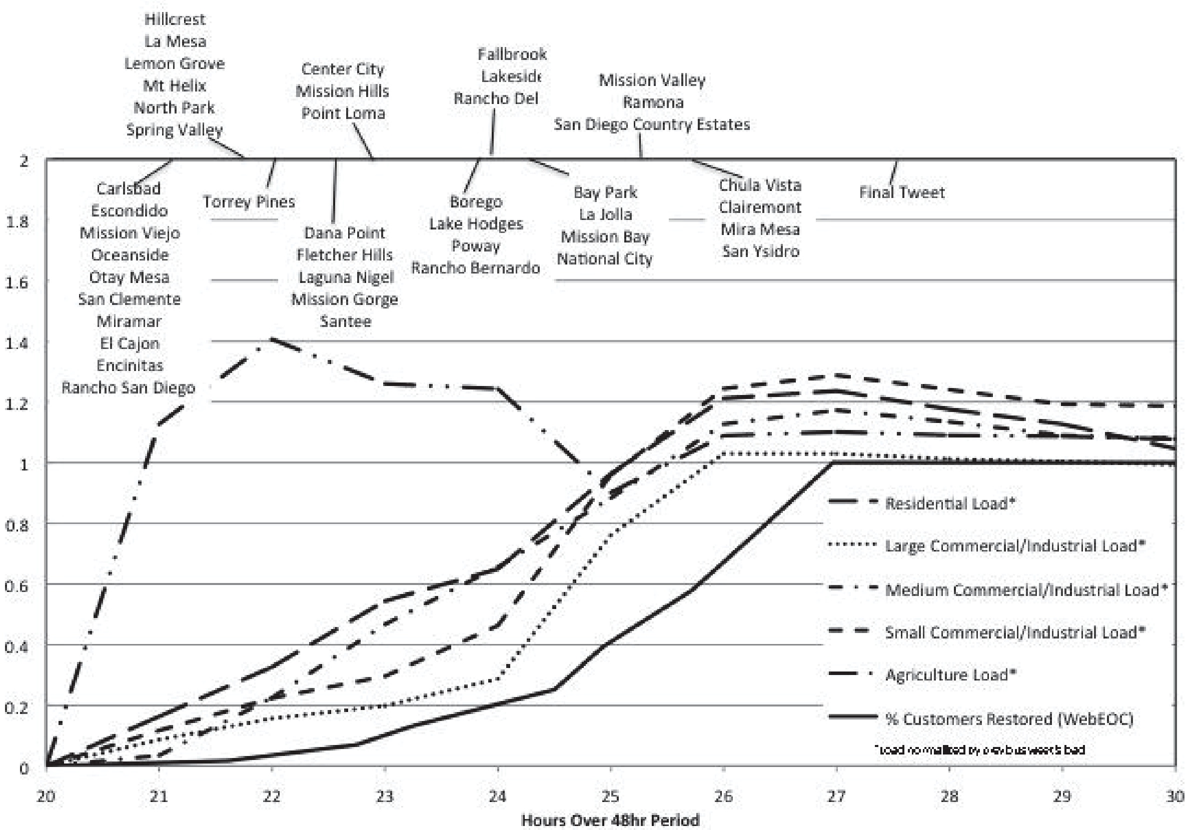

Figure 1. The fraction of total customers restored over time (black line) and the load profile of the SDG&E service area by economic sector. The load profile data starts at 8pm 9/8/2011 (Hour 20 on the x-axis of the graph) and ends at 6am 9/9/2011 (Hour 48). The load profile data for this period is normalized by the load profile data covering the same two days the week prior, such that a value of 1 indicates the load is back to the "normal" load represented by the week prior.

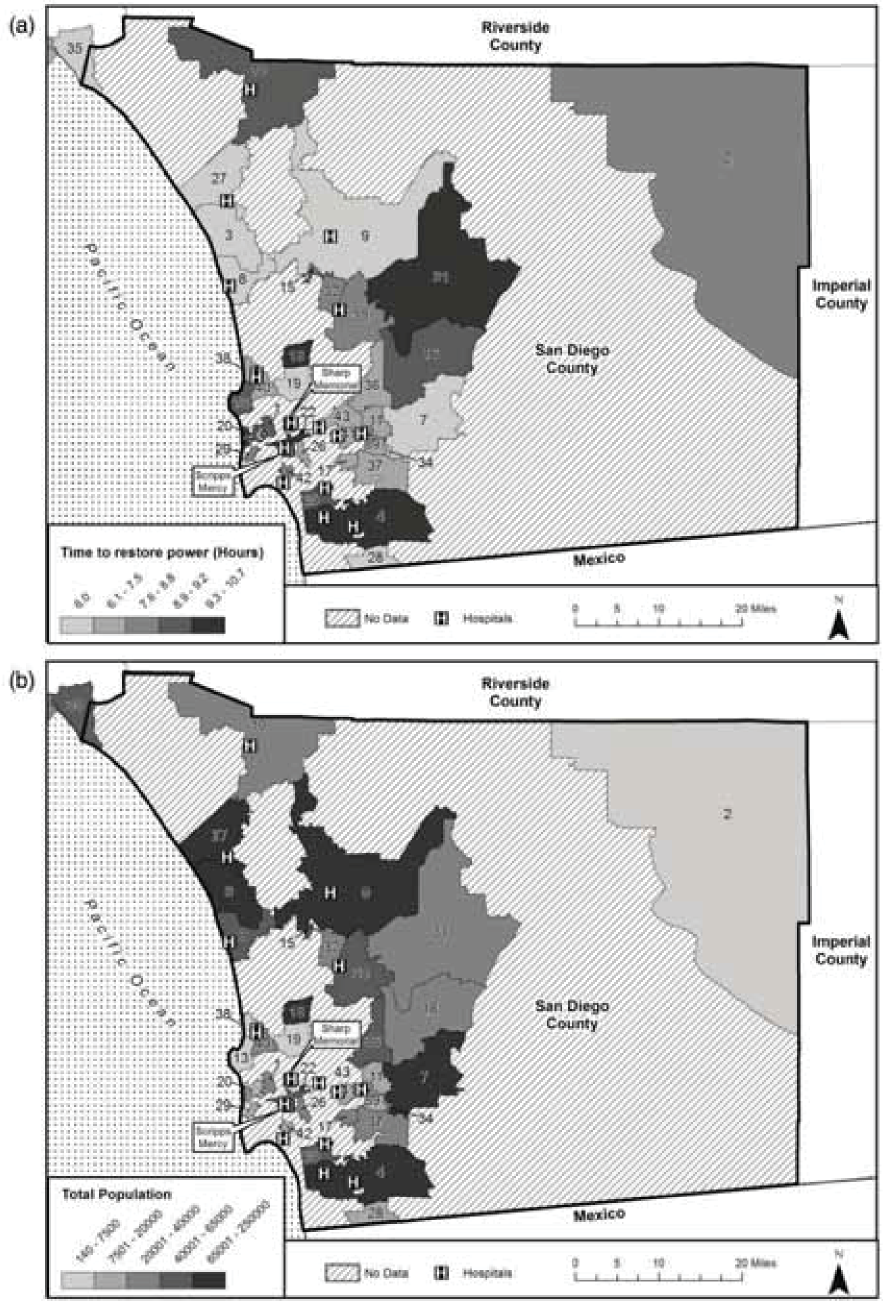

Figure 2. Map of estimated restoration times (a) and total population in 2010 (b) for select communities in San Diego County. (1) Bay Park; (2) Borrego Springs; (3) Carlsbad; (4) Chula Vista; (5) Claremont; (6) Dana Point; (7) El Cajon; (8) Encinitas; (9) Escondido; (10) Fallbrook; (11) Fletcher Hills; (12) Hillcrest; (13) La Jolla; (14) Laguna Niguel; (15) Lake Hodges; (16) Lakeside; (17) Lemon Grove; (18) Mira Mesa; (19) Miramar; (20) Mission Bay; (21) Mission Hills; (22) Mission Valley ; (24) Mission Viejo; (25) National City; (26) North Park; (27) Oceanside; (28) Otay Mesa; (29) Point Loma Heights; (30) Poway; (31) Ramona; (32) Rancho Bernando; (34) Rancho San Diego; (35) San Clemente; (36) Santee; (37) Spring Valley; (38) Torrey Pines; (39) Mt. Helix; (40) Westfield; (42) Centre City; (43) Mission Gorge. Data from SanGIS, San Diego County OES, and United States Census Bureau.

EXHIBIT 5

SDG&E Corrected Rebuttal Testimony with Public Attachments 26-35, 37-41

PUBLIC VERSION

Exhibit No.: ___________

In The Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) for a Certificate of Public Convenience and Necessity for the South Orange County Reliability Enhancement Project	Application 12-05-020

SAN DIEGO GAS & ELECTRIC COMPANY

REBUTTAL TESTIMONY

OF

JOHN JONTRY, KARL ILIEV, CORY SMITH, AND WILLIE THOMAS

*****redacted, public version*****

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

JUNE 24, 2015

CORRECTED SEPTEMBER 10, 2015

PUBLIC VERSION

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CHAPTER 1. INTRODUCTION AND OVERVIEW (Witness John Jontry)

The City of San Juan Capistrano ("City" or "SJC"), Office of Ratepayer Advocates ("ORA"), and Forest Residents Opposing New Transmission Lines ("Frontlines") served testimony in response to SDG&E's January 15, 2015 Prepared Testimony (as corrected, "SDG&E Opening Testimony") and SDG&E's April 7, 2015 Supplemental Prepared Testimony (as corrected, "SDG&E Supplemental Testimony").

SJC agrees that SDG&E is required to mitigate violations of NERC Reliability Standards in its South Orange County system, agrees that SDG&E's South Orange County transmission system should have a second 230 kV source of power to ensure redundancy, and agrees that Capistrano Substation should be rebuilt to ensure reliable service to SDG&E's customers served by it. SJC contends, however, that the second 230 kV source should be at SDG&E's existing Rancho Mission Viejo ("RMV") Substation (roughly as proposed by DEIR Alternative F) rather than Capistrano Substation, as proposed in SDG&E's Proposed Project.

As explained in Chapter 5, implementation of SJC's modified DEIR Alternative F does not mitigate all NERC Category C violations, their resulting load drop, or other Category C load shedding. In addition, SJC's modified DEIR Alternative F will not provide redundancy equivalent to the Proposed Project—considerably more work would be required to achieve such redundancy. Further, a 230/138/12 kV substation cannot be constructed on the existing RMV Substation site and expansion, if possible at all, would be very difficult as the site is bounded by Santa Margarita Water District water and sewer mains, hillside slopes, and biological open space. Assuming these obstacles could be overcome, site expansion would incur significant cost. If feasible at all, DEIR Alternative F either would not achieve the same reliability benefits as SDG&E's Proposed Project or, if modified to do so, would be more expensive.

ORA's position appears to be: (a) NERC reliability standards do not apply to SDG&E's South Orange County system; (b) nothing should be done to address NERC Category C violations in SDG&E's South Orange County system, or to mitigate the risk of SDG&E's over 300,000 South Orange County customers losing service as a result of load shedding in Category C contingencies, forced outages during maintenance events, or a loss of service from Talega Substation; and (c) SDG&E should remove two small Talega transformers to allow reconfiguration of Talega Substation to a more reliable breaker and a half arrangement.

SDG&E addresses the ORA's mistaken interpretation of SDG&E's legal obligations in Chapter 2. In brief, NERC Reliability Standards are applicable to SDG&E's South Orange County transmission system, both pursuant to Federal Power Act § 215 and through CAISO's Planning Standards. Further, neither Footnote b of NERC TPL-003-0b nor the CAISO Planning Standards permit non-consequential load loss after a single Category B contingency. Moreover, SDG&E not only must comply with NERC Reliability Standards, but considers the Category C load shedding and risk of customer service interruptions caused by a forced outage during maintenance events to be inconsistent with its obligation to provide reliable electric service to the over 300,000 people in South Orange County.

ORA's recommendation that the Proposed Project be rejected and the two Talega transformers simply be removed fails to understand mandatory NERC reliability requirements or adequately protect SDG&E's customers. As explained in Chapter 3, the two small Talega transformers cannot be removed and not replaced without a second source of power to South Orange County because that would violate NERC TPL-002-0b as a transformer outage would leave SDG&E unable to serve peak load in South Orange County. And without being able to remove the two small Talega transformers, Talega Substation's 230 kV bus for Bank 63 cannot be re-arranged. Moreover, reconfiguring Talega Substation does not mitigate all of the other reliability risks for South Orange County.

Frontlines offers a slight variation on DEIR Alternative B-1, contending that reconductoring one 138 kV line in South Orange County, rebuilding Capistrano Substation, and replacing the two aging Talega transformers in the same non-standard configuration is sufficient. Like ORA, Frontlines contends that SDG&E's South Orange County customers are not protected by NERC Reliability Standards; like ORA, Frontlines is mistaken. Like DEIR Alternative B-1, Frontlines' proposal fails to mitigate NERC Category C violations or the risk of Category C load shedding, forced outages during maintenance events, or the loss of all service to South Orange County in the event service from Talega Substation is interrupted. In Chapters 6 and 7, SDG&E discusses the flaws in Frontlines' proposal and cost estimate, and responds to Frontlines' criticisms.

Finally, both ORA and Frontlines propose new alternatives to providing a second source of power to South Orange County at a rebuilt 230/138/12 kV Capistrano Substation. Neither actually recommends providing redundancy to SDG&E's South Orange County customers. Both recommend interconnecting SDG&E's 138 kV system to SCE's 230 kV system. While ORA recommends rebuilding one of SDG&E's existing Pico or Trabuco Substations to 230/138/12 kV, Frontlines proposes constructing a 230/138 kV GIS substation near either Pico or Trabuco, and then connecting the new GIS substation to one of the existing substations. Neither conducted any power flow analyses of their concepts, nor has any design for the rebuilt substations, the new GIS substation, or transmission to connect them. Neither proposal was evaluated for environmental impacts in the Commission's Draft Environmental Impact Report; only a variation of ORA's Trabuco proposal is evaluated in the Commission's Recirculated Draft Environmental Impact Report.

In Chapters 8 and 9, SDG&E explains that these conceptual proposals are infeasible, ineffective, and would cost more than the Proposed Project. As an initial matter, an SCE interconnection would delay fixing South Orange County's reliability issues for years, have negative impacts on both SDG&E's and SCE's systems, and require Reliability Upgrades that will add time and costs to mitigating the risks addressed by SDG&E's Proposed Project. Moreover, each proposal requires additional work to provide the same redundancy benefit as the Proposed Project. Further, neither Pico nor Trabuco substations could accommodate a 230 kV substation without acquiring more property (displacing existing businesses), a cost not required to rebuild Capistrano Substation on existing SDG&E-owned property.

SDG&E's Proposed Project resolves the South Orange County reliability needs for at least the 10-year transmission planning period, and at a lower cost than other alternatives that provide the same reliability benefit.

CHAPTER 2. SDG&E's SOUTH ORANGE COUNTY SYSTEM IS SUBJECT TO THE NERC RELIABILITY STANDARDS (Witness John Jontry)

Section 1. Introduction

ORA and Frontlines, neither of which is subject to Federal Power Act § 215, FERC jurisdiction, or the NERC Reliability Standards, assert that SDG&E is not legally required to comply with the NERC Reliability Standards with respect to SDG&E's South Orange County 138 kV system. From there, ORA, which has no obligation to serve electrical customers in South Orange County and "recommends that the Commission rejects SDG&E's Proposed Project,"[1] appears to recommend that SDG&E should not mitigate the reliability risks to its South Orange County customers described in SDG&E's prepared testimony because ORA believes that SDG&E is not legally required to do so.

As set forth below, ORA and Frontlines are mistaken in asserting that SDG&E's South Orange County 138 kV transmission system is not part of the NERC-defined "Bulk Electric System" and that the NERC Reliability Standards therefore do not apply. SDG&E's South Orange County 138 kV transmission system is part of the NERC-defined "Bulk Electric System." Moreover, even if it were not, which it is, the CAISO Planning Standards and CAISO's Transmission Control Agreement with SDG&E explicitly apply the NERC Reliability Standards to transmission facilities under its operational control, which includes SDG&E's South Orange County 138 kV transmission system.

ORA and Frontlines also are mistaken in believing that "footnote b" to Table 1 of NERC TPL-002-0b and TPL-003-0b, or CAISO Planning Standards, somehow exempt SDG&E from complying with the NERC Reliability Standards with respect to its South Orange County 138 kV transmission system. SDG&E discusses the legal and contractual framework below.

In all events, while ORA recommends minimal reliability of electric service for South Orange County, SDG&E takes its obligation to serve its electric customers seriously. Even if SDG&E were not bound to comply with NERC Reliability Standards, which it is, SDG&E would seek to address the reliability issues addressed by the Proposed Project. Indeed, while SDG&E has identified expected Category C violations that it must mitigate, SDG&E has also identified Category C load shedding and Category D catastrophic risks that it seeks Commission

[1] Mee Testimony at 11.

authorization to mitigate even though the NERC Reliability Standards do not require SDG&E to mitigate such risks. SDG&E seeks to provide reliable electric service to its South Orange County customers and the Proposed Project will allow it to do so.

Regardless of any standard, rule, requirement or regulation, power flowing through any transmission element located in South Orange County, including SDG&E's 138kV transmission network, is governed by physical laws and will respond to system failures accordingly. ORA and Frontlines have not disputed the facts presented by SDG&E that, without the Proposed Project, South Orange County customers will be removed from service to (i) prevent an overload, (ii) in response to an overload or (iii) as a result of the outage of Talega Substation.

Section 2. ORA and Frontlines' Assertion That SDG&E Does Not Need to Comply with NERC Standards in South Orange County Is Mistaken

ORA asserts: "Since the SOC area is a local network area, the NERC reliability standards are not applicable."[2] Frontlines similarly asserts: "It could even be argued that many of NERC's transmission planning standards (including TPL-002-13 0b, TPL-003-0b, and TPL-004-0a) are not applicable to the local network that comprises SDGE's 138 kV SOC system."[3]

For its assertion that "[t]he SOC area is a local network area, and NERC reliability standards do not apply to local network areas," Mr. Mee cites to "footnote b" to Table I found in NERC TPL-003-0b.[4] ORA appears confused. Footnote b is an explanatory note to the directive in Table 1 that a Category B contingency must not result in a loss of demand or curtailed firm transfers.[5] Footnote b only is applicable in assessing compliance of SDG&E's transmission system with NERC Reliability Standard TPL-002-0b, not whether NERC Reliability Standards are applicable to SDG&E's South Orange County 138 kV system. SDG&E explains why Footnote b is inapplicable below.

Frontlines cites to the NERC definition of Bulk Electric System ("BES") to argue that SDG&E's South Orange County 138 kV system is simply excluded from compliance with the NERC Reliability Standards. Ms. Ayer is wrong for two reasons.

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[2] Mee Testimony at 1, 6.
[3] Ayer Testimony at 3.
[4] Mee Testimony at 6 footnote 3.
[5] SDG&E Attachment 2 (TPL-003-0b, Table 1).

A. SDG&E's South Orange County 138 kV System is Part of the NERC-Defined Bulk Electric System

NERC Reliability Standard TPL-002-0b, Requirement R1, provides: "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."[6] TPL-003-0b includes a similar requirement, but "under the contingency conditions as defined in Category C of Table I."[7]

TPL-002-0b applies to "System Performance Following Loss of a Single Bulk Electric System Element (Category B)."[8] TPL-003-0b applies to "System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)."[9]

The definition of Bulk Electric System (BES) is provided in the NERC Glossary of Terms, most recently updated on May 19, 2015.[10] NERC provides a definition of BES, which then is refined by specific inclusions and exclusions. The definition of BES was designed to allow elements to be included or excluded as needed to ensure reliable operation of the bulk electric system. SDG&E's South Orange County 138kV transmission system falls within Inclusion 5 of the BES definition.

NERC provides the following definition of BES in relevant part:

> Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.
>
> Inclusions: …
>
> - **I5 –**Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a

[6] SDG&E Attachment 1 (TPL-002-0b).
[7] SDG&E Attachment 2 (TPL-003-0b, R1).
[8] SDG&E Attachment 1 (TPL-002-0b).
[9] SDG&E Attachment 2 (TPL-003-0b).
[10] http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions: …

- **E4 –** Reactive Power devices installed for the sole benefit of a retail customer(s).[11]

The capacitor bank located at SDG&E's Capistrano Substation and the STATCOM located at Talega Substation are connected at 138 kV. The capacitor bank supplies reactive power and the STATCOM can either supply or absorb reactive power. Both devices are connected to the South Orange County 138 kV network. The 138 kV network is connected to the 230 kV network at Talega Substation. Both devices support voltage on the 138 kV and the 230 kV networks. The 138 kV network is the conduit used to allow these devices to support voltages on the 230 kV network. As such, the devices contribute to power flowing over both the 138 kV and 230 kV networks. Neither device, nor the 138 kV network that connects them, is for "the sole benefit of a retail customer(s)." In other words, SDG&E's South Orange County 138 kV system falls within Inclusion I5 of the BES definition, and is not excluded by Exclusion E4.[12]

Therefore, SDG&E's South Orange County 138 kV system is part of the NERC-defined Bulk Electric System and subject to the NERC Reliability Standards.[13]

B. CAISO Planning Standards Apply the NERC Reliability Standards to SDG&E's South Orange County 138 kV System

As noted above, SDG&E's South Orange County 138 kV system is part of the NERC-defined Bulk Electric System. Even if it were not, however, it would still be subject to the

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[11] SDG&E Attachment 26 (NERC Glossary of Terms, BES Definition). SDG&E also provides the NERC definitions of Transmission and Element in Attachment 26.

[12] FERC and NERC made plain that Exclusions E1 and E3 do not override Inclusion I5. FERC Order Approving Revised Definition, Paragraph 24, Docket No. RD14-2-000, 146 FERC ¶ 61,199 (March 20, 2014) ("NERC modified inclusion I5 by adding the phrase "unless excluded by application of Exclusion E4" at the end to clarify that exclusion E4 "would exclude elements identified for inclusion in inclusion I5."31 NERC states that this is consistent with Order No. 773, where the Commission stated that exclusions E1 and E3 would not override inclusion I5 because exclusions E1 and E3 exclude transmission elements only and not resources.").

[13] Note that power can flow back out of the 138 kV network to the 69 kV network and back onto the 230 kV system at San Luis Rey (and vice versa), thus the 138 kV system in South Orange County has two connections to the bulk electric system. However, this connection is extremely limited in capacity and is not capable of serving any significant amount of load in South Orange County.

NERC Reliability Standards pursuant to the CAISO Planning Standards and SDG&E's Transmission Control Agreement with CAISO.

California Public Utilities Code § 345 provides: "The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of <u>planning</u> and operating reserve <u>criteria</u> <u>no less stringent than</u> those established by the Western Electricity Coordinating Council and <u>the North American Electric Reliability Council</u>." (Emphasis added).

The current (and former) CAISO Planning Standards provide: "1. Applicability of NERC Reliability Standards to Low Voltage Facilities under ISO Operational Control: The <u>ISO will apply NERC Transmission Planning (TPL) standards</u>, the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant, and the approved WECC Regional Criteria <u>to facilities</u> with voltages levels less than 100 kV <u>or otherwise not covered under the NERC Bulk Electric System definition that have been turned over to the ISO operational control</u>."[14]

SDG&E's South Orange County 138 kV system was turned over to CAISO operational control in 1999, and has been under CAISO operational control since then. Therefore, it is subject to the NERC Reliability Standards pursuant to the CAISO Planning Standards.

CAISO's Transmission Control Agreement with SDG&E also mandates that SDG&E transmission facilities under CAISO's operational control are subject to the NERC Reliability Standards. As SDG&E testified: "Under the CAISO's Transmission Control Agreement, Section 6.1.3: 'In operating and maintaining its transmission facilities, each Participating TO … shall act in accordance with Good Utility Practice, applicable law, the CAISO Tariff, CAISO Protocols, the Operating Procedures, and the Applicable Reliability Criteria."[15] The Applicable Reliability Criteria are defined as "The <u>Reliability Standards and reliability criteria established by NERC</u> and WECC and Local Reliability Criteria, as amended from time to time, including any requirements of the NRC.'"[16]

SDG&E's South Orange County 138 kV system was turned over to CAISO operational control in 1999, and has been under CAISO operational control since then. Therefore, it is

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[14] SDG&E Attachment 13 (CAISO Planning Standards, effective April 1, 2015) (emphasis added).
[15] SDG&E Opening Testimony at 23 (quoting the Transmission Control Agreement).
[16] SDG&E Opening Testimony at 23 (quoting the Transmission Control Agreement).

subject to the NERC Reliability Standards pursuant to the CAISO Transmission Control Agreement.

Section 3. ORA's and Frontlines' Contention that TPL-003-0b Footnote b Authorizes Shedding South Orange County Load is Mistaken

ORA contends: "The SOC area is a local network area, and NERC reliability standards do not apply to local network areas.3."[17] ORA's footnote 3 cites "Footnote (b) of the NERC Reliability Standard TPL-003-0."[18] Footnote b reads:

> b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, <u>connected to or supplied by the Faulted element or by the affected area</u>, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.[19]

As noted above, Footnote b is an explanatory note to the TPL-002-0b directive in Table 1 that a Category B contingency must not result in a loss of demand or curtailed firm transfers.[20] Footnote b does not exclude transmission facilities from application of the NERC Reliability Standards, but instead addresses whether a transmission system subject to the Reliability Standards has violated NERC TPL-002-0b. Nowhere does Footnote b state "NERC reliability standards do not apply to local network areas," as contended by ORA.[21]

However, assuming that ORA meant to say that SDG&E's South Orange County 138 kV system will not violate TPL-002-0b or TPL-003-0b because Footnote b authorizes dropping or shedding load during a Category C contingency, ORA remains mistaken.

As SDG&E previously testified[22]:

> In adopting the relevant NERC TPL reliability standards, FERC stated: "Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency."[23] <u>Referring to "footnote b" of Table I</u>, FERC stated it "allows for the

[17] Mee Testimony at 6.
[18] Mee Testimony at 6 n. 3.
[19] SDG&E Attachment 2 (TPL-003-0b, Table I, footnote b; emphasis added). Note that footnote b is the same in TPL-002-0b as Table I is the same in TPL-001, TPL-002, TPL-003 and TPL-004.
[20] SDG&E Attachment 2 (TPL-003-0b, Table 1).
[21] Mee Testimony at 6.
[22] SDG&E Supplemental Testimony at 47-48 (emphasis added; footnotes in original quote).
[23] Attachment 14 (FERC Order 693, Paragraph 1795, 72 Federal Register 16416, 16583 (April 4, 2007)).

> interruption of firm load for consequential load loss,"[24] which FERC defined as "the load that is directly served by the elements that are removed from service as a result of the contingency."[25] FERC further stated: "The Commission agrees that footnote (b) should permit manual adjustments including generation redispatch and transmission reconfiguration, but not load shedding, to return the system to a normal operating state within the time period permitted by the emergency or short term ratings."[26] FERC repeated this admonition in later Order 762: "In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency."[27]

SDG&E identified 18 Category C1, C2 and C3 events that will result in SDG&E's transmission facilities in South Orange County exceeding their Applicable Ratings without use of a Special Protection System ("SPS"). Because SPSs are not available to address this many contingencies, SDG&E would have to shed load pre-contingency to avoid violating Applicable Ratings in the event of the Category C contingency. Although Footnote b addresses Category B contingencies, it is relevant because a Category C3 contingency is a Category B contingency followed by manual adjustments followed by another Category B contingency.[28] Regardless, FERC has stated that Footnote b does not authorize load shedding.

ORA's contention that TPL-003-0b's Footnote b authorizes SDG&E to plan to interrupt electric service to South Orange County customers to keep its facilities within Applicable Ratings during a Category C3 event is a misapplication of the standard and contrary to FERC's interpretation of Footnote b, and thus mistaken.

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[24] Attachment 14 (FERC Order 693, Paragraph 1772 fn. 453, 72 Federal Register at 16580).

[25] Attachment 14 (FERC Order 693, Paragraph 1795 fn. 461, 72 Federal Register at 16583).

[26] Attachment 14 (FERC Order 693, Paragraph 1797, 72 Federal Register at 16583) (emphasis added).

[27] Attachment 15 (FERC Order 762, Paragraph 4, 77 Federal Register 26686, 26687 (May 7, 2012)).

[28] Attachment 14 (FERC Order 693, Paragraph 1797, 72 Federal Register at 16583) ("The Commission disagrees with PG&E's statement that the difference between footnote (b) as part of Category B and Category C.3 is that footnote (b) applies before the second N–1 contingency, whereas Category C.3 applies after the second N–1 contingency. Rather, manual adjustments referred to in both cases apply after the first N–1 contingency. The Commission, therefore, directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.") (emphasis added).

Frontlines makes the same mistaken contention, implying that Footnote b both authorizes non-consequential load loss and permits shedding load as a system adjustments to prepare for the next contingency.[29] FERC rejected both such interpretations of Footnote b, as set forth above. TPL-003-0b, Table 1, Category C.3 allows load shedding only <u>after</u> the second transmission line or transformer is removed from service, not <u>before</u>.

Section 4. ORA's and Frontlines' Assertion that CAISO Planning Standards Allow SDG&E to Drop Up to 250 MW of South Orange County Load Is Mistaken

Frontlines asserts: "The CAISO Planning Standard that was in effect at the time SDGE filed its Initial Testimony contradicts SDGE's contention that it is a violation of NERC standard TPL-002-0b to shed load in the SOC following the first contingency event to prepare for the next contingency. Specifically, Section 6 of the CAISO standard set forth the principals for determining when transmission infrastructure improvements are appropriate to eliminate load drop that is otherwise permitted by WECC and NERC planning standards, and it specifically recognizes that, under certain circumstances, load may be dropped after the first Category B contingency event to prepare for the next worst contingency."[30] Although it cites no authority, ORA asserts: "According to the CAISO planning standard, under category B (N-1) contingencies, interruption of transmission service to the SOC area is allowed but should not be more than 250 megawatt (MW)."[31]

Frontlines and ORA misunderstand the application of the CAISO Planning Standard upon which they rely. Ms. Ayers cites to Planning Standard 6 of the CAISO Planning Standards that was effective from September 18, 2014 to March 30, 2015. The current CAISO Planning Standards became effective on April 1, 2015, and the standard upon which Frontlines relies is now Planning Standard 5.[32]

Frontlines and ORA fail to recognize that CAISO Planning Standard 5 applies only when assessing whether to upgrade a transmission system to correct load dropping "otherwise

[29] Ayer Testimony at 3.
[30] Ayer Testimony at 2.
[31] Mee Testimony at 1.
[32] Compare SDG&E Attachment 4 to SDG&E Attachment 13. Ms. Ayer states that she refers to the now superceded CAISO Planning Standard "for the sake of consistency," Ayer Testimony at 2 fn.3, but it is no longer effective.

permitted" by the NERC Transmission Planning Standards. CAISO Planning Standard 5 provides, in relevant part:

> This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or <u>to eliminate load dropping otherwise permitted</u> by WECC and NERC planning standards through transmission infrastructure improvements. It does not address all circumstances under which load dropping is permitted under NERC and WECC planning standards.
>
> 1. No single contingency (TPL-001-4 P1) should result in loss of more than 250 MW of load. [33]

CAISO explained the purpose of Planning Standard 5, Paragraph 1, as follows:

> This standard is intended to coordinate ISO planning standards with the WECC requirement that all transmission outages with at least 300 MW or more be directly reported to WECC. It is the ISO's intent that no single contingency (TPL-001-4 P1) should trigger loss of 300 MW or more of load. The 250 MW level is chosen in order to allow for differences between the load forecast and actual real time load that can be higher in some instances than the forecast and to also allow time for transmission projects to become operational since some require 5-6 years of planning and permitting with inherent delays. It is also ISO's intent to put a cap on the radial and/or <u>consequential loss of load allowed under NERC standard</u> TPL-001-4 single contingencies (P1).[34]

The Category C overloads identified in SDG&E's Opening Testimony, Chapter 4, Section 6 are not permitted by NERC planning standards, and therefore this Planning Standard is not applicable. Moreover, those overloads resulted in non-consequential load loss, as discussed therein. Planning Standard 5 is not applicable to those Category C NERC violations.

Frontlines quotes a sentence from the superceded CAISO Planning Standards to argue that shedding load after one Category B outage is acceptable to prepare for the next Category B outage: "Standard 6 states (with emphasis added): "No single contingency (TPL002 and ISO standard [G-1] [L-1]) should result in loss of more than 250 MW of load. This includes consequential loss of load as well as *load that may need to be dropped after the first contingency (during the system adjustment period) in order to position the electric system for reliable operation in anticipation of the next worst contingency*."[35]

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[33] SDG&E Attachment 13 (CAISO April 1, 2015 Planning Standards at p. 6, Standard 5; emphasis added).
[34] SDG&E Attachment 13 (CAISO April 1, 2015 Planning Standards at 14).
[35] Ayer Testimony at 2.

Frontlines is mistaken. As an initial matter, the currently effective CAISO Planning Standards do not include this sentence, and thus it is not applicable to SDG&E's South Orange County system. More importantly, as discussed above, then-CAISO Planning Standard 6 remained applicable only "when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements."[36] FERC has made plain that Footnote b does not allow load shedding after a single contingency. CAISO has recognized and accepted the FERC's position.[37] Therefore, then-Standard 6, Paragraph 1, did not apply to shedding load after a single Category B contingency.

Section 5. NERC Transmission Planning Standards are Changing, But Still Do Not Authorize Shedding Load after a Single Contingency as a Long Term Planning Solution

Frontlines also asserts: "Moreover, it appears that TPL-001-0.1 itself will be replaced by TPL-001-4 at the beginning of next year. TPL–001-4 addresses "Transmission System Planning Performance Requirements" for the development of a reliable BES, and it appears to include several noteworthy provisions that address consequential load losses and controlled interruption of electric supply to local network customers connected to the faulted element following a specific single contingency events (P1)."[38]

The change in NERC transmission planning standards does not authorize shedding load after a single contingency as a long term planning solution. Thus, even if the standards had already changed, the outcome of SDG&E's analysis would not.

NERC transmission planning standards TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a (Old TPLs) have been combined into NERC TPL-001-4. The Old TPLs will become inactive on 12/31/2015 and the new TPL-001-4 will become the active transmission planning standard. The change from the Old TPLs to the new TPL-001-4 does not change the need for the Project. Instead, TPL-001-4 changes the terms used and adds some clarifying statements concerning load loss.

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[36] SDG&E Attachment 4 (CAISO Planning Standards, effective 9/18/14-3/30/15, Standard 6).
[37] See SDG&E Attachment 16 (R. Sparks 4/25/2012 email to SDG&E and W. Stephenson).
[38] Ayer Testimony at 6 (footnotes omitted).

Category A, B and C contingencies have been replaced with Category P0-P7 contingencies. Category D (extreme events) contingencies have been replaced by specific steady-state and stability contingencies.

Contingency in Old TPLs	Equivalent TPL-001-4 Contingency
Category A – No Contingency	P0 – No Contingency
Category B – Single Contingency	P1 – Single Contingency
Category C1 – Bus Section	P2.2 – Bus Section
Category C2 – Breaker (failure or internal fault)	P2.3 & P2.4 – Internal Breaker Fault
Category C3 – Category B + System Adj + Category B	P6 – Two overlapping P1 contingencies.

NERC TPL-002-0b footnote b, applicable to Category B contingencies, has been replaced with TPL-001-4 footnote 12, applicable to Category P1 contingencies.

Footnote b states:

> "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers."[39]

This will be replaced by footnote 12 which states;

> "An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction."[40]

Footnote 12 allows SDG&E to use Non-Consequential Load Loss in the Near-Term Transmission Planning Horizon as part of a Corrective Action Plan to remove overloads caused

[39] SDG&E Attachment 1 (NERC TPL-002-0b, Table I, footnote b).
[40] SDG&E Attachment 27 (NERC TPL-001-4, Table 1, footnote 12).

by a P1 (Category B) Contingency. It does not extend to the Long Term Transmission Planning Horizon.

Under the NERC Glossary of Terms, "Near-Term Transmission Planning Horizon" is defined as "The transmission planning period that covers Year One through five."[41] Both the CPUC and CAISO use a 10-year planning horizon for new transmission projects.[42]

Attachment 1 to NERC TPL-001-4 provides the process that a "Transmission Planner" (here, SDG&E) must follow if it wishes to use non-consequential load loss to address the BES performance requirements in its Near-Term Transmission Planning Horizon. In brief, under Attachment 1: "During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process."[43]

Further: "Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either: … The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW."[44]

CAISO has provided the following interpretation and guidance on the application of Footnote 12 in its current Planning Standards:

> Footnote 12 of TPL-001-4 Interpretation and Applicable Timeline7: The shedding of Non-Consequential load following P1, P2-1 and P3 contingencies on the Bulk Electric System of the ISO Controlled Grid <u>is not considered appropriate in meeting the performance requirements</u>. In the near-term planning horizon, the requirements of Footnote 12 may be applied until the long-term mitigation plans are in-service. In the near-term transmission planning horizon, the non-consequential load loss will be limited to 75 MW and has to meet the conditions specified in Attachment 1 of TPL-001-4.[45]

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[41] SDG&E Attachment 26 (NERC Glossary of Terms).

[42] *See, e.g.*, Scoping Memo at 8 ("Is the Project necessary to accommodate the projected load growth in the Project area over the next ten years").

[43] SDG&E Attachment 27 (NERC TPL-001-4, Attachment 1, Paragraph I).

[44] SDG&E Attachment 27 (NERC TPL-001-4, Attachment 1, Paragraph III).

[45] SDG&E Attachment 13 (CAISO April 1, 2015 Planning Standards at p. 17-18).

Under the new TPL-001-4, Category P6 describes acceptable performance following two overlapping single contingencies. The overlapping contingencies starting on page 51 of SDG&E's January 2015 Prepared Testimony each will be a NERC Category P6 contingency; a transmission line or transformer outage (a P1 contingency), followed by a system adjustment, followed by a second transmission line or transformer outage.

Use of Non-Consequential Load Loss is not allowed following a P1 contingency with the limited exception found in Footnote 12;

> An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction."

Non-Consequential load loss is may be used for "Near-Term Transmission Planning Horizon", but Non-Consequential Load Loss is not allowed for the Long Term Planning Horizon. In any case, even as a near-term solution, SDG&E and CAISO would have to get approval to use Non-Consequential Load Loss as described in Attachment 1 of the standard.

SDG&E identified and proposed to CAISO a South Orange County Project that became the Proposed Project starting in 2007. In 2011, CAISO approved the Proposed Project. In 2012, SDG&E filed this Application for a Certificate of Public Convenience and Necessity to construct the Proposed Project. NERC TPL-001-4 was not approved by FERC until October 2013, and its performance requirements do not become effective until January 2016. In the meantime, NERC TPL-002-0b and TPL-003-0b remain active until December 31, 2015.[46] SDG&E proposed the

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[46] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-003-0b&title=System%20Performance%20Following%20Loss%20of%20Two%20or%20More%20Bulk%20Electric%20System%20Elements%20(Category%20C)&jurisdiction=United%20States. SDG&E notes that the version of TPL-003-0b attached as SDG&E Attachment 2 shows an inactive date of 12/31/2014. The link is to an updated version of TPL-003-0b that updated the "inactive date" to 12/31/2015.

Proposed Project, among other reasons, to comply with the then and currently-effective NERC Reliability Standards.

SDG&E has not sought, or obtained, permission to plan for non-consequential load loss under Footnote 12 of the new TPL-001-4. As an initial matter, SDG&E is now eight years into its effort to address South Orange County reliability issues. SDG&E is seeking CPUC approval to address those issues to provide reliable electric service to its customers—it is not seeking CPUC permission to continue to leave its customers exposed to a loss of electric service.

Moreover, CAISO already has indicated that Footnote 12 is not a solution to the South Orange County reliability issues. As set forth in CAISO's Planning Standards: "The shedding of Non-Consequential load following P1, P2-1 and P3 contingencies on the Bulk Electric System of the ISO Controlled Grid is not considered appropriate in meeting the performance requirements. In the near-term planning horizon, the requirements of Footnote 12 may be applied until the long-term mitigation plans are in-service."[47] In other words, Footnote 12 may only excuse non-consequential load shedding until long term mitigation plans are in service. The Proposed Project is SDG&E's long term mitigation plan, and Footnote 12 does not excuse a failure to implement a long term mitigation plan.

Section 6. ORA Ignores the Risk of Category D Events

Noting SDG&E's concerns about low probability, but severe consequence, events at Talega Substation, ORA notes: "These extreme events can be considered as Category D events under NERC standards. While these events are required to be studied, no mitigation action is required."[48] While ORA is correct that SDG&E is not required by the NERC Reliability Standards to mitigate Category D events, ORA misses the point.

SDG&E explained the risks to 230 kV and/or 138 kV service from Talega Substation, the potential duration of such outages, and the severe consequences of such outages on South Orange County. Dr. Sullivan estimated the total economic cost of a three week outage at $2.38 to $4.77 billion in direct and indirect costs.

NERC requires utilities to study Category D events to identify those with severe consequences and consider mitigation. SDG&E studied this risk and presented the risk to the CAISO, which agreed that the consequences are severe enough that it should be addressed,

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[47] SDG&E Attachment 13 (CAISO April 1, 2015 Planning Standards at p. 17-18).
[48] Mee Testimony at 6.

particularly as the Proposed Project solves many other reliability risks to SDG&E's South Orange County customers.

The need for a second source in South Orange County is recognized in the DEIR. Alternatives C, D, E, F, G and H all include a second source of supply.

Section 7. TPL-001-0.1 Is Currently Effective

Frontlines correctly points out that NERC TPL-001-1, quoted by SDG&E in its original Opening Testimony at 16-18, was rejected by FERC Order 762. As stated in FERC Order 762: "In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency."[49] SDG&E has corrected that quotation in its current corrected Opening Testimony.

The currently effective NERC reliability standard for Category A requirements is NERC TPL-001-0.1, which contains the "footnote b" that FERC previously directed NERC to revise to prevent entities from planning for the loss of non-consequential firm load in the event of a single contingency. The language that FERC directed NERC to revise states: "b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." NERC TPL-001-0.1, Table 1, footnote b.

As discussed in detail in SDG&E's Supplemental Testimony at 47-49, FERC stated: "The Commission agrees that footnote (b) should permit manual adjustments including generation redispatch and transmission reconfiguration, <u>but not load shedding</u>, to return the system to a normal operating state within the time period permitted by the emergency or short term ratings."[50]

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[49] SDG&E Attachment 15 (FERC Order 762, Paragraph 4, 77 Federal Register 26686, 26687 (May 7, 2012)).

[50] Attachment 14 (FERC Order 693, Paragraph 1797, 72 Federal Register at 16583) (emphasis added).

CHAPTER 3. ORA'S TESTIMONY ABOUT TALEGA SUBSTATION IS MISTAKEN

Section 1. Introduction (Witness Cory Smith)

In its opening testimony, SDG&E testified that there are reliability issues at Talega Substation, including but not limited to a non-standard configuration of the 230 kV bus that cannot be remedied within the existing substation property. SDG&E noted that, because Talega Substation is the sole source of power to SDG&E's South Orange County system, and because of the non-standard configuration, "a single forced outage (such as Category B events) that occurs during a planned maintenance outage at Talega will drop service to all or some SDG&E customers in South Orange County."[51] With respect to rebuilding Talega Substation to create space to remedy the non-standard configuration, SDG&E testified: "Because Talega Substation currently is the source of all power to South Orange County, Category D events at Talega Substation (loss of the 230 kV service or the loss of 138 kV service) would drop service to all SDG&E customers in South Orange County—roughly around 300,000 people. Therefore, SDG&E does not consider rebuilding Talega Substation to be a prudent or cost-effective solution to the South Orange County reliability issues."[52]

SDG&E testified that the Proposed Project, by installing two 230/138 kV transformers at the rebuilt Capistrano Substation, would allow SDG&E to address the non-standard configuration at Talega Substation without placing South Orange County load at risk:

> Second, by removing these two transformers from Talega Substation, there would be room within the existing Talega Substation to reconfigure Bank 63 to be fed from a more reliable breaker and a half configuration (where the transformer may stay in-service during a bus outage and vice versa). Because there would be a second source at San Juan Capistrano Substation, the work to perform this reconfiguration would not place SDG&E's South Orange County customers at risk from a single forced outage during the construction work. Once performed, maintenance work at Talega Substation could be performed without placing SDG&E's customers at risk from a single forced outage during a planned maintenance outage.[53]

ORA appears to believe that the Proposed Project is meant solely to allow SDG&E to remedy the non-standard configuration at Talega Substation. It is not. From this erroneous assumption, ORA contends that the non-standard configuration can be remedied simply by removing the two small and aging transformers at Talega (Banks 60 and 62), and moving Bank

[51] SDG&E Opening Testimony at 90.
[52] SDG&E Opening Testimony at 94.
[53] SDG&E Opening Testimony at 91.

63 to a breaker and a half arrangement. This also is wrong, as it would violate NERC TPL-002-0b and expose SDG&E's South Orange County customers to service interruption in the event of a single transformer outage. SDG&E addresses each issue below.

Section 2. Reconfiguring the Talega 230 kV Bus Does Not Resolve All Reliability Issues in South Orange County (Witness Cory Smith)

Focusing only on SDG&E's concerns about Talega Substation's bus configuration, ORA asserts: "Because the proposed project does not address the actual engineering problems at the Talega Substation, it would result in overbuilding unneeded transmission."[54]

ORA's analysis and conclusion are mistaken. First, as discussed in Chapter 2, SDG&E must comply with NERC Reliability Standards. Fixing Talega Substation's configuration problem would only address certain maintenance outage issues, and would not mitigate the expected Category C violations in SDG&E's South Orange County system. Second, SDG&E considers the nature and number of Category C, Category D and maintenance contingencies that would leave some or all of its South Orange County customers without electricity to be unacceptable. Fixing Talega Substation's configuration problem would only address certain maintenance outages issues, and leave SDG&E's customers exposed to the remaining reliability risks. To address remaining risks, SDG&E needs to inject 230 kV power in the South Orange County load center or upgrade numerous 138 kV transmission lines.

ORA seems not to understand the purpose of the Proposed Project. ORA seems to believe that the Proposed Project is being constructed simply to allow SDG&E to reconfigure the Talega Substation 230 kV bus. This is simply wrong and ignores SDG&E's testimony about how the Proposed Project will mitigate Category C violations, Category C load shedding, forced outages during maintenance events at other South Orange County substations, and the potential Category D loss of 230 kV or 138 kV service from Talega Substation. Reconfiguring the Talega Substation bus will not mitigate these reliability risks.

Section 3. Without a Second 230 kV Source in South Orange County, the Two Small Transformers at Talega Substation Cannot Be Removed (Witness Cory Smith)

ORA notes that SDG&E's proposed solution to the non-standard bus configuration at Talega Substation is to remove the two small transformers, which then creates the space

[54] Mee Testimony at 9.

necessary to reconfigure the transformer 230 kV position into a more reliable breaker and a half configuration (the "Reconfiguration Work").[55] ORA, however, ignores the fact that SDG&E proposes this solution only once the Proposed Project is implemented.[56]

Instead, ORA asserts that, even without a second source in South Orange County, the two small transformers simply can be removed and not replaced, thus creating space to reconfigure the Talega 230 kV bus. ORA testifies:

> Today, the coincident peak load in the SOC area is not more than 443.3 MW, but the total power supply capacity of the four transformer banks at Talega Substation is around 1,100 MVA, which could provide as much as 1,100 MW of real power. Talega Substation has more than double the power supply capacity to serve the SOC area. Even if two of the old banks (Bank #60 with 162 MVA and Bank #62 with 150 MVA) at the Talega Substation are removed, the substation would still have a power supply capacity of 784 MVA (Bank #61 with 392 MVA and Bank #63 with 392 MVA) to serve the SOC area load.[57]

ORA apparently does not understand the NERC transmission planning requirements, enforceable by FERC under the Federal Power Act § 215. ORA asserts the power supply capacity of Talega Substation to be 784 MVA based on the size of the two large transformer banks, Bank #61 and Bank #63, assuming the two small banks, Bank #60 and Bank #62, are retired and removed from the substation. This is incorrect. Banks #61 and #63 each have a continuous rating of 392 MVA and it is correct that the sum of the two banks is 784 MVA, but power supply capacity must take into account the loss of one of the banks to comply with NERC TPL-002-0b. Therefore, only 392 MVA may be considered to be continuously supplied by Talega Substation, and 392 MVA is less than required to serve South Orange County's peak load. Relying on only two transformers to supply South Orange County, as suggested by ORA, is an unacceptable reliability risk that would exacerbate the South Orange County supply problem (a single source of supply at Talega Substation) and violate TPL-002-0b.

By contrast, the Proposed Project adds two 230/138 kV transformers at Capistrano Substation. This addition constitutes a second source of supply at Capistrano, with the other source of supply at Talega Substation. With the Project in place, the two 230/138 kV transformers at Capistrano and the two 230/138 kV transformers at Talega will supply South

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[55] Mee Testimony at 6-7.
[56] SDG&E Opening Testimony at 91.
[57] Mee Testimony at 8-9 (footnote omitted).

Orange County when the two smaller transformer banks at Talega are removed. This will leave four 230/138kV transformers serving South Orange County. To change the interconnection arrangement of one of the remaining Talega 230/138 kV transformers, the transformer will be de-energized during construction. This will leave three transformers to supply South Orange County (two 230/138 transformers at Capistrano and one at Talega), and thus ensure that South Orange County would not lose electric service in the event of a forced outage of a transformer during such construction.

Thus, with the Proposed Project, removing the two small transformers at Talega Substation will not violate TPL-002-0b nor will de-energizing Bank 63 at Talega Substation to allow its reconfiguration to a breaker and a half arrangement.

Disregarding the risk of removing the two small 230/138 kV transformers at Talega Substation without another 230 kV source in South Orange County (which would violate NERC TPL-002-0b and expose <u>some</u> of SDG&E's South Orange County customers to the risk of losing service if either transformer failed), ORA proposes further increasing the risk to SDG&E's South Orange County customers by leaving South Orange County dependent on a single transformer during construction work (which would expose <u>all</u> of SDG&E's South Orange County customers to the risk of losing service if the only connected transformer failed). ORA testifies:

> ORA observes that <u>without SDG&E's Proposed Project</u>, it is possible for SDG&E to fix the asserted engineering problems at Talega Substation. SDG&E can <u>remove transformer banks #60 and #62</u>, and then reconfigure transformer bank #63 so that it can be fed from a more reliable breaker-and-a-half configuration. ORA understands that during this reconfiguration exercise, <u>there will be only one 230/138 kV transformer bank</u>, with a capacity of 394 megavolt-ampere (MVA), supplying power to the SOC area, which is less than the peak demand of 443.3 MW. However, SDG&E could <u>perform this reconfiguration exercise during off-peak hours</u>. <u>ORA is aware that during maintenance, the power supply of the energized transformer could also be interrupted</u>; however, with careful safety procedure in place the risk of interrupting power supply can be minimized. After the reconfiguration is completed, power supply to the SOC area would be improved.[58]

ORA's proposal violates NERC TPL-002-0b and imprudently places all of SDG&E's approximately 300,000 customers at risk of a single transformer outage during months of construction work. Without a second source of power to SDG&E's South Orange County system, the two small and aging transformers at Talega Substation cannot be removed.

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[58] Mee Testimony at 7 (emphasis added).

Section 4. Without a Second Source in South Orange County, Talega Substation Cannot be Reconfigured On Its Existing Site (Witness Karl Iliev)

As set forth above, the two small and aging Talega transformers cannot be removed and not replaced without a second source of power to SDG&E's South Orange County system. As SDG&E testified, the reliability issues at Talega Substation cannot be addressed within its existing property unless SDG&E is able to remove those two transformers to open up more space within the existing substation.

SDG&E reiterates that space limitations at the current Talega Substation site prevent its reconfiguration unless and until the two transformers can be removed safely and in compliance with TPL-002-0b. At Talega Substation, there is currently only one vacant position in the 230 kV switchyard, and two vacant positions in the 138 kV switchyard. To improve the site reliability, Banks 60 and 63 would need to be moved from their current single breaker single bus configuration to a proper breaker and a half bay position. Since there are insufficient unused breaker and a half positions in the 230 kV switchyard to accommodate this relocation, another breaker and a half bay would need to be added. This cannot be done as the two Synchronous Condensers on the site prevent expanding the 230kV switchyard south to add this bay.

Furthermore, Bank 50, Bank 60, and Bank 63 would also need to be moved from their 138 kV single breaker single bus configuration to 138 kV breaker and a half positions. There are insufficient 138 kV breaker and a half unused positions available to accommodate this relocation either. Another 138 kV breaker and a half bay would need to be added to the 138 kV switchyard in order to accommodate this reconfiguration. Additional bays cannot be added to the 138 kV switchyard as both the existing Bank 50 infrastructure and the STATCOM block this expansion to the north.

To properly reconfigure Talega Substation, SDG&E would need to acquire property in environmentally sensitive areas to the north and south of the substation, fill the sloped hillside, demolish and rebuild the existing STATCOM, Synchronous Condensers, and Bank 50 infrastructure, and expand both 138 kV and 230 kV switchyards.

Even if the above noted infrastructure changes were feasible, more infrastructure changes would be necessary. Transformer connections to the switchyard should not be located in the same bay positions because this causes a single element failure risk (which is the risk of the bus tie breaker failing). An outage to the Bus Tie breaker would cause an outage to both transformers in that bay. To fix this problem, SDG&E would need to relocate the transformer connections in the switchyards. Underground cables would have to be used extensively to relocate connection points for both transformers and transmission lines to create a more reliable switchyard configuration.

Even after all of the above work, Talega Substation would remain the sole source of power to SDG&E's South Orange County system, and thus Category D events at Talega would leave approximately 300,000 people in South Orange County without electricity, potentially for weeks.[59] Reconfiguring Talega Substation also would not mitigate the Category C violations, Category C load shedding, and forced outages during maintenance events at other South Orange County substations.[60] Nor would reconfiguring Talega Substation address the reliability concerns at the aging Capistrano Substation.

After updating estimated costs to current projected values, the costs for implementing a Talega rebuild alternative that would provide similar reliability benefits range from $669 million to $818 million.[61] This estimate not only includes the estimated cost to rebuild the 230 kV and 138 kV busses at an expanded Talega Substation, but also include the necessary rebuilding of the existing Capistrano substation as a 138/12 kV substation, adding a future voltage control device at Capistrano or Talega when the existing Talega STATCOM reaches the end of its useful life, and bringing a second source into the area from a 138kV feed to Southern Orange Country from the San Luis Rey Substation. Since the rebuilding of Talega Substation only addresses reliability problems at Talega Substation and does not provide redundancy for South Orange County, the cost to create a second source should be included into the Talega Rebuild option. Otherwise, the Talega rebuild alternative does not provide the same reliability benefits and cannot be compared to the Proposed Project. The estimated cost, however, does not include any necessary upgrades of SDG&E's South Orange County 138 kV system or costs to acquire property (if possible) adjacent to Talega Substation.

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[59] SDG&E Supplemental Testimony, Chapter 2.

[60] SDG&E Opening Testimony at 44-72.

[61] SDG&E previously testified: "SDG&E estimated that it would cost $782 million and require incremental construction of system improvements and ultimately result in SDG&E having to include the costs associated with the No Project Alternative (regarding the rebuilding of Capistrano Substation and upgrading the 138 kV system) in with this rebuild, significantly increasing the cost of this alternative in excess of the Proposed Project cost." SDG&E Opening Testimony at 94.

The Proposed Project addresses the reliability concerns at Talega Substation in a far superior way. It essentially proposes relocating elements (transformers and lines) from the existing 230 kV and 138 kV switchyards at Talega, and moves them to Capistrano Substation. With the reduced number of elements, Talega Substation can be reconfigured to provide proper spacing and electrical connections, optimizing its reliability and operating flexibility, while creating at Capistrano Substation the 230 kV redundancies necessary to reliably feed SDG&E's South Orange County system.

Section 5. ORA Assertion that the Proposed Project Will Not Address the Configuration Concern at Talega Substation Is Misplaced (Witness Cory Smith)

ORA asserts that "SDG&E's Proposed Project will not address the engineering problems at Talega Substation."[62] ORA states: "SDG&E's Proposed Project is a workaround approach that does not fix the root problems at Talega Substation. SDG&E asserts that after the construction of the Proposed Project, SDG&E will be able to fix the problems at Talega Substation. In other words, SDG&E's Proposed Project does not ultimately solve the problems at Talega Substation, but is only one of the steps toward fixing the Talega Substation problems."[63]

ORA's criticism is misplaced.

- First, SDG&E's approach to reconfiguring Talega Substation depends upon the Commission's decision regarding the Proposed Project. If the Proposed Project is constructed, the Talega Substation solution is relatively straightforward—implementation of the Reconfiguration Work, which then can be performed within the existing footprint without exposing South Orange County customers to the risk of a single outage causing service interruption.
- Second, as discussed above, the Talega Substation configuration is not the only reliability issue in South Orange County. The Proposed Project was never meant solely to allow SDG&E to perform the Reconfiguration Work.

Section 6. ORA's Criticism of the Proposed Project Cost is Misplaced (Witness Cory Smith)

ORA testifies: "SDG&E estimates that its Proposed Project will cost approximately $420 million, in addition to ongoing annual operation and maintenance costs at ratepayers' expense.

[62] Mee Testimony at 8.
[63] Mee Testimony at 8.

This is an unnecessary expense and unnecessary workaround toward fixing the actual problems at Talega Substation."[64] ORA then turns to its claim that Talega Substation's configuration problems can be solved by the Reconfiguration Work without the Proposed Project. In doing so, ORA implies that the Reconfiguration Work is all that is needed to address reliability concerns in South Orange County.

As discussed above, SDG&E's Proposed Project is not solely directed at Talega Substation's configuration issue. Moreover, performing the Reconfiguration Work alone, without a second source of power to SDG&E's South Orange County system, would violate NERC TPL-002-0b—and would not solve any of the other reliability concerns addressed by the Proposed Project. Because all of the Proposed Project work is necessary to address those reliability concerns, ORA has not shown that the work or its costs are "unnecessary" for SDG&E to provide reliable electric service to the approximately 300,000 people in South Orange County who depend on it.

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[64] Mee Testimony at 8 (footnotes omitted). SDG&E notes that ORA asserts that the Proposed Project will cost approximately $420 million based on SDG&E's testimony that it will cost "$380.9 Million +/- 10%." Mee Testimony at 8 fn.9. . SDG&E since has corrected that testimony to "$383.6 million +/- 10%." SDG&E Supplemental Testimony at 126.

CHAPTER 4. ORA'S AND FRONTLINES' CRITICISM OF THE PROPOSED PROJECT'S SECOND 230 KV SOURCE FOR SOUTH ORANGE COUNTY IS MISPLACED

Section 1. The Proposed Project Creates Redundancy (Witness Cory Smith)

ORA and Frontlines claim that adding a second 230 kV source at Capistrano Substation, as SDG&E's Proposed Project would do, does not provide redundancy for SDG&E's South Orange County transmission system.[65] This is incorrect.

Currently, three 230kV transmission lines terminate at the Talega Substation 230 kV bus, where power is transformed to 138 kV, and serves SDG&E's South Orange County customers through a network of 138 kV transmission lines. Two 230 kV transmission lines connect Talega Substation to San Onofre Substation and one 230 kV transmission line connects Talega Substation to Escondido Substation. The common point of failure is the termination of all three transmission lines at Talega Substation, not the proximity of the 230 kV transmission lines near Talega Substation.

SDG&E's Proposed Project would add a second 230 kV source at Capistrano Substation approximately 7.5 miles from Talega Substation. Two 230 kV transmission lines will connect the Capistrano 230 kV substation to the 230 kV network. One "2-terminal" 230 kV transmission line will connect Capistrano to San Onofre, and the other "3-terminal" 230 kV transmission line will connect Capistrano to both Talega and Escondido. As for Talega Substation, one 2-terminal 230 kV transmission line will connect Talega Substation to San Onofre and, as described for Capistrano Substation, one 3-terminal 230 kV transmission line will connect Talega to both Capistrano and Escondido.[66] In Figure 4-1 below, the thick green lines with arrows represent the 230kV transmission lines and show how South Orange County will be supplied once the Project has been completed.

Most transmission lines have 2-terminals or said another way, connect two substations. When a 2-terminal transmission line experiences a fault, it will be removed from service by the protection system and no longer connect the two substations. This is the case for the two 2-terminal 230 kV transmission lines shown in Figure 4-1: San Onofre to Capistrano Substation and San Onofre to Talega Substation. A three terminal transmission line connects three

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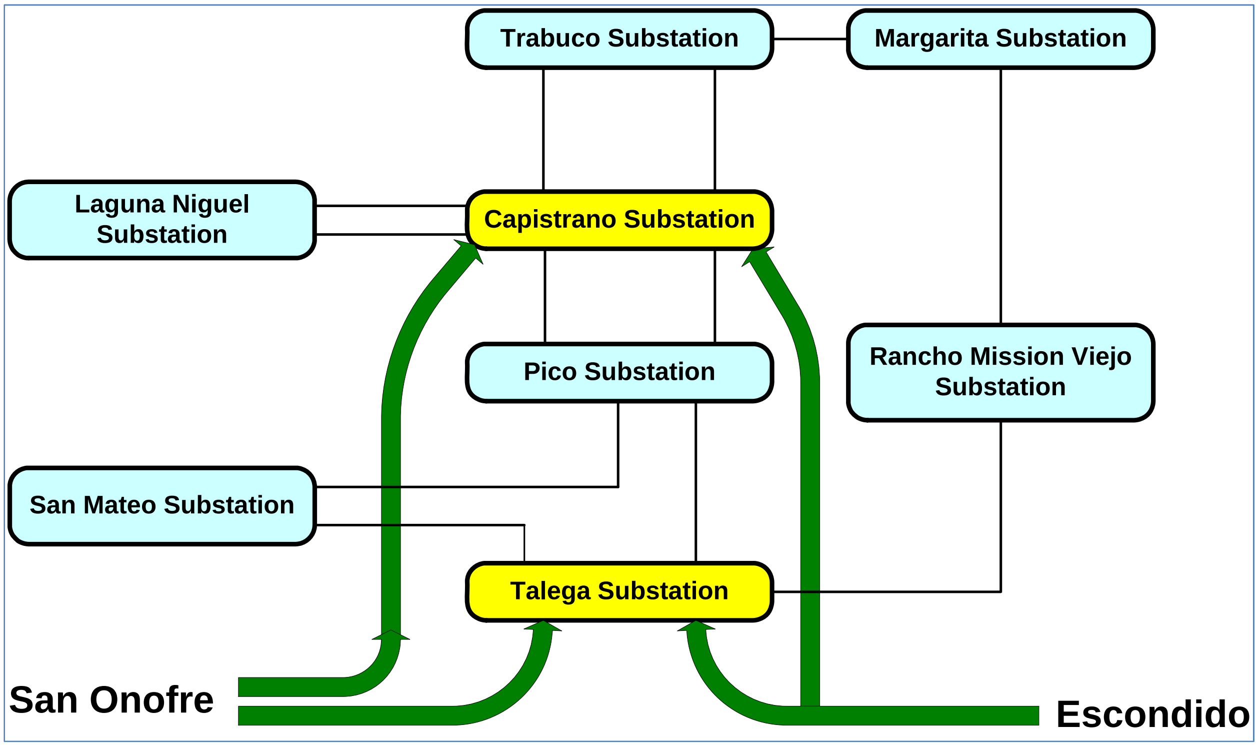
[65] Mee Testimony at 9-10; Ayer Testimony at 20.

[66] SDG&E notes that ORA's depictions of SDG&E's transmission system in South Orange County are inaccurate, as shown in Attachment 40.

substations. When a three terminal transmission line experiences a fault, it will be removed from service by the protection system and no longer connect the three substations. This is the case for the 3-terminal line shown in Figure 4-1: Escondido to Capistrano Substation and Talega Substation.

Figure 4-1



As shown in Figure 4-1, the Proposed Project creates redundancy for SDG&E's South Orange County 138 kV network. The possible outages to consider in determining if redundancy is present are:

1. **Loss of Talega Substation**. This will leave Capistrano Substation supplied with 230 kV power from San Onofre Substation. Capistrano Substation will supply South Orange County. Redundancy is present. Within hours, the 3-terminal transmission line connecting Escondido to Talega and Capistrano substations will be disconnected from Talega Substation. The transmission line will connect Escondido directly to Capistrano Substation. Capistrano Substation will then be supplied with 230 kV power from both San Onofre and Escondido substations. Redundancy is present and improved.

2. **Loss of Capistrano Substation.** This will leave Talega Substation supplied with 230 kV power from San Onofre Substation. Talega Substation will supply South Orange County. Redundancy is present. Within hours, the 3-terminal

transmission line connecting Escondido to Talega and Capistrano substations will be disconnected from Capistrano Substation. The transmission line will connect Escondido directly to Talega Substation. Talega Substation will then be supplied with 230 kV power from both San Onofre and Escondido substations. Redundancy is present and improved.

3. **Loss of both of the transmission lines from San Onofre.** This will leave both Capistrano and Talega substations supplied from Escondido Substation. Talega and Capistrano substations will supply South Orange County. Redundancy is present.

4. **Loss of the transmission line from San Onofre to Capistrano and the transmission line from Escondido.** This will leave Talega Substation supplied from San Onofre. Talega Substation will supply South Orange County. Redundancy is present.

5. **Loss of the transmission line from Escondido.** This will leave Capistrano and Talega substations supplied from San Onofre. Capistrano and Talega substations will supply South Orange County. Redundancy is present.

In sum, the Proposed Project creates redundancy for the benefit of SDG&E's South Orange County customers.

Section 2. ORA's and Frontlines' Concerns are Misplaced (Witness Willie Thomas)

ORA and Frontlines ignore this increased redundancy to focus on the potential loss of all three 230 kV transmission lines at the same time. ORA asserts that, due to the close proximity of the 230 kV transmission lines around Talega Substation, a fire, earthquake, explosion or vandalism near Talega Substation could remove all three transmission lines from service.[67] Frontlines focuses on the risk to all three lines from seismic or wildfire events.[68]

While it is true that loss of all three 230 kV transmission lines at the same time will interrupt service to South Orange County, ORA and Frontlines are missing key points: (a) wildfire is not a significant risk to overhead 230 kV lines on steel structures; (b) seismic events are not a significant risk to overhead 230 kV lines on steel structures; and (c) transmission lines

[67] Mee Testimony at 10 ("Thus, if disaster such as fire, explosion, earthquake, vandalism, or terrorism occurs at the existing transmission lines, near the Talega Substation, the existing transmission lines as well as the new transmission lines connected to the upgraded Capistrano Substation could lose power at the same time. This would result in both the Talega Substation and the Capistrano Substation losing power at the same time and the whole SOC area load being disrupted.")

[68] Ayer Testimony at 20 ("Thus it seems that the 230 kV lines proposed to supply the new Capistrano substation in the SOCRE Project are just as susceptible to wildfire and earthquake failures as the 230 kV lines that currently supply Talega.").

can be repaired and returned to service in a reasonable amount of time (usually hours), while substation damages may take days or weeks. Therefore, a second 230kV substation is needed as proposed by the Project.

A. Wildfire Normally Does Not Damage 230 kV Lines on Steel Structures.

ORA and Frontlines suggest that a wildfire near Talega Substation could remove all three transmission lines serving both Talega Substation and Capistrano Substation from service. The transmission lines enter Talega Substation on opposite sides of the substation and the transmission corridors extend in opposite directions. In order for a wildfire to reach all three transmission lines, as suggested by ORA and Frontlines, the fire would have to overwhelm Talega Substation. If this were to happen, the substation, not the transmission lines around it, would be subject to a long term outage.

SDG&E has never experienced the loss of a transmission steel pole or lattice tower due to any kind of fire. The 230 kV lines from San Onofre to Talega Substation share steel lattice tower structures while the 230 kV line from Escondido to Talega Substation is on steel poles and lattice towers. The Proposed Project's 230 kV lines would be on self-supporting steel poles. The risk of physical damage to the steel structures, wires or insulators requiring replacement is very low. SDG&E has not needed to replace equipment as a result of any recent fires. For example, in the May 2014 fires, SDG&E had flames/fire in and around 230kV lines (TL23051/11), and it withstood the fires without damage.

As SDG&E testified, heavy smoke can cause arcing, which will take transmission lines out of service temporarily.[69] During the May 2014 fires, SDG&E did have a flash-over, which caused a line to trip out of service, but it was placed back into service in less than a day after it was deemed safe to access by Fire Coordinators and found to be good working condition by SDG&E maintenance crews. In some cases, insulators may require washing to remove contamination, but this can be accomplished within a few hours once it is deemed safe to access by Fire Coordinators. Similarly, SDG&E may be requested by fire-fighting crews to de-energize a line for safety reasons when they respond to an actual fire near the lines,[70] but the line can be quickly re-energized when the need has passed.

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[69] SDG&E Supplemental Testimony at 11.
[70] SDG&E Supplemental Testimony at 11-12.

By contrast, if a substation is consumed or damaged by fire, it will take days or weeks to repair. Under ORA's and Frontlines' scenario, of a wildfire so large that it forced out of service the 230 kV transmission lines on both sides of Talega Substation, then Talega Substation itself likely would suffer significant damage. After a severe fire that has forced a line out of service and a maintenance team has performed an inspection, typically within hours, crews would restore and re-energize the 230 kV transmission lines and, if the Proposed Project has been constructed, South Orange County would be supplied from Capistrano Substation. Within days or weeks, repairs would be concluded at Talega Substation and Talega would be restored to service. Without the Proposed Project, however, South Orange County would be without electric service until Talega Substation was restored to service.

B. Earthquakes Normally Do Not Damage Transmission Structures.

Transmission structures are designed to withstand forces greater than earthquake shaking, i.e., seismic events are not the controlling load case for structure design. The wires and insulators dampen motion of the transmission structure during earthquake shaking. Although insulators may fail on occasion, crews can replace insulators in a few hours. SDG&E avoids installing transmission structures on seismic faults, and the structures supporting 230 kV transmission lines from San Onofre and Escondido substations to Talega Substation are not installed on known seismic faults.

With respect to the Proposed Project, as SDG&E testified: "Seismic loading for transmission lines will be considered and is above and beyond what is required by GO 95, or by the National Electric Safety Code (NESC), or by the American Society of Civil Engineers (ASCE). SDG&E will avoid locations on seismic faults and will design for seismic induced soil liquefaction if foundations are located in soils prone to liquefaction. Currently GO 95 and NESC focuses on loading requirements based on effects of wind, ice, gravity, and temperature induced loading. The American Society of Civil Engineers (ASCE) No. 74 Manual "Guidelines for Electrical Transmission Line Loading" similarly has no provisions for seismic loading, but do comment in Appendix F that transmission structures are not typically designed for seismic loading, and wind/ice combinations and broken wire generally exceed design earthquake loads."[71]

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[71] SDG&E Supplemental Testimony at 137.

Neither ORA nor Frontlines responded to SDG&E's testimony above, or provided any data to support their claim that seismic events would force all of the relevant 230 kV lines out of service, even for a short duration. Moreover, the transmission lines enter Talega Substation on opposite sides of the substation and the transmission corridors extend in opposite directions. In order for an earthquake to damage all three transmission lines, as suggested by ORA and

Frontlines, it would most likely damage Talega Substation as well. If this were to happen, the substation, not the transmission lines around it, would be the long term outage. Within hours, crews would restore and re-energize the transmission lines and, if the Proposed Project has been constructed, South Orange County would be supplied from Capistrano Substation. Within days or weeks, repairs would be concluded at Talega Substation and Talega would be restored to service. Without the Proposed Project, however, South Orange County would be without electric service until Talega Substation were restored to service.

CONFIDENTIAL SECTION BELOW

[redacted]

[redacted]

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END OF CONFIDENTIAL SECTION

[redacted]

CHAPTER 5. THE CITY OF SAN JUAN CAPISTRANO'S MODIFIED DEIR ALTERNATIVE F IS NEITHER FEASIBLE NOR COST-EFFECTIVE

Section 1. Introduction (Witness John Jontry)

The City of San Juan Capistrano ("City" or "SJC"), through its witness Dr. Shirmohammadi, testifies that DEIR Alternative F would be more suitable than the Proposed Project.[75] The City describes Alternative F as follows:

> Under this alternative, the SDG&E 138 kV Rancho Mission Viejo Substation would be upgraded to a 230 kV substation and a new double-circuit 230 kV line from Talega Substation to Rancho Mission Viejo Substation would be constructed along the Eastern Talega Transmission Line Route replacing the existing 138 kV line between the two substations. One circuit of this double circuit line would operate at 138 kV and the other at 230 kV. The 138 kV line termination at Talega Substation could be allowed to bypass Talega Substation and feed the 138 kV loop in case that substation is completely incapacitated as hypothesized by SDG&E.[76]

The City agrees that "SDG&E can and should address these Capistrano Substation problems by rebuilding that substation independent of dealing with NERC reliability criteria violations in the SDG&E's Southern Orange County transmission loop."[77]

The DEIR describes Alternative F as follows:

> Under this alternative, the applicant's 138/12-kV Rancho Mission Viejo Substation (Figure 3-4) would be expanded to a 230/138/12-kV substation with specifications comparable to those of the proposed project's new San Juan Capistrano Substation. Capistrano Substation would not be expanded, but equipment at Capistrano Substation found to be inadequate would be replaced.
>
> To bring a new 230-kV source into the South Orange County service area, a new, double-circuit 230-kV Talega–Rancho Mission Viejo line would be constructed along the Eastern Talega 230-kV Transmission Line Route described in the PEA. This route follows the existing Talega–Rancho Mission Viejo 138-kV Line (TL13831). Although two new 230-kV circuits would be installed, one of the circuits would be energized at 138 kV and operated as TL13831. The existing TL13831 structures and conductor would be removed, and the existing ROW (100-feet wide) would be increased by approximately 20 feet.

DEIR at 3-17. The DEIR further explained:

> Under Alternative F, a new double-circuit 230-kV line that follows the route of TL13831 would be constructed that is approximately 1 mile shorter than the 230-kV route for the proposed route. New ROW would be required, however, to widen the existing 138-kV

[75] Shirmohammadi Testimony at 10.
[76] Shirmohammadi Testimony at 10.
[77] Shirmohammadi Testimony at 7.

> ROW between Talega and Rancho Mission Viejo substations (approximately 6.5-miles long and 20-feet wide), which would result in more land disturbance than the propose route within existing ROW. It is assumed that additional land disturbance would be required for the installation of new 138-kV facilities and 138-kV reconductoring to make use of the additional power that would be available from an upgraded 230/138/12-kV Rancho Mission Viejo Substation. In addition, the expansion of Rancho Mission Viejo Substation would require a similar amount of land disturbance compared to the construction of San Juan Capistrano Substation.

DEIR at 5-16. The DEIR found that Alternative F would have greater environmental impacts in many resource areas than the Proposed Project.[78]

As noted above, the City agrees that Capistrano Substation should be rebuilt to "address the problems identified by SDG&E … i.e., the non-standard breaker configuration of the Capistrano Substation and the old and non-earthquake resistant equipment in that substation."[79] The City agrees that the 138/12 kV substation should be rebuilt separate from the operating existing substation as "it will allow the 138 /12 kV rebuild to go forward more smoothly and expeditiously and without major disruptions to the operation of the existing substation."[80]

Section 2. Alternative F Does Not Add a 230 kV Source at the Load Center for South Orange County (Witness John Jontry)

As noted by the California ISO in testimony of Robert Sparks, a second 230/138 kV source at Rancho Mission Viejo Substation (DEIR Alternative F) would be connected within one bus of the existing source at Talega Substation. This would leave the second source at Rancho Mission Viejo ("RMV") Substation vulnerable to cascading outages during contingencies at Talega Substation, and defeat the purpose of adding a second 230 kV bulk power connection.[81]

In addition to being electrically in close proximity to Talega Substation, a second connection to the bulk power system at RMV Substation would be on the wrong side of the South Orange County load center. As can be seen from Fig. 5-1 below, the electrical load center for South Orange County is west of RMV Substation, within a mile of Capistrano Substation. As

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78 DEIR at 5-3, Table 1. Dr. Shirmohammadi notes that SDG&E did not object to DEIR Alternative F in its April 7, 2015 Supplemental Prepared Testimony. SJC Testimony at 10. SDG&E's Supplemental Prepared Testimony, Chapters 3-5, addresses the infeasibility of the DEIR alternatives identified as "environmentally superior." The DEIR does not identify Alternative F as "environmentally superior" to the Proposed Project.

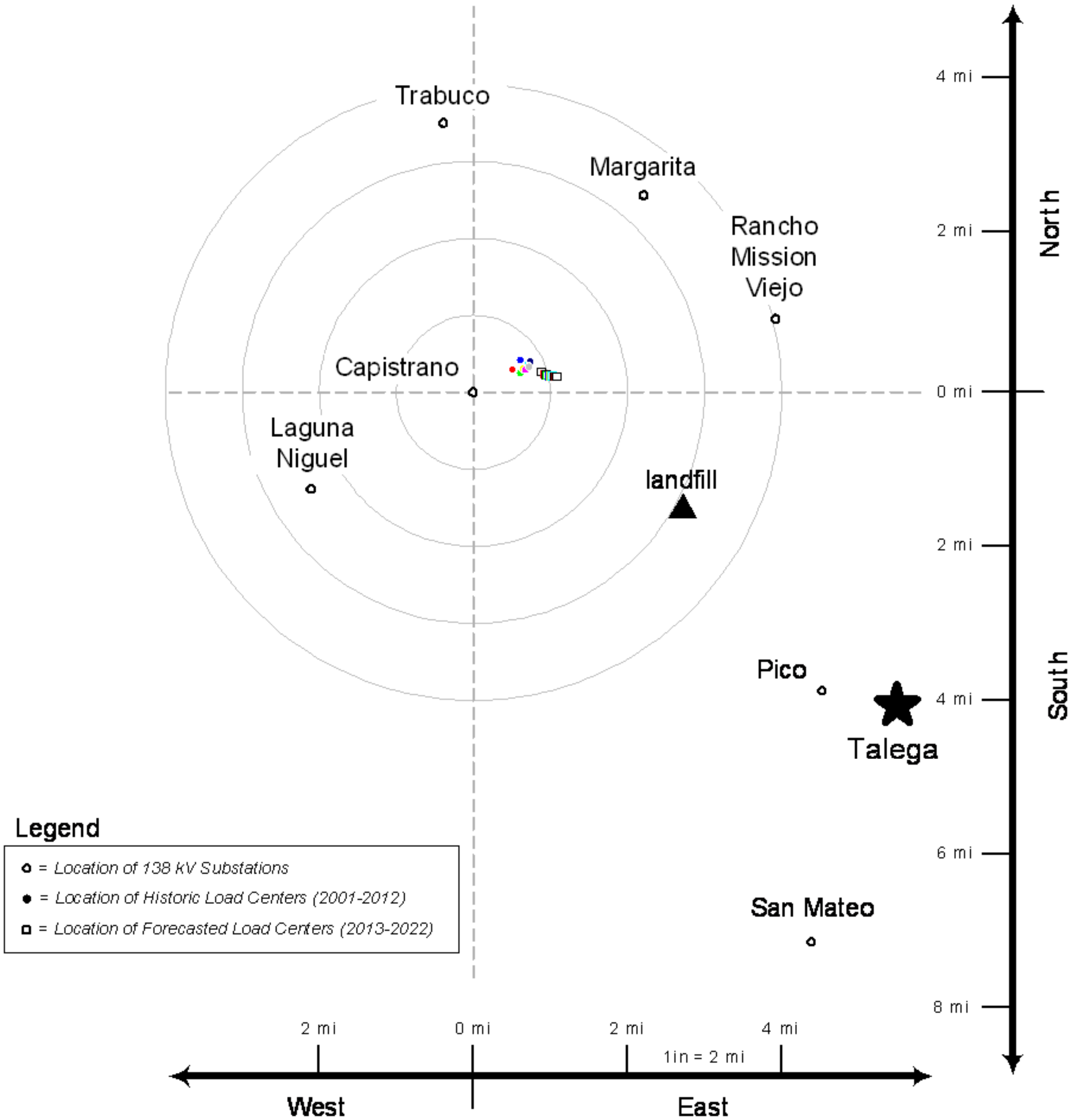
79 Shirmohammadi Testimony at 7.

80 Shirmohammadi Testimony at 13.

81 Testimony of Robert Sparks at 18-19.

a result, a second 230/138 kV source at RMV would be in the wrong place electrically – the energy to serve South Orange County would still flow west through the 138 kV network from RMV and Talega substations towards the load center near Capistrano. A second 230 kV source at RMV Substation would require upgrading of the 138 kV lines west of RMV Substation to serve the flow of energy toward the load center. Because Capistrano is closer to the load center, placing the second 230 kV source there negates the need to upgrade SDG&E's 138 kV lines in South Orange County within the current ten-year planning window, and for some time thereafter. See Fig. 5-1 below, which represents the load center analysis for South Orange County and indicates the relative proximity of all of the substations:

Figure 5.1 – South Orange County Load Center Analysis



Load Center based on Historic Loads		
Year	Miles North of CP	Miles East of CP
2001	0.299	0.506
2002	0.254	0.605
2003	0.419	0.605
2004	0.306	0.644
2005	0.293	0.681
2006	0.370	0.712
2007	0.410	0.728
2008	0.401	0.734
2009	0.401	0.734
2010	0.336	0.721
2011	0.337	0.721
2012	0.336	0.721

Load Center based on Forecasted Loads		
Year	Miles North of CP	Miles East of CP
2013	0.270	0.884
2014	0.234	0.924
2015	0.228	0.942
2016	0.221	0.959
2017	0.215	0.982
2018	0.211	1.003
2019	0.211	1.024
2020	0.210	1.045
2021	0.210	1.062
2022	0.205	1.083

Section 3. Alternative F Will Not Address South Orange County Category C Reliability Needs Without Additional Work to SDG&E's Transmission System (Witness Cory Smith).

SJC agrees that SDG&E's South Orange County transmission system faces "various NERC reliability criteria violations" that obligate SDG&E and CAISO "to develop solutions that would address the reported violations."[82] Dr. Shirmohammadi states that Alternative F is a more suitable alternative that "meets all the original objectives of the SOCREP Project."[83] This is incorrect. SDG&E's project objectives include transmission system reliability, specifically reducing the risk of load shedding, removing the risk of dropping load and compliance with mandatory NERC, WECC and CAISO Planning Standards.[84] Yet nowhere in SJC's testimony does SJC contend that DEIR Alternative F will mitigate these expected NERC violations, remove the risk of load dropping or reduce the risk of load shedding. Further, SJC's witness never conducted the load flow analyses necessary to determine whether DEIR Alternative F would mitigate these expected NERC violations.[85]

SDG&E was not able to do a comprehensive study, but using the description provided in SJC testimony, SDG&E made the following changes to its power flow model:

- Added a four element ring bus.
- Added a single 230/138 kV transformer.
- Opened TL13831 and connected to the ring bus.
- Extended TL23007 to RMV and connected to the new ring bus through the new transformer.

SDG&E's power flow analysis found that connecting a 230 kV line to a rebuilt RMV Substation does not meet the project objectives and is at the wrong location for a 2nd 230 kV connection to South Orange County.

In fact, a single 230/138 kV transmission line between RMV Substation and Talega Substation, as proposed by DEIR Alternative F, would <u>not</u> remove violations of all NERC Category C contingencies. By 2025, South Orange County peak load is expected to exceed 500 MW. The overlapping outage of TL13833 and TL13838 (Category C.3) will result in TL13834

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82 Shirmohammadi Testimony at 5.
83 Shirmohammadi Testimony at 10.
84 SDG&E Opening Testimony at 4.
85 SDG&E Attachment 28 (SJC Response to SDG&E Second Set of Data Requests, Question 3) ("Dr. Shirmohammadi did not perform any power flow analyses of DEIR Alternative F in support of his testimony").

and TL13816 exceeding emergency ratings. Following the outage of TL13833 (or TL13838), non-consequential load will have to be shed (deliberately disconnected) to prepare for the outage of TL13838 (or TL13833). Neither NERC TPL-001-4, nor its predecessors TPL-003-0b and TPL-002-0b, allow non-consequential load to be shed following a single transmission line outage. This situation will get worse. When South Orange County load grows to over 535 MW, assumed to be the year 2030, along with the violation identified in year 2025, TL13838 will be at its emergency limit for the overlapping outage of TL13836 and TL13846.

SJC's DEIR Alternative F also would require SDG&E to shed load (interrupt customer service) under Category C contingencies listed on Table 5-1.

Table 5-1: SJC's DEIR Alternative F Overloads Requiring Load Shedding

	Near Term Transmission Planning Horizon	Long Term Transmission Planning Horizon	
Year =	2020	2025	2030
Contingency	Overloaded Element	Overloaded Element	Overloaded Element
C1: PI E	13838	13838	13838
C2: PI 13836	13838	13838	13838
C2: PI 13846	13838	13838	13838
C3: CP BK41 + 13838	13833	13833	13833
C3: CP BK40 + 13838	-	-	13833
C3: 13816 + 13838	13833	13833	13833
C3: 13816 + 13835	-	-	13834
C3: 13833 + 13838	13834 & 13816	13834 & 13816	13834 & 13816
C3: 13834 + 13838	-	13833	13833
C3: 13835 + 13836	-	13846C	13846C
C3: 13835 + 13838	13816	13816	13816
C3: 13836 + 13838	13846A & 13846C	13846A & 13846C	13846A & 13846C
C3: 13836 + 13846	13830 & 13838	13830 & 13838	13830 & 13838
C3: 13838 + 13846	13836	13836	13836
C3: 23052 + 23030	RMV 230/138 xfmr	RMV 230/138 xfmr	RMV 230/138 xfmr

Although the NERC Reliability Standards allow SDG&E to shed load following the second outage of a Category C contingency, shedding customer load has been used very sparingly in the past because of its potential customer impact, and any South Orange County solution should mitigate such load shedding to the extent feasible. The Proposed Project not only mitigates the NERC Category C violations, but also the Category C load shedding events.

Section 4. Alternative F Will Not Address The Risk of Load Shedding for Maintenance Outages Without Additional Work to SDG&E's Transmission System (Witness Cory Smith).

DEIR Alternative F also would require additional work to mitigate the reliability concern about a forced outage during maintenance events at South Orange County substations.[86] RMV Substation is not the correct location for a second source of 230 kV power. Most of the maintenance outages listed on Tables 4-4, 4-5 and 4-6 of SDG&E's January 2015 Prepared Testimony will still exist if DEIR Alternative F is constructed. These outages lead to a loss of over 50% of SDG&E's South Orange County customers.

Section 5. Alternative F Will Not Provide a Useful Second Source Without Additional Work to SDG&E's Transmission System (Witness Cory Smith).

SJC proposes a variation on DEIR Alternative F which would connect the new RMV 230kV bus directly to San Onofre, thereby removing the common point of failure at Talega Substation.[87] SJC proposes removing TL23007 from Talega and extending it to RMV.[88] This does not constitute a fully redundant source, for the following reasons:

1) South Orange County's peak load was over 415 MVA in 2014 and, by 2020 peak load is expected to reach 475 MVA.[89]

2) An outage of both 230 kV buses at Talega would leave all South Orange County load connected to a rebuilt 230/138/12 kV RMV Substation, which would be served by a single 230 kV line (TL23007) rated at only 456 MVA and which is proposed to have a single 230/138 kV transformer rated at 392 MVA (assuming installation of SDG&E's standard 230/138 kV transformer). Both will overload under heavy summer loading conditions.

3) If the single 230 kV line serving a rebuilt RMV Substation is out of service for any reason and either the 230 kV or 138 kV service at Talega is interrupted for any reason, the rebuilt RMV Substation will not be able to provide the second 230 kV source to South Orange County. The Proposed Project allows for a maintenance outage of one 230 kV line to Capistrano Substation while keeping the other 230 kV line to Capistrano in service.

4) If the 230/138 kV bank at the rebuilt RMV Substation is increased to 450 MVA, as suggested by SJC, it would still be too small and would overload during peak

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[86] See SDG&E Opening Testimony at 42-44 (Talega Substation) and 70-72 (other SOC substations).
[87] Shirmohammadi Testimony at 12.
[88] See Figure 3 of Shirmohammadi Testimony at 12.
[89] SDG&E Supplemental Testimony at 55 (Table 2-1).

load conditions. It would also require purchase of a second non-standard 450 MVA bank as a spare.

5) An outage of both 138 kV buses at Talega would leave all South Orange County load connected to the rebuilt RMV through two single 138 kV lines (TL13830 and TL13838) rated at 195 MVA and 273 MVA, respectively.

If Talega Substation is unavailable and RMV Substation is the only connection to the 230 kV system as described under SJC's proposed alternative, SDG&E's South Orange County customers will be exposed to rolling blackouts. In order to carry South Orange County load during an outage of either Talega 230 kV service or 138 kV service, at a minimum:

1) Both TL13838 and TL13830 would need to be upgraded, preferably by adding a second circuit from RMV substation to Margarita Substation to Trabuco Substation.

2) A second 230/138 kV 392 MVA[90] bank would need to be installed at the rebuilt RMV Substation.

3) TL23007 would be upgraded or a second 230 kV line would need to be extended from Talega to the rebuilt RMV Substation to provide a second connection to the 230 kV bulk power system.

4) The Talega STATCOM, which was to be decommissioned and removed at the end of its useful life, would instead need to be replaced.

Finally, to remove the risk of dropping South Orange County load changes to the existing South Orange County system would need to be done;

1) Both TL13835A and TL13837 will need to be upgraded.

2) The Capistrano 138 kV capacitor bank will need to be replaced with a larger capacitor bank (approximately three times the size).

3) A second 230/138 kV transformer would need to be installed at RMV.

Note that this would still not provide the level of reliability as the Proposed Project, for the reasons discussed in Sections 2-4 above. Additional work may be required, depending on the final plan of service, to address any remaining Category C overloads and risk of load shedding due to maintenance outages.

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[90] SDG&E's standard transformer size is 392 MVA, not 450 MVA, and a 450 MVA transformer is not an "off-the-shelf" item. Since SDG&E does not use 450 MVA transformers, a spare would need to be purchased, stored and maintained. Given that, it would not be cost-effective to use 450 MVA transformers.

Section 6. Alternative F Will Not Avoid Necessary Work at Talega Substation (Witness Cory Smith).

DEIR Alternative F does not allow SDG&E to avoid certain work at Talega Substation that SDG&E believes would be avoided by the Proposed Project. Under DEIR Alternative F, unless there are two 392 MVA 230/138 kV transformers at a rebuilt RMV Substation, SDG&E would need to replace the two aging transformers at Talega Substation at an estimated cost of between $15-20 million. In addition, SDG&E would need to replace the Talega STATCOM, when it reaches the end of its useful life, to maintain voltage support at an estimated cost of $81-99 million. This cost estimate does not include the potential purchase of additional property (if feasible) to accommodate the replacement equipment. Neither of these replacements at Talega Substation is needed if the Proposed Project is constructed.

Section 7. RMV Substation Does Not Have Space to Add a 230 kV Switchyard, and Expansion Would be Difficult and Costly (Witness Karl Iliev).

SDG&E's existing RMV Substation does not have space to add a 230 kV switchyard. To expand the substation would be very difficult, may have significant environmental impacts, and would be very costly. Below, SDG&E describes the current substation, the work that would be necessary to construct a 230/138/12 kV substation meeting SDG&E's reliability needs, why it does not fit in the existing space, the difficulties associated with expanding the substation, and why SJC's proposed substation design does not work.

A. RMV Substation Does Not Have Space to Add a 230 kV Switchyard.

The 138/12 kV RMV Substation is built on an irregular shaped parcel of approximately 2.5 acres. See Attachment 29 (aerial photo view of RMV Substation). The existing distribution substation currently includes:

- Two 138kV transmission lines with associated overhead feeds into the substation
- Two 138/12kV distribution transformers
- Two 138kV busses sectionalized with a 138kV bus-tie circuit breaker
- Two 12kV 4-circuit switchgear units
- Two 12kV capacitor banks.
- Standard distribution substation sized control shelter

A 230/138/12 kV substation is considerably larger than a distribution substation. Compare Attachment 30 (standard BAAH transmission substation diagram) to Attachment 31 (standard single bus distribution substation diagram). A 230/138/12 kV substation will not fit on the existing RMV Substation property.

SDGE's requirement for a 230/138 kV transmission bus serving bulk power transformers is a breaker and half arrangement. This is required for a cost effective, reliable bus configuration that allows for breaker and/or bus maintenance without line/bank interruption and minimal disruption in a breaker failure situation. It is also SDG&E's standard to build at least one spare position when constructing a new substation to allow for future growth and/or maintenance activities. Doing so is prudent and cost-effective, while failing to do so could result in significant additional costs if rebuilding the substation is later necessary to address such issues.

If RMV Substation were rebuilt as a 230/138/12 kV substation, the minimum requirements for the substation would be:

- A 230 kV 6 element 3000A breaker and half arrangement, with two (one initial, two ultimate) 230 kV TL positions, two 230/138 kV transformer positions and a spare bay (TL or bank spare position), and a voltage regulating device.
- A new control shelter would be needed to house the additional control & protection necessary for the added transmission elements.
- A 138 kV 12 element 3000 amp breaker and half bus arrangement, four distribution transformers (two current, two spare), two connections for the 230/138kV transformers, four 138 kV TLs (two current, two spares), and spare positions.

To allow for property line setback requirements and required landscaping required by local or state jurisdictions and/or noise requirements, fire safety requirements, and standard drive aisle access, a minimum size yard for a 230/138/12 kV substation yard would be approximately 6-7 acres using GIS technology or approximately 12 acres using AIS technology – depending on the topography and arrangement of the land. This acreage accounts for the space requirements for water quality and hydromodification management criteria, as required by the Regional Water Quality Control Board, which is usually met through the combined use of underground infiltration tanks, and above ground detention basins. This space also accounts for required drive aisles between equipment for maintenance access, placement of equipment for optimum EMF and noise requirements, installation of required underground termination connections, cable pulling space requirements and any required pole placements.

There is insufficient space at the existing RMV Substation to construct a 230/138/12 kV substation meeting SDG&E's standards.

DEIR Alternative F proposes only a single 230 kV line to feed RMV Substation. For the reasons stated in Section 3 above, this would not be adequate to provide redundancy for

SDG&E's South Orange County system. However, even if the Commission were to determine that providing redundancy for South Orange County is not appropriate, interconnection of this single 230 kV line would require the addition of the equipment stated above. There is not sufficient space inside the existing RMV Substation site to fit this equipment in an ultimate site configuration or to meet the space requirements needed to keep any construction within the current fenceline away from infrastructure that feeds existing customer load.

B. Expansion Would be Difficult and Costly.

RMV Substation is built on an irregular shaped parcel of approximately 2.5 acres, making expansion of the substation very difficult. The site was designed to conform with utility and easement constraints and to avoid environmental impacts to the nearby biological open space. The sloped terrain on the east and north-east sides of the substation contain a Santa Margarita Water District large diameter 66" water transmission main, a 16" non-domestic water line, and a sewer force main. To the south is biological open space. See Attachments 29, 37, 38. Any work affecting the water and/or sewer lines and hillside will require major earth work and/or retaining walls. If Alternative F uses GIS technology, an expanded 230/138/12 kV RMV Substation would require an additional 4-5 acres (approximately), depending upon topology and type of transmission connections). If the existing substation would have to be rebuilt, then a total of 6-7 acres would be required.

Assuming that SDG&E is able to acquire additional land around the existing RMV Substation, then a key driver for this additional land would be the construction sequence. The sequence would be as follows:

- New build of a new 138 kV breaker and a half configuration GIS on new property that would be acquired. This prevents interruption of service by customers being fed from the existing 138 kV infrastructure.
- Relocation of the current 12 kV infrastructure to the new 138 kV GIS, allowing de-energizing of old 138 kV infrastructure.
- Demolition and expansion of the existing 138 kV portion of the switchyard to accommodate the 230 kV GIS.
- Building of the GIS infrastructure and final energizing in the new configuration.
- If the layout (depending on land acquisition) cannot accommodate keeping the 12 kV infrastructure in-place, more construction sequencing would be required to completely rebuild and relocate the existing 12 kV infrastructure (to optimize the facilities location on the property). This would have significant negative impacts

> in the cost, scope, environmental impact, and project duration described above. To accommodate a 230/138/12 kV substation, SDG&E would have to acquire additional property (by negotiation or condemnation) and mitigate the site constraints outlined above.

The layout and visual aesthetics of a 230/138/12 kV RMV Substation, constructed with GIS technology, would be greater than the Proposed Project's rebuild of Capistrano Substation due its proximity to new residential construction planned in the area. SDG&E would expect to construct a wall and install landscaping to screen the substation, but it would include two 40-50 foot GIS buildings.

The impact to the area would involve site work noise and dust suppression, and construction in the streets of the surrounding area for almost the entire construction duration. Construction would be lengthy due to the relocation of the existing distribution circuits and possible undergrounding of the138kV transmission lines. Traffic going to the site could also be impaired by the haul trucks required for the site development work.

SDG&E cannot provide even a high level cost estimate for constructing a 230/138/12 kV RMV Substation because the uncertainty is too great. Even assuming that Santa Margarita Water District would be willing to move its water and sewer lines, SDG&E cannot estimate the cost for it to do so. Similar, the earthwork and retaining walls necessary to convert sloped hillside into a useable substation site would be significant and SDG&E cannot estimate that cost without considerable engineering work and likely outside cost estimating. Environmental mitigation also is unknown.

It is reasonable to expect that constructing and equipping a 230/138/12 kV substation at a rebuilt RMV Substation would be similar to the cost of constructing and equipping a 230/138/12 kV substation at a rebuilt Capistrano Substation. However, SDG&E already owns the Capistrano property and would have to pay to acquire property near RMV Substation and to move existing water and sewer utilities (if feasible at all). Moreover, the earthwork and retaining walls at RMV Substation would be more extensive than at Capistrano Substation, and thus more costly. In addition, as SJC agrees, SDG&E would still have to rebuild Capistrano Substation at an estimated stand-alone cost of $135 million to $165 million (including permitting, mitigation and AFUDC).

C. SJC'S Proposed Layout Is Not Feasible.

In response to an SDG&E data request, SJC provided a proposed layout for a 230/138/12 kV RMV Substation, prepared by a non-witness Mr. Arun Arora. Mr. Arora attempts to fit all of the necessary equipment on the existing RMV Substation site, but his layout does not meet SDG&E's minimum reliability requirements. The flaws include:

- The proposed 138 kV GIS building is located in close proximity to the existing 138kV bus. This would require an outage to the existing 138 kV infrastructure during construction of the building, forcing an outage to most customers fed from RMV Substation for several months.

- The proposed 138 kV GIS building is laid out for a 4-element initial and ultimate configuration. This leaves no expansion capability for future 138 kV infrastructure. SJC itself admits that this facility represents the largest growth within the Southern Orange County region, but proposes infrastructure that only meets the minimum requirements for the current capacity of the substation, and leaves no potential expansion for the expected load growth.

- The proposed layout does not meet minimum reliability requirements for the distribution infrastructure currently existing in the substation. Tying the distribution transformers to the same feed off of the 138 kV ring bus leaves no sectionalizing capability for a single failure. Typically 138/12 kV transformers are separated with their own circuit breakers from the 138 kV bus, so that a single failure of that position would not force out both transformers. If a single failure on a 138/12 kV transformer were to occur with the proposed layout, all customers fed from the substation would lose service. A proper reliable configuration would expand the GIS building much larger than what Mr. Arora proposes. This, coupled with the construction requirements necessary to avoid impact to customers fed from the existing substation, would force expansion of the existing fence-line.

- The layout presumes that the 138 kV dead-ends can be re-used to feed into the 138 kV GIS with overhead wire. This is not feasible based on the angles presented in SJC's proposal. Additionally, the 138kV dead-end structures are not feasible in a 230kV application as it does not meet the clearance requirements (phase to phase) for 230 kV. These structures would have to be replaced for a 230kV application, either forcing underground 230 kV entry into the substation or expanding the switchyard to accommodate new structures. With the location of the existing water pipeline adjacent to the substation, any undergrounding of a transmission line would be extremely difficult and may require a relocation of this water main.

- The location of the proposed 230/138 kV transformer sits too close to the property line, creating noise violations that would have to be studied to see if they can be mitigated.

- Mr. Arora proposes the use of a single 450 MVA 230/138 kV transformer instead of SDG&E's standard 392 MVA transformer. As noted in Section 3 above, SDG&E's current load forecast for South Orange County predicts load will exceed 450 MW in 2017.[91] As a result, RMV Substation would not be able to provide redundancy for South Orange County in the event of a Talega Substation outage even before construction of the proposed RMV Substation would be complete. Even if load growth is a bit slower, or the Commission does not believe providing redundancy is appropriate, designing the system only to a near-term planning horizon is short sighted. The expected service life of a transformer is over 60 years. If RMV Substation has only a single 450 MVA transformer, then additional infrastructure will likely be required if there is unexpected load growth within the transformer's service life. This event would require installation of another transformer and the infrastructure required to connect it to the grid, which would require further expansion of the substation, and result in greater future costs.

- Moreover, SDG&E must look at the practice of custom equipment from a global system perspective. Increasing the rating of a transformer also increases the rating of the equipment around it. The bus, circuit breakers, etc. must be analyzed to ensure they meet the larger MVA rating of the larger capacity transformer. Moreover, to ensure reliability in the event the 450 MVA transformer were to fail, SDG&E would need to acquire a spare 450 MVA transformer as this is a non-standard size for which SDG&E has no spare. It may also cause reliability issues for shortage of spares on any larger sized equipment that is also customized due to the higher MVA rating of the transformer. To mitigate this issue, any spare equipment deemed "unique" must also be ordered and incorporated into SDG&E's spare policy. Warehousing and ongoing upkeep of these devices add "hidden" costs that need to be accounted for in analyzing the financial impact of this decision. Additionally, impedance values must be analyzed and size/spacing must be custom designed to meet any increases in equipment size caused by additional cooling design changes in the equipment, which are necessary to meet the higher rating.

- Because a single 230 kV transmission line and a single transformer would be inadequate to meet SDG&E's reliability standards, SDG&E would initially seek to build the 230kV switchyard with an ultimate design of a minimum of 6-elements. This could accommodate two 230/138 kV transformers and a spare future position, a minimum of two 230 kV transmission line positions (the proposed alternative line and a future line), and an extra position as typical breaker and a half schemes require elements added in pairs. The likely footprint of this switchyard would exceed that proposed by Mr. Arora.

[91] SDG&E Supplemental Testimony at 55 (Table 2-1).

Section 8. Rebuilding Capistrano Substation Is Necessary, and Would Have Similar Impacts as the Proposed Project (Witness Karl Iliev)

SDG&E appreciates the City's agreement that Capistrano Substation must be rebuilt. Based upon careful analysis, SDG&E concluded that only replacing equipment in the existing Capistrano Substation will not provide adequate reliability for SDG&E's customers in the City and South Orange County. Adequate reliability can only be gained by a complete rebuild and expansion of the existing substation. Replacing aging infrastructure in kind and rebuilding a limited size substation in the existing yard will not achieve the improvements provided by the Proposed Project, and will not achieve SDG&E's goal to provide reliable electric service to its South Orange County customers.

SDG&E agrees that if the second 230 kV source for South Orange County were to be moved to another site, then Capistrano Substation should be rebuilt as a 138/12 kV substation. If rebuilt as a stand-alone project, a Capistrano 138/12 kV substation is estimated to cost between $135 million to $165 million (including permitting, mitigation and AFUDC costs).

The City asserts, however, that "the rebuilt 138 /12 kV facilities at the Capistrano Substation under the DEIR Alternative F can be housed within the current open space in Capistrano Substation east of the historic building in the western end of substation."[92] As set forth below, while SDG&E agrees that Capistrano Substation must be rebuilt, the City is mistaken in asserting a 138/12 kV substation could be safely and easily constructed and operated in the existing open space east of the existing building at the western end of the substation, which is not used for utility operations and SJC refers to as "historic."

The Capistrano site is constrained by the site elevations, RWQCB water mitigation requirements, and access roads for proper safe access to large apparatus on-site. The current Proposed Project design balances the need for all three, while minimizing the environmental impacts created during construction. Keeping the old building would require unusable footprint within the existing project layout, which would cause significant impacts to the project design and add negative environmental impacts. SDG&E affirms that the Proposed Project cannot keep the existing building footprint, while maintaining the existing Project scope.

[92] Shirmohammadi Testimony at 13.

Section 9. SJC's Alternative F Would Cost More Than the Proposed Project (Witness Willie Thomas)

SJC asserts that Alternative F will cost at least $58.8 million less than SDG&E's Proposed Project. Rather than prepare an independent cost estimate, SJC developed the "approximate cost of Alternative F … by utilizing the cost projections for the SDG&E SOCREP alternative, as provided by SDG&E in its April 7, 2015 Supplemental Testimony and by eliminating the costs of items which will not be necessary under the DEIR Alternative F."[93] SJC provides its comparison, and assumptions, in Table 3 of Dr. Shirmohammadi's testimony.

Contrary to SJC's claim, SJC's Alternative F will cost more than the Proposed Project. The fundamental flaws include SJC's purported "very conservative" and "conservative" assumptions, which are mistaken, and work elements that need to be added to make this closer to an "apples to apples" comparison.

- SJC states that it "[v]ery conservatively assumed that the 230 kV upgrade of the Ranch Mission Viejo Substation plus 138/12 kV rebuild of Capistrano Substation will cost as much as the 230 kV upgrade and complete rebuilding of the Capistrano Substation." That is not a reasonable assumption. As discussed in Section 7.B above, it is reasonable to expect that constructing and equipping a 230/138/12 kV substation at RMV Substation location would cost as much as constructing and equipping a 230/138/12 kV substation at Capistrano Substation,[94] and that property acquisition, water and sewer main relocation, earthwork and retaining walls at the RMV Substation location would cost much more than at Capistrano Substation, which is already owned by SDG&E, does not have water and sewer mains to be relocated, and would require much more site grading to accomplish this plan based on surrounding slopes. Further, SJC's Alternative F includes rebuilding SDG&E's Capistrano Substation as a 138/12 kV Substation, which SDG&E estimates will cost $135 million to $165 million. Even ignoring many of the anticipated RMV Substation costs, which cannot reasonably be estimated at this time, the cost of rebuilding two substations (RMV and Capistrano), rather than just Capistrano, means that the substation work under SJC's Alternative F will cost at least $135 million to $165 million more than the Proposed Project.

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[93] Shirmohammadi Testimony (Errata) at 14.

[94] As discussed in Section 5 above, a 230/138/12 kV rebuilt RMV Substation will require two 392 MVA 230/138 kV transformers, as does the Proposed Project.

- Alternative F would require the need to rebuild (reconductor) TL 13835 to avoid potential outage issues prior to construction of the new 230kV line from Talega to RMV. The reconductor of TL13835 and the associated outage requirements puts the Laguna Niguel Substation at risk because it would be fed by only one 138kV line during that time period.

- As discussed in Section 5 above, to allow a rebuilt 230/138/12 kV RMV Substation to serve all South Orange County load in the event Talega Substation were not in service, which SDG&E's Proposed Project would do, the following additional work would need to be done: (a) both TL13831 and TL13838 would need to be upgraded, preferably by adding a second circuit from RMV to Margarita Substation to Trabuco Substation; and (b) a second 230 kV line would need to be extended from Talega to the rebuilt RMV Substation to provide a second connection to the 230 kV bulk power system.

- As set forth in Section 6 above, the Proposed Project allows SDG&E to remove and not replace two transformers at Talega Substation, and not to replace the Talega STATCOM when it reaches the end of its useful life. With SJC's Alternative F, SDG&E will need to replace the two transformers soon at an estimated cost of $15 million to $20 million (unless two transformers are included at a rebuilt RMV Substation), and to replace the STATCOM at the end of its useful life at an estimated cost of $81 million to $99 million (with AFUDC, $89 million to $109 million).

SJC's Table 3 with SDG&E Responses[95]

SOCREP Cost Component	SDG&E Alternative (Millions)	DEIR Alt. F (Millions)	SJC Notes	SDG&E Rebuttal Notes	SDG&E Rebuttal Cost (Millions)
Capistrano Substation Cost	$160.8	$160.8	Very conservatively assumed that the 230 kV upgrade of the Ranch Mission Viejo Substation plus 138/12	SJC's assumption is not reasonable. A 230/138/12 kV RMV Substation will cost at least as much as a 230/138/12 kV Capistrano	$160.8 for RMV plus $135-165 for Capistrano (includes AFUDC).

[95] SJC's Table reflects the estimated costs for SDG&E's Proposed Project contained in SDG&E's original April 7, 2015 Supplemental Testimony, and SJC's claimed savings. SDG&E's corrected Supplemental Testimony makes minor changes to its estimate for SDG&E's Proposed Project. Such changes are immaterial for the purposes of the comparison in SJC's Table and SDG&E's responses thereto.

			kV rebuild of Capistrano Substation will cost as much as the 230 kV upgrade and complete rebuilding of the Capistrano Substation	Substation. A rebuilt 138/12 kV Capistrano Substation is estimated to cost another $135 to $165 million.	Total: $$295.8 to $325.8
Talega Substation	$0.3	$0.3	Conservatively assumed the same cost	Accept for purposes of this comparison (but not including replacement of two transformers plus STATCOM)	$0.3
Talega Area 138kV Transmission	$9.9	$9.9	Conservatively assumed the same cost	Accept for purposes of this comparison	$9.9
Capistrano 138 kV Underground Gateway	$15.6	$-	No undergrounding at Capistrano Substation needed	If SJC prefers to have 138 kV lines into a rebuilt Capistrano overhead rather than underground, SDG&E would study such an option and how best to address lines in railroad ROW. Without sufficient details on the substation layout for the rebuild, and time to conduct outage sequencing to ensure outage frequency and duration are kept to a minimum, overhead lines	For purposes of this comparison only, SDG&E estimates this cost as “more than zero.”

				may not be a feasible option and/or the cost savings may not be as stated. SJC should clarify if it wishes 138 kV lines into Capistrano to be overhead.	
230 kV Overhead (includes removal of the 138 kV)	$63.6	$48.847.7	Very conservatively assumed that per-mile cost of the 230 kV build into the Ranch Mission Viejo Substation will be the same as the 230 kV upgrade into the Capistrano Substation (Alternative F requires 2 miles less of 230 kV overhead than SDG&E alternative and does not require many transmission and distribution line relocations)	The RMV-TA line will be only 1 mile less than the proposed OH 230 kV line from TA to CAP (7.5 mi vs. 6.44 mi), not 2 miles shorter as SJC assumes. Because there is only one line in the corridor and limited access roads, the grading for access pads and spur roads are likely greater than in the Proposed Project. Without further engineering and design, estimating the additional costs would be speculative. Therefore, SDG&E only corrects the per mile cost.	$50.3
230kV Underground	$27.3	$-	No Need to underground any 230kV line for Alternative F	It should be assumed some undergrounding of at least 230kV transmission line will be necessary at RMV	$9.3

				to accommodate the construction and arrangement. Without being able to conduct detailed engineering and knowing the final sub arrangement, assume 1,000ft UG of 230kV + cable pole by scaling the Proposed project by \$33.3M x 1,000ft/1,800ft/2 (one circuit vs two)	
Permitting, Environmental and Mitigation	\$31.6	\$31.6	Conservatively assumed same cost	This is not a reasonable assumption as both the Proposed Project and SJC's Alternative F will have construction to rebuild Capistrano Substation, and SJC's Alternative F adds construction at RMV Substation, which is adjacent to biological open space and would include considerable earthwork, retaining walls, and relocation of underground water and sewer lines.	SDG&E cannot estimate the additional cost without further design, engineering and environmental review. Therefore, for purposes of this comparison only, SDG&E estimates the cost as "more than \$31.6"

ROW Acquisition	1.0	$1.0	Assumed same cost	SJC's Alternative F will have greater property acquisition cost because SDG&E owns the Capistrano Substation site to be used in the Proposed Project, but would have to attempt to acquire property around RMV Substation to construct a 230/138/12 kV substation. In addition, as recognized in the DEIR at 5-16, SJC's Alternative F would require app. 6.5 miles of 20 ft additional ROW width from TA to RMV. Some of this ROW is located on Camp Pendleton, and the Department of the Navy may not agree to provide it.	Therefore, for purposes of this comparison only, SDG&E estimates the cost as "more than $1.0"
AFUDC	$63.7	$63.7	Conservatively assumed same cost	This is not a reasonable assumption because the Alternative F project costs will be greater than the Proposed Project, and therefore the AFUDC cost will be greater. A portion	For purposes of this comparison only, SDG&E estimates the cost as "more than $63.7"

				of the additional AFUDC cost is reflected in the estimated $135 - $165M cost of a 138/12 kV rebuilt Capistrano Substation, as that estimate includes AFUDC.	
Distribution Circuits	$7.1	$7.1	Conservatively assumed same cost	Accept for purposes of this comparison	$7.1
Reconductor 138kV between RMV-MAR (TL13838), MAR-TB (TL13830)	Not part of Proposed Project because not needed when 230 kV source is at Capistrano Substation	Missing	Missing	As discussed in Section 5, Both TL13838 and TL13830 would need to be upgraded, preferably by adding a second circuit from RMV to Margarita Substation and Margarita to Trabuco Substation. 1) RMV to Margarita Substation (TL13838) would include at a minimum the installation of approximately 1.3 miles of new overhead conductor, temporary stringing sites, and traffic control	SDG&E cannot estimate the additional cost without further design, engineering and environmental review. Therefore, for purposes of this comparison only, SDG&E estimates the cost as “more than zero”

				measures along Cow Camp Road. 2) Margarita to Trabuco Substation (TL13830) would include at a minimum the installation of 0.7 mi new overhead conductor, temporary stringing sites, 1.3 miles of new underground cable, 13 new splices vaults, and traffic control measures along portions of Antonio Parkway, Corporate Rd, Terrace Rd, Windmill Avenue, Sienna Parkway, Flintridge Ave, Roanoke Dr, Oneill St, Crown Valley Parkway, and Puerta Real.	
Add second 230 kV line	Not part of	Missing	Missing	As discussed in Section 5,	SDG&E cannot

from Talega to rebuilt RMV Substation to provide second connection to the 230 kV bulk power system	Proposed Project because not needed when 230 kV source is at Capistrano Substation			need to add a second 230 kV line from Talega to rebuilt RMV Substation to provide a second connection to the 230 kV bulk power system, so that a 230/138/12 kV RMV Substation can serve SOC load during loss of Talega Substation	estimate the additional cost without further design, engineering and environmental review. Therefore, for purposes of this comparison only, SDG&E estimates the cost as “more than zero”
Upgrade TL13835A and TL13837	Not part of Proposed Project because not needed when 230 kV source is at Capistrano Substation	Missing	Missing	As discussed in Section 5, these lines would need to be upgraded to avoid dropping load.	For purposes of this comparison only, SDG&E estimates the cost as “more than zero”
The Capistrano 138 kV capacitor bank will need to be replaced with a larger capacitor bank (approximately three times the size).	Not part of Proposed Project because not needed when 230 kV source is at Capistrano Substation	Missing	Missing	See Section 5 above. .	TBD
Replace 2 Talega	Not	Missing	Missing	See Sections 5 and 6	$81 million - $99

transformers and Talega STATCOM	necessary with SDG&E's Proposed Project			above. With SJC's Alternative F, but not with SDG&E's Proposed Project, will need to replace 2 Talega transformers ($15-20M) and Talega STATCOM at the end of its useful life ($80-100M). However, if a rebuilt 230/138/12 kV RMV Substation had two transformers, then SDG&E would not need to replace the two Talega transformers. As SDG&E assumes two RMV transformers in the rebuilt RMV costs above, SDG&E does not include the Talega transformer replacement cost here.	million (with AFUDC, $89 million to $109 million)
Total	$380.9	$322.1	Total project cost reduced by at least $66M via DEIR Alternative F	Estimated costs are higher than assumed by SJC	More than $$558 to $608.1

Even without adding the work necessary to make a 230/138/12 kV rebuilt RMV Substation able to provide the redundancy for SDG&E's South Orange County customers that is provided by SDG&E's Proposed Project, SJC's Alternative F is estimated to be significantly more expensive than the Proposed Project. This is because Alternative F requires rebuilding an expanded RMV Substation to 230/138/12 kV and rebuilding a 138/12 kV Capistrano Substation whereas the Proposed Project only rebuilds Capistrano

Substation to 230/138/12 kV on SDG&E-owned land. Once the additional work necessary to make Alternative F provide such redundancy is included, the costs of SJC's Alternative F are even greater.

CHAPTER 6. FRONTLINES' PIECEMEAL APPROACH DOES NOT ADDRESS SOUTH ORANGE COUNTY'S RELIABILITY NEEDS

Section 1. Introduction (Witness John Jontry)

Frontlines offers a piecemeal approach to some of the South Orange County reliability issues identified by SDG&E, with recommendations to address 18 identified Category C violations, 14 Category C contingencies that would force load shedding, and the risks of outage during maintenance events. Frontlines appears ambivalent about the need to provide redundancy to SDG&E's 300,000 South Orange County customers, stating: "if a second 230 kV power source in SOC is deemed appropriate, then there are alternatives to establishing Capistrano as a new 230 kV substation."[96]

In this Chapter, SDG&E addresses Frontlines' proposals for addressing South Orange County's reliability needs other than redundancy. SDG&E addresses Frontlines' proposed alternatives to provide redundancy in Chapters 8 and 9. However, SDG&E notes that the Proposed Project solves all of the reliability issues by injecting 230 kV power at South Orange County's load center, whereas Frontlines' piecemeal approach requires upgrading more of SDG&E's 138 kV network because it does not.

In SDG&E's original Corrected Prepared Testimony, SDG&E identified 18 Category C contingencies requiring instantaneous load shedding.[97] Frontlines recommends that these contingencies be addressed through implementation of the following actions:

1. Overhaul or rebuild the Capistrano 138 kV substation.
2. Replace the existing ACSR conductor on TL13835 [Talega-Laguna Niguel] with ACSS/AW conductor that has the same diameter and weight per unit length as the existing ACSR conductor. This differs slightly from what was proposed in the Draft EIR as part of Alternative B1 in that it relies on an aluminum conductor/aluminum clad steel supported configuration rather than just an aluminum conductor/steel supported configuration.
3. Replace two aged transformers at Talega.[98]

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[96] Ayer Testimony at 17.
[97] SDG&E's current corrected Opening Testimony at 50-59 identifies 22 such Category C contingencies.
[98] Ayer Testimony at 7.

To address the 14 Category C contingencies identified by SDG&E as forcing load shedding,[99] Frontlines testifies that, as to the Scenario 1, "Upgrading the underground portion of TL13833 to 260 MW should address this concern through 2024."[100] Ms. Ayers further testifies: "Regarding Scenarios 2-14, the projected load shed events could be prevented by increasing the transmission capacity of TL13835 [Talega-Laguna Niguel] from 138 MVA to 228 MVA," as proposed above.[101]

With respect to the risks posed by outages during maintenance events at Talega and other South Orange County substations, Frontlines testifies that four scenarios can be avoided "when SDGE removes transformer banks 60 and 62," and replaces Bank 60 with a "higher capacity transformer."[102] As for the rest, Frontlines testifies that reconductoring TL13835 will reduce the amount of load that must be dropped and that SDG&E can try to schedule work for times when expected load will be below the increased system capability.[103]

SDG&E addresses Frontlines' proposed approach below. In sum, Frontlines' approach: (a) fails to mitigate Category C violations and load shedding in South Orange County; (b) fails to address reliability issues at Talega Substation arising from a non-standard configuration that places all South Orange County customers at risk during maintenance events; (c) fails to mitigate the risk of a forced outage during maintenance events at other South Orange County substations; and (d), by not providing a redundant second source of power in South Orange County, leaves SDG&E's over 300,000 South Orange County customers at risk of a loss of service at Talega Substation. SDG&E's Proposed Project solves each of these reliability concerns.

Section 2. SDG&E Agrees that Capistrano Substation Must be Rebuilt (Witness Karl Iliev)

SDG&E appreciates Frontlines' agreement that Capistrano Substation must be rebuilt or overhauled. Based upon careful analysis, SDG&E concluded that only replacing equipment in the existing Capistrano Substation will not provide adequate reliability for SDG&E's customers in the City of San Juan Capistrano and South Orange County. Adequate reliability can only be

[99] SDG&E original corrected Opening Testimony at 55-65 (SDG&E's current corrected Opening Testimony at 59-70 identifies 19 such Category C contingencies).
[100] Ayer Testimony at 15.
[101] Ayer Testimony at 15.
[102] Ayer Testimony at 16.
[103] Ayer Testimony at 16-17.

gained by a complete rebuild and expansion of the existing substation. Replacing aging infrastructure in kind and rebuilding a limited size substation in the existing yard will not achieve the improvements provided by the Proposed Project, and will not achieve SDG&E's goal to provide reliable electric service to its South Orange County customers.

SDG&E agrees that if the second 230 kV source for South Orange County were to be moved to another site, then Capistrano Substation should be rebuilt as a 138/12 kV substation. If rebuilt as a stand-alone project, a Capistrano 138/12 kV substation is estimated to cost between $135 million to $165 million (including permitting, mitigation and AFUDC costs).

Section 3. Reconductoring TL13835 Will Not Mitigate all Category C Overloads (Witness Cory Smith).

As noted above, Frontlines contends that reconductoring TL13835 to 228 MVA would resolve essentially all of the NERC Category C violations identified in SDG&E's Opening Testimony.[104] To test Frontlines' contention, SDG&E conducted power flow analyses assuming implementation of Frontlines' recommendations to reconductor TL13835 (to an even higher 273 MVA capacity), rebuild a 138/12 kV Capistrano Substation (thereby replacing the limiting equipment on TL13834 and achieving a new rating of 273 MVA), and replacing two transformers at Talega. The power flow analyses, which model how the system would perform, demonstrate that Frontlines' recommendations do not mitigate all Category C violations, prevent load shedding under a variety Category C contingencies, or prevent dropping South Orange County load during maintenance.

Frontlines' approach, which is a piecemeal approach that does nothing to address the long-term need for an additional connection to the 230 kV bulk power system for South Orange County, is fundamentally incomplete. SDG&E performed a more thorough analysis of Frontline's proposal by preparing a 2020 load flow case with the rating for TL13835 and TL13834 adjusted to 273 MVA and removal of the existing SPS. The following Table 6-1

[104] Ayer Testimony at 9-11. Frontlines contends that it is not necessary to reconductor TL13835 to 273 MVA, as SDG&E stated in assessing the feasibility of placing new conductors on existing structures as assumed by the DEIR Alternative B1. See SDG&E Supplemental Testimony at 88; Ayer Testimony at 11. SDG&E disagrees, but even reconductoring TL13835 to the higher 273 MVA capacity does not resolve the Category C issues noted in Table 6-1.

describes the numerous Category C violations and Category C load shedding that would still occur:

Table 6-1: Category C Overloads in 2020 with Reconductored TL 13835

Monitored Element	**Contingency**	**Requires N-1 Load Shed in Violation of NERC TPL-003-0b**
13816	C3: 13831+13833	123% of Emergency Rating
13816	C3: 13831+13835	112% of Emergency Rating
13816	C3: 13833+13835	103% of Emergency Rating
13816	C3: 13833+13838	112% of Emergency Rating
13816	C3: 13835+13838	104% of Emergency Rating
13833	C3: CP BK40+13831	N/A
13833	C3: CP BK40+13838	N/A
13833	C3: 13816+13831	N/A
13833	C3: 13831+13834	N/A
13833	C3: 13834+13838	N/A
13836	C3: 13831+13846	115% of Emergency Rating
13836	C3: 13835+13846	102% of Emergency Rating
13836	C3: 13838+13846	106% of Emergency Rating
13846A	C3: 13831+13836	102% of Emergency Rating
13846A	C3: 13835+13836	N/A
13846A	C3: 13836+13838	N/A
13846A	C2:TA 8T	102% of Emergency Rating
13846C	C3: 13831+13836	102% of Emergency Rating
13846C	C3: 13835+13836	N/A
13846C	C3: 13836+13838	N/A
13846C	C2:TA 8T	102% of Emergency Rating

Note that even after TL13835 is reconductored, twenty-one combinations of contingencies and monitored elements result in overloaded facilities, affecting five different lines, line segments, or transformer banks. Assuming that replacing the underground segment of TL13833 would increase the normal and emergency ratings of that line from 205 MVA to 274 MVA, that would reduce the number of combinations from twenty-one to sixteen. This is still well beyond what can be effectively addressed by a special protection scheme, even if such a scheme were permitted by the CAISO criteria limiting the number of contingencies and monitored elements permitted for any given SPS, which it is not. As discussed in SDG&E's Opening Testimony at 46-49, SDG&E's Supplemental Testimony at 51-52, and CAISO's

Testimony of Robert Sparks at 9-10, the use of Special Protection Systems ("SPS") is limited by CAISO Planning Standards and good utility practice to six local contingencies and four monitored elements.

Of the twenty-one contingency and monitored element combinations listed in Table 6-1, twelve would require load shedding pre-contingency, after the first outage, in order to prevent exceeding a transmission line's emergency rating after the second outage. As a result, these are violations of NERC TPL-003-0b that must be corrected, as shedding non-consequential load after a single Category B outage is not permitted. Note that none of the contingencies requiring pre-contingency load shedding are addressed by increasing the rating of TL13833.

By contrast, reconductoring of TL13835 or TL13833 will not be necessary if SDG&E's Proposed Project is implemented.

Section 4. Replacing the Two Small Transformers At Talega Substation Is Not a Viable Solution Without the Proposed Project (Witness Karl Iliev)

Frontlines recommends replacing the "two aged transformers at Talega."[105] SDG&E agrees that, if no project is approved to provide a second source of power to SDG&E's South Orange County transmission system, SDG&E will need to replace the two aging transformers (Banks 60 and 62). As discussed in Chapter 3 above, those two transformers cannot be removed and not replaced without a second source, and Talega Substation cannot be reconfigured into a more reliable arrangement within its current footprint without removing those two transformers.

Frontlines' proposal to simply replace the two aged transformers at Talega Substation, however, does nothing to solve the Talega Substation reliability issues identified in SDG&E's Opening Testimony and SDG&E's Supplemental Testimony.

Simply replacing the two aged transformers at Talega Substation will not provide the reliability benefits of a second source of power to South Orange County and will not address the reliability issues arising from having all four 230/138kV transformers at one substation. As discussed in SDG&E's Supplemental Testimony, Chapter 2, having Talega Substation as the sole source of power to SDG&E's South Orange County system is not prudent.

Further, as discussed in SDG&E's Opening Testimony, "Talega Substation has an unusual non-standard configuration in that two of the four 230/138 kV transformers are

[105] Ayer Testimony at 7.

connected directly to the 230 kV bus instead of a connection to a circuit breaker then to the bus. This means that for loss of either of these two transformers, it is necessary to take the entire bus out of service to disconnect the failed equipment. … [T]he existing Talega Substation configuration restricts the conditions under which maintenance can be done and creates twenty-nine different outage scenarios during planned maintenance outages that would cause uncontrolled loss of the entire customer load in South Orange County."[106] Simply replacing the two aged transformers does not mitigate the non-standard configuration that creates these risks.

Further, simply replacing the two aged transformers does not mitigate reliability issues at Talega Substation that arise because of a lack of space. As discussed in SDG&E's Opening Testimony:

> Because of space constraints within the substation footprint, the transformers are in close proximity to each other, which increases the equipment damage and outage impact if an adjacent transformer or other equipment catches fire or fails. Currently Banks 61 and 62 are immediately adjacent to the control shelter without enough separation to install a fire wall. If one of these transformers catches fire, it will create difficulty in entering the control shelter to perform operations necessary to de-energize the equipment to allow workers to safely extinguish the fire.
>
> Also because of space constraints, transformer Banks 60 and 63 are currently fed directly off the 230kV bus without bank breakers. This is a non-ideal configuration because any bus outage will force a transformer outage and vice-versa. There is not sufficient space in the current substation footprint to reconfigure Bank 63 to be fed from a more reliable breaker and half configuration. Banks 61 and 62 are currently fed from breaker and half configuration but are in the same bay, which does not meet current SDG&E's reliability criteria as they are exposed to a single point of failure from their shared bus tie breaker.[107]

Even if Banks 60 and 62 were replaced with larger transformers, it would not address these reliability concerns. By constructing a second source of 230 kV power to SDG&E's South Orange County system at Capistrano Substation, the Proposed Project will allow SDG&E to remove the two aged transformers at Talega Substation and reconfigure the substation to a more reliable arrangement within its existing footprint.

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[106] SDG&E Opening Testimony at 11.
[107] SDG&E Opening Testimony at 89.

Section 5. Using SPS is Not a Viable Solution (Witness John Jontry)

Based on its belief that its other recommendations mitigate all of SDG&E's identified NERC violations other than Scenarios 7 and 11 in SDG&E's original corrected Opening Testimony (Scenarios 11 and 15 in SDG&E's current corrected Opening Testimony at 53-55), Frontlines asserts that, "if these scenarios do result in line ratings being potentially exceeded, they can be handled via SPS without violating CAISO's SPS guidelines and standards."[108]

As discussed in Section 3 above, even after implementing Frontlines' recommendations, the remaining number of Category C contingencies that result in overloaded elements, plus the number of elements affected, exceed that permitted by the CAISO planning standards.

Section 6. Reducing the Number of Customers Who Would Lose Power From a Forced Outage During a Maintenance Event Is Not Sufficient (Witness John Jontry)

Frontlines recognizes that SDG&E customers would lose power if a forced outage occurs during a planned maintenance event at Talega and other South Orange County substations.[109] Frontlines suggests that its recommendations can assist in addressing this risk.

First, referring to its Table 3, Frontlines asserts: "Scenarios 1 – 4 stem from the non-standard bus configuration at the Talega substation. However, it seems that these scenarios can be addressed to some extent when SDGE removes transformer banks 60 and 62."[110] This is simply incorrect. As discussed in Chapter 3 and in Section 4 above, without a second source in South Orange County, transformer banks 60 and 62 would need to be replaced, not removed, and without removing them, it is not feasible to reconfigure the bus configuration at Talega Substation to a more reliable arrangement.

Referring to Scenarios 5-10 of its Table 3 and a host of Category C contingencies, Frontlines asserts: "By increasing the capacity of TL13835 to 228 MVA or more (through reconductoring with ACSS/AW), it seems that the potential load losses occurring under Scenarios 5-10 can be significantly reduced (by 30%). These losses could perhaps even be

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108 Ayer Testimony at 11.

109 Ayer Testimony at 16 ("these events can result in loss of service in SOC").

110 Ayer Testimony at 16.

avoided altogether if the maintenance activities from which they stem are scheduled only when the SOC load is less than the revised TL13835 rating."[111]

As an initial matter, simply reducing the number of customers who lose electric service is not the same as providing reliable electric service. The Proposed Project would mitigate the risk entirely. Further, Frontline's proposal would do nothing to mitigate the risk of loss of the entire South Orange County customer load during maintenance of the 138 kV or 230 kV buses at Talega.

Section 7. SDG&E Would Mitigate a Loss of Capistrano Substation (Witness Cory Smith).

Frontlines asserts: "If the SOCRE Project is constructed as proposed by SDGE, an event which removes the Capistrano substation from service will drop all load served by the Laguna Niguel Substation (nearly 25% of the current SOC load)."[112]

Following the Proposed Project, Laguna Nigel Substation would be served by two 138 kV lines from the rebuilt Capistrano Substation. If both 138kV busses at the rebuilt Capistrano Substation were lost, then Laguna Niguel Substation would temporarily lose service. However, SDG&E has made provisions for such an event in the final design. Overhead jumpers will be stored at Capistrano. In the event that the rebuilt Capistrano Substation can no longer serve Laguna Niguel, the jumpers will be installed on poles west of Capistrano Substation. Laguna Niguel will be fed by bypassing Capistrano Substation. SDG&E estimates that the overhead jumpers could be installed within 6 to 8 hours.

Section 8. Frontlines Wrongly Asserts that TL 13835 Could be Reconductored Without Replacing the Transmission Structures (Witness Willie Thomas).

Frontlines contends:

> In Supplemental Testimony, SDGE disputes the viability of reconductoring TL 13835. SDGE argues that replacing the TL13835 line with ACSS conductor that is similar in size to the existing conductor will not achieve a 273 MVA rating, and that a 273 MVA rating can only be achieved by using a thicker conductor, which would increase line sag. Therefore (according to SDGE) all the structures on TL13835 would have to be replaced to accommodate the thicker conductor and ensure compliance with GO 95. This in turn would require alterations to a number of distribution circuits.

[111] Ayer Testimony at 16, 17.
[112] Ayer Testimony at 20.

> This argument against reconductoring is premised on the erroneous assumption that a 273 MVA rating on TL13835 is required to address SDGE's concerns regarding load shed issues, perceived NERC violations, emergency line rating exceedences, etc. However a 273 MVA line rating on TL13835 seems unnecessary to address these issues. In fact, it seems that a TL13835 line rating of 228 MVA would be sufficient to address these concerns through 2024 …[113]

Based upon its belief that a 228 MVA rating would be sufficient, Frontlines asserts that "a 228 MVA line rating can be achieved on TL13835 by replacing the existing ACSR conductor with an Aluminum Conductor/ Aluminum Clad-Steel Reinforced ("ACSS/AW") conductor that has a diameter and weight that is identical to the existing conductor that is already in place."[114]

As an initial matter, as set forth in Section 3 above, even reconductoring TL 13835 to a 273 MVA rating does not mitigate the NERC Category C violations and load shedding events listed in Table 6-1. Thus, reconductoring TL 13835 to a 228 MVA rating will not mitigate such contingencies.

However, Frontlines also is mistaken in assuming that installing ACSS/AW conductor of the same diameter and weight could meet a 228 MVA rating and that structure replacement would not be necessary. Based on SDG&E ratings methodology, this wire cannot be operated at a high enough temperature to achieve a 228 MVA rating. Additionally, the elevated temperature of the wire would cause the wire to sag more than what exists today such that minimum ground clearances cannot be maintained. In order to meet a rating of even 228 MVA, a larger size ACSS/AW wire would be required, which would increase conductor sag and create ground clearance violations, and would increase mechanical loading on the structure due to additional wind forces caused by larger diameter conductor.

For the reasons stated above, it is best to assume a larger conductor would be required to meet even the 228 MVA rating noted by Frontlines, and that structures would need replacement to accommodate the larger conductor due to increases in sag and structural loading.

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[113] Ayer Testimony at 11.
[114] Ayer Testimony at 12.

CHAPTER 7. FRONTLINES' COST ESTIMATE FOR ITS RECOMMENDED APPROACH DOES NOT ACCURATELY REFLECT THE WORK REQUIRED NOR DOES IT PROVIDE THE SAME RELIABILITY BENEFITS

Section 1. Introduction (Witness John Jontry)

As noted above, Frontlines' recommended approach to the reliability issues in SDG&E's South Orange County transmission system is: "1. Overhaul or rebuild the Capistrano 138 kV substation. 2. Replace the existing ACSR conductor on TL13835 [Talega-Laguna Niguel] with ACSS/AW conductor that has the same diameter and weight per unit length as the existing ACSR conductor. … 3. Replace two aged transformers at Talega."[115]

Frontlines then provides an estimated cost for "FRONTLINES recommended alternative approach: "Reconductor TL13835 w/out structures replaced [($75-$91 million)*0.3547] = $26 – $32 mill; Do not upgrade/replace TL 13816, 13836, and 13846C = $0; Rebuild Capistrano = $135 - $165 mill; Replace transformers at Talega = $15 - $20 mill; TOTAL = $176 - $217 mill."[116]

Frontlines' approach and cost estimate are fundamentally flawed. First, as discussed in Chapter 6, Frontlines' approach fails to mitigate the reliability concerns in South Orange County and thus is missing large scopes of work required to provide reliability benefits similar to the Proposed Project. Second, while SDG&E accepts its own costs for certain elements of Frontlines' approach, Frontlines' estimated costs for the other elements is not accurate because it does not adequately represent the work required.

Section 2. Frontlines' Proposed Plan of Service Is Missing Key Elements (Witness Cory Smith)

As set forth in Chapter 6, Frontlines' approach fails to mitigate South Orange County's reliability needs:

- Reconductoring TL13835, whether to a 273 MVA rating (as SDG&E assumed in evaluating the DEIR Reconductoring Alternative) or to a 228 MVA rating (as urged by Frontlines), does not mitigate the NERC Category C violations or the Category C load shedding identified in Table 6-1 of Chapter 6, Section 3 above.

- Adding reconductoring of an underground portion of TL13833 (which Frontlines mentions in testimony but does not include in its "recommended approach" or its

[115] Ayers Testimony at 7.
[116] Ayers Testimony at 20.

cost estimate) still leaves 16 Category C overloads, including 12 NERC Category C violations.

- Rather than provide a second source of power to South Orange County, Frontlines' approach would simply replace two aging transformers at Talega and ignore the risk of a forced outage during a maintenance event at Talega Substation. Such an outage could interrupt electric service to all of South Orange County.
- As Frontlines concedes, its recommended approach would not mitigate the risk of a forced outage during maintenance events at Pico, Margarita or Rancho Mission Viejo substations. Instead, Frontlines simply states that fewer customers would be left without electricity.
- Frontlines' recommended approach also does not provide redundancy for the over 300,000 people dependent upon SDG&E's South Orange County system. Instead, those customers remain at risk of a loss of 230 kV or 138 kV service at Talega Substation. Outages caused by substation damage could last from hours to weeks or months.[117] A three week outage of South Orange County could result in direct and indirect economic losses of $2.3 to $4.7 billion, as well as adverse social impacts.[118]
- Frontlines recommended approach does not allow SDG&E to avoid the cost of replacing the Talega STATCOM when it reaches the end of its useful life.

By contrast, SDG&E's Proposed Project addresses all of the reliability issues noted above.

Frontlines' recommended approach is most similar to the DEIR Alternative B-1-Reconductor Laguna Niguel-Talega 138 kV Line," which also proposed reconductoring TL13835. Frontlines includes rebuilding Capistrano Substation and replacing the two aging transformers at Talega, but otherwise Frontlines' recommended approach has all of the same defects as DEIR Alternative B-1. As discussed in SDG&E Supplemental Testimony, Chapter 4, the estimated cost of DEIR Alternative B-1, when the work necessary to address South Orange County's reliability defects is included, is $572 million to $699 million. SDG&E estimates that Frontlines' recommended approach, when the work necessary to address South Orange County's reliability defects is included, would be the same.

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[117] SDG&E Supplemental Testimony at 39-42.
[118] SDG&E Supplemental Testimony, Chapter 9.

Section 3. Frontlines' Cost Estimate for Its Approach Is Incorrect (Witness Willie Thomas)

Even for Frontlines' recommended approach, certain elements of its cost estimate are incorrect. SDG&E accepts the $135 million to $165 million estimated cost to rebuild a 138/12 kV Capistrano Substation and the $15 million to $20 million (with AFUDC, $17 million to $21 million) simply to replace the two aging transformers at Talega Substation. However, the other elements of Frontlines' cost estimate are mistaken.

A. Reconductoring TL 13835 Will Require Replacment of Overhead Structures And Replacement of Underground Cable.

Frontlines' estimate asserts: "Reconductor TL13835 w/out structures replaced [($75-$91 million)*0.3547] = $26 – $32 mill."[119] Frontlines assertion that TL 13835 can be reconductored without replacing its supporting structures rests on two contentions. First, Frontlines disagrees with SDG&E that any reconductor of TL 13835 should achieve a 273 MVA rating, contending that "it seems that a TL13835 line rating of 228 MVA would be sufficient to address these concerns through 2024."[120] Second, Frontlines claims that "a 228 MVA line rating can be achieved on TL13835 by replacing the existing ACSR conductor with an Aluminum Conductor/ Aluminum Clad-Steel Reinforced ('ACSS/AW') conductor that has a diameter and weight that is identical to the existing conductor that is already in place. Using this ACSS/AW conductor would obviate the need for TL13835 structure replacement, distribution line modifications, etc."[121]

Frontlines' contentions are mistaken. First, as discussed in Chapter 6, Section 3, even a 273 MVA rating does not mitigate the Category C overloads, so a 228 MVA rating will not mitigate such overloads. Second, an ACSS/AW conductor of the same diameter and weight could not meet a 228 MVA rating. Based on SDG&E ratings methodology, this wire cannot be operated at a high enough temperature to achieve a 228 MVA rating. Additionally, the elevated temperature of the wire would cause the wire to sag more than what exists today such that minimum ground clearances cannot be maintained. In order to meet a rating of even 228 MVA, a larger size ACSS/AW wire would be required, which would increase conductor sag and create

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119 Ayer Testimony at 20.
120 Ayer Testimony at 11.
121 Ayer Testimony at 12.

ground clearance violations, and would increase mechanical loading on the structure due to additional wind forces caused by larger diameter and weight per foot conductor. For these reasons, it is best to assume a larger conductor would be required to meet even the 228 MVA rating noted by Frontlines, and that structures would need replacement to accommodate the larger conductor due to increases in sag and structural loading.

Frontlines also failed to include the additional reconductoring of the underground sections of TL13835, which includes approximately 10,000 feet of underground between Laguna Niguel Substation to Capistrano Substation and approximately 1,800ft in Vista Montana near San Juan Hills High School (Supplemental Testimony, page 77). Both underground sections are not rated to support 228MVA rating. Replacement of cables in these two sections would also require traffic control measure to allow for the cable pulling and splicing.

To achieve the line rating proposed by Frontlines most, if not all, of the TL 13835 structures and underground cable would need to be replaced. Frontline's estimate fails to include these costs. Based on conceptual engineering and previous estimates provided in Supplemental Testimony, the estimated cost for reconductoring TL13835 would be approximately $66 million – $80 million (includes EMF Mitigation and AFUDC).

B. Frontlines Fails to Include Reconductoring The Underground Segment It Seems to Recommend be Reconductored

Frontlines testifies: "Upgrading the underground portion of TL13833 to 260 MW should address [certain overloads] through 2024."[122] Yet Frontlines' cost estimate does not include the cost of this reconductoring. This scope of work would require the replacement of underground cable in Vista Montana for both TL13816 and TL13833. To do so, portions of the TL13816 trench and conduit need to be relocated, and a new vault installed to facilitate the replacement of cable on TL13833 to achieve the 260 MW rating recommended by Frontlines. Based on conceptual engineering and cost estimating, the cost is estimated to be $1.5 million - $1.8 million.

[122] Ayer Testimony at 15.

C. Upgrading TL 13816, 13836, and 13846C is Necessary

Frontlines' estimate asserts: "Do not upgrade/replace TL 13816, 13836, and 13846C = $0."[123] This appears to be Frontlines' response to SDG&E's testimony that DEIR Alternative B-1 would need to reconductor these transmission lines as well as TL13835 to "remain compliant with mandatory NERC transmission planning standards."[124] Presumably, Frontlines' exclusion of such work is based upon its belief that reconductoring only TL13835 is sufficient to mitigate all NERC violations. As set forth in Chapter 6, Section 3, it is not.

Frontlines approach does nothing to prevent dropping large blocks of South Orange County load during substation maintenance. SDG&E considers this an unacceptable risk. To prevent load dropping, SDG&E would make changes to the South Orange County 138 kV network if the Proposed Project is not approved. Upgrading TL 13833 and 13846A are required even if SDG&E were required to accept the reduced rating of TL13835 as proposed by Frontlines. These project components, TL 13833 and 13846A rearrangement at Pico ($4 - 5 million), and the reconductors near Talega of TL 13816, 13836, and 13846C ($22.9-$28 million), are estimated to be a total of about $27 to $33million.

These costs are included in SDG&E's estimated costs for DEIR Alternative B-1, including the work necessary to deliver the same reliability benefits as the Proposed Project.

Section 4. Frontlines' Criticism of SDG&E's Cost Estimates Is Misplaced (Witness Karl Iliev)

A. The Talega STATCOM

Frontlines asserts: "This cost estimate does not include the Talega STATCOM replacement cost, nor should it. According to SDGE, the Talega STATCOM provides 100 MVAR of reactive support to the SOC 138 kV system, and the service life for substation class equipment like the STATCOM is between 20-60 years. According to a technical paper written jointly by Mitsubishi Corporation staff and SDGE staff, the STATCOM was installed on or around 2002. Thus it does not seem likely that the STATCOM will require replacement within the 10 year planning horizon considered for the SOCRE Project (i.e. before 2024, which is at the

[123] Ayer Testimony at 20.
[124] SDG&E Supplemental Testimony at 85.

extreme low end of the 20-60 year life cycle range indicated by SDGE)."[125] Frontlines also asserts that "the $80-$100 million estimate for a new STATCOM device is quite large compared to the cost of other, recently approved, dynamic voltage support projects."[126]

As an initial matter, the transmission planning period does not alter the fact the future costs will be incurred without the Proposed Project. Based upon current predictions for its system, SDG&E believes that the Proposed Project will make it unnecessary to replace the STATCOM when it reaches the end of its useful life. Frontlines' recommended alternative does not.

Moreover, SDG&E took a conservative and general estimate of a voltage control device by escalating the past costs SDG&E has incurred in installing these devices to the year 2020, which is a similar dollar escalation to the other elements in the proposed project. Although the year 2020 represents the earliest that this device would be replaced, SDG&E cannot foresee the exact service life of the STATCOM and would seek to optimize the remaining life of the device and replace it only when it either becomes either cost prohibitive to operate or until such time as the aging device poses a reliability risk to the SDG&E system.

Frontlines compares SDG&E's estimated cost to an SVC technology.[127] SDG&E agrees that SVC costs in general are lower, but SVC would not be a proper technology choice for the applications proposed in SDG&E testimony, as the SVC takes up a much larger footprint due to the array of capacitors and reactors necessary to reach this rating. Therefore, an SVC would not be a likely replacement for the STATCOM replacement at Talega or any of proposed alternatives that may contain a voltage control device.

B. SDG&E Estimated Cost of Substations

Frontlines criticizes SDG&E's estimate of the Prima Desecha Landfill substation:

> For example, SDGE estimates that a new 12- 18 acre AIS 230/138 kV substation at Prima Desecha landfill (consisting of 2 230 kV transformers, 19 relays and circuit breakers) will cost 53% more to construct than a 230/138 kV GIS substation that has significantly more infrastructure (including extensive 138 kV and 12 kV elements). This doesn't make sense even if the cost of land at the Prima Desecha landfill exceeds $6 million per acre (which seems unlikely given that it is a working landfill). In the event that land values at

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[125] Ayer Testimony at 22 (footnote omitted).
[126] Ayer Testimony at 22 (footnote omitted).
[127] Ayer Testimony at 22, footnote 59.

> Prima Desecha are that high, then a GIS substation at Prima Desecha should be considered instead.[128]

SDG&E escalated its estimated costs for an AIS or GIS alternative at Prima Desecha Landfill because the substation would be built on a landfill site. This poses both seen and unforseen challenges, including improper soil compaction and ground settling over time that could damage structures and pose risk to SDG&E facilities. SDG&E likely will have to account for these risks in its geotechnical analysis and create mitigation measure in the design of the site. Because of these known risks, and other potential unforeseen risks, SDG&E utilized a "reasonable worst case" scenario in estimating the cost of constructing a substation at this location.

[128] Ayer Testimony at 22.

CHAPTER 8. ORA'S AND FRONTLINES' "PICO SUBSTATION ALTERNATIVE" IS NEITHER FEASIBLE NOR COST-EFFECTIVE

Section 1. Introduction (Witness John Jontry)

ORA and Frontlines, through the testimony of Mr. Mee and Ms. Ayer, propose two alternatives to SDG&E's Proposed Project that are not found in the Draft Environmental Impact Report ("Draft EIR") prepared by the Commission's Energy Division. Although ORA's and Frontlines' new alternatives appear to differ in some respects, they are the same in suggesting an interconnection with a Southern California Edison ("SCE") 230 kV transmission line at or near SDG&E's existing Pico or Trabuco Substations.[129] This Chapter addresses the proposed interconnection at Pico Substation (the "Pico Substation Alternative") while Chapter 9 addresses the proposed interconnection at Trabuco Substation (the "Trabuco Substation Alternative").

ORA and Frontlines appear to suggest the Pico Substation Alternative solely because it is located near certain SCE transmission lines.

- Neither Mr. Mee nor Ms. Ayer present any power flow analysis of the impact on the interconnected electrical system of the proposed SCE interconnection at or near Pico Substation, much less how it performs under the applicable NERC transmission planning standards and the CAISO Planning Standards. In response to data requests, both conceded that they did not conduct any power flow analyses to determine the system impacts of, and how the system would perform with, their proposed versions of the Pico Substation Alternative.[130]

- Having failed to conduct a proper power flow analysis, neither Mr. Mee nor Ms. Ayer provide adequate information about the additional work required on SDG&E's South Orange County 138 kV network to allow a 230 kV interconnection at or near Pico Substation to serve South Orange County in the event Talega Substation were unable to serve the 138 kV network.

- Mr. Mee presents no information about design or construction of the expanded 230/138/12 kV Pico Substation, much less its feasibility or cost. Ms. Ayer presents no information about design or construction of the 230 kV GIS substation located somewhere near Pico Substation or any necessary changes to

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[129] Mee Testimony at 12; Ayer Testimony at 17-19.

[130] Attachment 32 (ORA Response to SDG&E's Second Set of Data Requests, Question 12 ("ORA did not generate power flow analysis regarding the Pico Alternative"); Attachment 34 (Frontlines' Response To SDG&E's Sixth Set Of Data Requests, Question 21 ("FRONTLINES has not conducted a power flow analysis of any 230 kV GIS substation near the Pico substation that FRONTLINES identified in testimony.").

Pico Substation to interconnect to such substation, much less the feasibility or cost of the required work at both locations.

- Mr. Mee presents no information about where or how to construct the proposed SCE interconnection to Pico Substation. Ms. Ayer presents no information about where or how to construct the proposed interconnection of an SCE transmission line to the 230 kV GIS substation located somewhere near Pico Substation, or the interconnection between such substation and Pico Substation.

- Neither Mr. Mee nor Ms. Ayers present a complete plan of service to address the reliability issues in South Orange County.

ORA describes its proposed Pico Substation Alternative as follows:

> ORA also identifies the Pico Substation alternative (see Figure 4-1). SDG&E's Pico Substation is approximately 225 feet away from SCE's 230 kV transmission lines. In order to provide a second power supply source to the SOC area from the Pico Substation, ORA recommends the following:
>
> 1) Use the existing ROW or acquire land next to the Pico Substation and construct a 230 kV yard.
>
> 2) Install a 230/138 kV transformer with a capacity of 392 MVA, and connect it to one of SCE's 230 kV transmission lines.
>
> 3) Construct a 138 kV bus position at the 138 kV yard.
>
> 4) Connect the 138 kV side of the 230/138 kV transformer to the 138 kV bus position.
>
> 5) Separate the SOC load into two parts by setting some of the 138 kV circuit breakers "Normal Open". Under normal operating conditions, the existing Talega Substation will supply one part of the SOC load and the upgraded Pico Substation will supply the other part of the SOC load. When one of the 230 kV power supplies (for example, Talega Substation) is not available, the "Normal Open" circuit breakers can be closed so the other 230 kV power supply (for example, Pico Substation) can supply critical load to the whole SOC area.[131]

In response to data requests, ORA stated that it "did not have enough information" to provide a schematic diagram showing the proposed equipment layout, to identify the major components, to identify work areas during construction, or provide any documents relating to design of a rebuilt 230/138/12 kV Pico Substation.[132] ORA also stated that it did not have

[131] Mee Testimony at 18.
[132] Attachment 32 (ORA Response to SDG&E's Second Set of Data Requests, Question 14).

sufficient information to identify a route for the transmission line to connect Pico Substation to an SCE transmission line (or even which SCE transmission line SDG&E should connect to).[133]

Frontlines describes its proposed Pico Substation Alternative as follows:

> These alternatives involve interconnections to SCE's 230 kV system on WECC Path 43. There are two 138 kV substations on SDGE's SOC system that lay in close proximity to SCE's 230 kV lines: Pico (which lies adjacent to SCE's lines) and Trabuco (which is approximately 1,000 feet from the SCE Path 43 ROW). A small 230 kV GIS substation looped in to an adjacent SCE 230 kV lines could be sufficient as a second source in SOC. … All four of the SCE 230 kV lines that comprise WECC path 43 are also located immediately adjacent to the Pico substation. Given the topology of the area surrounding the Pico substation, it may be necessary to use pad construction not unlike what SDGE proposes at Capistrano under the SOCRE Project.[134]

In responses to data requests, Frontlines explained that it proposes interconnecting an SCE line to a 230 kV GIS substation located near Pico Substation, which then would be interconnected to Pico Substation by a 138 kV transmission line.[135]

In responses to data requests, Frontlines further explained that: (a) it did not specify any location near Pico Substation for a 230 kV GIS substation; (b) does not have any one-line diagram or design schematics for such substation; (c) does not have proposed paths for the transmission lines interconnecting SCE's 230 kV line to the 230 kV GIS substation or from there to Pico Substation; and has no one-line diagram or design schematics for Pico Substation showing an interconnection with such a 230 kV GIS substation.[136]

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[133] Attachment 32 (ORA Response to SDG&E's Second Set of Data Requests, Question 16) ("SDG&E is invited to identify which line is easiest to connect considering electrical, geographical and economical issues. ORA does not have enough geographic information to determine the best route to interconnect the Pico Substation to the SCE 230 kV transmission lines since electrical maps for this aea are unavailable to ORA.").

[134] Ayer Testimony at 17-18, 19.

[135] Frontlines' Response To SDG&E's Fourth Set Of Data Requests, Question 14 ("FRONTLINES testimony did not recommend the construction of a rebuilt 230/138/12 kV Trabuco [sic] Substation. FRONTLINES testimony identified the Pico substation because it was located adjacent to the SCE 230 kV right of way and because the SCE 230 kV right of way included vacant land that could perhaps accommodate a 230 kV GIS substation with a transformer that could feed power to the SOC area via Pico. FRONTLINES cannot provide information regarding a rebuilt 230/138/12 kV Pico substation because FRONTLINES' testimony does not address such a thing."

[136] Attachment 34 (Frontlines' Response to SDG&E's Sixth Set of Data Requests, Questions 22-28).

Based on its review and analysis of the Pico Substation Alternative, SDG&E concludes that the Pico Substation Alternative (whether ORA's version or Frontlines' version) is neither feasible nor cost-effective.

Section 2. The Pico Substation Alternative Does Not Add a 230 kV Source that is Sufficiently Electrically Independent from Talega Substation (Witness John Jontry)

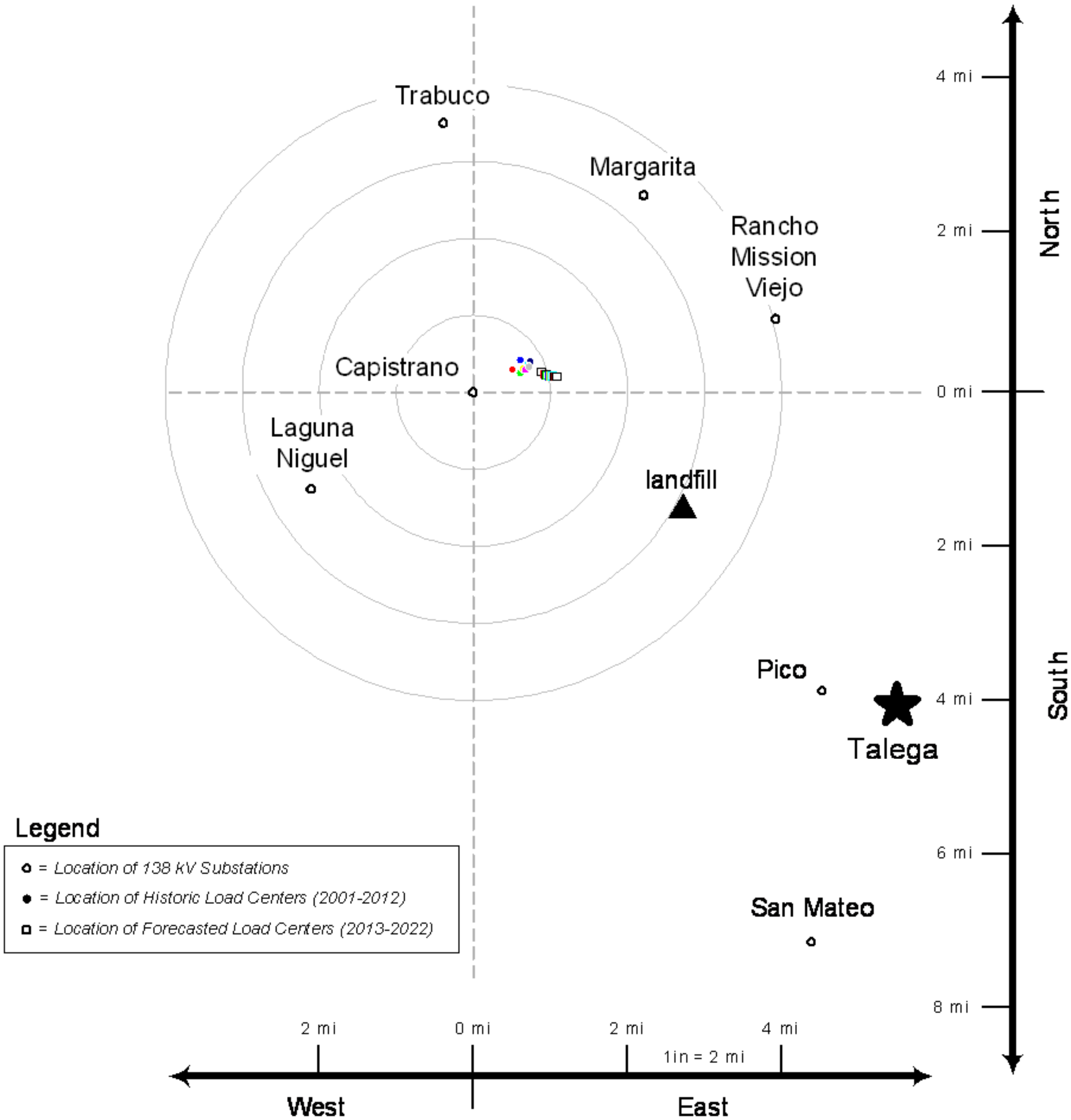
As noted by the CAISO in testimony of Robert Sparks, a second 230/138 kV source at Rancho Mission Viejo Substation (DEIR Alternative F) would be connected within one bus of the existing source at Talega Substation. This would leave the second source at Rancho Mission Viejo Substation vulnerable to cascading outages during contingencies at Talega Substation, and defeat the purpose of adding a second 230 kV bulk power connection.[137]

Similarly, SDG&E's Pico Substation is within one bus of Talega Substation. Therefore, a second 230/138 kV source at Pico Substation would be subject to the same limitations, and would not provide the same electrically independent, fully redundant source as that provided by a second source at Capistrano Substation. Note that two of the existing 138 kV transmission lines connecting at Pico also connect to Talega (TL13836 and TL13846); a severe disturbance at Talega will likely also directly affect those lines and could reduce the remaining lines out of Pico from four to two. Two 138 kV lines are insufficient to reliably serve all of the South Orange County load.

In addition to being electrically too close to Talega Substation, a second connection to the bulk power system at Pico would be on the wrong side of the South Orange County load center. See Fig. 8-1 below, which represents the load center analysis for South Orange County and indicates the relative proximity of all of the substations:

[137] Testimony of Robert Sparks at 18-19.

Figure 8.1 – South Orange County Load Center Analysis



Load Center based on Historic Loads		
Year	Miles North of CP	Miles East of CP
2001	0.299	0.506
2002	0.254	0.605
2003	0.419	0.605
2004	0.306	0.644
2005	0.293	0.681
2006	0.370	0.712
2007	0.410	0.728
2008	0.401	0.734
2009	0.401	0.734
2010	0.336	0.721
2011	0.337	0.721
2012	0.336	0.721

Load Center based on Forecasted Loads		
Year	Miles North of CP	Miles East of CP
2013	0.270	0.884
2014	0.234	0.924
2015	0.228	0.942
2016	0.221	0.959
2017	0.215	0.982
2018	0.211	1.003
2019	0.211	1.024
2020	0.210	1.045
2021	0.210	1.062
2022	0.205	1.083

As can be seen from Fig. 8-1, the electrical load center for South Orange County is west of Pico Substation, between Pico and Capistrano substations. As can be clearly seen in Fig. 8-1, the load center is calculated to be within only a mile of Capistrano Substation. As a result, a second 230/138 kV source at Pico would be electrically indistinguishable from the source at Talega Substation– the energy to serve South Orange County would still flow west from Pico and Talega substations towards the load center close to Capistano, through the 138 kV network. A second 230 kV source at Pico Substation is likely to require upgrading of the 138 kV lines west of Pico Substation to serve the flow of energy toward the load center. Because Capistrano is closer to the load center, placing the second 230 kV source there negates the need to upgrade SDG&E's 138 kV lines in South Orange County within the current ten-year planning window, and likely for some time thereafter. This is simply because energy injected into the 138 kV system from a new 230 kV source at Capistrano will tend to flow out in all directions, rather than in one direction as it would if injected at Pico. This has been confirmed by load flow studies performed by both SDG&E and the CAISO.

Section 3. An Interconnection with SCE at Pico Substation Would Take Years to Accomplish (Witness John Jontry)

SDG&E's Supplemental Testimony, Chapter 5, Section 2 explained the required process for SDG&E to seek interconnection with SCE's system. "SDG&E would need to comply with SCE's Transmission Owner Tariff, the Transmission Control Agreement among transmission owners and the California Independent System Operator ("CAISO"), and the CAISO Tariff."[138] As described in more detail in SDG&E's Supplemental Testimony: "SDG&E estimates that it would take a minimum of twelve months and could take as long as twenty-four months to complete an interconnection application, System Impact Study, and a Facilities Study for an interconnection with SCE as described in the SCE Alternative."[139] SDG&E also would need to obtain CAISO approval.[140] "SDG&E believes that such an application would go through the normal annual transmission planning process. Depending when the CPUC provided such direction, and SCE completed its studies, it could be up to a year before CAISO would decide

[138] SDG&E Supplemental Testimony at 99.
[139] SDG&E Supplemental Testimony at 101.
[140] SDG&E Supplemental Testimony at 102-04.

whether to approve the Commission's preferred solution (and any "Reliability Upgrades" to SCE's or other systems determined to be necessary to permit the interconnection)."[141] The same process would apply if SDG&E were to seek an interconnection to SCE's system as part of the Pico Substation Alternative.

Frontlines contends that SDG&E has overstated that amount of time it would take to obtain approval of an SCE interconnection from CAISO, asserting: "The interconnection studies and agreements can be developed on a track which parallels the CAISO approval process."[142] While this assertion sounds reasonable, in reality the CAISO and other stakeholders cannot evaluate an interconnection application that is not yet complete – the CAISO approval process would likely not move forward until reasonably detailed studies are agreed upon and completed by SDG&E and SCE. Also, it is instructive to recall that the SOCRE project has already been subjected to the CAISO stakeholder process, and included in subsequent annual transmission planning. A proposal to change the SOCRE project by seeking an interconnection with SCE's WECC Path 43 likely would be carefully scrutinized for impacts on the CAISO-controlled grid and the flow paths between Southern California and its neighbors; Arizona, Nevada and Mexico.

ORA's Mr. Mee states: "ORA disagrees with SDG&E's assertion. SOC load is not new, but has existed for many years. SCE and the CAISO are both aware of the existence of the SOC load."[143] Mr. Mee then provides several arguments about why he thinks the impact on the CAISO grid would be similar whether South Orange County load is served by SDG&E or SCE. Neither Mr. Mee's statement above nor his arguments addresses the time it would take for SDG&E to cause SCE to complete a System Impact Study and a Facilities Study, and submit it for review in the CAISO annual transmission planning process or the effect interconnecting to SCE versus SDG&E may have on power imports into Southern California. SDG&E addresses the flaws in Mr. Mee's arguments in the next section.

Neither Frontlines nor ORA addressed the additional years of delay that would arise if CAISO refused to approve an SCE interconnection.[144] Referring to the Draft EIR alternatives that included an SCE interconnection, CAISO witness Robert Sparks testified: "While these

[141] SDG&E Supplemental Testimony at 103.
[142] Ayer Testimony at 18.
[143] Mee Testimony at 21.
[144] SDG&E Supplemental Testimony at 103.

alternatives meet some of the immediate reliability concerns in the South Orange County area, they are unacceptable because of their negative impact on transfer capability on the major transmission corridor between San Diego and the Los Angeles basin."[145]

Neither Frontlines nor ORA addressed the additional years of delay that would arise if, to enable the SCE interconnection, the CAISO found that Reliability Upgrades were necessary, conditioned its approval on such upgrades, and such upgrades required CPUC approval for construction.[146] Referring to the Draft EIR alternatives that included an SCE interconnection, CAISO has determined that additional SDG&E 138 kV upgrades would be needed and that further studies would be needed to determine whether SCE upgrades are needed.[147] The Application in this proceeding was filed in May 2012. SDG&E cannot predict how long it would take for the Commission to approve any Reliability Upgrade projects that require CPUC permitting.

As SDG&E noted: "Throughout this period of time, SDG&E's approximately 300,000 South Orange County customers are at risk of losing electric service under a variety of outage scenarios."[148]

Frontlines asserts: "SDGE overstates the load loss risk that SOC will face during the SCE interconnection study/approval process. … [T]he simple alternatives described above are readily available and can address these "outage scenarios" once implemented."[149] As set forth in Chapter 6, Frontlines' "simple alternatives" would not mitigate the risk to many SDG&E customers in South Orange County. Moreover, leaving aside all the other reasons that the Pico Substation Alternative is flawed, it would not be prudent to rebuild Capistrano Substation as a 138/12 kV substation before knowing whether an alternative 230 kV source would be approved, the required scope to make it work, and the associated costs.

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[145] CAISO Sparks Testimony at 16.
[146] SDG&E Supplemental Testimony at 103-04.
[147] CAISO Sparks Testimony at 18.
[148] SDG&E Supplemental Testimony at 104.
[149] Ayer Testimony at 18.

Section 4. An SCE Interconnection at or Near Pico Substation Would Have Impacts to Both the SCE and SDG&E Transmission Systems (Witness John Jontry).

As discussed in SDG&E's Supplemental Testimony, Chapter 5, Section 3, an interconnection with SCE would parallel a robust 230 kV path with a relatively weak 138 kV network. This would have the dual negative impacts of restricting the allowable flow on the 230 kV path while subjecting the 138 kV system to network flows for which it was not designed. Restricting allowable flow on the SCE lines in South Orange County could result in limiting the transfer capability between the SDG&E and SCE systems, resulting in reduced import capability for both utilities. In fact, such an interconnection may have a significant impact on Southern California's import capability.

Any interconnection with SCE's 230 kV transmission lines in South Orange County would result in the same negative impacts--whether such interconnection is at Pico Substation or at a 230 kV GIS substation near Pico Substation that is then interconnected to Pico Substation.

The California ISO identified the same concerns with any alternative that would include a similar connection to SCE's 230 kV system, as expressed by CAISO witness Robert Sparks[150]:

> The Group 3 DEIR alternatives [alternatives that incorporate elements that parallel the South Orange County 138 kV system with the SCE 230 kV system] provide a new independent transmission source to serve the SDG&E's South Orange County service area from the SCE system. […] The SCE 230 kV line is a critical facility associated with the transmission corridor between the Los Angeles area and the San Diego area. As a consequence, the Group 3 DEIR alternatives result in the 138 kV network being paralleled to the existing 230 kV corridor linking the Los Angeles basin and San Diego. This paralleling of lower capacity networks with higher capacity networks lowers the overall capability of the 230 kV corridor.
>
> The CAISO conducted additional analysis to test the impact of the Group 3 DEIR alternatives on the capability of the 230 kV corridor. Based on this analysis, the CAISO found numerous overloading concerns under Category B and Category C contingencies in the South Orange County and SCE systems. The CAISO identified four thermal overloads for Category B contingencies and 52 thermal overloads for Category C contingencies in the 2024 Summer Off-Peak case. Even for the 2024 Summer Peak case with only about 200 MW flowing northbound between the two areas, there were 3 thermal overloads identified for Category C contingencies. This indicates that the Alternatives have significant adverse impacts on the Transfer Capability between the two

[150] Sparks Testimony at 17-18.

areas and system operation without further improvement in the south Orange County system.

SCE's System Impact Study is similarly likely to identify significant impacts to a number of important import paths and therefore require Reliability Upgrades to SCE's and SDG&E's systems at SDG&E's expense (which would be passed on to CAISO ratepayers). To properly assess the risk to the import limit, a WECC PRG (Path Rating Group) would be formed to determine any additional projects that would be needed to mitigate the impact to the import limit. These costs also would be attributed to SDG&E and then to CAISO ratepayers.

Because none of the Reliability Upgrades or WECC projects have been identified at this time (and would not be for at least several years), their environmental impacts have not been assessed.

Frontlines does not address these impacts, the projects it would take to mitigate them, or the cost of such mitigation.

In response to SDG&E's analysis, based on power flow modeling of an SCE interconnection, ORA's witness, who did not conduct any power flow modeling of an SCE interconnection, opines: "Whether the SOC load is interconnected to the SDG&E system or interconnected to the SCE system, the impact on the CAISO controlled grid will be similar."[151] Mr. Mee then provides four "reasons"—none of which actually analyze the impact of an SCE interconnection on either SDG&E's system or SCE's system. Below are Mr. Mee's "reasons" and SDG&E's responses:

1) The SOC load is located at the "border" of the SDG&E and SCE transmission systems. The distance between Talega Substation and the Trabuco or Pico Substations, is approximately 10 miles. To a 230 kV transmission system, the impedance of a 10 mile transmission line is negligible.[152]

This assertion is factually wrong – Pico and Talega substation are separated by less than two miles – as well as conceptually backwards. Paralleling a strong 230 kV system with a weak 138 kV link that is short and has relatively low impedance will tend to cause inadvertent loop flow on the 138 kV system, rather than inhibit it. Moreover, this assertion is contradicted by the

[151] Mee Testimony at 21.
[152] Mee Testimony at 21.

actual study work performed by the CAISO and referenced in Robert Spark's testimony, which indicate significant issues with paralleling the 138 kV system with the SCE 230 kV system.

> 2) Both SDG&E's and SCE's transmission systems were turned over to CAISO operational control almost 20 years ago. Both SCE's and SDG&E's transmission systems are now integrated as parts of the CAISO controlled grid. The CAISO controlled grid is obligated to provide services to all transmission users. Specifically, the SCE transmission system is obligated to provide access to any load including the load that is originally served by the SDG&E transmission system.[153]

The fact that CAISO has had operational control of both SDG&E's and SCE's transmission systems since 1999 does not provide any information about the impacts to either system of creating a new interconnection between them. Similarly, the requirement in SCE's Transmission Owner Tariff to allow interconnection, upon certain conditions, does not provide any information about the impacts of such interconnection. As discussed in SDG&E's Supplemental Testimony, Chapter 5, Section 2, the Transmission Owner Tariff requires a careful process to determine the impact of such an interconnection (a System Impact Study), determine the "Direct Assignment Facilities and, if applicable, any Reliability Upgrades required to provide the requested interconnection,"[154] and imposes those costs on the party requesting the interconnection. Mr. Mee has performed none of this work and does not refute SDG&E's and CAISO's testimony that reliability upgrades will be required.

> 3) Furthermore, no matter how or whether SDG&E's SOC load is interconnected to SDG&E's transmission system or to SCE's transmission system, the SOC load will be charged the same uniform transmission access charge.[155]

The transmission access charge provides no information about the impact of an SCE interconnection on either SDG&E's or SCE's transmission systems.

> 4) After the shutdown of the San Onofre Nuclear Generation Station (SONGS), approximately 2,150 MW of generation disappeared and the same amount of power flow disappeared on Path 43 and Path 44. So the electric pathways of Path 43 and Path 44 must be very relaxed at this time. The SOC load is now interconnected to Path 44 which is in the SDG&E service territory. With the SCE interconnection alternatives, part of the load will be disconnected from Path 44 and interconnected to Path 43, which is in the SCE service territory. Since the amount of load shifting between the SDG&E transmission system and SCE transmission system is small compared to the

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[153] Mee Testimony at 21-22.
[154] Transmission Owner Tariff, Section 8.1.2.
[155] Mee Testimony at 22.

> disappearance of the 2,150 MW generations from SONGS, there should be no technical issues. Since there are no economic or technical constraints for this interconnection, there is no reason for the SCE's transmission systems to take years to integrate part of the SOC load.[156]

The "economic" constraints noted by Mr. Mee are irrelevant to system impacts. Under the CAISO's transmission owner tariff, needed Reliability Upgrades are required and those costs must be paid and assigned to ratepayers. Moreover, the disappearance of SONGS had little or no impact on the 138 kV network in South Orange County, but as the CAISO's analysis demonstrated, paralleling that system with SCE's 230 kV Path 43 certainly will.

Furthermore, although it is correct that there is no longer 2,150 MW of generation at San Onofre, the power needed to make up for the loss of San Onofre will flow over Paths 43 and 44. Paths 43 and 44 remain important paths connecting the Los Angeles load center with generation in the southwest. Paths 43 and 44 carry, on a regular basis, hundreds of megawatts of energy north to the Los Angeles load center even in the absence of SONGS generation, with historical flows reaching as high as 1440 MW post-SONGS. The assertion that these paths are "relaxed" and carry little or no flow is incorrect.

Loop flow caused by a Pico connection to SCE will constrain the amount of power which can flow north over Path 43. Results of analysis with approximately 1000 MWs flowing north on Path 43 (out of SDG&E into SCE) show violations of NERC Category B and C contingencies. In order to prevent these violations, limitations will be placed on the amount of power flowing on Path 43 unless and until Reliability Upgrades are made. A connection to SCE at Pico will adversely affect the transmission system.

Section 5. The Pico Substation Alternative Will Not Address South Orange County Reliability Needs Without Additional Work to SDG&E's 138 kV Transmission System (Witness Cory Smith).

Neither ORA nor Frontlines presents a coherent plan of service to address the reliability issues in SDG&E's South Orange County system. ORA describes its Pico Substation Alternative as an interconnection of Pico Substation and an SCE transmission line, but does not describe any other work it recommends to address the South Orange County reliability issues (other than its infeasible and ineffective suggestions regarding Talega Substation, addressed in

[156] Mee Testimony at 22.

Chapter 3). ORA's cost estimate for its Pico Substation Alternative expressly excludes "the costs of rebuilding Capistrano Substation as a 138/12 kV substation, or the cost of reconfiguring the Talega Substation," and ORA nowhere identifies any upgrades to SDG&E's 138 kV system .[157]

Slightly differing from ORA, Frontlines proposes an SCE interconnection to a 230 kV GIS substation located at an unknown location near Pico Substation, which is then connected by a 138 kV transmission line to Pico Substation. But Frontlines does not estimate its "Pico Substation Alternative" costs at all and does not include its Pico Substation Alternative in its "recommended alternative approach."[158]

SDG&E, which has an obligation to provide reliable electric service to its South Orange County customers, must address the reliability issues in its system with a coherent and comprehensive plan of service. Given ORA's and Frontlines' failure to provide sufficient information about their Pico Substation Alternatives, SDG&E used reasonable assumptions about a potential design to model the alternatives impact on SDG&E's South Orange County transmission system through power flow analyses. The model assumed two 230/138 kV 392 MVA transformers at a rebuilt Pico Substation.[159] The transformers were tied together in a breaker and a half scheme on the 230 kV side of the transformer and tied directly to the Pico East and West buses on the 138 kV side.

The Pico Substation Alternative did not remove the NERC Category C violations, all of which would be mitigated by SDG&E's Proposed Project.

<u>Table 8-1 NERC Violations Under Pico Substation Alternative</u>

Contingency	2020	2025	2030
C3: 13816 + 13831	-	13833	13833
C3: 13816 + 13833	-	13831	13831
C3: 13831 + 13833	13834, 13816	13834, 13816	13834,13816
C3: 13833 + 13838	13834, 13816	13834, 13816	13834,13816
C1: PI W	-	13831	13831
C2: PI BT	-	13831	13831

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[157] Mee Testimony at 18, 20.
[158] Ayer Testimony at 20.
[159] For the reasons discussed in Chapter 5 with respect to a second source at RMV Substation, neither a single 392 MVA 230/138 kV transformer nor a single 450 MVA 230/138 kV transformer would be sufficient to serve South Orange County load in the event Talega Substation were out of service.

C2: PI 13833	-	13831	13831
C2: PI 13816	-	13831	13831
C3:CP BK41 + 13831		-	13833
C3:CP BK41 + 13833		-	13831

The Pico Substation Alternative also does not mitigate the need to shed load under numerous Category C contingencies, all of which would be mitigated by SDG&E's Proposed Project.

Table 8-2 Load Shed Required Under Pico Substation Alternative

Contingency	2020	2025	2030
C3:13816 + 13831	13833	13833	13833
C3:13816 + 13833	13831	13831, 13838	13838,13831
C3:13816 + 13835	13834	13834	13834,13833
C3:13816 + 13838	13833	13833	13833
C3:13831 + 13833	13834,13816	13834,13816	13834,13816
C3:13831 + 13834	13833	13833	13833,13816
C3:13831 + 13835	13816	13816	13816
C3:13833 + 13835	13816	13816	13816
C3:13833 + 13838	13834, 13816	13834,13816	13834,13816
C3:13834 + 13838	13833	13833	13833
C3:13835 + 13838	13816	13816	13816
C1:PI W	13831	13838,13831	13838,13831
C2:PI BT	13831	13838,13831	13838,13831
C2:PI13833	13831	13838,13831	13838,13831
C2:PI13816	13831	13838,13831	13838,13831
C3:CP BK40 + 13831	13833	13833	13833
C3:CP BK40 + 13838	13833	13833	13833
C3:CP BK41 + 13831	13833	13833	13833,13830
C3:CP BK41 + 13833	13831	13831	13831
C3:CP BK41 + 13838	13833	13833	13833

A 230 kV substation at Pico would also require some type of voltage support to provide MVars to the SCE system. The summary analysis conducted by SDG&E, although was not comprehensive, identified low voltages. In order to specify the size and type (static or dynamic) of voltage support equipment needed, SDG&E would be required to do a comprehensive analysis. Further, to support voltage in South Orange County, SDG&E also would need to replace the Talega STATCOM when it reaches the end of its useful life or install a new dynamic voltage control device (SVC, STATCOM or Synchronous Condenser) at the rebuilt Capistrano Substation at that time.

As discussed in Section 3 and 4 above, SCE's System Impact Study, CAISO's transmission studies, and a WECC Path Rating Group would determine whether additional Reliability Upgrades are necessary to address the impacts of the SCE interconnection on SDG&E's system, SCE's system, the CAISO controlled grid, and the rest of the WECC interconnection. SDG&E has not addressed any such Reliability Upgrades in its testimony.

Section 6. Pico Substation Does Not Have Space to Add a 230 kV Switchyard, and Expansion Would be Difficult and Costly (Witness Karl Iliev).

A. Pico Substation Does Not Have Space to Add a 230 kV Switchyard

SDG&E's existing Pico Substation is built on a pad approximately 250 ft x 220 ft. The substation was built as a single bus- single breaker 138/12 kV distribution substation, with a planned ultimate configuration of four 138/12 kV transformers and four 138 kV transmission lines. Pico Substation currently has four 138 kV transmission lines and two 138/12 kV transformers. Confidential Attachment 36 shows the Pico Substation general arrangement.

Pico Substation takes up the entire lot of the property acquired for the substation and is smaller than SDGE's current standard for a distribution 138/12 kV substation, which estimates a minimum of 265' x 290' plus 25% for space requirements for water quality and hydromodification management criteria, as required by the Regional Water Quality Control Board, which is usually met through the combined use of underground infiltration tanks, and above ground detention basins. SDG&E's standard for distribution substation also takes into account a larger control shelter, fire safety requirements, and noise requirements.

ORA's Pico Substation Alternative proposes to convert Pico Substation into a 230/138/12 kV substation. Such a substation is considerably larger than a distribution substation and will not fit on the existing Pico Substation property lot.

SDGE's requirement for a 230/138 kV transmission bus serving bulk power transformers is a breaker and half arrangement (see Attachment 30 for a standard breaker and a half diagram) This is required for a cost effective, reliable bus configuration that allows for breaker and/or bus maintenance without line/bank interruption and minimal disruption in a breaker failure situation. It is also SDG&E's standard to build at least one spare position when constructing a new substation to allow for future growth and/or maintenance activities. Doing so is prudent and cost-effective, while failing to do so could result in significant additional costs if rebuilding the substation is later necessary to address such issues.

If Pico Substation were rebuilt as a 230/138/12 kV substation, the minimum requirements would be:

- A 230 kV, 6-element, 3000A (possibly 4000A due to the SCE connection) switchyard with a breaker and half bus arrangement, with two 230 kV TL positions, two 230/138 kV transformer positions and a spare bay (TL and bank spare position), and a voltage regulating device.
- A new control shelter to house the increased Transmission control & protection equipment.
- A 138 kV 3000 amp switchyard with a breaker and half bus arrangement, with four distribution transformers (two now with two future), two connections for the 230/138kV transformers, four 138 kV Transmission Lines). At least 10 positions are needed.

To allow for property line setback requirements and required landscaping required by local or state jurisdictions, and/or noise requirements, fire safety requirements, and standard drive aisle access, a minimum size 230/138/12 kV substation yard meeting SDG&E's standards would be approximately 6-7 acres using GIS technology or approximately 12 acres using AIS technology – depending on the topography and arrangement of the land. This acreage accounts for the space requirements for water quality and hydromodification management criteria, as required by the Regional Water Quality Control Board, which is usually met through the combined use of underground infiltration tanks, and above ground detention basins. This space also accounts for required drive aisles between equipment for maintenance access, placement of equipment for optimum EMF and noise requirements, installation of required underground termination connections, cable pulling space requirements and any required pole placements. A 230/138/12 kV substation cannot be built on SDG&E's existing Pico Substation property.

B. Expanding and Rebuilding Pico Substation Would be Difficult and Costly

Assuming ORA's proposed Pico Substation Alternative uses GIS technology, an expanded 230/138/12 kV Pico Substation would require approximately an additional 4-5 acres, depending upon topology and type of transmission connections. If the existing substation must be rebuilt, then a total of 6-7 acres would be required.

To accommodate a 230/138/12 kV substation, SDG&E would have to acquire additional property (by negotiation or condemnation) of the commercial businesses to the east or west of the existing substation property. North of the substation is a street and south of the substation is the hillside with SCE transmission corridor that may be affected by an expansion to the south. See Attachment 35. SDG&E would incur a cost to acquire such properties that would not be incurred with the Proposed Project, where SDG&E would be able to construct a 230/138/12 kV substation on SDG&E-owned Capistrano Substation property.

A key driver for the amount of additional land would be the construction sequence. The sequence would be as follows:

- New build of a new 138 kV breaker and a half configuration GIS on new property that would be acquired. This prevents interruption of service by customers being fed from the existing 138 kV infrastructure.
- Relocation of the current 12 kV infrastructure to the new 138 kV GIS, allowing de-energizing of old 138 kV infrastructure.
- Demolition and expansion of the existing 138 kV portion of the switchyard to accommodate the 230 kV GIS.
- Building of the 230 kV GIS infrastructure and final energizing in the new configuration.
- If the layout (depending on land acquisition) cannot accommodate keeping the 12kV infrastructure in-place, more construction sequencing would be required to completely rebuild and relocate the existing 12 kV infrastructure (to optimize the facilities location on the property). This would have significant negative impacts in the cost, scope, environmental impact, and project duration described above. Additionally, based on the location and layout (determined by land acquisition), overhead 230 kV and 138 kV may no longer be feasible, increasing cost to account for undergrounding transmission lines into the substation.

The layout and visual aesthetics of a 230/138/12 kV Pico Substation, constructed with GIS technology, would be very similar to the Proposed Project's rebuild of Capistrano Substation. SDG&E would expect to construct a wall and install landscaping to screen the substation, but it would include two 40-50 foot GIS buildings and a voltage control device.

The impact to the area would involve site work noise and dust suppression, and construction in the streets of the surrounding businesses for almost the entire construction duration. Street construction would be lengthy due to the relocation of the existing distribution circuits (if affected by the layout) and possible undergrounding of the138kV transmission lines. Traffic could also be impaired by the haul trucks required for the site development work.

Without any engineering being done to determine the exact grading and hydromodification requirements, the size and cost of the 230/138 kV Substation, which may be able to connect to the existing distribution components in Pico Substation, is estimated to be comparable to the Proposed Project work at Capistrano Substation, and thus approximately $135 million to $165 million (with AFUDC, $148 million to $181 million). If the existing Pico Substation must be relocated, including the distribution equipment and circuits, then the cost would be approximately $171 million to $209 million (including AFUDC). Neither of these estimated costs include relocating the existing 138kV transmission or distribution circuits, adding new 138kV and 230kV transmission lines, permitting, mitigation, property acquisition costs, or ROW. Property acquisition costs, including business relocation, would be significant—and avoided by the Proposed Project.

Additional costs at Pico Substation would include a voltage control device, which may cost as much as $81-$99 million (with AFUDC, $89 million to $109 million), with the needed support to be determined after additional study.

C. Frontlines' Proposal for a 230 kV GIS Substation At an Unknown Location Near Pico Substation Is Unsupported.

SDG&E cannot evaluate Frontlines' proposal for a 230 kV GIS substation near Pico Substation because Frontlines has provided essentially no information about this proposed alternative. Frontlines has not identified any particular location, so SDG&E cannot evaluate its size, topography, what would be displaced if SDG&E were to acquire such property, the feasibility of connecting transmission lines to a substation at such location, the paths such transmission lines would use to approach or leave such substation, or the environmental impacts of such construction. Without such information, SDG&E cannot begin to assess the required work or estimate its costs. A proposed alternative that does not include the location for a proposed 230 kV substation is not feasible.

SDG&E also cannot evaluate Frontlines' proposed design for a 230 kV substation because Frontlines has no design information. SDG&E sought such information through data requests to Frontlines and was informed "FRONTLINES does not possess any schematics or figures of the 230 kV GIS substation located near the Pico substation that is referred to in FRONTLINES testimony," nor does Frontlines have a one-line diagram of such substation [160]

SDG&E also cannot evaluate Frontlines' proposed changes to Pico Substation to interconnect to the proposed 230 kV GIS substation. SDG&E sought such information through data requests to Frontlines and was informed: "Neither FRONTLINES nor Ms. Ayer possess a one line diagram of the Trabuco substation as configured to accommodate an interconnection with a 230 kV GIS substation located near Trabuco."[161] Further, SDG&E was informed: "FRONTLINES does not possess any schematics or one-line diagrams of any SOC substations (including Pico) other than what SDGE has provided in the record of this proceeding or in response to discovery requests. Nor has FRONTLINES prepared any such diagrams. In addition, FRONTLINES does not possess any layout figures for any SOC substations (including Pico) other than aerial figures which FRONTLINES has already provided to SDGE in prior data request responses."[162]

The 138 kV bus at Pico substation would have to be rebuilt if transmission elements are added to it into a more reliable breaker and a half configuration. Even if SDG&E accepted the existing single-breaker single-bus arrangement, expansion of the 138kV bus inside the existing site footprint is not possible as there is insufficient space to maintain proper maintenance access to the existing equipment with the extra bus segment. Additionally, simply adding another element to the existing bus is not possible without addressing the bus rating. The current bus does not meet the load rating that would be required to feed Southern Orange County in peak loading conditions and would have to be replaced with infrastructure that had higher ratings.

In short, Frontlines has not provided sufficient information about its proposal for SDG&E to evaluate its feasibility, much less its costs. However, Frontlines' version of a Pico Substation Alternative would include constructing a 230/138 kV GIS substation at some acquired property near Pico, expanding and rebuilding at least some of Pico Substation, and rebuilding a 138/12 kV Capistrano Substation whereas SDG&E's Proposed Project only rebuilds a 230/138/12 kV Capistrano Substation on SDG&E-owned property. SDG&E expects that Frontlines' Pico

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[160] Attachment 34 (Frontlines' Response to SDG&E's Sixth Set of Data Requests, Questions 22 & 23).
[161] Attachment 34 (Frontlines' Response to SDG&E's Sixth Set of Data Requests, Question 24).
[162] Attachment 34 (Frontlines' Response to SDG&E's Sixth Set of Data Requests, Question 25).

Substation Alternative would cost considerably more for substation work than the Proposed Project.

Although Frontlines provides essentially no design information for its proposal, Frontlines asserts that SDG&E over-estimates the amount of space required to add a 230 kV switchyard to an existing SDG&E South Orange County substation:

> According to SDGE, an air insulated 230 kV substation ("AIS") requires a 12 acre space and a gas insulated substation ("GIS") 230 kV substation requires a 6-7 acre space. However, these size requirements appear inflated. For example, consider the San Juan Capistrano substation that SDGE proposes to construct as part of the SOCRE Project. According to the Proponents Environmental Assessment ("PEA"), it will be constructed on four different pads at various elevations and accommodate the following 230 kV equipment:
>
> - A 230 kV GIS substation with 3 bays in a breaker and a half configuration to accommodates 1 three 230 kV lines and 3 transformers which occupies less than 0.4 acres of pad 3.
> - A 230 kV capacitor bank that occupies less than 0.45 acres of pad 4.
> - Three 230/138 kV transformers that occupy less than 0.25 acres of pad 2.
>
> Even assuming an 85+ foot separation distance between the transformers and other substation elements, this equipment occupies a substantially smaller footprint than the 6-7 acres that SDGE claims is needed for a GIS substation interconnected to SCE's system.[163]

SDG&E's size approximations include areas which are dependent upon on the topography and arrangement of the land. If the proposed substation site is perfectly flat and rectangular shape then the substation would take less land than if the site has hills, requires retaining walls, and/or has a lot of unusable space due to boundary configurations. This acreage also accounts for the space requirements for hydromodifications, required drive aisles between equipment for proper maintenance access and equipment transport, placement of equipment for optimum EMF and noise requirements, installation of required underground termination connections and cable pulling space requirements and any required pole placements. Required landscaping and aesthetic modifications must also be accounted for in approximating land size.

[163] Ayer Testimony at 18-19 (footnotes omitted).

Frontlines also refers to an article about the Sinatra 230/138/12 kV GIS substation in Las Vegas to contend "an SCE interconnection with a GIS 230 kV substation could be accommodated on a parcel that is a fraction of the 6-7 acre size posited by SDGE."[164]

Frontlines' comparison of a GIS substation near Pico Substation to the Sinatra substation in Las Vegas is missing critical differences in the two situations. According to an article regarding the installation[165]:

> The 230-kV GIS from ABB (Zurich, Switzerland) at the northern end of the site features three 230-kV line terminals in a four-breaker ring bus. The two initial underground 230-kV lines use two cross-linked polyethylene (XLPE)-insulated 2500-kcmil copper cables per phase supplied by Prysmian Power Cables and Systems (Lexington, South Carolina, U.S.). South of the 230-kV GIS is a 180/240/300//336-MVA, 230/138-kV autotransformer manufactured by Siemens (Munich, Germany).
>
> The low side of the autotransformer is attached to an ABB 138-kV GIS, vertically stacked six-breaker ring bus. In addition to being connected to the autotransformer, the 138-kV GIS is connected to two underground 138-kV circuits from the Suzanne and Bellagio substations, plus a future 138-kV position. The two initial underground 138-kV lines use Nexans (Paris, France) XLPE-insulated 2000-kcmil copper cable. The 138-kV GIS also features two air-insulated terminals for mobile transformer connection.

The use of a ring bus at the Sinatra Substation limits the ultimate capacity of the substation configuration, thus lowering space requirements to a fraction of that using a breaker and a half configuration. A ring bus also provides much lower reliability than a breaker and a half configuration affords. SDG&E's Proposed Project requires much more elements in its ultimate configuration due to its proposed scope and therefore cannot accommodate a ring bus configuration. Because of this, the Proposed Project and its alternatives should not be compared to a GIS with an ultimate configuration that can fit into a ring bus.

Additionally, standard construction for a utility is determined by that utility's maintenance, safety, and regulatory programs. First, environmental and construction requirements at the City and State level are vastly different in California as compared to Las Vegas. Water runoff, air quality impact, visual mitigation, noise mitigation, traffic mitigation, etc. are much different, which impact cost and space requirements. As mentioned previously,

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[164] Ayer Testimony at 19.

[165] http://tdworld.com/substations/more-power-las-vegas.

RWQCB requirements to address water quality impacts alone can account for an additional 25% of substation space in California.

Additionally, the Sinatra substation does not provide for sufficient maintenance access inside the substation, meaning failed equipment would force cranes to shut down traffic outside of the substation in order to replace any failed GIS or transformer equipment. Normal preventive maintenance access is also eliminated, requiring design of transformers, circuit breakers, and other devices that are not regularly serviced, further lowering reliability. Additionally, SDG&E prefers indoor GIS as it has been proven to keep the temperature of the GIS equipment more constant, leading to longer life of GIS sealing technology, and thus minimizing long-term air quality impact from fugitive Sulfur Hexaflouride gas (which according to the EPA has approximately 22,000 times the impact of CO2 as a greenhouse gas). Leaving the GIS outdoors lowers the service life of the equipment, obtaining reduced space by reducing performance.

In sum, substations outside of SDG&E's service territory cannot be compared to SDG&E's substations for various reasons including:

- Permitting requirements of each site specific jurisdiction, including the RWQCB hydromodification requirements applicable in California
- Equipment requirements – each utility may have different equipment specifications which will result in different size and spacing requirements
- Work practices and safety rules requiring different equipment layouts.
- Aesthetic mitigation requirements – each local jurisdiction will require its own property setbacks and landscaping requirements
- Reliability requirements – each utility requires its own layout and equipment specifications to meet its own reliability concerns
- Transmission and/or distribution system requirements specific to the utility system.

Section 7. Rebuilding a 138/12 kV Capistrano Substation Is Necessary, and Would Have Similar Impacts as the Proposed Project (Witness Karl Iliev)

SDG&E appreciates Frontlines' agreement that Capistrano Substation must be rebuilt or overhauled. Based upon careful analysis, SDG&E concluded that only replacing equipment in the existing Capistrano Substation will not provide adequate reliability for SDG&E's customers in the City and South Orange County. Adequate reliability can only be gained by a complete rebuild and expansion of the existing substation. Replacing aging infrastructure in kind and rebuilding a limited size substation in the existing yard will not achieve the improvements provided by the Proposed Project, and will not achieve SDG&E's goal to provide reliable electric service to its South Orange County customers.

The rebuild of the Capistrano Substation would expand to the lower yard within SDG&E-owned property and add a minimum of two spare 138kV positions for future needs that may arise outside of the planning time horizon, but within the expanded lifetime of the newly rebuilt substation. The substation cannot be rebuilt in its current location and needs to be built in the lower yard to maintain construction safety and station reliability during the rebuild project.

Moreover, SDG&E has not had sufficient time to properly analyze this Alternative and Capistrano Substation may have to accommodate additional 138kV transmission lines.

SDG&E agrees that if the second 230 kV source for South Orange County were to be moved to another site, then Capistrano Substation should be rebuilt as a 138/12 kV substation. If rebuilt as a stand-alone project, a Capistrano 138/12 kV substation is estimated to cost between $135 million to $165 million (including permitting, mitigation and AFUDC costs).

Section 8. Transmission and Distribution Work that Would be Required by the Pico Substation Alternative (Witness Willie Thomas)

The Pico Substation Alternatives from both ORA and Frontlines lack sufficient detail to determine the full scope of work necessary to accommodate the interconnection with the adjacent SCE line. In particular, without substation layout details it is difficult to determine how lines will enter and exit the substation, and if they will be overhead or underground. Given the lack of details on such an interconnection and due to lack of time to conduct detailed engineering studies and consultation with SCE, SDG&E has assumed that the substation will be expanded and rebuilt at the same general location to accommodate the interconnection. The scope of work listed below may not incorporate all aspects of the design nor illustrate the construction sequence, nor does it suggest building a 230/138/12 kV substation is physically possible at this location due to site constraints. At a minimum, the following would likely be required to make the SCE interconnection possible at Pico Substation:

- Three SCE towers adjacent to the newly expanded Pico substation would be removed and four new terminal dead-end double circuit structures (designed to handle all wires off on one side) installed to accommodate the looping in of the SCE line. The SCE lattice tower directly south of Pico would be replaced with two terminal dead-end double circuit structures to allow the looping in of one of the SCE lines and bypassing of the second SCE line as the existing tower is likely not designed to handle the imbalanced loading that would be imparted by the new arrangement. Additionally, it would provide better reliability and maintenance to install separate structures. The remaining tower removals, one tower east and one tower west of Pico look to be tangent structures, which are typically not designed to handle changes in span length or tensions, and it would be prudent to assume they also need to be replaced with terminal dead-end double circuit structures to accommodate the new arrangement. Additional grading and site development would also be required to facilitate this construction, and may include retaining walls due to the steep terrain to ensure adequate working space around each of the structures.

- The adjacent TL13835 line would need to be relocated to accommodate the SCE line being looped into the newly expanded Pico substation. Without detailed engineering, it should be assumed that an underground route is necessary to accommodate the crossing of the SCE line. The length of this underground is assumed to be approximately 1,400ft and would require removal of three H-frame wood structures and installation of two cable poles and one dead-end foundation pole.

- Tielines TL13816, 33, 36, and 46 would likely enter into the newly expanded substation in underground positions to accommodate the 230 kV interconnection and to minimize outages during construction. It might be possible to construct A-frame structures on the West and East side of the substation; however, not having a detailed substation arrangement and not having conducted detailed engineering to ensure clearances can be met, it should be assumed that the lines would terminate on cable pole structures (four total, one for each 138kV line terminating in Pico) either adjacent to or inside the newly expanded substation. Removals would include the removal of two dead-end foundation poles south of Pico, a single tangent lattice tower north of Pico, and removal of associated overhead wire and hardware.

The scope of work described above is similar to that described in the Supplemental Testimony page 114 for a new substation at Prima Deschecha Landfill, however, the 138kV underground and 230kV overhead are assumed to be shorter in length. It is assumed the Pico to SCE interconnection costs are roughly 75% of the costs to build the SCE interconnection at Prima Deschecha Landfill, and is estimated to cost between $20 million and $24 million (including EMF mitigation and AFUDC).

Section 9. The Pico Substation Alternative Would Cost More Than the Proposed Project (Witness Willie Thomas)

Because ORA's Pico Substation Alternative was first presented in ORA's testimony, and was not evaluated in the Commission's Draft EIR, SDG&E has not had time to fully conduct even a high level evaluation of its costs (assuming it were otherwise feasible).

At this point, subject to further review and engineering, SDG&E notes the following estimated costs:

- As set forth in Section 6.B above, SDG&E estimates the cost of constructing a 230/138 kV substation at Pico to be comparable to the Proposed Project work at Capistrano Substation, and thus approximately $135 million to $165 million (with AFUDC, $148 million to $181 million). If the existing Pico Substation must be relocated, including the distribution equipment, then the cost would be approximately $171million to $209 million (including AFUDC). . These estimated costs do not include relocating the existing 138kV transmission, adding new 138kV and 230kV transmission lines, property acquisition costs, or ROW. (Permitting and mitigation costs are assumed to be covered in the Capistrano cost estimate). Property acquisition costs, including business relocation, would be significant.

- As set forth in Section 7 above, rebuilding Capistrano Substation as a 138/12 kV substation is estimated to cost, as a stand-alone project, between $135 million to $165 million (including permitting, mitigation and AFUDC costs).

- As set forth in Section 8 above, the cost of interconnecting Pico to an SCE transmission line is estimated to cost between $20 million and $24 million (including EMF mitigation and AFUDC).

- As discussed in Section 2, a second 230 kV source at Pico Substation is likely to require upgrading of the 138 kV lines west of Pico Substation to serve the flow of energy toward the load center. As set forth in Section 5, simply interconnecting an SCE 230 kV line to Pico Substation will not mitigate the NERC Category C violations set forth in Table 8-1 or the Category C load shedding set forth in Chapter 8-2. Therefore, implementation of the Pico Substation Alternative (if feasible) would require upgrading SDG&E's 138 kV network in South Orange County. At this point, SDG&E has not had time to conduct the studies necessary to identify the necessary upgrades.

- To provide the reliability benefits of the Proposed Project, a rebuilt 230/138/12 kV Pico Substation would need to be able to serve peak load in South Orange County during an outage of service from Talega Substation. At this point, SDG&E has not had time to conduct the studies necessary to identify the necessary upgrades to SDG&E's 138 kV network to allow a rebuilt Pico

Substation to do so. Two 392 MVA 230/138 kV transformers at the rebuilt Pico Substation would be necessary and are included in SDG&E' cost estimate above.

- As set forth in Section 5 above, a voltage control device will be necessary at a rebuilt Pico Substation to supply MVars to SCE and, as noted in Section 6.B above, such device may cost as much as $81-$99 million (with AFUDC, $89 million to $109 million) (appropriate size and type will require further study). In addition, voltage support is needed for South Orange County. SDG&E's Proposed Project includes two 230 kV capacitors at rebuilt Capistrano 230 kV bus. This proposed Pico Alternative will require an additional voltage control device at either Capistrano or at Talega when the existing Talega STATCOM reaches the end of its useful life, at an additional cost of $81-$99 million (with AFUDC, $89 million to $109 million).

SDG&E's estimated cost for its Proposed Project is $384 million. The elements of ORA's Pico Substation Alternative, for which SDG&E has had little time to estimate cost, totals $481 million to $588 million, even assuming that Pico distribution equipment does not need to be relocated. This cost does not include property acquisition and business relocation at the expanded Pico Substation, 138 kV upgrades to address NERC Category C violations and load shedding, 138 kV upgrades to mitigate the risk of forced outages during maintenance events, and 138 kV upgrades to make a rebuilt Pico Substation fully redundant for South Orange County in the event of a Talega service outage. As a result, SDG&E is confident that the Pico Substation Alternative will cost far more than the Proposed Project.

CHAPTER 9. ORA'S AND FRONTLINES' "TRABUCO SUBSTATION ALTERNATIVE" IS NEITHER FEASIBLE NOR COST-EFFECTIVE

Section 1. Introduction (Witness John Jontry)

As noted above, ORA and Frontlines also have proposed a "Trabuco Substation Alternative," consisting of interconnecting SDG&E's South Orange County system to an SCE 230 kV transmission line at or near SDG&E's existing Trabuco Substation. Like the Pico Substation Alternative, ORA and Frontlines appear to suggest the Trabuco Substation Alternative solely because Trabuco Substation is located near certain SCE transmission lines.

- Neither Mr. Mee nor Ms. Ayer present any power flow analysis of the impact on the interconnected electrical system of the proposed SCE interconnection at or near Trabuco Substation, much less how it performs under the applicable NERC transmission planning standards and the CAISO Planning Standards. In response to data requests, both ORA and Frontlines conceded that they did not conduct any power flow analyses to determine the system impacts of, and how the system would perform with, their proposed versions of the Trabuco Substation Alternative.[166]

- Having failed to conduct a proper power flow analysis, neither Mr. Mee nor Ms. Ayer provide adequate information about the additional work required on SDG&E's South Orange County 138 kV network to allow a 230 kV interconnection at or near Trabuco Substation to serve South Orange County in the event Talega Substation were unable to serve the 138 kV network.

- Mr. Mee presents no information about design or construction of the expanded 230/138/12 kV Trabuco Substation, much less its feasibility or cost. Ms. Ayer presents no information about design or construction of the 230 kV GIS substation located somewhere near Trabuco Substation or any necessary changes to Trabuco Substation to interconnect to such substation, much less the feasibility or cost of the required work at both locations.

- Mr. Mee presents no information about where or how to construct the proposed SCE interconnection to Trabuco Substation. Ms. Ayer presents no information about where or how to construct the proposed interconnection of an SCE transmission line to the 230 kV GIS substation located somewhere near Trabuco Substation, or the interconnection between such substation and Trabuco Substation.

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[166] Attachment 32 (ORA Response to SDG&E's Second Set of Data Requests, Question 2) ("ORA did not generate power flow analysis regarding the Trabuco Alternative"); Attachment 33 (Frontlines' Response To SDG&E's Sixth Set Of Data Requests, Question 5) ("FRONTLINES has not conducted a power flow analysis of the 230 kV GIS substation near the Trabuco substation that FRONTLINES described in testimony.").

- Neither Mr. Mee nor Ms. Ayer present a complete plan of service to address the reliability issues in South Orange County.

ORA describes its proposed Trabuco Substation Alternative as follows:

> ORA proposes to interconnect SDG&E's Trabuco Substation to SCE's San Onofre – Santiago transmission line (see Figures 3-1, 3-2, and 3-3). To complete this project, ORA recommends the following:
>
> (1) Acquire approximately 2 acres of land on the north side of the Trabuco Substation.
>
> (2) construct a 230-kV switchyard on the acquired 2 acres, including one 230kV/138kV transformer with a capacity of 392 MVA.18
>
> (3) Construct approximately 0.5 miles of double circuit transmission line from the San Onofre Switchyard-Santiago 230 kV transmission line to the 230 kV yard at the Trabuco Substation. The San Onofre Switchyard-Santiago 230-kV transmission line would become two new transmission lines: the San Onofre Switchyard-Trabuco 230 kV transmission line and the Trabuco-Santiago transmission line. Based on ORA's preliminary analysis, the point of interconnection should be at the San Onofre Switchyard-Santiago transmission lines on the east side of the San Diego Freeway (Interstate-5). From there, the interconnection would follow Puerta Real, over Interstate 5. The termination would be at the 230 kV yard, with the electric system components described in (2) above.
>
> (4) Separate the SOC load into two parts by setting some of the 138 kV circuit breakers "Normal Open". Under normal operating conditions, the existing Talega Substation will supply one part of the SOC load and the upgraded Trabuco Substation will supply the other part of the SOC load. When one of the 230 kV power supplies (for example, Talega Substation) is not available, the "Normal Open" circuit breakers can be closed so the other 230 kV power supply (for example, Trabuco Substation) can supply critical load to the whole SOC area-[167]

In response to data requests, ORA stated that it "did not have enough information" to provide a schematic diagram showing the proposed equipment layout, to identify the major components, to identify work areas during construction, or provide any documents relating to design of a rebuilt 230/138/12 kV Trabuco Substation.[168] When asked for the route and design for the transmission line to connect Trabuco Substation to an SCE transmission line, ORA

[167] Mee Testimony at 12-13 (footnotes omitted).
[168] Attachment 32 (ORA Response to SDG&E's Second Set of Data Requests, Question 4).

responded: "ORA requests that SDG&E conduct a cost analysis and select the least cost option" as well as determining the "feasibility" of such an interconnection.[169]

Frontlines describes its proposed Trabuco Substation Alternative as follows:

> These alternatives involve interconnections to SCE's 230 kV system on WECC Path 43. There are two 138 kV substations on SDGE's SOC system that lay in close proximity to SCE's 230 kV lines: Pico (which lies adjacent to SCE's lines) and Trabuco (which is approximately 1,000 feet from the SCE Path 43 ROW). A small 1 230 kV GIS substation looped in to an adjacent SCE 230 kV lines could be sufficient as a second source in SOC.
>
> Two of the SCE 230 kV lines that comprise WECC Path 43 are located quite close to the Trabuco substation, which itself is surrounded by existing developments and the Interstate 5 freeway. While there may not be sufficient area to accommodate a 230 kV substation within the Trabuco substation footprint, there could be sufficient space provided at several locations nearby on land that is already partly occupied by the SCE Path 43 lines. These parcels do not appear to be owned by a utility or municipality; their locations are shown in Exhibit 3. The topography of some of the parcels may require pad construction not unlike what SDGE proposes at Capistrano under the SOCRE Project. A 138 kV connection at the Trabuco substation could be made by extending the Trabuco bus.[170]

In responses to data requests, Frontlines explained that it proposes interconnecting an SCE line to a 230 kV GIS substation located near Trabuco Substation, which then would be interconnected to Trabuco Substation by a 138 kV transmission line.[171] Frontlines identified three potential locations for such a 230 kV GIS substation by circling open areas on an aerial photo.[172]

In responses to data requests, Frontlines further explained that: (a) does not have any one-line diagram or design schematics for such a 230 kV GIS substation; (b) does not have proposed paths for the transmission lines interconnecting SCE's 230 kV line to the 230 kV GIS substation

[169] Attachment 32 (ORA Response to SDG&E's Second Set of Data Requests, Question 6).
[170] Ayer Testimony at 17-18, 19.
[171] Frontlines' Response To SDG&E's Fourth Set Of Data Requests, Question 14 ("FRONTLINES testimony did not recommend the construction of a 230/138/12 kV Trabuco Substation."); Frontlines Response to SDG&E's Fifth Set of Data Requests, Question 5 ("In the Trabuco area, FRONTLINES identified locations along and adjacent to the SCE ROW that are near the Trabuco Substation where a small 230 kV GIS substation could be constructed along with the necessary 230/138 kV transformer equipment. The SOC system could be connected to 138 kV power at this location.")
[172] Ayer Testimony at 19, Exhibit 3.

or from there to Trabuco Substation; and (c) has no one-line diagram or design schematics for Trabuco Substation showing an interconnection with such a 230 kV GIS substation.[173]

Based on its review and analysis of the Trabuco Substation Alternative, SDG&E concludes that the Trabuco Substation Alternative is neither feasible nor cost-effective.

Section 2. The Trabuco Substation Alternative Does Not Add a 230 kV Source at the Load Center for South Orange County (Witness John Jontry)

As discussed above with respect to the Pico Substation Alternative, adding a 230 kV source at the load center for SOC is more effective and efficient because of the close proximity to the center of load in South Orange County to Capistrano Substation. Trabuco Substation is also not at the load center for South Orange County. Rather, it is located several miles north of the load center, with Capistrano Substation located between Trabuco and the calculated load center. See Fig. 8-1 above, which represents the load center analysis for South Orange County and indicates the relative proximity of all of the substations. Generally speaking, energy injected from the 230 kV system into the 138 kV system will then flow towards the load center, across the 138 kV network, before it can then flow out to serve customer load. Although Trabuco is located in a relatively better location than Pico to act as a second source to South Orange County (both closer to the load center and electrically removed from Talega), Capistrano is still the best of all existing locations as clearly demonstrated in Fig. 8-1.

Also, Trabuco Substation is located adjacent to three 138 kV transmission lines, unlike the six lines that will terminate at Capistrano Substation upon completion of the SOCRE Project, and the four lines that currently terminate at Talega Substation. In order for a second 230/138 kV source located at Trabuco Substation to be fully redundant to the existing source at Talega, and given that two of the lines are located in a common transmission corridor south of Trabuco Substation and could be subject to a common-mode failure, it would be necessary to add at least one additional 138 kV line from Trabuco Substation to Capistrano Substation. As discussed above, energy will tend to flow south from Trabuco towards the load center at Capistrano Substation. Following loss of Talega Substation, with Trabuco Substation acting as the sole source to South Orange County, this would result in several hundred megawatts of energy

[173] Attachment 33 (Frontlines' Response To SDG&E's Sixth Set Of Data Requests, Questions 6-9, 11); Attachment 34 (Frontlines' Response To SDG&E's Sixth Set Of Data Requests, Question 12).

flowing south from Trabuco. As both lines south of Trabuco (TL13834 and TL13833) share a common transmission corridor and could be subject to a common-mode failure, it is possible for a single N-2 contingency to remove both lines from service. This would effectively cut off Trabuco from the bulk of the South Orange County load. As a second source at a rebuilt 230/138/12 kV Capistrano substation would enjoy connectivity from six 138 kV lines, loss of any two lines will still allow Capistrano to supply the bulk of South Orange County load. As a result, substantial work is required on the 138 kV system to allow a 230 kV source at Trabuco Substation to serve South Orange County in the event of a service outage at Talega Substation.

Section 3. An Interconnection with SCE at Trabuco Substation Would Take Years to Accomplish (Witness John Jontry)

As discussed in SDG&E's Supplemental Testimony, Chapter 5, Section 2, any interconnection with SCE's system would take years to accomplish. Among other steps that would be required for a transmission interconnection to SCE's system, SDG&E would need to comply with SCE's Transmission Owner Tariff, the Transmission Control Agreement among transmission owners and the California Independent System Operator ("CAISO"), and the CAISO Tariff. These steps are time-consuming, not within SDG&E's control, likely to result in significant additional costs to SDG&E ratepayers (and other CAISO ratepayers), and may not result in approval of an SCE interconnection. SDG&E responded to ORA's and Frontlines' testimony on this issue in Chapter 8, Section 3.

Section 4. An SCE Interconnection at Trabuco Substation Would Have Impacts to Both the SCE and SDG&E Transmission Systems That Would Need to be Mitigated (Witness John Jontry).

As discussed extensively in SDG&E's Supplemental Testimony, Chapter 5, Section 3, and the preceding Chapter 8, Section 4, such an interconnection with SCE would parallel a robust 230 kV path with a relatively weak 138 kV network. This would have the dual negative impacts of restricting the allowable flow on the 230 kV path while subjecting the 138 kV system to network flows for which it was not designed. Restricting allowable flow on the SCE lines in South Orange County could result in limiting the transfer capability between the SDG&E and SCE systems, resulting in reduced import capability for both utilities. In fact, such an interconnection may have a significant impact on Southern California's import capability.

SCE's System Impact Study is similarly likely to identify significant impacts to a number of important import paths and therefore require Reliability Upgrades to SCE's and SDG&E's systems at SDG&E's expense (which would be passed on to CAISO ratepayers). To properly assess the risk to the import limit, a WECC PRG (Path Rating Group) would be formed to determine any additional projects that would be needed to mitigate the impact to the import limit. These costs also would be attributed to SDG&E and then to CAISO ratepayers.

Because none of the Reliability Upgrades or WECC projects have been identified at this time (and would not be for at least several years), their environmental impacts have not been assessed.

SDG&E responded to ORA's contentions about the impact of an SCE interconnection is Chapter 8, Section 4.

Section 5. The Trabuco Substation Alternative Has Not Been Assessed to Determine Its Effectiveness and Impacts (Witness Cory Smith).

Neither ORA nor Frontlines presents a coherent plan of service to address the reliability issues in SDG&E's South Orange County system. ORA describes its Trabuco Substation Alternative as an interconnection of Trabuco Substation and an SCE transmission line, but does not describe any other work it recommends to address the South Orange County reliability issues (other than its infeasible and ineffective suggestions regarding Talega Substation, addressed in Chapter 3). ORA's cost estimate for its Trabuco Substation Alternative expressly excludes "the costs of rebuilding Capistrano Substation as a 138/12 kV substation, or the cost of reconfiguring the Talega Substation," and ORA nowhere identifies any upgrades to SDG&E's 138 kV system.[174] ORA does not discuss how the SCE interconnection may affect the flow of power over the 138 kV and 230 kV transmission systems in South Orange County specifically, and the bulk power system in Southern California generally.

Slightly differing from ORA, Frontlines proposes an SCE interconnection to a 230 kV GIS substation located at any one of three locations near Trabuco Substation, which is then connected by a 138 kV transmission line to Trabuco Substation. Frontlines does not estimate the costs of its Trabuco Substation Alternative, and does not include its Trabuco Substation Alternative in its "recommended alternative approach."[175] Frontlines also fails to address how

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[174] Mee Testimony at 18, 20.
[175] Ayer Testimony at 20.

the SCE interconnection may affect the flow of power over the 138 kV and 230 kV transmission systems.

SDG&E, which has an obligation to provide reliable electric service to its South Orange County customers, must address the reliability issues in its system with a coherent and comprehensive plan of service. Assuming for the moment that all of the required work is feasible to construct and can be completed in a reasonable period of time, and based upon its preliminary analyses of the Trabuco Substation alternative, SDG&E sets forth below the necessary elements of a plan of service that includes an SCE 230 kV interconnection at an expanded and rebuilt Trabuco Substation. It does not include upgrades to neighboring systems which will only be known after a comprehensive analysis.

Lacking a plan from ORA or Frontlines, SDG&E made the following assumptions to create a high-level power flow assessment to determine the effectiveness of the Trabuco Substation Alternative. The following changes were made to the model:

- The existing Trabuco 138 kV straight bus was re-configured into a breaker and a half bus.
- A new breaker and a half 230 kV bus was created for the new Trabuco Substation 230 kV connection.
- 60 MVar capacitor banks were added to the end buses of the new Trabuco 230 kV breaker and a half bus.
- One of the two SCE 220 kV transmission lines which connect San Onofre to Santiago was opened and the ends connected to the new 230 kV bus at Trabuco Substation.
- Two 230/138 kV transformers were added to connect the Trabuco 230 kV bus to the Trabuco 138 kV bus.
- Talega Banks 60 and 62 were removed.
- WECC Path 43 was increased to 1161 MW.

SDG&E's power flow assessment found the following:

- Transmission line TL695, which is connected to the Talega 138 kV bus will need to be replaced, and 69 kV capacitors will need to be added at Oceanside and Basilone Road substations. Further analysis is needed to specify equipment size and location.

- When either Talega Bank 61 or 63 is out of service, flow on Path 43 will be constrained. Additional analysis is needed to determine the new path flow limit.

- Table 9-1 lists transmission elements which will load above the Applicable Rating in violation of NERC standards. Table 9-2 lists contingencies which will require load to be shed. Overloads of TL13834 were left off the table. It is assumed that the rating of TL13834 will increase to 274 MVA by rebuilding Capistrano Substation.

<u>Table 9-1: Contingencies Leading to Violation of Applicable Ratings with Trabuco Substation Alternative</u>

	Near Term Transmission Planning Horizon	Long Term Transmission Planning Horizon	
Year =	2020	2025	2030
Contingency	Overloaded Element	Overloaded Element	Overloaded Element
C3:TA BK61 + TB to SO230	TA BK63	TA BK63	TA BK63
C3:13846 + TB to SO230	-	13836	13836
C3:TB to SO230 + TB to Santiago230	-	13816	13816

Table 9-2: Contingencies Requiring Load to be Shed with Trabuco Substation Alternative

	Near Term Transmission Planning Horizon	Long Term Transmission Planning Horizon	
Year =	2020	2025	2030
Contingency	Overloaded Element	Overloaded Element	Overloaded Element
C3:13831 + TB to SO230	-	-	13816
C3:13835 + 13836	-	-	13846C
C3:13835 + TB to SO230	-	13816	13816
C3:13836 + TB to SO230	13846A, 13846C	13846A, 13846C	13846A, 13846C
C3:13846 + TB to SO230	13836	13836	13836
C3:TA BK61 + TB to SO230	TA BK63	TA BK63	TA BK63
C3:TA BK61 + TB to Santiago230	TA BK63	TA BK63	TA BK63
C3:TA BK63 + TB to SO230	TA BK61	TA BK61, TA 5E CB	TA BK61, TA 5E CB
C3:TA BK63 + TB to Sangiago230	-	TA BK61	TA BK61
C3:TB to SO230 + TB to Santiago230	-	13816, TA BK61, TA BK63	13816, TA BK61, TA BK63

With the Talega 138 kV bus out-of-service, South Orange County load will be limited by TL13833; the transmission line connecting Trabuco and Pico substations. The loss of TL13834 will load TL13833 to its maximum. To prevent damage to TL13833, South Orange County load will be limited to 388 MW. Upgrading TL13833 will not improve reliability. TL13833 and TL13834 are located in a common right of way and share structural supports. The overlapping outage of TL13833 and TL13834 would drop all load served from Capistrano, Laguna Niguel, Pico and San Mateo. To increase the load serving capability and continue to serve all South Orange County load, a fully redundant source at Trabuco is needed. In order for Trabuco to be fully redundant, a new 138 kV transmission line will need to be constructed from the vacant position on the Trabuco 138kV North bus to Capistrano. This will require a new transmission line position at Capistrano. There is no room for a new position and consequently, Capistrano will need to be rebuilt with new transmission line terminations added. This will allow Trabuco to carry 494 MW. SDG&E has not had sufficient time to estimate the cost of upgrading/adding these lines.

Controlling reactive power flow through South Orange County is another concern when connecting to the SCE 230 kV system. SDG&E will need to construct a new dynamic voltage control device (SVC, STATCOM or Synchronous Condenser) at the new Trabuco Substation at an estimated cost of $81 million to $99 million (without AFUDC, permitting or mitigation) to control the flow of MVars between South Orange County and the SCE system. Additional analysis is needed to determine the size and type of equipment. In addition to this device, another device will be needed to control voltage in South Orange County. For this reason, when the Talega STATCOM reaches the end of its useful life, SDG&E will either replace the STATCOM or install a new dynamic voltage control device (SVC, STATCOM or Synchronous Condenser) at the rebuilt Capistrano Substation at that time. The size, type and location of the voltage control device would be determined when plans are made to retire the STATCOM. SOCRE removes the needed for such a device.

For the reasons discussed in Chapter 5, a single 230/138 kV transformer at Trabuco is not a feasible alternative. The aggregate South Orange County peak load is forecast to exceed the capacity of SDG&E's standard 230/138 kV transformer (392 MVA), or even a non-standard 450 MVA transformer. Therefore, SDG&E would install at a minimum two 392 MVA 230/138kV transformers at Trabuco and reserve space for a future third transformer to enable enough capacity to feed the South Orange County load center at the system peak demand. The site for the transformers must be large enough to accommodate them, and will increase grading and below grade impact.

SDG&E notes that this alternative effectively adds an interconnection between SDG&E's 138 kV system and SCE's 230 kV system, where none exist today, and would subject the 138 kV system in SOC to significant and likely unpredictable loop flows. This alternative presents some significant operational challenges that would need to be thoroughly studied. Moreover, connecting to a major 230 kV transmission path may reduce the maximum amount of power which can be transferred into Southern California from Nevada, Arizona or Mexico. This can only be determined after a thorough study of the interconnection.

Section 6. Trabuco Substation Does Not Have Space to Add a 230 kV Switchyard, and Expansion Would be Difficult and Costly (Witness Karl Iliev).

A. Trabuco Substation Does Not Have Space to Add a 230 kV Switchyard

There is no room at the Trabuco Substation property for expansion to a 230/138/12 kV substation. Trabuco Substation is bounded by the I5 freeway to the east and Camino Capistrano to the west. There are businesses immediately north and south of the substation. See Attachment 41 (Google Earth aerial photo of Trabuco Substation).

SDG&E's existing Trabuco Substation is built on a pad approximately 290 ft x 323 ft. The substation was built as a single bus- single breaker 138/12 kV distribution substation, with a planned ultimate configuration of four 138/12 kV transformers and four 138 kV transmission lines. Trabuco Substation currently has three 138 kV transmission lines and four 138/12 kV transformers. Trabuco Substation was built with an older, less compact design, and thus is somewhat larger than Pico Substation. However, due to its layout of the 138 kV on the west side of the substation, along Camino Capistrano, and the 12 kV distribution coming from the east side out to Camino Capistrano, there is no room for expansion inside the Trabuco Substation site.

ORA's and Frontlines' Trabuco Substation Alternative proposes to convert Trabuco Substation into a 230/138/12 kV substation. Such a substation is considerably larger than a distribution substation.

SDG&E's requirement for a 230/138 kV transmission bus serving bulk power transformers is a breaker and half arrangement. (See Attachment 30). This is required for a cost effective, reliable bus configuration that allows for breaker and/or bus maintenance without line/bank interruption and minimal disruption in a breaker failure situation. It is also SDG&E's standard to build at least one spare position when constructing a new substation to allow for future growth and/or maintenance activities. Doing so is prudent and cost-effective, while failing to do so could result in significant additional costs if rebuilding the substation is later necessary to address such issues.

If Trabuco Substation were rebuilt as a 230/138/12 kV substation, the minimum requirement for the substation would be:

- A 6 element 230kV 3000A (possibly 4000A due to the SCE connection) breaker and half bus arrangement, with two 230 kV TL positions, two high side connections to the 230/138 kV transformer positions spare positions (TL and bank spare position), and a voltage regulating device.

- A new expanded control shelter to accommodate the additional control & protection necessary for the added transmission elements

- A minimum 12 element 138 kV 3000 amp breaker and half bus arrangement, with four 138/12kV transformers, two low side connections for the 230/138 kV transformers, four 138 kV TLs, and spare positions.

To allow for property line setback requirements and required landscaping required by local or state jurisdiction and/or noise requirements, fire safety requirements, and standard drive aisle access, a minimum size yard for a 230/138/12 kV substation yard would be approximately 6-7 acres using GIS technology or approximately 12 acres using AIS technology – depending on the topography and arrangement of the land. This acreage accounts for the space requirements for water quality and hydromodification management criteria, as required by the Regional Water Quality Control Board, which is usually met through the combined use of underground infiltration tanks, and above ground detention basins. This acreage also accounts for required drive aisles between equipment for proper maintenance access and equipment transport, placement of equipment for optimum EMF and noise requirements, installation of required underground termination connections, cable pulling space requirements, and any required pole placements.

Even using GIS technology, an expanded 230/138/12 kV Trabuco Substation will not fit on the existing substation property. Using GIS technology, an expanded 230/138/12 kV Trabuco Substation would require purchasing of the adjoining properties to the north and south of the existing substation site. This acreage is necessary to allow for construction of the new and required 230/138 kV breaker and half bus arrangement, and a complete rebuild in the northern property of the existing distribution station.

B. Expanding and Rebuilding Trabuco Substation Would be Difficult and Costly

As noted above, Trabuco Substation is bounded by the I5 freeway to the east and Camino Capistrano to the west. There are businesses immediately north and south of the substation, both of which would need to be acquired in order to build a 230/138/12kV substation. The parking lot to the north is part of an AT&T Operations District facility. To expand Trabuco Substation would require negotiating acquisition of one or more business properties, or pursuing condemnation if possible. Either would incur considerable additional cost, to be imposed on ratepayers, that does not exist at Capistrano Substation, where SDG&E already owns sufficient property to construct a 230/138/12 kV substation—and can do so efficiently while undertaking the required rebuild of the aging existing substation. While a cost of the property acquisition cannot be obtained on such a short time frame, the cost would be substantial due to the cost of property acquisition, and the cost of relocating the existing businesses that would have to be acquired.

The Trabuco Substation would have to be completely rebuilt to align the 230/138/12 kV within the narrow strip of land, while the existing Trabuco Substation remains in operation to serve customers. The new 138/12kV substation would be moved to the property north of the existing substation property in order to accommodate the new 230 kV GIS and bank additions in both the existing property and the property to the South. Trabuco Substation has not been identified at this point as an aging substation required to be rebuilt, and an early rebuild would impose unnecessary costs on ratepayers.

Although no preliminary engineering has been performed, the non- budgetary estimated cost to build a 230/138/12kV substation at Trabuco would be higher than the proposed 230/138/12 kV rebuilt Capistrano Substation because Trabuco has more existing equipment than Capistrano that would need to be replaced in the rebuilt substation. The estimated cost of constructing a 230/138/12 kV substation at Trabuco and the relocation of the existing distribution circuits is approximately $189- $231 million. This cost does not include relocating the existing 138kV transmission, adding new 138kV and 230kV transmission lines, permitting, mitigation, property acquisition costs or the purchase of ROW.

Attached as Attachment 39 is a simple block diagram of what a 230/138/12 kV layout at a rebuilt Trabuco Substation would look like at a minimum. This block diagram is based on equipment sizes from the Proposed Project’s Capistrano layout. However, without a complete engineering study and detailed design work, this diagram cannot account for hydro modification, setback and noise requirements, distribution and transmission lines routes entering/exiting the substation, or actual number and size of required underground termination stands and/or poles.

Also, without a complete Planning study done on the SCE interconnection, the final actual ratings of the equipment cannot be determined--this may affect the final size of the equipment which may affect the layout. Additional property may need to be acquired to account for all the final engineered requirements.

The layout and visual aesthetics of a rebuilt 230/138/12 kV Trabuco Substation would be very similar to the proposed rebuilt 230/138/12 kV Capistrano Substation, with two 40-50 ft GIS buildings required for the 138 kV and the 230 kV GIS, and a voltage control device.

A 230/138/12 kV Trabuco Substation would have to be built in two phases. Phase 1 would include moving the entire existing substation to the north and rebuilding it to include 138 kV GIS and equivalent distribution equipment to the existing site (four 138/12kV transformers, four sections of 12 kV switchgear, and four 12 kV capacitors). Phase 2 would include removing existing equipment, grading, and installing the 230 kV equipment, including the two 230/138 kV transformers, 230 kV GIS and the required voltage control device. This 230 kV equipment would be placed on the existing yard and the property acquired immediately to the south of the existing site. The length of the construction would also be similar to Capistrano and would depend upon system outage requirements. The estimated construction length could be between 2-3 years.

The impact to the area would involve site work noise and dust suppression, and construction in the street of Camino Capistrano for almost the entire construction length. Street construction would be lengthy due to the relocation of the existing 16 distribution circuits and three 138 kV transmission lines and then the installation of the 230 kV transmission lines and new 138 kV lines to Capistrano Substation. Traffic would also be impaired by the haul trucks required for the site development work.

C. Frontlines' Proposal for a 230 kV GIS Substation At Certain Properties Near Trabuco Substation Is Unsupported.

SDG&E cannot evaluate Frontlines' proposal for a 230 kV GIS substation near Trabuco Substation because Frontlines has provided essentially no information about this proposed alternative. Frontlines identified three parcels on an aerial photo and suggested that SDG&E

could construct a GIS substation at any of them.[176] Frontlines states that these parcels are "already partly occupied by the SCE Path 43 lines."[177]

SDG&E has not had sufficient time to evaluate, for each of these locations, its size, topography, ownership, issues associated with constructing a substation in what appears to be an SCE transmission right of way, the paths such transmission lines would use to approach or leave such substation, or the environmental impacts of such construction. SDG&E can definitively state that Parcel 3, which Frontlines states is 1.5 acres in size, cannot accommodate a 230 kV GIS substation meeting SDG&E's standards.

SDG&E also cannot evaluate Frontlines' proposed design for a 230 kV substation because Frontlines has no design information. SDG&E sought such information through data requests to Frontlines and was informed "FRONTLINES does not possess any schematics or figures of the 230 kV GIS substation located near the Trabuco substation that is referred to in FRONTLINES testimony," nor does Frontlines have a one-line diagram of such substation [178]

SDG&E also cannot evaluate Frontlines' proposed changes to Trabuco Substation to interconnect to the proposed 230 kV GIS substation. SDG&E sought such information through data requests to Frontlines and was informed: "Neither FRONTLINES nor Ms. Ayer possess a one line diagram of the Trabuco substation as configured to accommodate an interconnection with a 230 kV GIS substation located near Trabuco."[179] Further, SDG&E was informed: "FRONTLINES does not possess any schematics or one-line diagrams of any SOC substations (including Trabuco) other than what SDGE has provided in the record of this proceeding or in response to discovery requests. Nor has FRONTLINES prepared any such diagrams. In addition, FRONTLINES does not possess any layout figures for any SOC substations (including Trabuco) other than aerial figures which FRONTLINES has already provided to SDGE in prior data request responses.[180]

SDG&E has only evaluated a breaker and a half design for the 138kV bus at Trabuco Substation. A different design would require additional analysis.

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[176] Ayer Testimony at 19 & Exhibit 3.
[177] Ayer Testimony at 19.
[178] Attachment 33 (Frontlines' Response to SDG&E's Sixth Set of Data Requests, Questions 6 & 7).
[179] Attachment 33 (Frontlines' Response to SDG&E's Sixth Set of Data Requests, Question 8).
[180] Attachment 33 (Frontlines' Response to SDG&E's Sixth Set of Data Requests, Question 9).

In short, Frontlines has not provided sufficient information about its proposal for SDG&E to evaluate its feasibility, much less its costs. However, Frontlines' version of a Trabuco Substation Alternative would include constructing a 230/138 kV GIS substation at acquired property near Trabuco, expanding and rebuilding at least some of Trabuco Substation, and rebuilding a 138/12 kV Capistrano Substation whereas SDG&E's Proposed Project only rebuilds a 230/138/12 kV Capistrano Substation on SDG&E-owned property. SDG&E expects that Frontlines' Trabuco Substation Alternative would cost considerably more for substation work than the Proposed Project.

SDG&E responded to Frontlines' contentions regarding the area necessary to construct a 230 kV GIS substation in Chapter 8, Section 6.C.

Section 7. Rebuilding a 138/12 kV Capistrano Substation Is Necessary, and Would Have Similar Impacts as the Proposed Project (Witness Karl Iliev)

Even if Trabuco Substation could be expanded to be 230/138/12 kV substation, SDG&E would still need to rebuild Capistrano Substation to address the reliability issues discussed in SDG&E's Opening Testimony, Chapter 5. Without rebuilding Capistrano Substation, at least as a 138/12 kV substation, SDG&E cannot provide reliable electric service to SDG&E's South Orange County customers. Moreover, Capistrano Substation may need to be rebuilt to interconnect at least one additional 138kV transmission line that may be needed between the expanded Trabuco Substation and Capistrano Substation.

The rebuild of the Capistrano Substation would expand to the lower yard within SDG&E-owned property and add a minimum of two spare 138kV positions for future needs that may arise outside of the planning time horizon, but within the expanded lifetime of the newly rebuilt substation. The substation cannot be rebuilt in its current location and needs to be built in the lower yard to maintain construction safety and station reliability during the rebuild project.

The estimated stand-alone cost of rebuilding Capistrano Substation as a 138/12 kV substation, with the same configuration and location as proposed in the Proposed Project, is between $135 million and $165 million (including AFUDC, permitting and mitigation). A voltage control device would also be needed at Capistrano Substation when the Talega STATCOM reaches the end of its useful life (in lieu of replacing the Talega STATCOM), which may cost as much as $81-$99 million (with AFUDC, $89 million to $109 million).

Section 8. Transmission Work that Would be Required by ORA's Trabuco Substation Alternative (Witness Willie Thomas)

SDG&E has not had sufficient time to study an interconnection route to SCE's Santiago-SONGS 230-kV line. It appears (with no engineering study being done) that the most feasible connection to SCE is north of Trabuco Substation, which would require undergrounding 230 kV south down Camino Capistrano to the Trabuco Substation site. It is unknown if there is room in Camino Capistrano to accommodate the necessary trenching, conduit, and vaults required for 230 kV undergrounding. It would also require a crossing of the 138 kV underground and the 230 kV underground, which may not be physically possible. There would be traffic issues on Camino Capistrano due to the lane closure requirements to construct this underground and installation of the vaults. Construction noise may also become an issue.

Another possible route is to string the 230kV transmission lines across Interstate 5 freeway north of the expanded substation and then construct underground east of the freeway to the location of the SCE 230 kV transmission line and connect via 230 kV cable poles. This appears to be the nearest connection to SCE, but it would involve at a minimum two sets of 230kV cable poles at approximately 165 ft tall each on the east side of I-5 and another at the interconnection with the existing SCE lines likely along Los Altos. More cable poles may be necessary north of the expanded Trabuco Substation to accommodate routing around the substation to the 230kV yard. New easements may also be required to accommodate the routing. The stringing of transmission lines across the freeway involves shutting down all lanes of the freeway multiple times, once for each phase of conductors. This route would also require considerable undergrounding in the business/community area east of the freeway and there may be conflicts with other utilities (water, sewer, gas, telecom, etc.) that would conflict with a 230kV trench, conduit and vault infrastructure.

Section 9. The Trabuco Substation Alternative Would Cost More Than the Proposed Project (Witness Willie Thomas)

ORA's Trabuco Substation Alternative, when even some of the work necessary to address South Orange County's reliability needs is included, is more costly than SDG&E's Proposed Project.

- As stated in Section 6.B above, the estimated cost of constructing a 230/138/12 kV substation at Trabuco and the relocation of the existing distribution circuits is approximately $189 - $231million. This does not include the cost of acquiring the necessary property, which would include the cost of relocating two businesses and any AT&T communications infrastructure located at its facility. This cost also does not include relocating the existing 138kV transmission, adding new 138kV and 230kV transmission lines, permitting, mitigation, or acquiring ROW. Thus, this cost likely will be considerably more.

- To interconnect a rebuilt Trabuco Substation with an SCE transmission line, the likely path (without any engineering study) would be 0.5 miles of 230 kV double circuit underground down Camino Capistrano, at an estimated cost of $16 - $20 million (includes AFUDC and EMF mitigation).

- As set forth in Section 5 above, to supply MVars to SCE's system, a voltage control device at a rebuilt Trabuco Substation may cost as much as $81-$99 million (with AFUDC, $89 million to $109 million) (appropriate size and type will require further study). To support South Orange County voltage, SDG&E's Proposed Project includes two 230 kV capacitors at a rebuilt Capistrano 230 kV bus. The proposed Trabuco alternative will require an additional voltage control device at either Capistrano or Talega when the existing Talega STATCOM reaches the end of its useful life at an additional cost of $81-$99 million (with AFUDC, $89 million to $109 million)

- As stated in Section 7 above, Capistrano Substation still must be rebuilt as a 138/12 kV substation to provide reliable electric service. The estimated stand-alone cost of rebuilding Capistrano Substation as a 138/12 kV substation, with the same configuration and location as proposed in the Proposed Project, is between $135 million and $165 million (including AFUDC, permitting and mitigation).

SDG&E's estimated cost for its Proposed Project is $384 million. The elements of ORA's Trabuco Substation Alternative for which SDG&E has had time to estimate a cost total $518 million to $634 million. This does not include additional costs for property acquisition and business relocation at the expanded Trabuco Substation, 138 kV upgrades to address NERC Category C violations and load shedding, 138 kV upgrades to mitigate the risk of forced outages during maintenance events, and 138 kV upgrades to make a rebuilt Trabuco Substation fully redundant for South Orange County in the event of a Talega service outage. For example, as discussed in Section 2 above, it would be necessary to add a third Trabuco-Capistrano 138 kV line in order to make a 230/138 kV source at Trabuco fully redundant to Talega. As a result, SDG&E is confident that the Trabuco Substation Alternative will cost far more than the Proposed Project.

STATEMENT OF QUALIFICATIONS

JOHN M. JONTRY

My name is John M. Jontry. My business address is 8330 Century Park Court, San Diego, California, 92123. I am employed by San Diego Gas & Electric Company (SDG&E) as Transmission Planning Manager. I have been employed by SDG&E since 2005. For the past five years I have managed the Grid Planning group within the Transmission Planning department, with the primary responsibility of overseeing the annual grid reliability studies and the planning studies for major special projects such as the South Orange Country Reliability Enhancement project (SOCRE). Prior to working for SDG&E, I worked for electric utilities in Texas and Illinois and for the Midwest Independent System Operator (MISO) in Indiana in various engineering and operational roles for approximately fifteen years. I hold a bachelor's degree in Electrical Engineering from the University of Illinois and a master's degree in Industrial Technology from Eastern Illinois University. I am a Registered Professional Engineer in the states of Illinois and Texas.

I have previously testified before this Commission.

KARL ILIEV, PE

My name is Karl Iliev and my business address is 8316 Century Park Court, San Diego, California 92123. I am the System Protection & Control Engineering Manager in the Electric Transmission & Distribution Engineering Department of San Diego Gas & Electric (SDG&E). My section's primary responsibilities are to provide protective relay and control schemes, settings, and communication systems for a safe and reliable grid, including providing technical support, scoping advice, and review of substation electrical designs.

I began work at SDG&E in June 1999 as an Engineering Intern and have held positions around the company on both transmission and distribution sides ranging from planning to engineering to construction and operations. Since 2003, I've held positions of increasing responsibility related to substation design and construction including work in System Protection Engineering & Maintenance, Substation Construction & Maintenance, and Substation Engineering & Design. I was the Substation Engineering & Design Manager for over 4 years from 2009 into 2014 where my responsibilities included cost estimation, design specifications and scoping, material procurement, apparatus assessment, engineering review, substation drawing management, construction support, and real-time operational involvement for all of SDG&E's substations and substation related capital projects.

Immediately prior to obtaining full time employment with SDG&E in 2001, I graduated California State University of Sacramento with a Bachelor of Science in Electrical and Electronic Engineering with a concentration in Power Systems and a minor in Physics. In 2004, I earned my license as a Professional Engineer in the State of California.

I have previously testified before this Commission.

CORY SMITH

My name is Cory Smith and my business address is 8330 Century Park Court, San Diego, California 92123. I am employed as a Principal Engineer in the Transmission Planning Department of San Diego Gas & Electric where I have worked since 2008. My duties include assessing SDG&E's transmission system for compliance with NERC Transmission Planning Standards and creating technical models of SDG&E's high voltage transmission system to assess transmission system performance.

Prior to joining SDG&E, I was employed by Northeast Utilities in Berlin, Connecticut as a Senior Engineer. My duties included the creation of technical models and the application of specialized software to assess the reliability performance of the high voltage transmission system owned by Northeast Utilities. Before my employment with Northeast Utilities I was employed as an Engineer by the New York Independent System Operator in Schenectady, New York. My duties included reliability assessments of the high voltage transmission system serving the State of New York.

I received my Bachelor of Science degree in Electrical Engineering from Arizona State University in 1989, my Master of Engineering degree in Electric Power Engineering from Rensselaer Polytechnic Institute in 1994 and my Master of Business Administration degree from The College of Saint Rose in 2003. In addition, I am a Registered Professional Engineer in the states of California and New York.

I have not previously testified before the Commission in a proceeding.

WILLIE THOMAS

My name is Willie Thomas and my business address is 8316 Century Park Court, San Diego, California 92123. I am currently the manager of Electric Transmission Engineering and Design at San Diego Gas & Electric (SDG&E). My duties for the past two years include managing a diverse group of designers and engineers in the design, engineering, construction and management of electric transmission facilities in the SDG&E service territory. In addition, my duties include the development of specifications, cost estimates, budgeting, managing material and engineering service contracts, and ensuring the proper application of electrical codes, safety regulations, and regulatory agency requirements governing the design and installation of electric transmission facilities. My previous experience includes the design and engineering for the Sycamore Penasquitos 230kV project (CPCN), the transmission facility relocations for the County of Orange La Pata Avenue Gap Closure project (Advice Letter), and the South Bay Substation relocation project (PTC). I hold a Bachelor's of Science in Electrical Engineering from California Polytechnic University of San Luis Obispo in 2004. I am a licensed Professional Engineer (Electrical) in the State of California and an active IEEE member.

I have previously testified before this Commission.

ATTACHMENT 26

Glossary of Terms Used in NERC Reliability Standards

Updated May 19, 2015

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Blackstart Resource [Archive]		8/5/2009	3/17/2011	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
Block Dispatch [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).
Bulk Electric System [Archive]	BES	2/8/2005	3/16/2007 (Becomes inactive on 6/30/2014)	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System[2] [Archive]	BES	01/18/2012	6/14/2013 (Replaced by BES definition FERC approved 3/20/2014)	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. **Inclusions:** • **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3. • **I2** - Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. • **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan. • **I4** - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

[2] FERC issued an order on April 18, 2013 approving the revised definition with an effective date of July 1, 2013. On June 14, 2013, FERC granted NERC's request to extend the effective date of the revised definition of the Bulk Electric System to July 1, 2014.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			**I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1. **Exclusions:** • **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating). Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			• **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. • **E3** - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating); b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). • **E4** – Reactive Power devices owned and operated by the retail customer solely for its own use. Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System [Archive]	BES	11/21/2013	3/20/14 (Becomes effective 7/1/2014) (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. **Inclusions:** • **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3. • **I2** – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA. Or, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA. • **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan. • **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. • **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4. **Exclusions:** • **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion. Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion. • **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. • **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following: a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			generation greater than 75 MVA (gross nameplate rating); b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). • **E4** – Reactive Power devices installed for the sole benefit of a retail customer(s). Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.
Bulk-Power System [Archive]		5/9/2013	7/9/2013	A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Facility [Archive]		2/7/2006	3/16/2007	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating [Archive]		2/8/2005	3/16/2007	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault [Archive]		2/8/2005	3/16/2007	An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk [Archive]		2/7/2006	3/16/2007	The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand [Archive]		2/8/2005	3/16/2007	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service [Archive]		2/8/2005	3/16/2007	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover [Archive]		2/7/2006	3/16/2007	An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate [Archive]		2/8/2005	3/16/2007	A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Limiting Element [Archive]		2/8/2005	3/16/2007	The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load [Archive]		2/8/2005	3/16/2007	An end-use device or customer that receives power from the electric system.
Load Shift Factor [Archive]	LSF	2/8/2005	3/16/2007	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity [Archive]	LSE	2/8/2005	3/16/2007	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Long-Term Transmission Planning Horizon [Archive]		8/4/2011	10/17/2013 (Becomes effective 1/1/2015)	Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.
Low Impact BES Cyber System Electronic Access Point [Archive]	LEAP	2/12/2015		A Cyber Asset interface that controls Low Impact External Routable Connectivity. The Cyber Asset containing the LEAP may reside at a location external to the asset or assets containing low impact BES Cyber Systems.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Non-Consequential Load Loss [Archive]		8/4/2011	10/17/2013 (Becomes effective 1/1/15)	Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.
Non-Firm Transmission Service [Archive]		2/8/2005	3/16/2007	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve [Archive]		2/8/2005	3/16/2007	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Clearing [Archive]		11/1/2006	12/27/2007	A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator [Archive]		5/2/2007	10/16/2008	Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power) [Archive]		5/2/2007	10/16/2008	The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transfer Capability [Archive]		2/8/2005	3/16/2007	The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is *not g*enerally equal to the transfer capability from “Area B” to “Area A.”
Transfer Distribution Factor [Archive]		2/8/2005	3/16/2007	See Distribution Factor.
Transient Cyber Asset [Archive]		2/12/2015		A Cyber Asset that (i) is capable of transmitting or transferring executable code, (ii) is not included in a BES Cyber System, (iii) is not a Protected Cyber Asset (PCA), and (iv) is directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless, including near field or Bluetooth communication) for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a PCA. Examples include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Transmission [Archive]		2/8/2005	3/16/2007	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

ATTACHMENT 27

NERC TPL-001-4

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. 8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. 9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. 10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. 13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in	

		Requirement 1 from Medium to High.	

* FOR INFORMATIONAL PURPOSES ONLY *

Enforcement Dates: Standard TPL-001-4 — Transmission System Planning Performance Requirements

United States

Standard	Requirement	Enforcement Date	Inactive Date
TPL-001-4	R1.	01/01/2015	
TPL-001-4	R2.	01/01/2016	
TPL-001-4	R3.	01/01/2016	
TPL-001-4	R4.	01/01/2016	
TPL-001-4	R5.	01/01/2016	
TPL-001-4	R6.	01/01/2016	
TPL-001-4	R7.	01/01/2015	
TPL-001-4	R8.	01/01/2016	

ATTACHMENT 28

City of San Juan Capistrano Responses
to SDG&E's Second Set of Data Requests

SECOND SET OF DATA REQUESTS OF
SDG&E TO CITY OF SAN JUAN CAPISTRANO
A.12-05-020

<u>DATA REQUEST NO. 1</u>:

Please admit that the load growth described at 6 starting at line 11 of the Testimony of Dr. Dariush Shirmohammadi can be served from the new 230 kV substation at San Juan Capistrano as proposed by SDG&E.

<u>RESPONSE NO. 1:</u>

Per SDG&E analyses presented in SDG&E's January 15, 2015 and April 7, 2015 testimony as well as in CAISO 2010-11 planning studies, SDG&E's SOCREP alternative, which includes upgrading the Capistrano Substation to 230 kV, can meet the load growth expected in the SDG&E South Orange County transmission loop, as acknowledged in Dr. Shirmohammadi's May 26, 2015 testimony.

<u>DATA REQUEST NO. 2</u>:

Page 6, line 14 of Dr. Shirmohammadi's testimony states that "50% of the load growth around the SDG&E's Southern Orange County transmission loop is occurring at a single substation in that loop: the Rancho Mission Viejo Substation…". Please admit that the load supplied from Rancho Mission Viejo Substation represents less than 10% of the total South Orange County load.

<u>RESPONSE NO. 2:</u>

As represented in the load forecast table (Table 1) in SDG&E' s January 15, 2015 testimony and re-printed in Dr. Shirmohammadi's testimony (at p.4), the load supplied from Rancho Mission Viejo Substation represents less than 10% of the total SDG&E South Orange County load.

<u>DATA REQUEST NO. 3</u>:

The Testimony of Dariush Shirmohammadi at 10 states: "DEIR Alternative F is a more suitable SOCREP alternative" than SDG&E's Proposed Project. Please provide for the DEIR Alternative F the following:

1) Starting powerflow cases in PSS/E text format
2) Final powerflow case(s) in PSS/E text format
3) All change files applied to the final cases
4) Identify the source of the starting case and any conversions.
6) A high-level summary of any modifications made to the original power flow case.
7) All contingency files applied to the final case(s).
8) All contingency run results.

<u>RESPONSE NO. 3:</u>

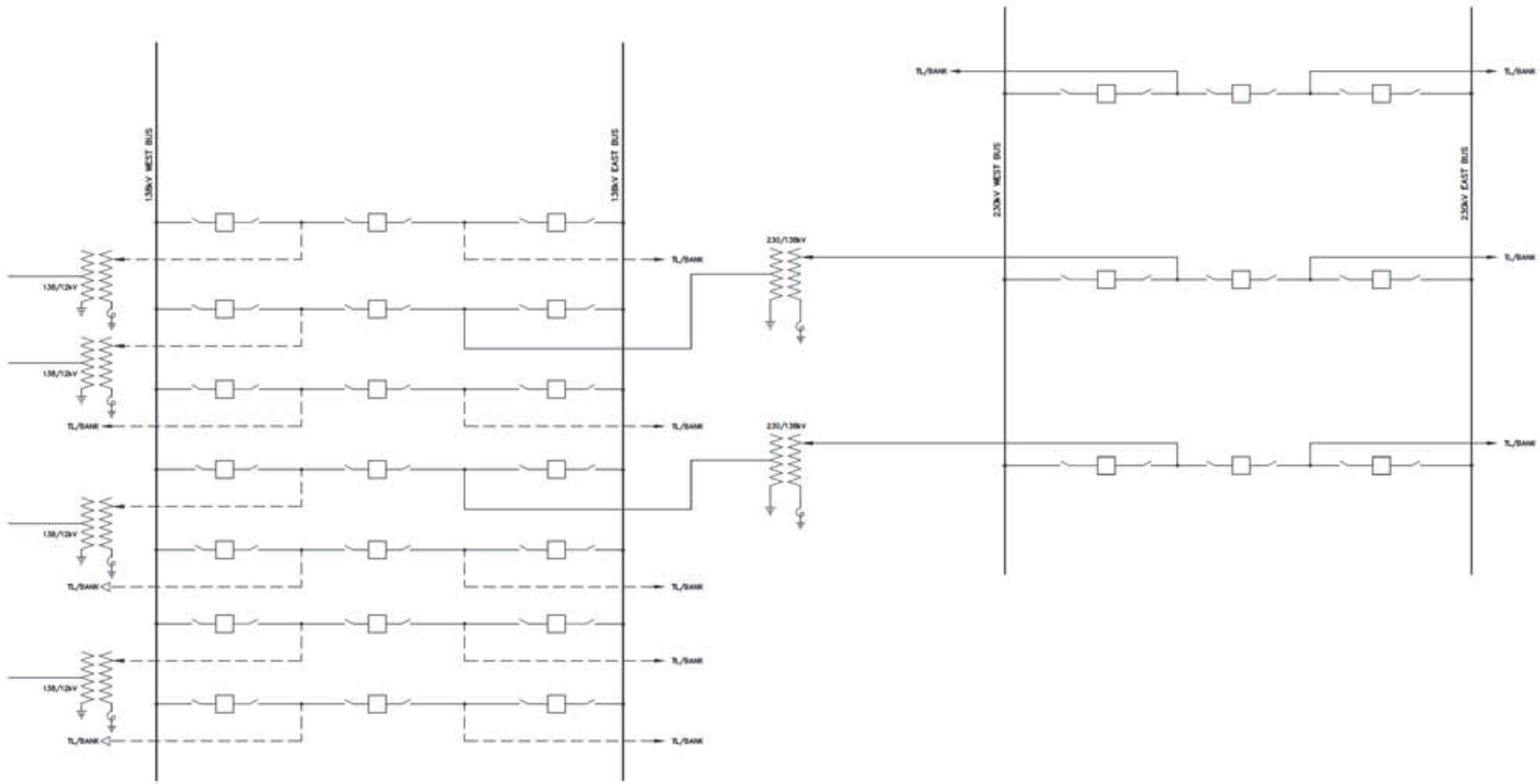
Dr. Shirmohammadi did not perform any power flow analyses of DEIR Alternative F in support of his testimony

ATTACHMENT 29

Aerial photo view of Rancho Mission Viejo Substation

ATTACHMENT 30

Standard Breaker And A Half (BAAH)
Transmission Substation Diagram



REVISIONS

SAN DIEGO GAS & ELECTRIC COMPANY
SAN DIEGO, CALIFORNIA

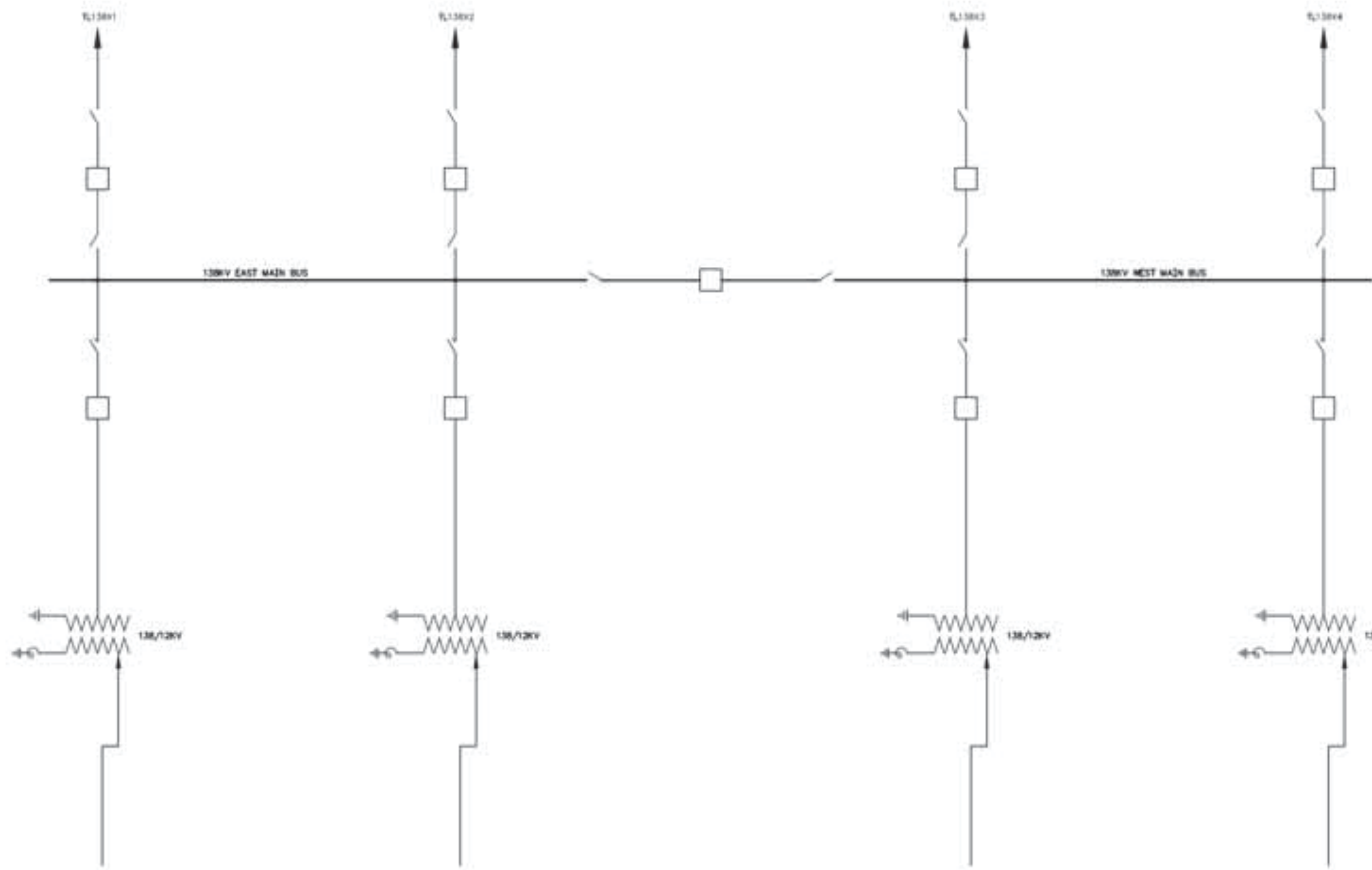
TRANSMISSION SUBSTATION

230/138kV BREAKER & A HALF ARRANGMENT

TVB6915

ATTACHMENT 31

Standard Single Bus Distribution Substation



REVISIONS

SAN DIEGO GAS & ELECTRIC COMPANY
SAN DIEGO, CALIFORNIA

DISTRIBUTION SUBSTATION
SINGLE BREAKER ONE LINE DIAGRAM

TVA6915

ATTACHMENT 32

Office of Ratepayer Advocates (ORA) Responses to

SDG&E's Second Set of Data Requests, Nos. 1-24

ORA

Office of Ratepayer Advocates
California Public Utilities Commission

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SPECIFIC OBJECTIONS AND RESPONSES TO THE "SECOND SET OF DATA REQUESTS PROPOUNDED BY SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) UPON THE OFFICE OF RATEPAYER ADVOCATES" DATA REQUEST #1-24

June 17, 2015

Dear Mr. Trial:

The Office of Ratepayer Advocates ("ORA") is in receipt of your data requests in the SOCREP matter (A. 12-05-020), dated: May 27, 2015. These data request responses are part of a rolling production.

Please find enclosed ORA's Data Request Responses to Data Requests #1-24.

Sincerely,

/s/ EDWARD MOLDAVSKY

Edward Moldavsky
ORA Staff Counsel
(213) 620-2635
edm@cpuc.ca.gov

ORA

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California Public Utilities Commission

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DATA REQUEST NO. 1: The May 26, 2015 Prepared Testimony of Charles Mee on behalf of the Office of Ratepayer Advocates ("Mee Testimony") starting at 12 states "ORA proposes to interconnect SDG&E's Trabuco Substation to SCE's San Onofre – Santiago transmission line." With respect to such proposal (hereinafter "ORA's Trabuco Alternative"), please identify the person(s) who first proposed this ORA proposal and when such such initial proposal was made.

RESPONSE NO. 1:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request is irrelevant and not reasonably calculated to lead to the discovery of admissible evidence pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure. ORA further objects to this data request to the extent that it seeks information that has already been provided. ORA also objects to this data request because it is vague and ambiguous.

Notwithstanding all general and specific objections, ORA states:

Charles Mee prepared ORA's Testimony on this topic, which reflects ORA's position. The parameters of the "initial proposal" are irrelevant.

DATA REQUEST NO. 2: Please provide all documents relating to ORA's analysis of ORA's Trabuco Alternative, including but not limited to:

a. Starting powerflow cases in PSS/E text format
b. Final powerflow case(s) in PSS/E text format
c. All change files applied to the final cases
d. Identify the source of the starting case
e. A high-level summary of the final powerflow case parameters, including load, net area interchange, and dispatch.
f. A high-level summary of any modifications to the Area 22 generation dispatch, load, and net area interchange (a summary in spreadsheet format or narrative is acceptable)
g. All contingency files applied to the final case(s)
h. All contingency run results

ORA

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RESPONSE NO. 2:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request seeks information that has already been provided to SDG&E. ORA further objects to this data request to the extent that it could be interpreted as seeking information and documents protected under attorney client privilege and/or work product doctrine. ORA also objects to this data request on the grounds that it is unduly burdensome and oppressive to produce information and documents that are already in SDG&E's possession. ORA also objects to this data request on the grounds that, as broadly defined by SDG&E, it is unduly burdensome and oppressive to produce "all documents relating to ORA's analysis of ORA's Trabuco Alternative."

Notwithstanding all general and specific objections, ORA states:

Please see ORA's Data Response 5, dated: June 5, 2015, in response to SDG&E's First Set of Data Requests, including Attachment 1. Given SDG&E's broad definitions, ORA also refers SDG&E to Attachments 2, 3, and 4, included in ORA's June 5, 2015 Data Responses.

Please review ORA's Testimony on the subject. (See *Prepared Testimony of Charles Mee on South Orange County Reliability Enhancement Project (SOCREP), dated: May 26, 2015, page 12, line 10 – page 18, line 1, including Table 1: Cost Estimation for Trabuco Alternative.*)

ORA did not generate power flow analysis regarding the Trabuco Alternative. ORA directs SDG&E to SDG&E's own files for power flows, as well as Energy Division's files.

DATA REQUEST NO. 3: Please state whether the Trabuco Substation, rebuilt as proposed under the ORA's Trabuco Alternative, with a single 230/138 kV transformer, would be able to serve all South Orange County load, now and throughout the 10-year planning period, if the Talega Substation were out of service.

1) If your answer is no, please identify the additional work that would be necessary for the rebuilt Trabuco Substation to do so, including both substation equipment and transmission line upgrades.
2) If your answer is yes, please identify your assumed ratings for the 230/138 kV transformer at the rebuilt Trabuco Substation, each transmission line between

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Trabuco Substation and other substations, and the rating of each such transmission line.

3) Please provide all documents, analyses and studies relating to your answers to this data request, including power flows.

RESPONSE NO. 3:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects to this data request to the extent that it seeks information that is under SDG&E's control. ORA further objects to this data request to the extent that it could be interpreted as seeking information and documents protected under attorney client privilege and/or work product doctrine. ORA also objects to this data request on the grounds that it is unduly burdensome and oppressive to produce information and documents that may already be in SDG&E's possession. ORA also objects to this data request on the grounds that, as broadly defined by SDG&E, it is unduly burdensome and oppressive to produce "all documents."

Notwithstanding general and specific objections, ORA states:

The entire Talega Substation being out of service is an extreme event. According to applicable transmission planning standards, SDG&E does not need to develop a transmission plan to address such low probability scenarios. However, SDG&E is required to conduct studies, document those studies, and provide the study results to the Regional Reliability Organization.[1]

Although installing one 230/138 kV transformer with a capacity of 392 MVA at Trabuco Substation would not serve the peak demand for the entire South Orange County (SOC) area, the upgraded Trabuco Substation can serve most of the SOC area load or the entire SOC area load most hours. With the Trabuco Substation being upgraded, SDG&E can fix the problems at the Talega Substation so that the power supply reliability of the Talega Substation can be improved.

Regarding "all documents":

ORA did not generate power flow analysis regarding the Trabuco Alternative. Given SDG&E's broad definitions, ORA refers SDG&E to Attachments 1, 2, 3, and 4, included in ORA's June 5, 2015 Data Responses. ORA further refers SDG&E to ORA's Testimony on the subject. (See *Prepared Testimony of Charles Mee on South Orange County Reliability Enhancement Project*

[1] NERC TPL-004-0a at 2.

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(SOCREP), dated: May 26, 2015, page 12, line 10 – page 18, line 1, including Table 1: Cost Estimation for Trabuco Alternative.) ORA also directs SDG&E to SDG&E's own files for power flows, as well as Energy Division's files.

DATA REQUEST NO. 4: With respect to the ORA's Trabuco Alternative, please:

a) Provide all documents relating to the design of a 230/138/12 kV Trabuco Substation;
b) Please provide schematic diagram(s) showing the equipment layout (including identification of major equipment and their dimensions) at the rebuilt Trabuco Substation;
c) Identify the major components included in the 230/138/12 kV rebuilt Trabuco Substation envisioned under ORA's Trabuco Alternative;
d) Please state any safety considerations used to determine ORA's proposed equipment layout.
e) Explain in the greatest detail you are able the location and dimensions of the work areas during construction of the rebuilt Trabuco Substation;
f) Admit that there is insufficient space on the existing Trabuco Substation property to construct a 230/138/12 kV Air-Insulated Substation. If you do not so admit, provide a design for such a substation on the existing Trabuco Substation property, including the layout of major components;
g) Admit that there is insufficient space on the existing Trabuco Substation property to construct a 230/138/12 kV GIS substation. If you do not so admit, provide a design for such a substation, including the layout of major components;
h) Provide all documents supporting or concerning your responses to the preceding subsections of this Data Request.

RESPONSE NO. 4:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request is unduly burdensome and oppressive. ORA further objects to this data request to the extent that it could be interpreted as seeking information and documents protected under attorney-client privilege and/or work-product doctrine. ORA also objects on the grounds that this data request is irrelevant and not reasonably calculated to lead to the discovery of admissible evidence pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure. ORA also objects to this data request to the extent that it seeks information that is under SDG&E's control.

Notwithstanding general and specific objections, ORA states:

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ORA does not have enough information to respond to this question. SDG&E may provide and discuss schematic diagrams, major components, safety considerations, the location and dimensions of work areas, space and design issues.

Regarding "all documents":

Given SDG&E's broad definitions, ORA refers SDG&E to Attachments 1, 2, 3, and 4, included in ORA's June 5, 2015 Data Responses. ORA further refers SDG&E to ORA's Testimony on the subject. (See *Prepared Testimony of Charles Mee on South Orange County Reliability Enhancement Project (SOCREP), dated: May 26, 2015, page 12, line 10 – page 18, line 1, including Table 1: Cost Estimation for Trabuco Alternative.*) ORA also directs SDG&E to SDG&E's own files for power flows, as well as Energy Division's files.

DATA REQUEST NO. 5: If you contend that the existing Trabuco Substation can remain in service while being rebuilt as proposed by ORA's Trabuco Alternative, please explain in the greatest detail you are able the sequencing of construction, installation of equipment, and energizing of equipment. If you do not so contend, please explain how SDG&E customers served by the existing Trabuco Substation will receive electricity throughout construction of the rebuilt substation.

RESPONSE NO. 5

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects to this data request to the extent that it seeks information that is under SDG&E's control.

Notwithstanding general and specific objections, ORA states:

ORA understands that the Trabuco Substation has two 138kV buses. Therefore, SDG&E can use one of these buses to serve load while upgrading the other bus. Another option is to shift the load from this substation to a nearby SDG&E's substation while the Trabuco Substation is being upgraded.

DATA REQUEST NO. 6: State whether the "approximately 0.5 miles of double circuit transmission line from the San Onofre Switchyard-Santiago 230 kV transmission line to the 230 kV yard at the Trabuco Substation," referenced in the Mee Testimony at 12, would be overhead

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or underground. Identify the location of each structure that would be constructed with respect to this transmission line.

RESPONSE NO. 6

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request is unduly burdensome and oppressive in seeking the "location of each structure that would be constructed with respect to this transmission line." ORA further objects to this data request to the extent that it seeks information that is under SDG&E's control.

Notwithstanding general and specific objections, ORA states:

ORA requests that SDG&E conduct a cost analysis and select the least cost option. In addition, SDG&E may provide detailed information to support its findings with regard to the feasibility and options of interconnecting Trabuco Substation to the SCE 230 kV transmission lines, including whether such facilities would be overhead or underground, and the location of each structure that would need to be constructed with respect to this transmission line.

DATA REQUEST NO. 7: State whether any other 138 kV transmission lines in SDG&E's South Orange County system would be upgraded or replaced as part of the ORA's Trabuco Alternative.

RESPONSE NO. 7

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request, regarding portions of SDG&E's system requiring upgrade or replacement, seeks information that is under SDG&E's control.

Notwithstanding general and specific objections, ORA states:

Based on the power transfer capability of the SOC local network, ORA does not see any need for replacing or upgrading the 138 kV transmission lines at this time.

DATA REQUEST NO. 8: Produce all documents constituting, reflecting or relating to whether any other 138 kV transmission lines in SDG&E's South Orange County system would be upgraded or replaced as part of the ORA's Trabuco Alternative, including any power flow analyses. If you do not produce any such documents, admit that ORA did not study whether any

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other 138 kV transmission lines in SDG&E's South Orange County system would be upgraded or replaced as part of the ORA's Trabuco Alternative.

RESPONSE NO. 8

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request seeks information outside the scope of ORA's Testimony.

Notwithstanding general and specific objections, ORA states:

Based on the power transfer capability of the SOC local network, ORA does not see any need for replacing or upgrading the 138 kV transmission lines at this time.

Regarding "all documents":

ORA did not generate power flow analysis regarding the Trabuco Alternative. Given SDG&E's broad definitions, ORA refers SDG&E to Attachments 1, 2, 3, and 4, included in ORA's June 5, 2015 Data Responses. ORA further refers SDG&E to ORA's Testimony on the subject. (See *Prepared Testimony of Charles Mee on South Orange County Reliability Enhancement Project (SOCREP), dated: May 26, 2015, page 12, line 10 – page 18, line 1, including Table 1: Cost Estimation for Trabuco Alternative.*) ORA also directs SDG&E to SDG&E's own files for power flows, as well as Energy Division's files.

DATA REQUEST NO. 9: Please provide ORA's environmental analysis, with all supporting documentation, for ORA's Trabuco Alternative.

RESPONSE NO. 9:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request seeks information outside the scope of ORA's Testimony. ORA further objects to this data request to the extent that it seeks information that has already been provided to SDG&E and/or is under SDG&E's control.

Notwithstanding general and specific objections, ORA states:

ORA

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California Public Utilities Commission

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ORA refers SDG&E to ORA's prior data request response #6, dated: June 2, 2015, to SDG&E's First Set of Data Requests.

Interpreting this data request as seeking ORA's analysis as to the impact of the Trabuco Alternative on the environment, ORA does not have responsive information.

DATA REQUEST NO. 10: With respect to ORA's cost estimate for ORA's Trabuco Alternative presented in the Mee Testimony, Table 1 at 18, please:

a) Describe in the greatest detail you are able the work, equipment and property giving rise to the costs included under "Trabuco 230kV Yard Land," identify the source of each cost assumed thereunder, and produce all documents relating thereto.
b) Describe in the greatest detail you are able the work, equipment and property giving rise to the costs included under "Trabuco 230kV transformer," identify the source of each cost assumed thereunder, and produce all documents relating thereto.
c) Describe in the greatest detail you are able the work, equipment and property giving rise to the costs included under "230 kV Breaker and a Half," identify the source of each cost assumed thereunder, and produce all documents relating thereto.
d) Describe in the greatest detail you are able the work, equipment and property giving rise to the costs included under "Double Operating Bus Sections - 2 new buses, spanning 2 positions," identify the source of each cost assumed thereunder, and produce all documents relating thereto.
e) Describe in the greatest detail you are able the work, equipment and property giving rise to the costs included under "230 kV Double Circuit Transmission Lines w/ 6 Tubular Steel Poles & Anchor Bolt Foundations," identify the source of each cost assumed thereunder, and produce all documents relating thereto.
f) Describe in the greatest detail you are able the work, equipment and property giving rise to the costs included under "ROW Acquisition," identify the source of each cost assumed thereunder, and produce all documents relating thereto.
g) Describe in the greatest detail you are able the calculation of "Allowance for funds used during construction (AFUDC)."

RESPONSE NO. 10:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request is unduly burdensome and oppressive. ORA further objects to this data request to the extent that it could be interpreted as seeking information and documents protected under attorney-client privilege and/or work product-doctrine. ORA also

ORA

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California Public Utilities Commission

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objects to this data request to the extent that it seeks information that has already been provided to SDG&E and/or is under SDG&E's control.

Notwithstanding general and specific objections, ORA states:

ORA refers SDG&E to ORA's prior data request response #7, dated: June 2, 2015, to SDG&E's First Set of Data Requests.

ORA's cost estimation relies on "SDGE-2014ProposedPerUnitCostGuide." See Attachment 1 to ORA's data request response #7, dated: June 2, 2015. SDG&E is invited to provide detailed cost estimation for the Trabuco Alternative.

DATA REQUEST NO. 11: The Mee Testimony starting at 18 describes ORA's "Pico Substation alternative." With respect to such proposal (hereinafter "ORA's Pico alternative"), please identify the person(s) who first proposed this ORA proposal and when such such initial proposal was made.

RESPONSE NO. 11:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request is irrelevant and not reasonably calculated to lead to the discovery of admissible evidence pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure. ORA further objects to this data request to the extent that it seeks information that has already been provided. ORA also objects to this data request because it is vague and ambiguous.

Notwithstanding all general and specific objections, ORA states:

Charles Mee prepared ORA's Testimony on this topic, which reflects ORA's position. The parameters of the "initial proposal" are irrelevant.

DATA REQUEST NO. 12: Please provide all documents relating to ORA's analysis of ORA's Pico alternative, including but not limited to:

a. Starting powerflow cases in PSS/E format
b. Final powerflow case(s) in PSS/E format
c. All change files applied to the final cases

ORA

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d. Identify the source of the starting case

e. A high-level summary of the final powerflow case parameters, including load, net area interchange, and dispatch.

f. A high-level summary of any modifications to the Area 22 generation dispatch, load, and net area interchange (a summary in spreadsheet format or narrative is acceptable)

g. All contingency files applied to the final case(s)

h. All contingency run results

RESPONSE NO. 12:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that it is unduly burdensome and oppressive to produce information and documents that are already in SDG&E's possession. ORA further objects to this data request to the extent that it could be interpreted as seeking information and documents protected under attorney client privilege and/or work product doctrine. ORA also objects to this data request on the grounds that, as broadly defined by SDG&E, it is unduly burdensome and oppressive to produce "all documents relating to ORA's analysis of ORA's Pico Alternative."

Notwithstanding all general and specific objections, ORA states:

Please review ORA's Testimony on the subject. (See *Prepared Testimony of Charles Mee on South Orange County Reliability Enhancement Project (SOCREP), dated: May 26, 2015, page 18, line 2 – page 21, line 1, including Table 2: Cost Estimation for Pico Substation Alternative.*)

Regarding "all documents":

ORA did not generate power flow analysis regarding the Pico Alternative. Given SDG&E's broad definitions, ORA also refers SDG&E to Attachments 2, 3, and 4, included in ORA's June 5, 2015 Data Responses. ORA directs SDG&E to SDG&E's own files for power flows, as well as Energy Division's files.

DATA REQUEST NO. 13: Please state whether the Pico Substation, rebuilt as proposed under the ORA's Pico Alternative, with a single 230/138 kV transformer, would be able to serve all

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South Orange County load, now and throughout the 10-year planning period, if the Talega Substation were out of service.

a) If your answer is no, please identify the additional work that would be necessary for the rebuilt Pico Substation to do so, including both substation equipment and transmission line upgrades.
b) If your answer is yes, please identify your assumed ratings for the 230/138 kV transformer at the rebuilt Pico Substation, each transmission line between Pico Substation and other substations, and the rating of each such transmission line.
c) Please provide all documents, analyses and studies relating to your answers to this data request, including power flow analyses.

RESPONSE NO. 13:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects to this data request to the extent that it seeks information that is under SDG&E's control. ORA further objects to this data request to the extent that it could be interpreted as seeking information and documents protected under attorney client privilege and/or work product doctrine. ORA also objects to this data request on the grounds that it is unduly burdensome and oppressive to produce information and documents that may already be in SDG&E's possession. ORA also objects to this data request on the grounds that, as broadly defined by SDG&E, it is unduly burdensome and oppressive to produce "all documents."

Notwithstanding general and specific objections, ORA states:

The entire Talega Substation being out of service is an extreme event. According to applicable transmission planning standards, SDG&E does not need to develop a transmission plan to address such low probability scenarios. However, SDG&E is required to conduct studies, document those studies, and provide the study results to the Regional Reliability Organization.[2]

Although installing one 230/138 kV transformer with capacity of 392 MVA at Pico Substation cannot serve the peak demand for the entire SOC area, the upgraded Pico Substation can serve most of the SOC area load or the entire SOC area load most hours. With the Pico Substation being upgraded, SDG&E can fix the problems at the Talega Substation so that the power supply reliability of the Talega Substation can be improved.

[2] NERC TPL-004-0a at 2.

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Regarding "all documents":

ORA did not generate power flow analysis regarding the Pico Alternative. Given SDG&E's broad definitions, ORA refers SDG&E to Attachments 2, 3, and 4, included in ORA's June 5, 2015 Data Responses. ORA further refers SDG&E to ORA's Testimony on the subject. (See *Prepared Testimony of Charles Mee on South Orange County Reliability Enhancement Project (SOCREP), dated: May 26, 2015, page 18, line 2 – page 21, line 1, including Table 2: Cost Estimation for Pico Substation Alternative.*) ORA also directs SDG&E to SDG&E's own files for power flows, as well as Energy Division's files.

DATA REQUEST NO. 14: With respect to the ORA's Pico Alternative, please:

(a) Provide all documents relating to the design of a 230/138/12 kV Pico Substation;
(b) Please provide schematic diagram(s) showing the equipment layout (including identification of major equipment and their dimensions) at the rebuilt Pico Substation;
(c) Identify the major components included in the 230/138/12 kV rebuilt Pico Substation envisioned under ORA's Pico Alternative;
(d) Please state any safety considerations used to determine ORA's proposed equipment layout.
(e) Explain in the greatest detail you are able the location and dimensions of the work areas during construction of the rebuilt Pico Substation;
(f) Admit that there is insufficient space on the existing Pico Substation property to construct a 230/138/12 kV Air-Insulated Substation. If you do not so admit, provide a design for such a substation on the existing Pico Substation property, including the layout of major components;
(g) Admit that there is insufficient space on the existing Pico Substation property to construct a 230/138/12 kV GIS substation. If you do not so admit, provide a design for such a substation, including the layout of major components;
(h) Provide all documents supporting or concerning your responses to the preceding subsections of this Data Request.

RESPONSE NO. 14:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request is unduly burdensome and oppressive. ORA further objects to this data request to the extent that it could be interpreted as seeking information and documents protected under attorney-client privilege and/or work-product doctrine. ORA also objects on the grounds that this data request is irrelevant and not reasonably calculated to lead to the discovery of admissible evidence pursuant to Rule 10.1 of the Commission's Rules of

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Practice and Procedure. ORA also objects to this data request to the extent that it seeks information that is under SDG&E's control.

Notwithstanding general and specific objections, ORA states:

ORA does not have enough information to respond to this question. ORA requests that SDG&E provide information on the feasibility and a detailed engineering approach for this alternative.

Regarding "all documents":

Given SDG&E's broad definitions, ORA refers SDG&E to Attachments 2, 3, and 4, included in ORA's June 5, 2015 Data Responses. ORA further refers SDG&E to ORA's Testimony on the subject. (See *Prepared Testimony of Charles Mee on South Orange County Reliability Enhancement Project (SOCREP), dated: May 26, 2015, page 18, line 2 – page 21, line 1, including Table 2: Cost Estimation for Pico Substation Alternative.*) ORA also directs SDG&E to SDG&E's own files for power flows, as well as Energy Division's files.

DATA REQUEST NO. 15: If you contend that the existing Pico Substation can remain in service while being rebuilt as proposed by ORA's Pico Alternative, please explain in the greatest detail you are able the sequencing of construction, installation of equipment, and energizing of equipment. If you do not so contend, please explain how SDG&E customers served by the existing Pico Substation will receive electricity throughout construction of the rebuilt substation.

RESPONSE NO. 15

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects to this data request to the extent that it seeks information that is under SDG&E's control.

Notwithstanding general and specific objections, ORA states:

ORA understands that the Pico Substation has two 138kV buses. Therefore, SDG&E can use one of these buses to serve load while upgrading the other bus. Another option is to shift the load from this substation to a nearby SDG&E's substation while the Pico Substation is being upgraded.

DATA REQUEST NO. 16: Identify which SCE transmission line would be connected to the rebuilt Pico Substation, describe the route of the new transmission line connecting such SCE

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transmission line to Pico Substation, and whether it would be overhead or underground. Identify the location of each structure that would be constructed with respect to this transmission line.

RESPONSE NO. 16

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request is unduly burdensome and oppressive in seeking the "location of each structure that would be constructed with respect to this transmission line." ORA further objects to this data request to the extent that it seeks information that is under SDG&E's control.

Notwithstanding general and specific objections, ORA states:

Generally, Pico Substation can interconnect to any one of the four 230 kV transmission lines that go to SCE service territory. Pico Substation is only 225 feet away from the SCE transmission lines, which should ease the interconnection. SDG&E is invited to identify which line is the easiest to interconnect considering electrical, geographical, and economical issues.

ORA does not have enough geographic information to determine the best route to interconnect the Pico Substation to the SCE 230 kV transmission lines since electrical maps for this area are unavailable to ORA. SDG&E may provide detailed information to support its findings with regard to the feasibility and options of interconnecting Pico Substation to the SCE 230 kV transmission lines.

DATA REQUEST NO. 17: State whether any other 138 kV transmission lines in SDG&E's South Orange County system would be upgraded or replaced as part of the ORA's Pico Alternative.

RESPONSE NO. 17

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request, regarding portions of SDG&E's system requiring upgrade or replacement, seeks information that is under SDG&E's control.

Notwithstanding general and specific objections, ORA states:

Based on the power transfer capability of the SOC local network, ORA does not see any need for replacing or upgrading the 138 kV transmission lines at this time.

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DATA REQUEST NO. 18: Produce all documents constituting, reflecting or relating to whether any other 138 kV transmission lines in SDG&E's South Orange County system would be upgraded or replaced as part of the ORA's Pico Alternative, including any power flow analyses. If you do not produce any such documents, admit that ORA did not study whether any other 138 kV transmission lines in SDG&E's South Orange County system would be upgraded or replaced as part of the ORA's Pico Alternative.

RESPONSE NO. 18

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request seeks information outside the scope of ORA's Testimony.

Notwithstanding general and specific objections, ORA states:

Based on the power transfer capability of the SOC local network, ORA does not see any need for replacing or upgrading the 138 kV transmission lines at this time.

Regarding "all documents":

ORA did not generate power flow analysis regarding the Pico Alternative. Given SDG&E's broad definitions, ORA refers SDG&E to Attachments 2, 3, and 4, included in ORA's June 5, 2015 Data Responses. ORA further refers SDG&E to ORA's Testimony on the subject. (See *Prepared Testimony of Charles Mee on South Orange County Reliability Enhancement Project (SOCREP), dated: May 26, 2015, page 18, line 2 – page 21, line 1, including Table 2: Cost Estimation for Pico Substation Alternative.*) ORA also directs SDG&E to SDG&E's own files for power flows, as well as Energy Division's files.

DATA REQUEST NO. 19: Please provide ORA's environmental analysis, with all supporting documentation, for ORA's Pico Alternative.

RESPONSE NO. 19:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request seeks information outside the scope of ORA's Testimony.

Notwithstanding general and specific objections, ORA states:

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Interpreting this data request as seeking ORA's analysis as to the impact of the Pico Alternative on the environment, ORA does not have responsive information.

DATA REQUEST NO. 20: With respect to ORA's cost estimate for ORA's Pico Alternative presented in the Mee Testimony, Table 2 at 21, please:

(a) Describe in the greatest detail you are able the work, equipment and property giving rise to the costs included under "Pico 230 kV Yard Land," identify the source of each cost assumed thereunder, and produce all documents relating thereto.
(b) Describe in the greatest detail you are able the work, equipment and property giving rise to the costs included under "Pico Substation 230/138 kV transformer," identify the source of each cost assumed thereunder, and produce all documents relating thereto.
(c) Describe in the greatest detail you are able the work, equipment and property giving rise to the costs included under "230 kV Breaker and a Half," identify the source of each cost assumed thereunder, and produce all documents relating thereto.
(d) Describe in the greatest detail you are able the work, equipment and property giving rise to the costs included under "Double Operating Bus Sections - 2 new buses, spanning 2 positions," identify the source of each cost assumed thereunder, and produce all documents relating thereto.
(e) Admit that ORA includes no cost for "ROW Acquisition" under its cost estimate for its Pico Alternative.
(f) Admit that ORA includes no cost for interconnecting the rebuilt Pico Substation to an SCE transmission line under its cost estimate for its Pico Alternative.
(g) Describe in the greatest detail you are able the calculation of "Allowance for funds used during construction (AFUDC)."

RESPONSE NO. 20:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request is unduly burdensome and oppressive. ORA further objects to this data request to the extent that it could be interpreted as seeking information and documents protected under attorney-client privilege and/or work product-doctrine.

Notwithstanding general and specific objections, ORA states:

ORA's cost estimation relies on "SDGE-2014ProposedPerUnitCostGuide." See Attachment 1 to ORA's data request response #7, dated: June 2, 2015. SDG&E is invited to provide detailed cost estimation for the Pico Alternative.

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DATA REQUEST NO. 21: Identify each communication with any person regarding ORA's Pico Alternative, and produce all documents constituting or reflecting such communications.

RESPONSE NO. 21:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request seeks information outside the scope of ORA's Testimony. Additionally, ORA objects to this data request to the extent that it could be interpreted as seeking information and documents protected under attorney-client privilege and/or work-product doctrine. ORA also objects to this data request because it seeks irrelevant information and is not reasonably calculated to result in the discovery of admissible evidence per Rule 10.1 of the Commission's Rules of Practice and Procedure. ORA further objects to this data request on the grounds that it is unduly burdensome and oppressive to produce information and documents which are already in SDG&E's possession.

Notwithstanding general and specific objections, ORA states:

ORA communicated with FRONTLINES and Energy Division. ORA directs SDG&E to Attachments 2 and 3, which were included in ORA's June 5, 2015 Data Responses.

DATA REQUEST NO. 22: Identify each communications with any person regarding ORA's Trabuco Alternative, and produce all documents constituting or reflecting such communications.

RESPONSE NO. 22:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request seeks information outside the scope of ORA's Testimony. Additionally, ORA objects to this data request to the extent that it could be interpreted as seeking information and documents protected under attorney-client privilege and/or work-product doctrine. ORA also objects to this data request because it seeks irrelevant information and is not reasonably calculated to result in the discovery of admissible evidence per Rule 10.1 of the Commission's Rules of Practice and Procedure. ORA further objects to this data request on the grounds that it is unduly burdensome and oppressive to produce information and documents which are already in SDG&E's possession.

Notwithstanding general and specific objections, ORA states:

ORA communicated with FRONTLINES and Energy Division. ORA directs SDG&E to Attachments 2 and 3, which were included in ORA's June 5, 2015 Data Responses.

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DATA REQUEST NO. 23: Identify each communication with Southern California Edison regarding ORA's Pico Alternative, and produce all documents constituting or reflecting such communications.

RESPONSE NO. 23:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request seeks information outside the scope of ORA's Testimony.

Notwithstanding general and specific objections, ORA states:

ORA did not communicate with Southern California Edison regarding the Pico Alternative.

DATA REQUEST NO. 24: Identify each communications with Southern California Edison regarding ORA's Trabuco Alternative, and produce all documents constituting or reflecting such communications.

RESPONSE NO. 24:

Incorporating the general objections served on SDG&E on June 3, 2015, ORA specifically objects on the grounds that this data request seeks information outside the scope of ORA's Testimony.

Notwithstanding general and specific objections, ORA states:

ORA did not communicate with Southern California Edison regarding the Trabuco Alternative.

ATTACHMENT 33

FRONTLINES Response to
SDG&E's Sixth Set of Data Requests, No. 1-11

FRONTLINES' REVISED RESPONSES TO SDGE'S FOURTH AND FITH DATA REQUESTS
AND
FRONTLINES PARTIAL RESPONSE TO
SDGE'S SIXTH SET OF DATA REQUESTS
A.12-05-020
Submitted to SDGE June 18, 2015

From SDGE's **FOURTH** Data Request:

DATA REQUEST NO. 1: Please describe in the greatest detail you are able the training, education and experience of Jacqueline Ayers in electric transmission planning, including identification of all transmission projects she has designed or constructed in the last 10 years.

Response to Data Request 1:
FRONTLINES objects to this data request on the grounds that it is ambiguous and that the terms "electric transmission planning" and "transmission project" are too vague and non-specific. Without waiving this objection, FRONTLINES responds that Ms. Ayer has not constructed any transmission projects. Ms. Ayer has participated in several transmission system and transmission project planning efforts, including various CAISO "white paper" discussions addressing specifically what constitutes "Advanced Transmission Technology" under EPAct, and whether such is deemed "Transmission". Ms. Ayer has also developed several electric transmission line project plan alternatives in various CPCN Proceedings before the CPUC. Ms. Ayer has also incorporated numerous transmission planning factors into extensive testimony and briefs offered in multiple proceedings before the CPUC and the FERC, and she has relied extensively upon CAISO transmission planning programs and CPUC transmission planning documents in these proceedings, including (but not limited to) the CSRTP, STEP, various annual CAISO Transmission Plans, Transmission Ranking Cost Reports, etc. If SDGE wishes a further response, please provide a more detailed explanation of what information is specifically sought and what is meant by the term "electric transmission planning" and "transmission projects" and "design".

From SDGE's **FIFTH** Data Request:

<u>DATA REQUEST NO. 1</u>:
State whether Ms. Ayers previously has designed or constructed, or supervised design or construction of, any substation with a high-side voltage of 138 kV or greater. If so, please:

(a) Identify any substation with a high-side voltage of 230 kV or greater that Ms. Ayers designed or constructed, or supervised design or construction of, and explain Ms. Ayers' role with respect to that substation;
(b) For each substation identified in response to subpart (a), state the voltage of the transformers present there, identify all transmission lines entering the substation, and all distribution lines leaving the substation;
(c) For each substation identified in response to subpart (a), state whether the substation utilized a GIS design and the nature of the design (canopy, building or underground);
(d) For each substation identified in response to subpart (a), state the cost of design, permitting and construction of the substation (excluding the cost of transmission and distribution lines other than actual interconnection at the substation).

<u>Response to Data Request 1:</u>
FRONTLINES objects to this data request on the grounds that it is ambiguous and that the term "design" is too vague and non-specific. Without waiving this objection, FRONTLINES responds that Ms. Ayer has not constructed or supervised the construction of any substations. However, Ms. Ayer has developed substation design alternatives in various CPCN Proceedings before the CPUC. For instance, in Docket A.07-06-031, Ms. Ayer presented a Vincent substation design alternative that was adopted by the CPUC and saved ratepayers $98 million. Similarly, Ms. Ayer has developed testimony pertaining to alternative designs for the LEAPS and Case Springs substations proposed in Docket A.10-07-001, however none of this was reflected in the record because the Nevada Hydro CPCN Application was dismissed before final rebuttal testimony and evidentiary hearings were scheduled. If SDGE wishes a further response, please provide a more detailed explanation of what information is specifically sought and what is meant by the word "design".

From SDGE's **SIXTH** Data Request:

DATA REQUEST NO. 1: Please state whether Jacqueline Ayer has designed any electric transmission project. If so, identify each such project, when she designed it, and the role she played in designing it.

RESPONSE NO. 1:
FRONTLINES objects that this data request is ambiguous and that the terms "design" and "electric transmission project" is too vague and non-specific. Without waiving this objection, FRONTLINES responds that Ms. Ayer has designed several electric transmission line project alternatives and proposed them in various CPCN Proceedings before the CPUC. For instance, in Docket A.07-06-031, Ms. Ayer presented alternative electric transmission project designs for the three 500 kV lines addressed as TRTP Segments 6 and 11. These electric transmission line designs were found by Southern California Edison's expert witness to be electrically similar to SCE's proposed project. It was also concluded that they would meet the Project objectives set forth by the TRTP project. If SDGE wishes a further response, please provide a more detailed explanation of what information is specifically sought, and what is meant and intended by the terms "design" and "electric transmission project".

DATA REQUEST NO. 2: Please state whether Jacqueline Ayer has ever used the GE PSLF computer program. If the answer is yes, please state when and for what purpose for each instance that she used it.

RESPONSE NO. 2:
FRONTLINES objects to this data request on the grounds that it is ambiguous and that the term "used" is too vague and non-specific. Without waiving this objection, FRONTLINES responds that Ms. Ayer has "used" various computer models that establish flows on the interconnected grid in various proceedings before the CPUC and the FERC by directing generation "inputs" to, and analyzing "outputs" from, such computer models. It is recollected that these models include both PLEXOS and GridView; it is not recollected whether the GE PSLF model was specifically "used" in any of these efforts. As in many CPUC Proceedings, Ms. Ayer and other parties have had opportunities to request access to, and make "runs" on, an applicant's computer models pursuant to Rule 10.4 of the CPUC's Rules of Practice and Procedure. However, in proceedings where parties (including Ms. Ayer) have deemed such requests necessary, the applicant has always elected to either conduct the computer modeling "runs" or have CAISO make the "runs" rather than provide the actual computer model to interested parties to "run". Therefore, while Ms. Ayer has not "used" these models in terms of putting hands on a keyboard, she has certainly "used" the models by directing changes to modeling "inputs" (specifically generation assumptions) and analyzed the modeled "outputs". If SDGE wishes a further response, please provide a more detailed explanation of what information is specifically sought, and what is meant and intended by the term "used."

<u>DATA REQUEST NO. 3</u>: Please state whether Jacqueline Ayer has ever used any computer program intended to model the electric transmission grid. If the answer is yes, please identify each such program and state when and for what purpose for each instance that she used it.

<u>RESPONSE NO. 3:</u>
See response to Data Request 2.

<u>DATA REQUEST NO. 4</u>: Please state whether Frontlines or Jacqueline Ayer has conducted any power flow modeling for any purpose related to this Application (including but not limited to analysis of SDG&E's Proposed Project or any alternative thereto). If the answer is yes, please describe all power flow modeling conducted, for what purpose such modeling was conducted, and produce for each power flow analysis:

a. Starting powerflow cases in PSLF format
b. Final powerflow case(s) in PSLF format
c. All change files (.epc or .p) applied to the final cases
d. Identify the source of the starting case
e. A high-level summary of the final powerflow case parameters, including load, net area interchange, and dispatch.
f. A high-level summary of any modifications to the Area 22 generation dispatch, load, and net area interchange (a summary in spreadsheet format or narrative is acceptable)
g. All contingency files applied to the final case(s)
h. All contingency run results

<u>RESPONSE NO. 4:</u>

FRONTLINES objects to this Data Request because it seeks information that is already in SDGE's possession. FRONTLINES also objects to this Data Request on the grounds that it is unduly burdensome to produce information that is already in SDGE's possession. Without waiving this objections, FRONTLINES offers the following response: Pursuant to the SOCRE Proceeding, Ms. Ayer took SDGE's peak load forecast and SDGE's projected peak load levels at each SOC substation and reconciled it with modeled spreadsheet data that SDGE provided to FRONTLINES on or before April 2015 pertaining to each of the 18 NERC violation scenarios that SDGE describes in Initial Testimony. From this information, Ms. Ayer calculated the power flows to each substation in the SOC for each of the scenarios identified by SDGE. It is based upon this power flow analysis that FRONTLINES concluded the SOCRE Project is not needed to address these 18 scenarios and further concluded that reconductoring of TL13835 to achieve a 228 MVA transmission capacity and making other changes would address these scenarios. All of the specific modeled powerflow information and inputs that SDGE seeks in this data requests are already in SDGE's possession.

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In response to SDG&E's Fifth Set of Data Requests, Request No. 5, Frontlines stated: "FRONTLINES did not propose a 230/138/12/kV Trabuco Substation. … FRONTLINES' testimony simply points out that 'A small 230 kV GIS substation looped in to an adjacent SCE 230 kV lines could be sufficient as a second source in SOC.' In the Trabuco area, FRONTLINES identified locations along and adjacent to the SCE ROW that are near the Trabuco Substation where a small 230 kV GIS substation could be constructed along with the necessary 230/138 kV transformer equipment. The SOC system could be connected to 138 kV power at this location." In Ms. Ayer's June 14, 2015 email to SDG&E's counsel, Frontlines further clarified: "FRONTLINES' testimony plainly and clearly addresses a small, new SDGE 230 kV gis substation with 230/138 transformer equipment that is located adjacent to or within SCE's ROW. The SDGE 138 kV line(s) emanating from this substation could interconnect at SDGE's existing Pico or Trabuco substation." For purposes of Data Requests 5 to 20, the "proposed 230 kV GIS Substation located near Trabuco Substation" will refer to the 230 kV GIS substation described in the foregoing Frontlines' data request response and Ms. Ayer's email.

DATA REQUEST NO. 5: Please admit that Frontlines has not conducted any power flow analysis of the impact on the electric transmission system of interconnecting the proposed 230 kV GIS Substation located near Trabuco Substation to an nearby SCE 230 kV transmission line, and connecting a 138 kV transmission line(s) from that 230 kV GIS substation to Trabuco Substation. If you do not so admit, please provide such power flow analysis, including but not limited to:

a. Starting powerflow cases in PSLF format
b. Final powerflow case(s) in PSLF format
c. All change files (.epc or .p) applied to the final cases
d. Identify the source of the starting case
e. A high-level summary of the final powerflow case parameters, including load, net area interchange, and dispatch.
f. A high-level summary of any modifications to the Area 22 generation dispatch, load, and net area interchange (a summary in spreadsheet format or narrative is acceptable)
g. All contingency files applied to the final case(s)
h. All contingency run results

RESPONSE NO. 5:
FRONTLINES has not conducted a power flow analysis of the 230 kV GIS substation near the Trabuco substation that FRONTLINES described in testimony. FRONTLINES presumes that such analysis would be done as part of the System interconnection/impact studies.

<u>DATA REQUEST NO. 6</u>: Please admit that neither Frontlines nor Ms. Ayer have a one line diagram for the proposed 230 kV GIS Substation located near Trabuco Substation. If you do not so admit, please provide a one line diagram for the proposed 230 kV GIS Substation located near Trabuco Substation.

<u>RESPONSE NO. 6:</u>
Neither FRONTLINES nor Ms. Ayer has a one line diagram of a 230 kV GIS substation near the Trabuco substation that FRONTLINES described in testimony.

<u>DATA REQUEST NO. 7</u>: With respect to the proposed 230 kV GIS Substation located near Trabuco Substation, please:

(a) Provide all documents relating to the design of such substation;
(b) Please provide schematic diagram(s) showing the equipment layout (including identification of major equipment and their dimensions) at such substation;
(c) Identify the major components included in such substation;
(d) Please state any safety considerations used to determine the equipment layout at such substation.
(e) Explain in the greatest detail you are able the location and dimensions of the work areas during construction of such substation;
(f) Provide all documents supporting or concerning your responses to the preceding subsections of this Data Request.

<u>RESPONSE NO. 7:</u>
FRONTLINES objects to this data request on the grounds that is unduly burdensome and oppressive and it seeks equipment layout, dimensional information, and safety consideration parameters that extend far beyond the scope of FRONTLINES testimony. Without waiving these objections, FRONTLINES offers the following response: FRONTLINES does not possess any schematics or figures of the 230 kV GIS substation located near the Trabuco substation that is referred to in FRONTLINES testimony.

DATA REQUEST NO. 8: Please admit that neither Frontlines nor Ms. Ayer have a one line diagram for Trabuco Substation following interconnection with the proposed 230 kV GIS Substation located near Trabuco Substation. If you do not so admit, please provide a one line diagram for Trabuco Substation following interconnection with the proposed 230 kV GIS Substation located near Trabuco Substation.

RESPONSE NO. 8:
Neither FRONTLINES nor Ms. Ayer possess a one line diagram of the Trabuco substation as configured to accommodate an interconnection with a 230 kV GIS substation located near Trabuco.

DATA REQUEST NO. 9: With respect to Trabuco Substation following interconnection with the proposed 230 kV GIS Substation located near Trabuco Substation, please:

(a) Provide all documents relating to any change in the design of the existing Trabuco substation;
(b) Please provide schematic diagram(s) showing the equipment layout (including identification of major equipment and their dimensions) at Trabuco Substation following such interconnection;
(c) Identify any change in the major components included in Trabuco Substation following such interconnection;
(d) Please state any safety considerations used to determine the equipment layout at Trabuco Substation following such interconnection.
(e) Explain in the greatest detail you are able the location and dimensions of the work areas during construction at Trabuco Substation to perform such interconnection;
(f) Provide all documents supporting or concerning your responses to the preceding subsections of this Data Request.

RESPONSE NO. 9:
FRONTLINES objects to this data request on the grounds that it is unduly burdensome and oppressive. FRONTLINES further objects to this data request on the grounds that it seeks equipment layout and dimensional information of the entire Trabuco substation, including equipment that is not addressed by, or considered in, the scope of FRONTLINES testimony. FRONTLINES further objects to this data request to the extent that it seeks information pertaining to Trabuco substation configuration that is under SDGE control. Without waiving these objections, FRONTLINES offers the following response: FRONTLINES does not possess any schematics or one-line diagrams of any SOC substations (including Trabuco) other than what SDGE has provided in the record of this proceeding or in response to discovery requests. Nor has FRONTLINES prepared any such diagrams. In addition, FRONTLINES does not possess any layout figures for any SOC substations (including Trabuco) other than aerial figures which FRONTLINES has already provided to SDGE in prior data request responses.

<u>DATA REQUEST NO. 10</u>: Please identify any location where Frontlines proposes that SDG&E locate the proposed 230 kV GIS Substation located near Trabuco Substation other than the locations identified in Exhibit 3 to the Frontlines Reply Testimony Of Jacqueline Ayer ("Ayer Testimony").

<u>RESPONSE NO. 10</u>
FRONTLINES objects to this data request on the grounds that it seeks information regarding locations that were not considered in FRONTLINES testimony, and therefore addresses matters outside the scope of FRONTLINES testimony. FRONTLINES further objects to this data request on the grounds that the term "any location" is vague and ambiguous, FRONTLINES further objects to this data request on the grounds that it is unduly burdensome and oppressive to demand that FRONTLINES identify "any" location near the Trabuco substation where FRONTLINES could propose that SDGE construct a 230 kV GIS substation. Without waiving this objection, FRONTLINES offers the following response: FRONTLINES has not proposed any locations for a 230 kV GIS substation near the Trabuco substation other than those locations described in FRONTLINES testimony.

<u>DATA REQUEST NO. 11</u>: Identify which SCE transmission line would be connected to the proposed 230 kV GIS Substation located near Trabuco Substation and, for each location identified Exhibit 3 to the Ayer Testimony and in response to Data Request No. 10 above, describe the route of the new transmission line connecting such SCE transmission line to the proposed 230 kV GIS Substation located near Trabuco Substation, and whether it would be overhead or underground. Identify the location of each structure that would be constructed with respect to this transmission line.

<u>RESPONSE NO. 11</u>
FRONTLINES objects to this data request on the grounds that it is unduly burdensome and oppressive in seeking "the location of each structure that would be constructed" for various transmission line route alternatives. FRONTLINES further objects on the grounds that it seeks information that may already be in SDGE's possession. Without waiving these objections, FRONTLINES offers the following response: SDGE is already in possession of transmission line routing alternatives in the vicinity of SCE's Right of Way near the Trabuco substation, as evidenced by SDGE's response provided to Energy Division on May 14, 2015 pursuant to Data Gap P-14. Other than this information provided by SDGE, FRONTLINEs does not possess any documents addressing transmission routes or transmission structure locations between the SCE ROW and any proposed 230 kV GIS substation near Trabuco. In addition, FRONTLINES has not identified which of the 2 SCE lines near Trabuco would be connected to this 230 kV GIS system. FRONTLINES presumes that such decisions would be made through the course of the system interconnect/impact study effort.

ATTACHMENT 34

FRONTLINES Remaining Response to
SDG&E's Sixth Set of Data Requests, Nos. 12-28

FRONTLINES' PARTIAL RESPONSE TO
SDGE'S SIXTH SET OF DATA REQUESTS
A.12-05-020
Submitted to SDGE June 22, 2015

DATA REQUEST NO. 12: For each location identified Exhibit 3 to the Ayer Testimony and in response to Data Request No. 10 above, describe the route of the new transmission line connecting the proposed 230 kV GIS Substation located near Trabuco Substation to Trabuco Substation, and whether it would be overhead or underground. Identify the location of each structure that would be constructed with respect to this transmission line.

RESPONSE NO. 12

FRONTLINES objects to this data request on the grounds that it is unduly burdensome and oppressive in seeking "the location of each structure that would be constructed" for various transmission line route alternatives. FRONTLINES further objects on the grounds that it seeks information that may already be in SDGE's possession. Without waiving these objections, FRONTLINES offers the following response: SDGE is already in possession of transmission line routing alternatives between the Trabuco substation and SCE's Right of Way near the Trabuco substation, as evidenced by SDGE's response provided to Energy Division on May 14, 2015 pursuant to Data Gap P-14. FRONTLINES does not possess any other documents or information addressing transmission routes or transmission structure locations between the locations identified in Exhibit 3 of FRONTLINES testimony and the Trabuco substation.

DATA REQUEST NO. 13: Please provide Frontlines' analysis of the environmental impacts for the construction and operation of the proposed 230 kV GIS Substation located near Trabuco Substation, at each location in Exhibit 3 to the Ayer Testimony and each location identified in response to Data Request 12 above, including the impacts on each resource area identified in Table 5-1 of the Draft Environmental Impact Report for the South Orange County Reliability Enhancement Project, found at http://www.cpuc.ca.gov/Environment/info/ene/socre/attachment/draftEIR/5.0%20Comparison%20of%20Alternatives.pdf.

RESPONSE NO. 13

Interpreting this data request as seeking FRONTLINES' analysis of the environmental impacts of 2) constructing and operating a 230 kV GIS substation at either location depicted in Exhibit 3; and 2) constructing and operating each possible transmission line route alternative that connects either of these 230 kV GIS substations to the Trabuco substation, FRONTLINES responds: FRONTLINES generally considered land use, topographic, and seismic issues relevant to the locations indicated in Exhibit 3 of

FRONTLINES testimony (as clarified in Response #9 provided by FRONTLINES pursuant to SDGE's Data Request #4). Beyond the information and references already provided in response to Data Request #4, FRONTLINES does not have any additional responsive documents regarding environmental impacts of constructing or operating a 230 kV GIS substation near the Trabuco Substation or constructing or operating any possible transmission lines between such a GIS system and Trabuco substation.

DATA REQUEST NO. 14: Please provide Frontlines' analysis of the environmental impacts for the construction and operation of the transmission lines interconnecting the proposed 230 kV GIS Substation located near Trabuco Substation to an SCE 230 kV transmission line and to Trabuco Substation, at each location in Exhibit 3 to the Ayer Testimony and each location identified in response to Data Request 12 above, including the impacts on each resource area identified in Table 5-1 of the Draft Environmental Impact Report for the South Orange County Reliability Enhancement Project, found at http://www.cpuc.ca.gov/Environment/info/ene/socre/attachment/draftEIR/5.0%20Comparison%20of%20Alternatives.pdf.

RESPONSE NO. 14

Interpreting this data request as seeking FRONTLINES' analysis of the environmental impacts of 2) constructing and operating 230 kV lines between an SCE 230 kV line and a 230 kV GIS substation at either location depicted in Exhibit 3; and 2) constructing and operating transmission lines for each transmission line route alternative that connects either 230 kV GIS substations to the Trabuco substation, FRONTLINES responds: FRONTLINES generally considered land use, topographic, and seismic issues relevant to the locations indicated in Exhibit 3 of FRONTLINES testimony (as clarified in Response #9 provided by FRONTLINES pursuant to SDGE's Data Request #4). Beyond the information and references already provided in response to Data Request #4, FRONTLINES does not have any additional responsive documents regarding environmental impacts of constructing or operating any such transmission lines.

DATA REQUEST NO. 15: Please provide Frontlines' analysis of the environmental impacts for the construction and operation of any necessary changes to Trabuco Substation to interconnect it to the proposed 230 kV GIS Substation located near Trabuco Substation, including the impacts on each resource area identified in Table 5-1 of the Draft Environmental Impact Report for the South Orange County Reliability Enhancement Project, found at http://www.cpuc.ca.gov/Environment/info/ene/socre/attachment/draftEIR/5.0%20Comparison%20of%20Alternatives.pdf.

RESPONSE NO. 15
The extent of the modifications to the Trabuco substation that were identified in FRONTLINES' testimony was to extend the 138 kV bus at Trabuco. FRONTLINES has not conducted an environmental impact analysis of extending the 138 kV Bus at Trabuco, and therefore has no responsive documents.

DATA REQUEST NO. 16: Please provide Frontlines' cost estimate for proposed 230 kV GIS Substation located near Trabuco Substation, breaking out the cost of each major element, identifying the source of each cost estimate, and producing all documents relating thereto.

RESPONSE NO. 16
FRONTLINE objects to this data request on the grounds that it seeks information that is outside the scope of FRONTLINES testimony. Without waiving this objection, FRONTLINES offers the following response. FRONTLINES does not have a cost estimate for a 230 kV GIS substation near Trabuco. However, FRONTLINES is in possession of ORA's prepared testimony that includes a cost estimates for ORA's Trabuco alternative for an SCE 230 kV interconnect.

DATA REQUEST NO. 17: Please provide Frontlines' cost estimate for the interconnection of the proposed 230 kV GIS Substation located near Trabuco Substation with an SCE 230 kV transmission line, breaking out the cost of each major element, identifying the source of each cost estimate, and producing all documents relating thereto.

RESPONSE NO. 17
FRONTLINES objects to this data request on the grounds that it seeks information that is outside the scope of FRONTLINES testimony. Without waiving this objection, FRONTLINES offers the following response. FRONTLINES does not have a cost estimate for the interconnection of an SCE transmission line and a 230 kV GIS substation near Trabuco. However, FRONTLINES is in possession of ORA's prepared testimony that includes a cost estimates for ORA's Trabuco alternative for an SCE 230 kV interconnect.

DATA REQUEST NO. 18: Please provide Frontlines' cost estimate for the interconnection of the proposed 230 kV GIS Substation located near Trabuco Substation with Trabuco Substation, breaking out the cost of each major element, identifying the source of each cost estimate, and producing all documents relating thereto.

RESPONSE NO. 18

FRONTLINES objects to this data request on the grounds that it seeks information that is outside the scope of FRONTLINES testimony. Without waiving this objection, FRONTLINES offers the following response. FRONTLINES does not have a cost estimate for the interconnection of a 230 kV GIS substation near Trabuco to the Trabuco substation. However, FRONTLINES is in possession of ORA's prepared testimony that includes a cost estimates for ORA's Trabuco alternative for an SCE 230 kV interconnect.

DATA REQUEST NO. 19: Please provide Frontlines' cost estimate for work at Trabuco Substation necessary to interconnect it with the proposed 230 kV GIS Substation located near Trabuco Substation, breaking out the cost of each major element, identifying the source of each cost estimate, and producing all documents relating thereto.

RESPONSE NO. 19

FRONTLINES objects to this data request on the grounds that it seeks information that is outside the scope of FRONTLINES testimony. Without waiving this objection, FRONTLINES offers the following response. FRONTLINES does not have a cost estimate for the work at Trabuco to connect it to a 230 kV GIS substation. However, FRONTLINES is in possession of ORA's prepared testimony that includes a cost estimates for ORA's Trabuco alternative for an SCE 230 kV interconnect.

DATA REQUEST NO. 20: Please admit that neither Frontlines nor Jacqueline Ayer has had any communication with Southern California Edison regarding interconnection of an SCE transmission line to SDG&E's South Orange County system. If you do not so admit, please describe each such communication and produce all documents constituting or reflecting such communications.

RESPONSE NO. 20

As FRONTLINES clearly stated in it response to SDGE's Data Request #4, FRONTLINES did not and has not consulted with SCE regarding any SDGE interconnection with SCE. Neither FRONTLINES nor Jacqueline Ayer has had any communication with SCE regarding interconnection of an SCE transmission line to SDGE's SOC system.

****

In response to SDG&E's Fifth Set of Data Requests, Request No. 5, Frontlines stated: "FRONTLINES did not propose a 230/138/12/kV Pico Substation, therefore the information requested cannot be provided. … FRONTLINES' testimony simply points out that 'A small 230 kV GIS substation looped in to an adjacent SCE 230 kV lines could be sufficient as a second source in SOC.' FRONTLINES' testimony also points out that SCE maintains four separate and distinct 230 kV lines near the Pico substation where such a substation could be constructed along with the necessary 230/138 kV transformer equipment. The SOC system could be connected to 138 kV power at this location." In Ms. Ayer's June 14, 2015 email to SDG&E's counsel, Frontlines further clarified: "FRONTLINES' testimony plainly and clearly addresses a small, new SDGE 230 kV gis substation with 230/138 transformer equipment that is located adjacent to or within SCE's ROW. The SDGE 138 kV line(s) emanating from this substation could interconnect at SDGE's existing Pico or Trabuco substation." For purposes of Data Requests 21 to 37, the "proposed 230 kV GIS Substation located near Pico Substation" will refer to the 230 kV GIS substation described in the foregoing Frontlines' data request response and Ms. Ayer's email.

DATA REQUEST NO. 21: Please admit that Frontlines has not conducted any power flow analysis of the impact on the electric transmission system of interconnecting the proposed 230 kV GIS Substation located near Pico Substation to an nearby SCE 230 kV transmission line, and connecting a 138 kV transmission line(s) from that 230 kV GIS substation to Pico Substation. If you do not so admit, please provide such power flow analysis, including but not limited to:

a. Starting powerflow cases in PSLF format
b. Final powerflow case(s) in PSLF format
c. All change files (.epc or .p) applied to the final cases
d. Identify the source of the starting case
e. A high-level summary of the final powerflow case parameters, including load, net area interchange, and dispatch.
f. A high-level summary of any modifications to the Area 22 generation dispatch, load, and net area interchange (a summary in spreadsheet format or narrative is acceptable)
g. All contingency files applied to the final case(s)
h. All contingency run results

RESPONSE NO. 21:

FRONTLINES has not conducted a power flow analysis of any 230 kV GIS substation near the Pico substation that FRONTLINES identified in testimony. FRONTLINES presumes that such analysis would be done as part of the System interconnection/impact studies.

DATA REQUEST NO. 22: Please admit that neither Frontlines nor Ms. Ayer have a one line diagram for the proposed 230 kV GIS Substation located near Pico Substation. If you do not so admit, please provide a one line diagram for the proposed 230 kV GIS Substation located near Pico Substation.

RESPONSE NO. 22:
Neither FRONTLINES nor Ms. Ayer has a one line diagram of a 230 kV GIS substation near the Pico substation that FRONTLINES identified in testimony.

DATA REQUEST NO. 23: With respect to the proposed 230 kV GIS Substation located near Pico Substation, please:

(a) Provide all documents relating to the design of such substation;
(b) Please provide schematic diagram(s) showing the equipment layout (including identification of major equipment and their dimensions) at such substation;
(c) Identify the major components included in such substation;
(d) Please state any safety considerations used to determine the equipment layout at such substation.
(e) Explain in the greatest detail you are able the location and dimensions of the work areas during construction of such substation;
(f) Provide all documents supporting or concerning your responses to the preceding subsections of this Data Request.

RESPONSE NO. 23:
FRONTLINES objects to this data request on the grounds that is unduly burdensome and oppressive and it seeks equipment layout, dimensional information, and safety consideration parameters that extend far beyond the scope of FRONTLINES testimony. Without waiving these objections, FRONTLINES offers the following response: FRONTLINES does not possess any schematics or figures of the 230 kV GIS substation located near the Pico substation that is referred to in FRONTLINES' testimony.

DATA REQUEST NO. 24: Please admit that neither Frontlines nor Ms. Ayer have a one line diagram for Pico Substation following interconnection with the proposed 230 kV GIS Substation located near Pico Substation. If you do not so admit, please provide a one line diagram for Pico Substation following interconnection with the proposed 230 kV GIS Substation located near Pico Substation.

RESPONSE NO. 24:
Neither FRONTLINES nor Ms. Ayer possess a one line diagram of the Pico substation as configured to accommodate an interconnection with a 230 kV GIS substation located near Pico.

DATA REQUEST NO. 25: With respect to Pico Substation following interconnection with the proposed 230 kV GIS Substation located near Pico Substation, please:

(a) Provide all documents relating to any change in the design of the existing Pico substation;
(b) Please provide schematic diagram(s) showing the equipment layout (including identification of major equipment and their dimensions) at Pico Substation following such interconnection;
(c) Identify any change in the major components included in Pico Substation following such interconnection;
(d) Please state any safety considerations used to determine the equipment layout at Pico Substation following such interconnection.
(e) Explain in the greatest detail you are able the location and dimensions of the work areas during construction at Pico Substation to perform such interconnection;
(f) Provide all documents supporting or concerning your responses to the preceding subsections of this Data Request.

RESPONSE NO. 25:

FRONTLINES objects to this data request on the grounds that it is unduly burdensome and oppressive. FRONTLINES further objects to this data request on the grounds that it seeks equipment layout and dimensional information of the entire Pico substation, including equipment that is not addressed by, or considered in, the scope of FRONTLINES testimony. FRONTLINES further objects to this data request to the extent that it seeks information pertaining to Pico substation configuration that is under SDGE control. Without waiving these objections, FRONTLINES offers the following response: FRONTLINES does not possess any schematics or one-line diagrams of any SOC substations (including Pico) other than what SDGE has provided in the record of this proceeding or in response to discovery requests. Nor has FRONTLINES prepared any such diagrams. In addition, FRONTLINES does not possess any layout figures for any SOC substations (including Pico) other than aerial figures which FRONTLINES has already provided to SDGE in prior data request responses.

DATA REQUEST NO. 26: Please identify any location where Frontlines proposes that SDG&E locate the proposed 230 kV GIS Substation located near Pico Substation.

RESPONSE NO. 26

FRONTLINES objects to this data request on the grounds that the term "any location" is vague and ambiguous, FRONTLINES further objects to this data request on the grounds that it is unduly burdensome and oppressive to demand that FRONTLINES identify "any" location near the Pico substation where a 230 kV GIS substation could be proposed. Without waiving this objection, FRONTLINES offers the following response: FRONTLINES has not proposed any specific location for a 230 kV GIS substation near the Pico substation, but notes that large areas of vacant land are located near Pico and adjacent to the SCE right of way.

<u>DATA REQUEST NO. 27</u>: Identify which SCE transmission line would be connected to the proposed 230 kV GIS Substation located near Pico Substation and, for each location identified in response to Data Request No. 26 above, describe the route of the new transmission line connecting such SCE transmission line to the proposed 230 kV GIS Substation located near Pico Substation, and whether it would be overhead or underground. Identify the location of each structure that would be constructed with respect to this transmission line.

<u>RESPONSE NO. 27</u>

FRONTLINES objects to this data request on the grounds that it is unduly burdensome and oppressive in seeking "the location of each structure that would be constructed" for various transmission line route alternatives from SCE's lines to "any location" where a 230 kV GIS substation could be constructed near Pico. Without waiving this objection, FRONTLINES offers the following response: FRONTLINEs does not possess any documents addressing transmission routes or transmission structure locations between SCE's lines near Pico and any proposed 230 kV GIS substation near Pico. In addition, FRONTLINES has not identified which of the 4 SCE lines near Pico would be connected to this 230 kV GIS system. FRONTLINES presumes that such decisions would be made through the course of the system interconnect/impact study effort.

<u>DATA REQUEST NO. 28</u>: For each location identified in response to Data Request No. 26 above, describe the route of the new transmission line connecting the proposed 230 kV GIS Substation located near Pico Substation to Pico Substation, and whether it would be overhead or underground. Identify the location of each structure that would be constructed with respect to this transmission line.

<u>RESPONSE NO. 28</u>

FRONTLINES objects to this data request on the grounds that it is unduly burdensome and oppressive in seeking "the location of each structure that would be constructed" for various transmission line route alternatives between Pico and "any location" where a 230 kV GIS substation could be proposed near Pico. Without waiving these objections, FRONTLINES offers the following response: FRONTLINES does not possess any documents or information addressing transmission routes or transmission structure locations between Pico and "any location" where a 230 kV GIS Substation could be located near Pico.

ATTACHMENT 35

Aerial Photo View of Pico Substation

Privileged and Confidential pursuant to
P.U. Code 583, 454.5(g), GO 66-C and D.06-06-066

CONFIDENTIAL

ATTACHMENT 36

PICO Substation Layout

ATTACHMENT 37

Rancho Mission Viejo Substation as Built 4

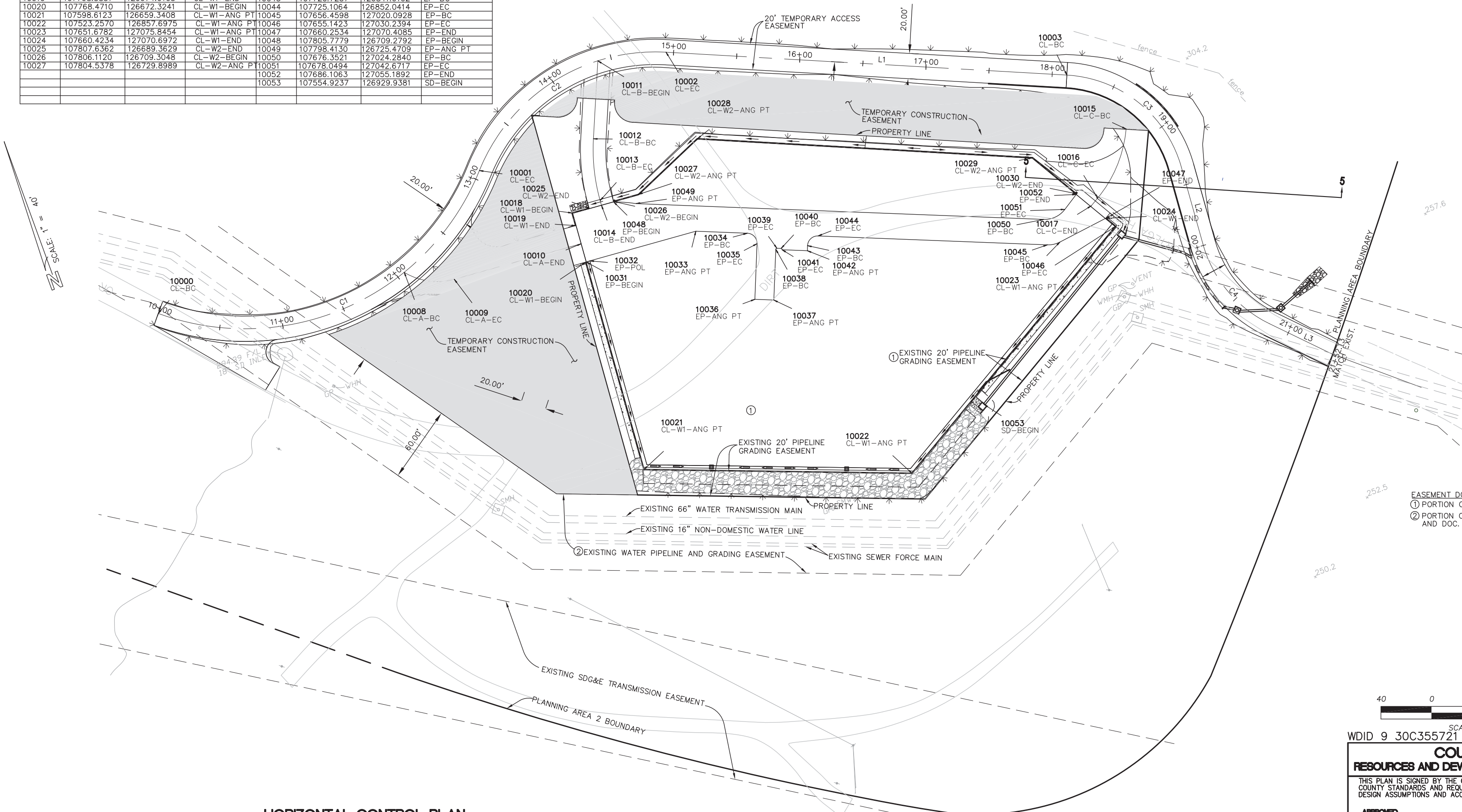
POINT	NORTHING	EASTING	DESCRIPTION	POINT	NORTHING	EASTING	DESCRIPTION
10000	107845.9970	126340.6297	CL–BC	10028	107830.0039	126788.6142	CL–W2–ANG PT
10001	107865.3465	126617.9604	CL–EC	10029	107725.1855	127032.5725	CL–W2–ANG PT
10002	107902.8178	126788.7130	CL–EC	10030	107686.4462	127055.7666	CL–W2–END
10003	107777.3489	127080.5419	CL–BC	10031	107768.4454	126672.6581	EP–BEGIN
10008	107810.0735	126534.5582	CL–A–BC	10032	107768.3314	126675.6582	EP–POL
10009	107791.3453	126569.8774	CL–A–EC	10033	107761.6960	126762.4677	EP–ANG PT
10010	107783.4018	126673.8014	CL–A–END	10034	107746.2830	126800.1998	EP–BC
10011	107914.8854	126735.6854	CL–B–BEGIN	10035	107735.8518	126804.5805	EP–EC
10012	107858.0887	126711.3172	CL–B–BC	10036	107695.1211	126787.9426	EP–ANG PT
10013	107810.3779	126699.6017	CL–B–EC	10037	107689.4488	126801.8288	EP–ANG PT
10014	107806.5401	126699.3083	CL–B–END	10038	107726.6280	126817.0159	EP–BC
10015	107721.2509	127109.9929	CL–C–BC	10039	107727.0843	126818.1025	EP–EC
10016	107677.6313	127070.2312	CL–C–EC	10040	107725.8199	126821.1980	EP–BC
10017	107673.5762	127063.3430	CL–C–END	10041	107724.5830	126821.5816	EP–EC
10018	107808.7036	126675.3993	CL–W1–BEGIN	10042	107717.0199	126840.0965	EP–ANG PT
10019	107798.3837	126674.6105	CL–W1–END	10043	107720.7257	126841.6102	EP–BC
10020	107768.4710	126672.3241	CL–W1–BEGIN	10044	107725.1064	126852.0414	EP–EC
10021	107598.6123	126659.3408	CL–W1–ANG PT	10045	107656.4598	127020.0928	EP–BC
10022	107523.2570	126857.6975	CL–W1–ANG PT	10046	107655.1423	127030.2394	EP–EC
10023	107651.6782	127075.8454	CL–W1–ANG PT	10047	107660.2534	127070.4085	EP–END
10024	107660.4234	127070.6972	CL–W1–END	10048	107805.7779	126709.2792	EP–BEGIN
10025	107807.6362	126689.3629	CL–W2–END	10049	107798.4130	126725.4709	EP–ANG PT
10026	107806.1120	126709.3048	CL–W2–BEGIN	10050	107676.3521	127024.2840	EP–BC
10027	107804.5378	126729.8989	CL–W2–ANG PT	10051	107678.0494	127042.6717	EP–EC
				10052	107686.1063	127055.1892	EP–END
				10053	107554.9237	126929.9381	SD–BEGIN

LINE TABLE

LINE	BEARING	LENGTH
L1	S66°44'07"E	317.66'
L2	S04°20'22"W	63.16'
L3	S44°08'40"E	55.59'

CURVE TABLE

CURVE	ANGLE	RADIUS	LENGTH
C1	88°03'23"	200.00'	307.37'
C2	71°17'03"	150.00'	186.62'
C3	71°04'28"	100.00'	124.05'
C4	48°29'02"	100.00'	84.62'



HORIZONTAL CONTROL PLAN

SCALE: 1" = 40'

EASEMENT DOCUMENT NUMBERS:
① PORTION OF PARCEL 14 PER DOC. NO. 91-616009
② PORTION OF PARCEL 14 PER DOC. NO. 91-616009 AND DOC. NO. 91-616013

40 0 40 80 120
SCALE 1" = 40'

AS-BUILT

WDID 9 30C355721

PRINTED ON: 8/30/2010

COUNTY OF ORANGE
RESOURCES AND DEVELOPMENT MANAGEMENT DEPARTMENT

THIS PLAN IS SIGNED BY THE COUNTY OF ORANGE FOR CONCEPT AND ADHERENCE TO COUNTY STANDARDS AND REQUIREMENTS ONLY. THE COUNTY IS NOT RESPONSIBLE FOR DESIGN ASSUMPTIONS AND ACCURACY.

APPROVED ______ PUBLIC WORKS ENGINEER ______ DATE

APPROVED ______ UTILITIES ENGINEER ______ DATE

REVISIONS

NO.	WORK DONE	DATE	BY:	APP'D:	NO.	WORK DONE	DATE	BY:	APP'D:	NO.	WORK DONE	DATE	BY:	APP'D:	NO.	WORK DONE	DATE	BY:	APP'D:
1	REVISE TO INCLUDE RETAINING WALL PER RW100027 AND REALIGNMENT OF ADJACENT ROADWAY.																		

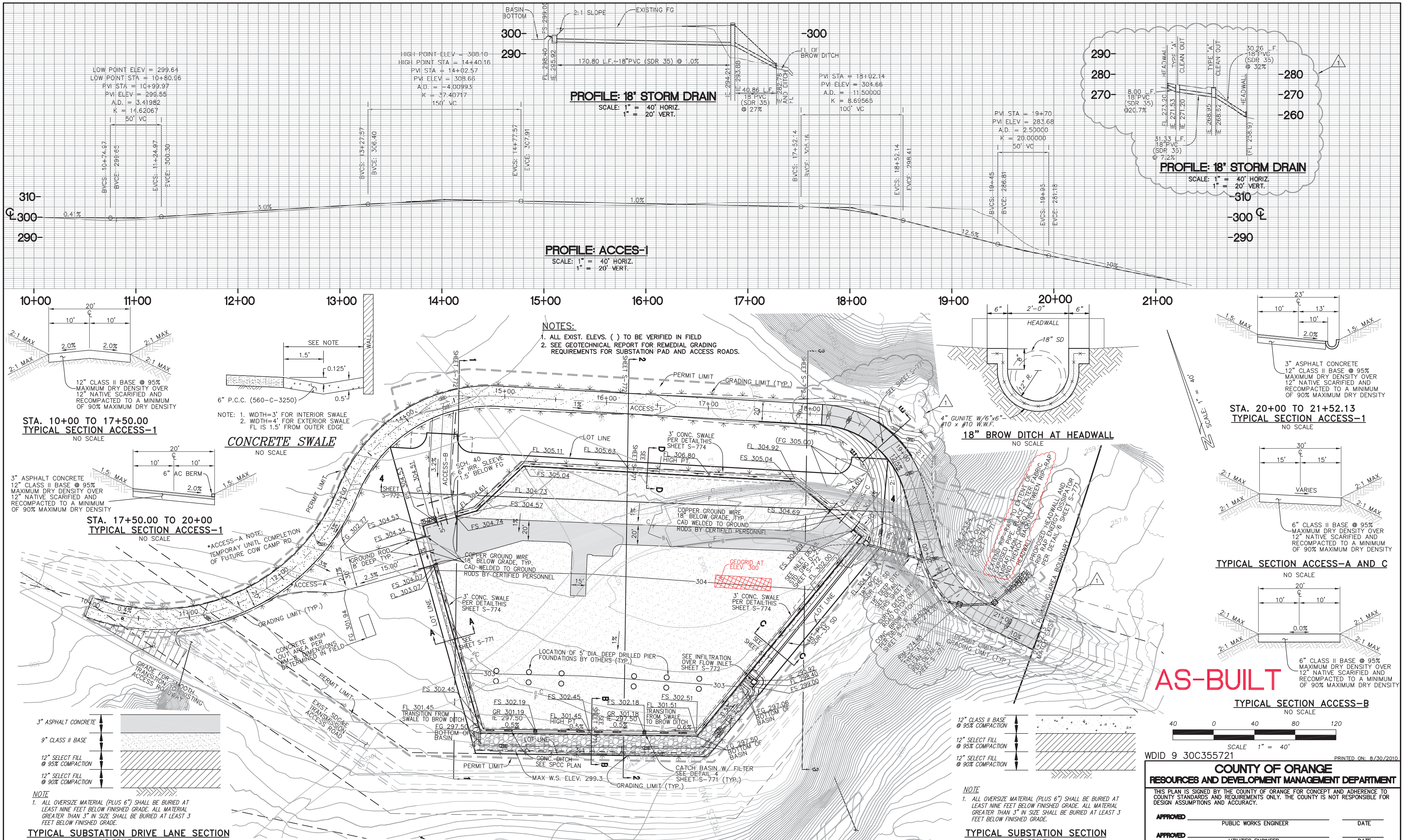
RANCHO MISSION VIEJO SUBSTATION
SAN DIEGO GAS & ELECTRIC COMPANY
SAN DIEGO, CALIFORNIA

HORIZONTAL CONTROL PLAN

DRAWN BY: JAH	DATE: 4/12/10	SCALE: 1" = 40'	W.O. / REV.
CHECKED BY:	DATE:		
APPROVED BY:	DATE:		RMV-S-773
CAD NO.:	PLOT SCALE: 1=1		

ATTACHMENT 38

Rancho Mission Viejo Substation as Built 5



WDID 9 30C355721

PRINTED ON: 8/30/2010

COUNTY OF ORANGE
RESOURCES AND DEVELOPMENT MANAGEMENT DEPARTMENT

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APPROVED ____ PUBLIC WORKS ENGINEER ____ DATE

APPROVED ____ UTILITIES ENGINEER ____ DATE

REVISIONS

NO.	WORK DONE	DATE	BY:	APP'D:
1	REVISE TO INCLUDE RETAINING WALL PER RW100027 AND REALIGNMENT OF ADJACENT ROADWAY.			
REV-1	REVISE ACCESS RD (WEST) / ADD RET. WALL/ REV. SD / ADD FIRE DEPT. TURN OUT (EAST)	2/19/10	HALE	

RANCHO MISSION VIEJO SUBSTATION
SAN DIEGO GAS & ELECTRIC COMPANY
SAN DIEGO, CALIFORNIA

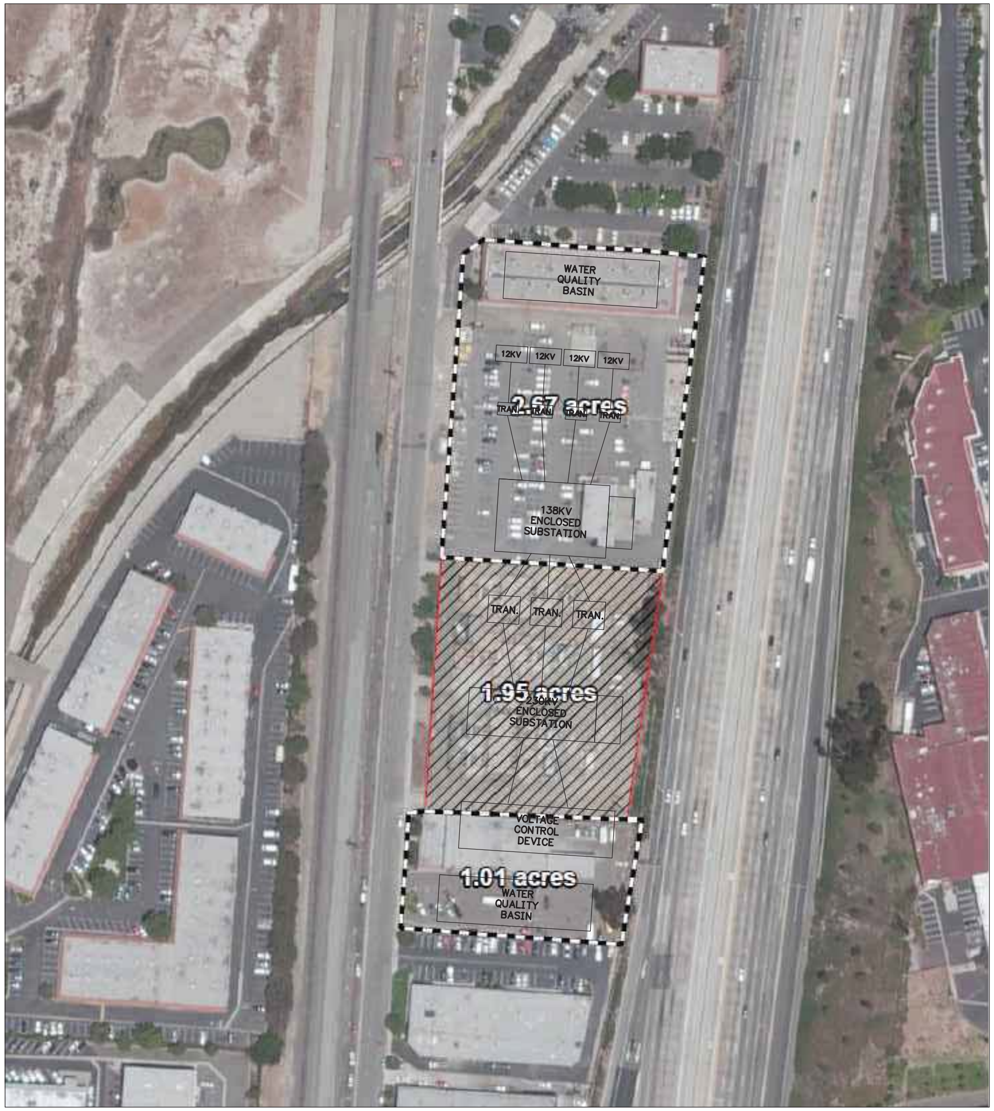
GRADING PLAN

DRAWN BY: JAH DATE: 4/12/10 SCALE: 1" = 40' W.O. REV.
CHECKED BY: DATE:
APPROVED BY: DATE:
CAD NO.: PLOT SCALE: 1=1

RMV-S-774

ATTACHMENT 39

Trabuco Block Diagram



REVISIONS

NO.	WORK DONE	DATE:	BY:	APP'D:
0	NEW DRAWING			

SAN DIEGO GAS & ELECTRIC COMPANY
SAN DIEGO, CALIFORNIA

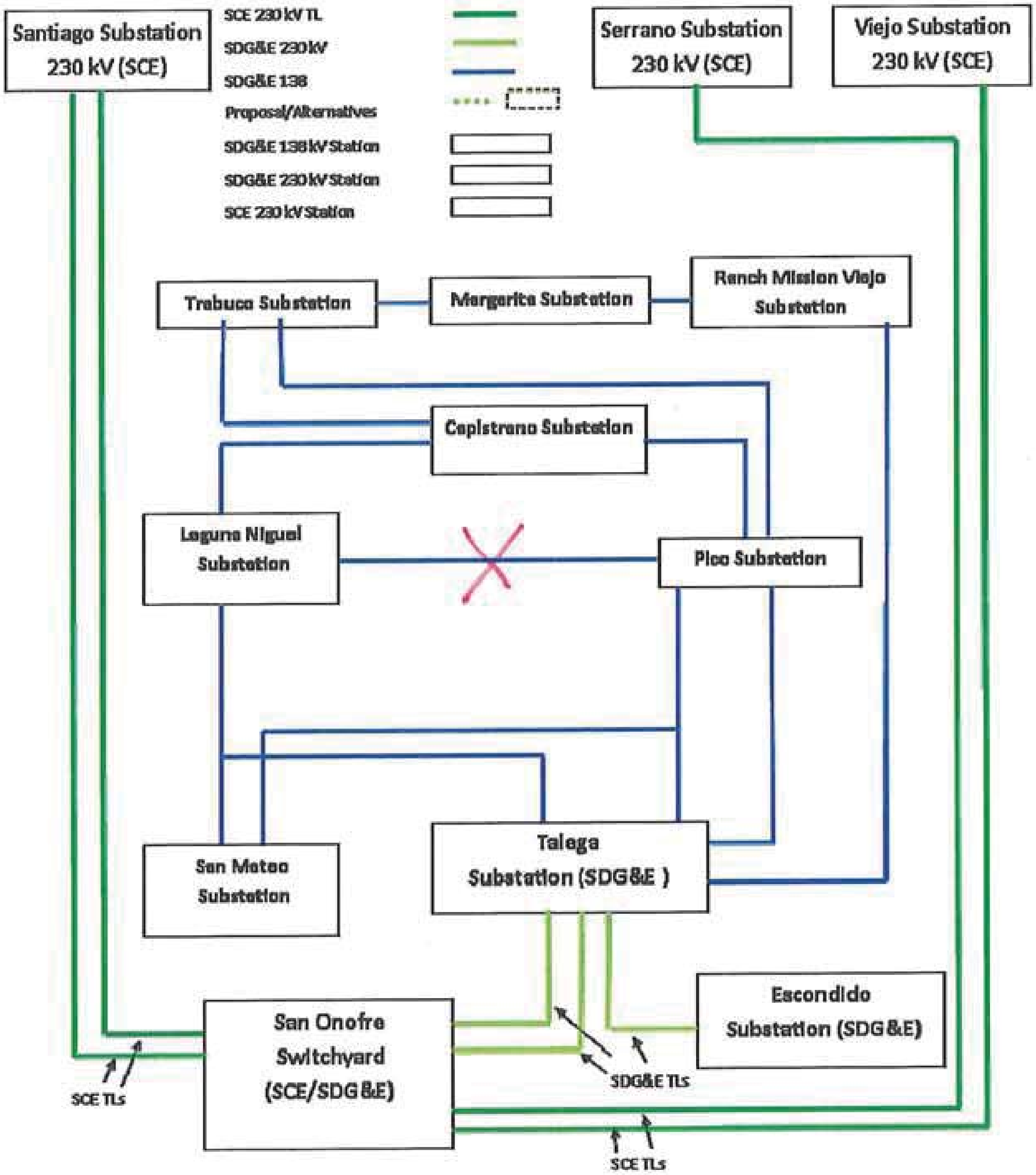
TRABUCO SUBSTATION

DRAWN BY:	DATE:	SCALE:	W.O.:
CHECKED BY:	DATE:		REV.:
APPROVED BY:	DATE:		
CAD NO.:	PLOT SCALE: 1 = 1		

May 14, 2015 – 07:58:29

ATTACHMENT 40

Aerial Photo View of Trabuco Substation



1 **Figure 1: Existing South Orange County Electrical Interconnection**

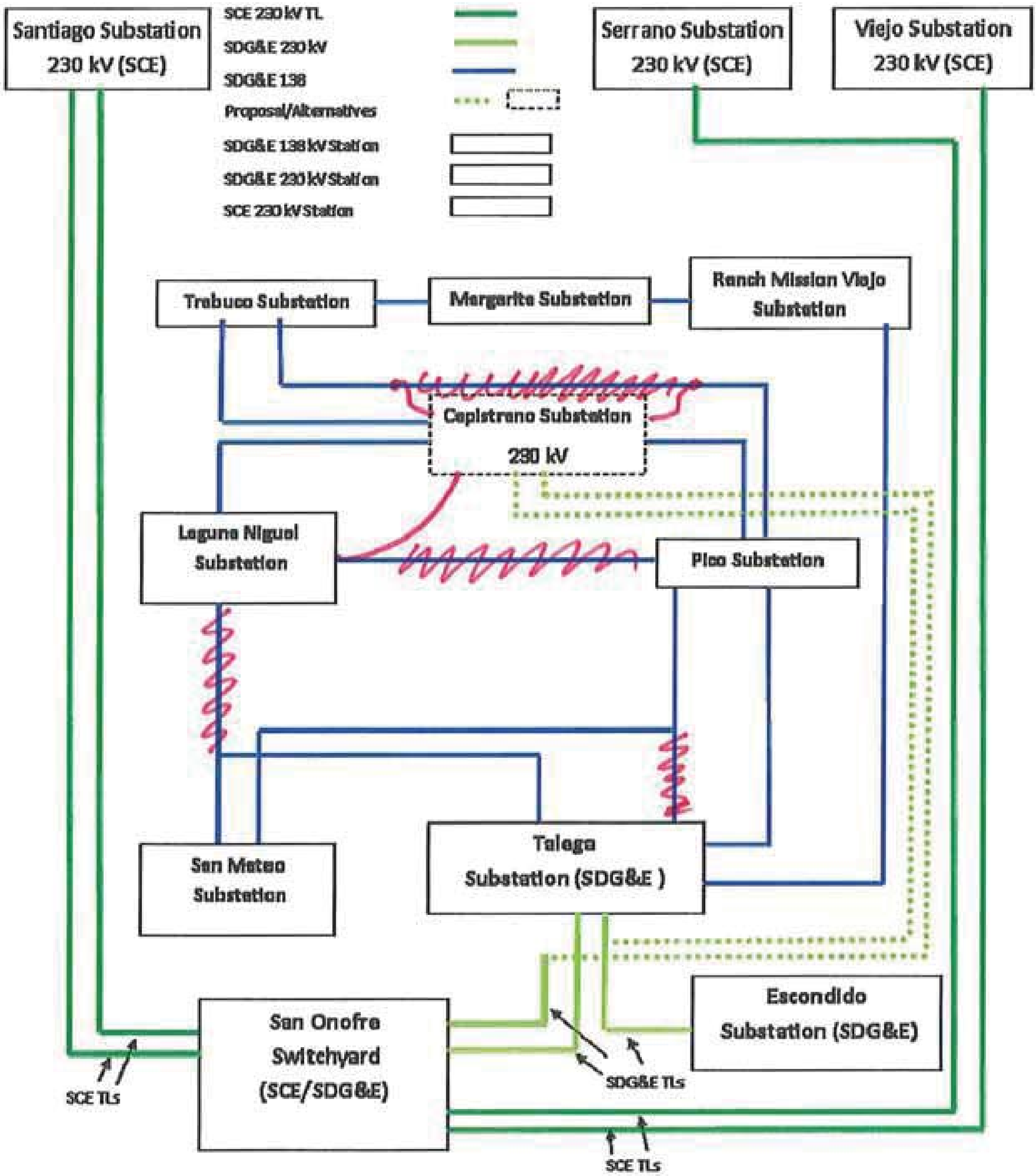
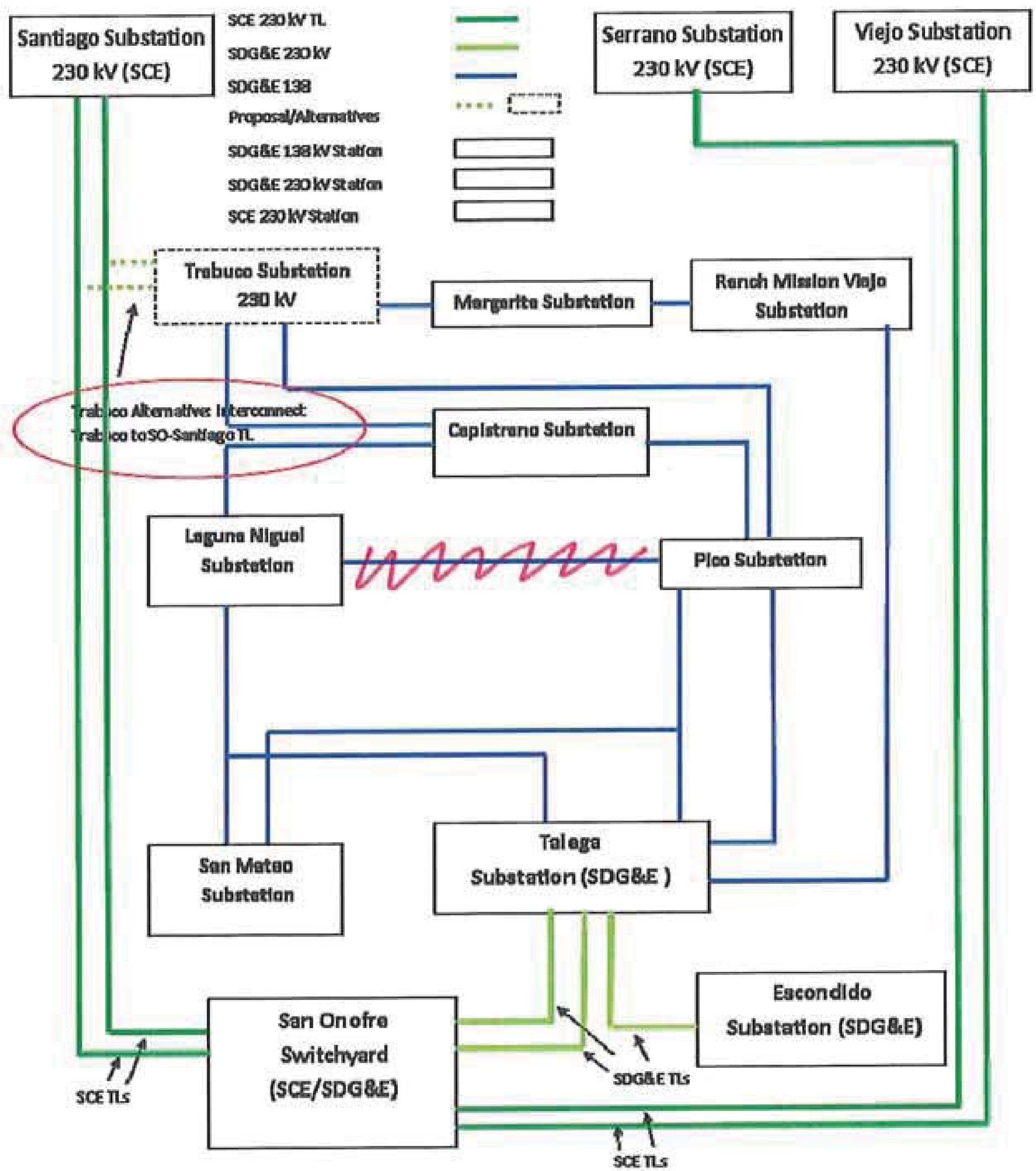


Figure 2: SDG&E Proposed Project Electrical Interconnection



1 **Figure 3-1: ORA Proposed Trabuco Alternative Electrical Interconnection**

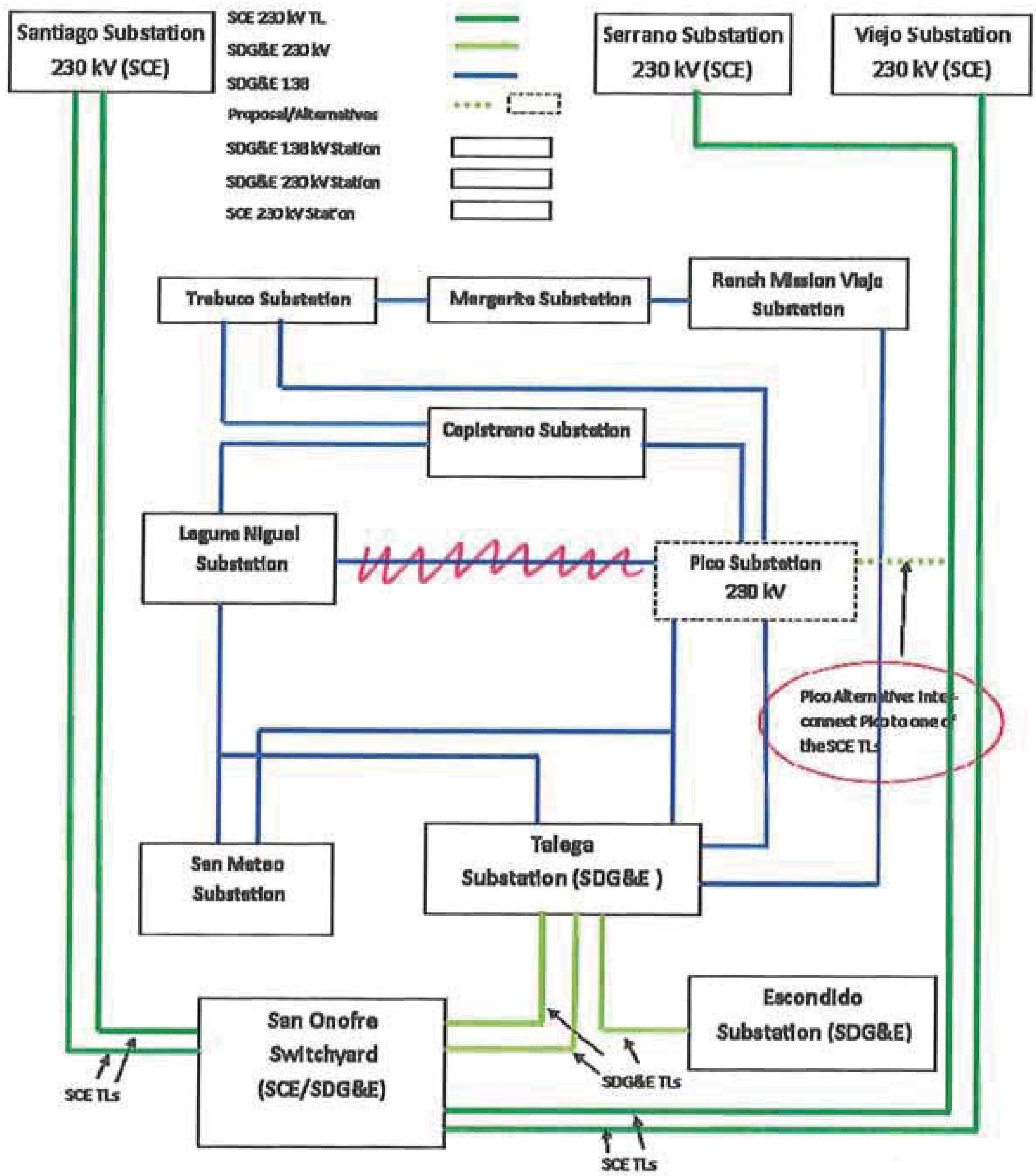


Figure 4-1: ORA Proposed Pico Alternative Electrical Interconnection

ATTACHMENT 41

Aerial Photo View of Trabuco Substation

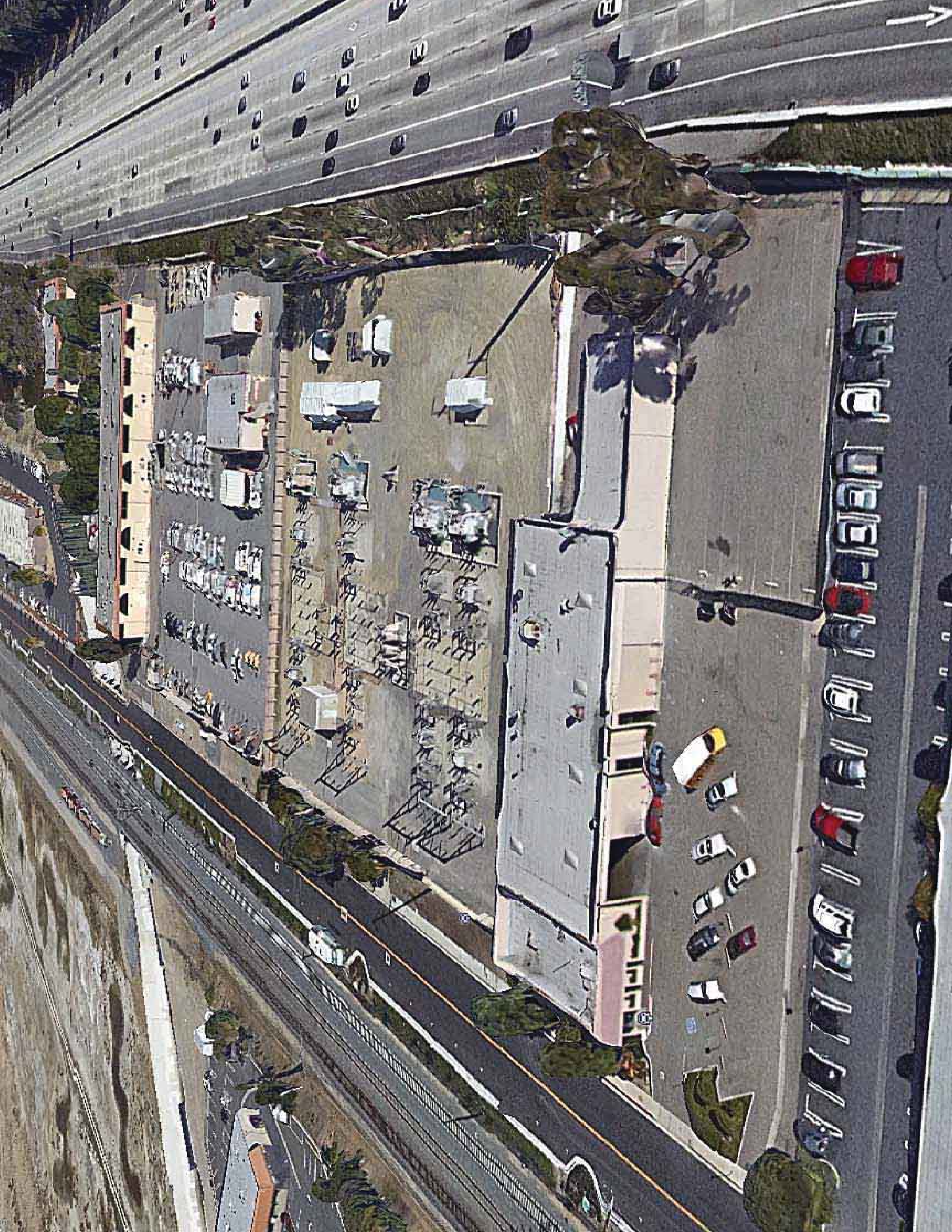


EXHIBIT 6

SDG&E Second Supplemental Testimony with Public Attachments 43-52, 56 and without Confidential Attachments 42, 53-55

Exhibit No.: __________

In The Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) for a Certificate of Public Convenience and Necessity for the South Orange County Reliability Enhancement Project	Application 12-05-020

SAN DIEGO GAS & ELECTRIC COMPANY

SECOND SUPPLEMENTAL TESTIMONY OF

JOHN JONTRY, CORY SMITH, WILLIE THOMAS, SCOTT BOCZKIEWICZ, KARL ILIEV, JEFFREY SYKES, ROBERT FLETCHER, JR., AND DEBBIE SCHAFER

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

SEPTEMBER 14, 2015

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CHAPTER 1. INTRODUCTION AND OVERVIEW (Witness John Jontry)

Pursuant to the Administrative Law Judge's July 16, 2015 email ruling, San Diego Gas & Electric Company ("SDG&E") submits the following supplemental testimony on the changes presented in the Recirculated Draft Environmental Impact Report for the South Orange County Reliability Enhancement Project ("Recirculated DEIR"). The Recirculated DEIR identified three new impacts associated with SDG&E's Proposed Project, and identified a new project alternative, "Alternative J – SCE 230-kV Loop In to Trabuco Substation" (the "RDEIR Trabuco Alternative"). Because the RDEIR Trabuco Alternative is similar to, but not the same as, the ORA's Trabuco Alternative, SDG&E will refer back to its Rebuttal Testimony regarding the ORA's Trabuco Alternative at times and otherwise provide testimony necessary to address the RDEIR Trabuco Alternative in context.

SDG&E's Second Supplemental Testimony is organized as follows:

- Chapter 2: SDG&E's Proposed Project can be constructed without significant impact on the existing utility structure identified in the Recirculated DEIR by reducing Capistrano Substation's ultimate distribution capacity to three banks.
- Chapter 3: SDG&E's Proposed Project can be constructed under SDG&E's NCCP/HCP without significant impact to the conservation easements discussed in the Recirculated DEIR.
- Chapter 4: The Recirculated DEIR's "Alternative—SCE 230 kV Loop In to Trabuco Substation" is infeasible.

CHAPTER 2. SDG&E's PROPOSED PROJECT CAN BE CONSTRUCTED TO AVOID SIGNIFICANT IMPACT TO THE RECIRCULATED DEIR-IDENTIFIED HISTORIC RESOURCE.

Section 1. The Recirculated DEIR Finds the Proposed Project Will Have a Significant Impact on a Potential Historic Resource (Witness Scott Bockiewicz)

The Recirculated DEIR notes that SDG&E's Capistrano Substation includes a "1918-constructed building that fronts Camino Capistrano," which the Recirculated DEIR refers to as the "former utility structure"[1] and which SDG&E refers to herein as the existing utility structure. The Recirculated DEIR notes that three qualified consultants, including one retained by the Commission, found that the existing utility structure was not eligible for listing on the National Register of Historic Places (NRHP), and was not an "historical resource" under CEQA.[2] As stated in the Recirculated DEIR:

> On April 29, 2015, the State Historic Resources Commission (SHRC) held its quarterly commission meeting in San Diego. The nomination of the former utility structure was on the agenda. Office of Historic Preservation staff presented the nomination to the six SHRC members, followed by a presentation by the nominator, Ilse Burns. SDG&E and SCE objected to the proposed nomination, commenting that the building lacks sufficient integrity, and it was once part of an integral complex that is no longer extant. SDG&E pointed out that three qualified consultants (including a third party consultant from the CPUC) did not find the building eligible. The SHRC voted unanimously in favor of recommending the building as eligible for the NHRP. The recommendation was forwarded to the Keeper of the NRHP on July 17, 2015.

The SHRC recommendation of eligibility to the NRHP occurred after the Commission's Draft EIR for this Project was made available for public comment in February 2015. On August 21, 2015, SDG&E submitted to the Keeper its objection to the proposed determination of eligibility of the existing utility structure for the NRHP, opposing the SHRC's recommendation. As of the date of this testimony, SDG&E has not learned whether the Keeper will determine the existing utility structure eligible for listing on the NRHP.

Based upon the SHRC recommendation, the Recirculated DEIR finds: "Because the former utility structure's eligibility for listing in the NRHP has not yet been determined, it is assumed for the purposes of this analysis that the structure will be determined to be eligible for listing in the NRHP. Therefore, the demolition of the former utility structure would be

[1] RDEIR at 2-86.
[2] RDEIR at 2-86 to 2-87.

considered a significant impact under CEQA because this structure is potentially a historic resource as defined by CEQA."[3]

Section 2. With a Modification, SDG&E'S Proposed Project Can Be Constructed Without Significant Impact to the Existing Utility Structure (Witness Karl Iliev)

Following the SHRC determination regarding the existing utility structure, SDG&E identified and retained a historic preservation consulting firm, Chattel, Inc., to determine what would be necessary to avoid significant impact to the existing utility structure, assuming the Keeper finds that the structure is eligible for NRHP listing. In coordination with Chattel, Inc., SDG&E has developed a plan to avoid a significant impact to the existing utility structure in accordance with the Secretary of the Interior's Standards for the Treatment of Historic Properties with Guidelines for Preserving, Rehabilitating, Restoring, and Reconstructing Historic Buildings ("SOI Standards").

Based upon Chattel Inc's recommendations, if the Keeper finds the structure eligible for NRHP listing, SDG&E could, and if authorized by the Commission, would construct its Proposed Project in a manner that avoids significant impact to the existing utility structure. The east wing of the structure (located away from Camino Capistrano, which is less visible from the street and has less architectural detail) would be removed and the west wing of the structure rehabilitated in conformance with the SOI Standards. By reducing the ultimate distribution capacity of the proposed rebuilt Capistrano Substation from 120 MVA to 90 MVA, the proposed 230/138/12 kV substation could be constructed within SDG&E's existing property. This modification would reduce the number of distribution 138/12kV transformers, 12kV switchgear sections and 12kV capacitors from four to three each. SDG&E will refer to its Proposed Project, as so modified, as the "Modified Proposed Project." All other elements of the Modified Proposed Project (new 230kV transmission lines, 138kV power line relocations and undergrounding west of the Capistrano Substation site, and 12kV distribution line relocations) would be the same as the Proposed Project (refined as set forth in Chapter 3).

Under the Modified Proposed Project, in order to incorporate the retained portion of the existing utility structure into the rebuilt Capistrano Substation design, modifications to the design, specifications, and layout of the substation were made compared to the Capistrano

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3 RDEIR at 2-97.

Substation design included in SDG&E's Proposed Project. The primary modification to the substation design is a reduction in the size of the rebuilt 138/12 kV substation located on the "lower pad" portion of the substation site. Attachment 42 provides the substation site plan for the Capistrano 230/138/12kV Substation under the Modified Proposed Project.

The east wing of the existing utility structure would be removed and the west wing would be retained and incorporated into the Capistrano Substation design.

Substation design modifications include:

- The existing earthen mounds, vegetation and trees along the western edge of the property (between Camino Capistrano and the existing utility structure) would be removed and replaced with landscaping that returns the existing utility structure's setting to an earlier appearance.

- Because the substation grade would be raised approximately 5 feet to accommodate vehicles carrying equipment, an approximately 5 foot tall retaining wall would be constructed parallel to the northern and eastern walls of the existing utility structure. The retaining wall would be set back a minimum of 5 feet from the existing utility structure walls providing a personnel access way on these sides of the building.

- The western perimeter of the substation (along Camino Capistrano) would have a masonry wall approximately 10 feet tall on the inside of the substation and when viewed from the exterior would vary from approximately 12 feet to 15 feet in height. This is due to the fact that the substation grade behind the wall is raised by approximately 5 feet. The lower approximately 5 feet is the retaining wall, which would be coupled with an upper approximately 10 feet of masonry wall to collectively serve as the substation security and screen wall. The northern and southern perimeter walls would remain at approximately 10 feet in height, identical to the Proposed Project.

- The security screen wall would abut the existing utility structure on the north and south sides terminating approximately 4 inches from the structure (refer to Attachment 42) creating separation between the existing utility structure and the western perimeter wall.

- The southern and western walls of the retained portion of the existing utility structure would be located outside of the secured substation facility and would be visible from Camino Capistrano. The northern and eastern walls of the existing utility structure would effectively act as part of the substation security wall.

- New steel replacement doors would be installed in the southern, eastern and northern walls of the existing utility structure and would replace the existing doors at these locations. The northern and eastern doors will serve as part of the security wall.

- A driveway access to the existing utility structure would be constructed from the main substation access drive to the structure's southern door.

- The southern driveway's vehicle access gate to the rebuilt Capistrano Substation would be set back approximately 80 feet from Camino Capistrano.

- The northern driveway's access gate would remain (similar to the Proposed Project) set back approximately 35 feet from Camino Capistrano.

- The northern and southern vehicular access gates would be approximately 30 feet in width, each comprised of a pair of black wrought iron sliding gates, each approximately 15 feet in width.

- Grading and the phased site development, including cut and fill, would be similar to that of Proposed Project substation design.

With respect to the existing utility structure itself, the west wing would be retained and rehabilitated per the SOI Standards. The east wing would be removed to provide adequate room for redevelopment of the substation. The northern and eastern walls of the retained portion of the existing utility structure would serve as part of the security wall of the substation, and would only be entered from the exterior (which would be inside the substation security wall). Proposed modifications to the existing utility structure include:

- East Wing Demolition –12 inches of roof and walls would be retained at the point where the east wing intersects the west wing of the existing utility structure. This work is designed to allow the remaining portion of the roof and wall visually to read as a "ghost" of the east wing once it is removed.

- West Wing Rehabilitation:

  - Western Wall –The exterior wall where earthen mounds are to be removed would be repaired and waterproofed. The concrete wall iron jacking would be repaired at locations where steel rebar is exposed at western interior wall. Window rehabilitation would include removal of existing glazing, repairing existing sash and frames, and reglazing with like-kind translucent wire glass. Security bars on all windows would be installed on the interior.

  - Northern Wall – Deteriorated, non-original doors, sidelights, and transom window would be replaced to match the original. Doors, sidelights and transom would be constructed of steel rather than wood for increased security. Due to lack of visibility from the street, it is not proposed to include glazing, but rather this door assembly would be constructed exclusively of steel following the original pattern. The northern wall and replacement door would serve as part of the security wall of the substation and would only be accessed from the exterior (i.e., from within the substation).

  - Eastern Wall –The interior door at the location of demolished east wing would be replaced with a new exterior door to match the original, but designed for exposure to the elements. Due to the lack of visibility from the street, it is not proposed that glazing be included in either the new exterior door or existing windows, but rather for these assemblies would be constructed exclusively of steel following the original pattern. The eastern wall, windows and replacement door would serve as part of the security wall of the substation and would only be accessed from the exterior (i.e., from within the substation).

- Southern Wall – Deteriorated, non-original doors, sidelights, and transom window would be replaced to match the original. Doors, sidelights and transom would be constructed of steel rather than wood for increased security. Due to the visibility from the street, it is proposed to include translucent wire glass at the transom only, but otherwise the new door assembly would be constructed of steel following the original pattern. Where glazing occurs at the transom, security bars would be installed on the interior.

- Interior Window Sills - Damage to concrete would be repaired at windows sills where water infiltration has occurred.

- Interior Crane – The moveable crane would be retained.

- Lighting - Development and implementation of a lighting plan would include exterior wall sconces on the north and south walls. Such exterior wall sconces would operate manually.

As mitigation, SDG&E would retain a qualified professional historic architect meeting the Secretary of the Interior's Professional Qualifications Standards to ensure conformance with the SOI Standards. SDG&E also would prepare Historic American Building Survey (HABS) photographic documentation for the existing utility structure before the east wing is removed.

With the foregoing modifications and mitigation measures, Chattel, Inc. has found that the Modified Proposed Project described above is in conformance with the SOI Standards, and thus would have a less than significant impact on the existing utility structure under CEQA.[4]

Section 3. The Modified Proposed Project Achieves SDG&E's Project Objectives (Witness Karl Iliev)

SDG&E's Modified Proposed Project still achieves SDG&E's project objectives even though the ultimate distribution capacity of the rebuilt Capistrano Substation will be reduced. If the Keeper determines that the existing utility structure is a historic resource, the reduction in ultimate distribution capacity is an acceptable trade-off for its preservation. Even as modified, SDG&E's Modified Proposed Project remains the best way to address reliability concerns in

[4] Chattel, Inc. is preparing a report that will be submitted with SDG&E's comments on the Recirculated DEIR on September 24, 2015. SDG&E will provide the Chattel report to the parties at that time, and of copy of it will be included as Attachment 43 to this Second Supplemental Testimony when presented at evidentiary hearings.

South Orange County. For the reasons stated in SDG&E's Supplemental and Rebuttal Testimony, the other alternatives identified in the Recirculated DEIR are infeasible.

As discussed in SDG&E's Rebuttal Testimony, Chapter 5, Section 2, SDG&E's Capistrano Substation is within a mile of the load center for South Orange County. As a result of its location, "placing the second 230 kV source there negates the need to upgrade SDG&E's 138 kV lines in South Orange County within the current ten-year planning window, and for some time thereafter."[5] The Modified Proposed Project will provide transmission system reliability.

As discussed in detail in SDG&E's Opening Testimony, Chapter 5, and Supplemental Testimony, Chapter 3, Section 3, SDG&E's existing Capistrano Substation must be rebuilt to provide reliable electric service to SDG&E's SOC customers. Capistrano Substation, built over 60 years ago, needs to be rebuilt to, among other things, upgrade its current bus configuration to a more reliable configuration, replace deteriorating infrastructure and equipment near the end of its useful life, meet current seismic, safety and security standards, and allow 12 kV ties with neighboring substations that increase the reliability of the overall system. Expanding Capistrano Substation to include a 230 kV substation on existing substation property during the required rebuild is cost-effective, as well as placing the second 230 kV source at the appropriate location.

Modifying SDG&E's Proposed Project to preserve the existing utility structure as set forth above and thereby reduce Capistrano's ultimate distribution capacity still achieves SDG&E's project objectives to rebuild Capistrano to replace aging equipment and increase capacity, improve transmission and distribution operating flexibility, and accommodate customer load growth.

- A new substation can be built on the Capistrano property without compromising the reliability of the existing substation during construction or placing construction personnel at risk;
- The new substation will facilitate SDG&E's long range transmission and distribution's forecasted 10 year planning needs to serve its customers; and
- The new substation would comply with SDG&E's current operating and reliability criteria and seismic and safety design requirements

Currently, Capistrano Substation 138/12 kV transformer loading is at 85% capacity at peak. When customer load exceeds the current capacity, the existing substation cannot accommodate the required amount of additional transformers. High transformer loading at

[5] SDG&E's Rebuttal Testimony at 36.

Capistrano also limits its ability to support neighboring substations via 12 kV circuit ties, thereby limiting flexibility in distribution line equipment and substation transformer outages.

In the Modified Proposed Project, rebuilding the entire Capistrano substation will allow for expansion from the existing 60 MVA substation to an ultimate 90 MVA substation. This additional capacity will allow for future load increases and for load transfers from neighboring substations into the new Capistrano Substation when needed during the near future. Simply replacing equipment in kind will not allow room for the expansion necessary for a more reliable configuration or to allow an additional transformer and its 12kV switchgear and capacitor to be installed without deviating from SDG&E reliability criteria. Without Capistrano Substation being fully rebuilt, the capacity of the existing substation cannot be increased.

The preservation of the existing utility structure in the Modified Proposed Project will not affect the reliability improvements at Capistrano Substation. Reliability will increase because the new substation will still be rebuilt to SDG&E's current operating and reliability standards. Operational flexibility will also increase by the addition of an additional 12 kV bus tie. When operating a substation with three distribution transformers, SDGE typically connects two transformers to one bus and the third transformer to another 12kV bus. These two busses are separated by an open12kV bus tie. There is an additional bus tie between the two transformers that normally is closed, but also has the flexibility of opening in case of a bus fault or other failure that requires sectionalizing the transformers from each other. This results in limited load loss and the flexibility to isolate the problem.

Even though the Modified Proposed Project reduces the ultimate distribution capacity of the rebuilt Capistrano Substation to 90 MVA from 120 MVA, with three transformers rather than four, it does provide the capacity required for the 10 year distribution planning horizon. The addition of a third transformer allows for planned load growth as well as creating redundant capacity to offload circuits in nearby substations Trabuco and Laguna Niguel in the event of equipment outages at those sites. It also increases the short-term operating flexibility and reliability through adding an additional 12kV bus tie, further sectionalizing outage impacts caused by 12kV bus faults at Capistrano.

The major difference between the Modified Proposed Project and the Proposed Project is the capability of installing a fourth 138/12kV distribution transformer at Capistrano in the future to create capacity for future circuit expansion. This also is known as "ultimate capacity."

Although the Proposed Project would not immediately require this capacity and would not install it, future load growth and/or expansion outside of the 10-year planning horizon could require it. Both Laguna Niguel and Trabuco (the substations adjacent to Capistrano) are built out to their ultimate 4-transformer capacity already. Therefore, at some point beyond the10-year planning horizon, under the Modified Proposed Project, sufficient continued load growth would require an expansion of Capistrano Substation beyond its current fence-line or construction of a new substation at a new location.

CHAPTER 3 SDG&E's PROPOSED PROJECT CAN BE CONSTRUCTED TO AVOID SIGNIFICANT IMPACT TO THE CONSERVATION EASEMENTS DISCUSSED IN THE RECIRCULATED DEIR

Section 1. RDEIR Discussion of Conservation Easements and Habitat Conservation Plans (Witness Rob Fletcher)

The Recirculated DEIR asserts that the Proposed Project would have significant impacts on Biological Resources and Land Use and Planning based upon a potential purported inconsistency of the Proposed Project with SDG&E's Subregional Natural Community Conservation Plan/Habitat Conservation Plan ("NCCP/HCP").

The Recirculated DEIR recognizes that SDG&E is governed by its state-level NCCP/HCP rather than Orange County Southern Subregion HCP, and that certain areas traversed by the Proposed Project may be considered "preserve areas" under SDG&E's NCCP/HCP, stating:

> The proposed project would be located within areas of Orange County covered by the Orange County Southern Subregion Habitat Conservation Plan (HCP). However, because the applicant's activities are regulated at the statewide level rather than at the local level, the legally applicable equivalent plan is the SDG&E Subregional Natural Community Conservation Plan (NCCP)/Habitat Conservation Plan (HCP) (SDG&E 1995a). Under the SDG&E Subregional NCCP/HCP, certain areas containing habitat for Covered Species are considered preserve areas. Preserve areas include existing reserve or conservation areas established by regional planning documents (e.g., Orange County Southern Subregion HCP) …[6]

> The proposed project would traverse through several areas that may be considered preserve areas; City of San Juan Capistrano open space; a conservation easement at Orange County's Prima Deshecha Landfill; City of San Clemente open space, including a yet-to-be recorded conservation easement in the Talega Corridor; and San Onofre State Beach.[7]

> The proposed project traverses a small portion of a conservation easement at Orange County's Prima Deshecha Landfill that was preserved as mitigation under the Orange County Southern Subregion HCP to compensate for impacts on other areas by landowners participating in the HCP.[8]

With respect to Biological Resources, Impact BR-6 "Conflict with the provisions of an adopted Habitat Conservation Plan, Natural Community Conservation Plan, or other approved

[6] RDEIR at 2-138
[7] RDEIR at 2-46.
[8] RDEIR at 2-46.

local, regional, or state habitat plan," the Recirculated DEIR finds a "significant" conflict.[9] The DEIR had found that SDG&E's NCCP/HCP, which provides a process for determining mitigation in preserve areas, plus proposed Mitigation Measure BR-10, which required coordination with local jurisdictions, mitigated any conflict with HCPs, NCCPs or other plans to less than significant.

The Recirculated DEIR, however, states:

> The proposed project may conflict with two conservation easements established within the Orange County Southern Subregion HCP and considered preserve areas under the SDG&E NCCP/HCP. The two conservation easements in question are the Talega Conservation Easement (unrecorded) and the Prima Deshecha Landfill Conservation Easement (recorded). Potential conflicts with the Talega Conservation Easement cannot be determined until the easement is recorded and the applicant conducts further consultation with the USFWS regarding the applicant's existing ROW, the establishment of new ROW, and the potential use of ground disturbing construction techniques within the Talega Conservation Easement. Much of the proposed project in the Talega Corridor would lie within the boundaries of the Talega Conservation Easement.
>
> Potential conflicts with the Prima Deshecha Landfill Conservation Easement cannot be determined until the construction disturbance limits of the proposed project have been delineated in relation to the conservation easement boundary and the applicant's existing ROW. A small part of the proposed project crosses through this easement. The CPUC is in the process of gathering additional information pertaining to the boundaries and allowable uses in each easement. Based on recent discussions with the USFWS, establishing new ROW or impacting areas outside of the applicant's existing ROW and within the boundaries of the conservation easement(s) would conflict with both conservation easements, resulting in a significant impact (Snyder 2015).
>
> The USFWS has indicated that establishing new ROW within the Talega Conservation Easement or impacting areas of the Prima Deshecha Landfill Conservation Easement that are outside of the applicant's existing ROW would directly conflict with the provisions of the aforementioned conservation easement(s), and thereby the provisions of the Orange County Southern Subregion HCP. MM BR-10 would require the applicant to participate in further coordination with the implementing agencies. While consultation with the USFWS may identify mechanisms for reducing potentially significant impact to less than significant levels, MM BR-10 on its own is does not adequately ensure consistency with an adopted HCP at this time. Measures to avoid, minimize, and mitigate potentially significant impacts to less than significant levels cannot be evaluated until the Talega Conservation Easement is recorded and additional consultation between the applicant and the wildlife agencies occurs. Therefore, impacts under this criterion are being treated as significant and unavoidable until additional information is gathered.[10]

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[9] RDEIR at 2-75.
[10] RDEIR at 2-77.

The Recirculated DEIR makes a similar change from the DEIR in evaluating Land Use and Planning, Impact LU-3 "Conflict with any applicable habitat conservation plan or natural community conservation plan."[11]

Section 2. SDG&E's NCCP/HCP (Witness Rob Fletcher)

A. SDG&E's NCCP/HCP Provides Mitigation for Any Biological Impacts of SDG&E's Transmission Projects

The Recirculated DEIR refers to SDG&E's NCCP/HCP, a true and correct copy of which is attached hereto as Attachment 44. SDG&E's Subregional Natural Community Conservation Plan (NCCP) is an NCCP formed under state law (pursuant to the NCCP Act) and a Habitat Conservation Plan (HCP) under federal law that was developed and approved by the U.S. Fish and Wildlife Service (USFWS) and the California Department of Fish and Wildlife (CDFW) in 1995. As part of the NCCP process, SDG&E, USFWS, and CDFW entered into a long-term Implementing Agreement, which provides the legal obligation to implement and maintain SDG&E's HCP.

The purpose of SDG&E's NCCP is to allow the utility to develop, install, maintain, operate, and repair its gas and electric facilities within nearly all of its service territory in San Diego County and portions of Orange and Riverside Counties, in its effort to provide reliable utility service to its customers while reducing any potential impacts on the environment to the extent feasible. SDG&E prepared its HCP following the NCCP approach authorized by the Federal Endangered Species Act (ESA), the California Endangered Species Act (CESA) and California's NCCP Act. The NCCP complies with the ESA and CESA, and is designed to authorize take, if necessary, of species and habitat, as identified and described in the NCCP (these species are referred to as "covered species" in the NCCP documentation).

The NCCP was created to protect and preserve San Diego County's natural resources, while at the same time reducing and streamlining the regulatory processes typically involved with the operation, maintenance, and typical expansion of the existing gas and electric systems within SDG&E's service territory. Implementation of the NCCP provides assurance to SDG&E, the USFWS, and the CDFW that all covered species (identified in the Plan) and their habitat would be protected as if they were listed under the ESA or CESA. It also provides assurance

[11] RDEIR at 2-144.

that avoidance and minimization measures that have been previously identified within the NCCP would not be subject to modifications during the term of the Implementing Agreement.

SDG&E's NCCP/HCP, Section 6, specifically addresses SDG&E activities in Preserve Areas.

6. SDG&E Activities Within Habitat Conservation Plan Preserves

As generally described in Section 2 of this Subregional Plan, SDG&E Activities will include the maintenance, repair, and replacement of existing Facilities as well as the installation, maintenance, repair, and replacement of new Facilities. Existing Facilities are and new Facilities may be expected to be, in part, located within established Preserve Areas of Habitat Conservation Plans (HCPs), state, federal, or local preserve areas including public and private lands or other areas set aside for the protection of plants and animals.

As a part of its efforts to coordinate the implementation of this Subregional Plan with any effective HCP which may be affected by SDG&E Activities, the following agreements will be adhered to for Activities occurring or proposed to occur in preserve areas.

6.1 Maintenance, Repair, and Replacement of Existing Facilities

Without further authorization from USFWS or CDFG, SDG&E may conduct all necessary maintenance, repair, and replacement Activities with respect to all existing Facilities which are now or may hereafter be located within a Preserve Area of an HCP, if conducted in accordance with the provisions of this Subregional Plan.

6.2 Installation, Maintenance, Repair, and Replacement of New Facilities

6.2.1 New Gas and Electric Transmission Facilities

As a result of the extensive, rapid, and continuing development with the Subregional Plan Area, existing and proposed Preserve Areas are or will be dispersed among and in some cases surrounded by developed areas. USFWS and CDFG recognize that as a public utility SDG&E is obligated to provide safe, reliable, efficient, and cost-effective electric and gas service throughout the developed area of its service territory in compliance with the Public Utilities Code and subject to the jurisdiction of the California Public Utilities Commission. Unavoidably, therefore, the construction of new electric and gas transmission Facilities though or within Preserve Areas will be necessary in certain circumstances to meet the service requirements of developing areas. Where SDG&E determines that new electric or gas transmission Facilities are necessary within part of a Preserve Area, it will coordinate with USFWS and CDFG in accordance with the procedure set forth below to plan and construct such new Facilities in a manner which avoids or minimizes any impacts to Covered Species and their habitat, to the extent possible, while not impairing SDG&E's ability to meet the service demands of its customers in accordance with its responsibilities as a public utility.

The SDG&E NCCP/HCPs contains specific avoidance, minimization and mitigation measures defined as operational protocols (Section 7.1 Operational Protocols), which are designed to reduce the biological impacts associated with SDG&E's maintenance and new construction activities. Operational protocols represent an environmentally sensitive approach to traditional utility construction, maintenance, and repair activities, recognizing that small adjustments in construction techniques can yield major benefits for the environment.

SDG&E, in conjunction with the USFWS and the CDFW developed the 69 protective and conservation measures known as operational protocols to avoid, minimize, or mitigate any impacts to covered species during construction. Protection of the covered species includes avoidance of impacts, whenever feasible. In addition, SDG&E and contractor personnel attend regular environmental trainings (or tailboards) conducted by SDG&E and/or their consultants to explain the purpose of the NCCP permit and specific environmental requirements that must be adhered to during construction activities.

Pursuant to the NCCP, SDG&E will conduct pre-construction studies for all activities occurring off of existing access roads in natural areas. An independent biological consulting firm will survey all proposed project impact areas and prepare a Pre-activity Study Report (PSR) outlining all anticipated impacts related to the Proposed Project. Pursuant to the NCCP, completed PSRs are submitted to representatives of both the USFWS and CDFW for review and comment. CDFW and USFWS may suggest additional avoidance and minimization measures.

Biological monitors may be present during project activities to assure implementation of the avoidance and minimization measures. If the previously-delineated work areas must be modified during construction, the monitors will survey the additional impact area to determine if any sensitive resources will be impacted by the proposed activities, to identify avoidance and minimization measures, and to document any additional impacts. Any additional impacts are included in a Post-Construction Report (PCR) for purposes of calculating the appropriate mitigation, which generally includes site enhancement or credit withdrawal from the SDG&E mitigation bank. Impact and mitigation numbers are submitted to the USFWS and the CDFW as part of the NCCP Annual Report pursuant to requirements of the NCCP and the NCCP Implementing Agreement.

B. SDG&E's Proposed Project Replaces a 138 kV Line with a 230 kV Line, and Requires No Further Authorization Under NCCP/HCP Section 6.1

As noted above, Section 6.1 of the NCCP/HCP states that "[w]ithout further authorization from USFWS or CDFG, SDG&E may conduct all necessary maintenance, repair, and replacement Activities with respect to all existing Facilities which are now or may hereafter be located within a Preserve Area of an HCP, if conducted in accordance with the provisions of this Subregional Plan."

Although the increase in voltage capacity means that for purposes of the CPUC the Proposed Project is considered a "new" project, a distinction based on the voltage of the replacement line is not made in the NCCP/HCP. Ground disturbance and the concurrent biological impacts are not affected by the voltage of the line.

No further consultation with or authorization from USFWS and CDFW is required pursuant to Section 6.1 of the NCCP/HCP, as the only activities in the preserve areas are the replacement of one of SDG&E's existing facilities. As recognized in the Draft EIR, the Proposed Project involves: "Replacing a single-circuit 138-kV transmission line between the applicant's Talega and Capistrano substations with a new double-circuit 230-kV transmission line (approximately 7.8-miles long)."[12]

Thus, SDG&E's replacement activities are completely consistent with its NCCP/HCP. The conclusion in the Recirculated DEIR that the Proposed Project conflicts with the requirements of the NCCP/HCP is mistaken.

C. If NCCP/HCP Section 6.2.1 Is Applicable, SDG&E Already Engaged in the Required Process and No Further Authorization Is Required

Although SDG&E believes that it was and is not required to obtain further authorization under Section 6.1, it has completed the coordination process under Section 6.2.1. Section 6.2.1 of the NCCP/HCP states:

> Whenever SDG&E determines that it is necessary to install a new electric transmission line, or electric substation … in any part of a Preserve Area, SDG&E shall provide USFWS and CDFG with written notice of its intent to install such Facilities which shall contain a detailed description of such Facilities and of their location, along with a map of the area. <u>At a minimum, the information on the pre-activity survey form is required</u>.

[12] DEIR at 2-1; accord RDEIR, Notice of Availability ("Replacing a single-circuit 138-kV transmission line between the applicant's Talega and Capistrano substations with a new double-circuit 230-kV transmission line (approximately 7.8 miles long)).")

> Within twenty (20) working days of its receipt of SDG&E's notice, USFWS and CDFG shall provide SDG&E with their written response setting forth any objections to and alternatives to the location of the Facilities with the Preserve Area. Within ten (10) working days of receiving the objections of USFWS of CDFG, or both, SDG&E shall provide USFWS and CDFG with its written reply to their response. Within ten (10) working days of receiving the SDG&E reply, USFWS and CDFG shall approve or deny SDG&E's proposed location for the Facilities within the Preserve Area. If no objections are received by SDG&E from USFWS or CDFG within twenty (20) working days of SDG&E's notice, USFWS and/or CDFG shall be deemed to have concurred with the Activity described in SDG&E's original notice. If USFWS and CDFG deny the location, SDG&E may, with ten (10) working days of receiving such denial appeal to a review panel consisting of Regional Director, USFWS, Director, CDFG, and SDG&E, whose decision shall be final for purposes of this Subregional Plan. The appeal conference must be held within twenty (20) working days.[13]

As discussed in Part B above, under Section 6.1, no further authorization from USFWS or CDFW is required for SDG&E to proceed with replacement work. However, even if the Proposed Project's replacement of SDG&E's existing 138 kV line with a 230 kV line in a "preserve area" were not a "replacement" activity, SDG&E has fully complied with the relevant requirements there as well. Under Section 6.2.1, coordination with USFWS and CDFW is required and may be accomplished through several means, including but not limited to providing USFWS and CDFW with the information typically contained in a Pre-activity Survey Report (PSR), a Proponent's Environmental Assessment (PEA), or the Draft Environmental Impact Report (Draft EIR).

For the South Orange County Reliability Enhancement Project (Proposed Project), the PEA and the Draft EIR each contained more than adequate information for USFWS and CDFW to conduct the necessary review and provide any comments or concerns with the Proposed Project's impacts within defined Preserve Areas. USFWS and CDFW received both the PEA and the Draft EIR for the Proposed Project, and the agencies provided a joint comment letter to the CPUC on the Draft EIR.[14]

In accordance with SDG&E's NCCP/HCP, USFWS and CDFW requested: "additional coordination with SDG&E to determine if the project will result in impacts that are in conflict with existing conservation easements. If such impacts are anticipated, we request additional coordination among SDG&E, the Wildlife Agencies, the easement holder(s), and CPUC with the

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[13] SDG&E NCCP/HCP at Section 6.0, pp. 99-100.
[14] A copy of the joint comment letter provided by USFWS and CDFW is attached hereto as Attachment 45.

goal of modifying the project to avoid potential impacts to areas anticipated to be permanently protected. If such impacts cannot be avoided, additional coordination with the easement holders will be necessary to discuss a process for addressing the anticipated impacts in a manner that does not compromise existing conservation plans."[15]

As set forth below, SDG&E engaged in such further coordination with USFWS, as contemplated by SDG&E's NCCP/HCP on September 11, 2015. SDG&E agreed to modifications to its project that would reduce the need for new SDG&E ROW, and would reduce permanent impacts to areas outside SDG&E's easements that are proposed to be subject to the unrecorded "Talega Conservation Easement. Any remaining impacts would be mitigated to less than significant by drawing against SDG&E's mitigation bank under the NCCP/HCP. USFWS agreed that there is no conflict between the Proposed Project and the Prima Deshecha Landfill Conservation Easement.

In short, even if Section 6.2.1 is applicable, SDG&E complied with its NCCP/HCP requirements for new activities in "preserve area" through its coordination with USFWS, and by project modifications to reduce the impacts to the extent feasible and providing mitigation credits for any remaining impacts. The Recirculated DEIR's finding that the Proposed Project results in a "significant conflict" with the provisions of SDG&E's NCCP/HCP is inaccurate.

Section 3. SDG&E's Right of Way Easement Pre-Dates the Conservation Easements Referenced in The RDEIR (Witness Jeff Sykes)

SDG&E has land rights under several Right of Way Easements being utilized by the Proposed Project. True and correct copies of those easements (collectively, "SDG&E ROW Easements") are attached hereto as Attachment 46. The two main easements grant similar rights. Under the easement numbered 15813, recorded November 19, 1964, SDG&E has a right of way 150.00 feet in width "… in, upon, over, under and across the lands hereinafter described to erect, construct, change the size of, improve, reconstruct, relocate, replace, repair, maintain and use a line or numerous lines of poles and/or steel towers and wires and/or cables suspended therefrom and supported thereby … including guys, anchorage, crossarms, braces and all other appliances and fixtures for use in connection therewith ….."[16] In addition, SDG&E has "the right of ingress and egress therefrom, to and along said right of way by a practical route or routes in, upon, over

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[15] Attachment 45 (Comment Letter, Enclosure page 2, Comment 7).
[16] Attachment 46 (Easement 15813 at 1).

and across the hereinafter described lands."[17] Finally, the ROW Easements state that "no other easement or easements shall be granted on, under or over the above described easement of right of way without the previous written consent of [SDG&E]."[18]

SDG&E has obtained and reviewed the recorded conservation easement at Orange County's Prima Deshecha Landfill, which consists of two Conservation Easement Deeds from the County of Orange to The Reserve at Ranch Mission Viejo, an original 2012 deed and a 2014 amendment to the earlier deed to add additional acreage ("Prima Deshecha Conservation Easement"). A true and correct copy of the Prima Deshecha Conservation Easement is attached as Attachment 47.

The Prima Deshecha Conservation Easement, Paragraph 10 makes plain that the easement rights conveyed by the Conservation Easement are "expressly subject to all matters of record as of the date this Conservation Easement is executed." The Prima Deshecha Conservation Easement was executed long after the SDG&E ROW Easement was recorded, and thus the Prima Deshecha Conservation Easement is subject to SDG&E's rights under the SDG&E ROW Easements. Furthermore, the express terms of the SDG&E ROW Easements make clear that no other easements may impair the rights of the SDG&E ROW Easements without the previous written consent of SDG&E, which was not sought and was not given. The Prima Deshecha Conservation Easement cannot, and does not, prohibit any rights and uses granted in the SDG&E ROW Easements.

Therefore, the Prima Deshecha Conservation Easement does not conflict with SDG&E's Proposed Project activities that are authorized by the SDG&E ROW Easement. These activities include but are not limited to ingress and egress to the existing and proposed SDG&E facilities, construction of the proposed SDG&E facilities, removal of the certain of SDG&E facilities, grading of access roads, grading of maintenance pads, grading of temporary work pads, preparation of stringing sites, and staging of materials for use in the easement areas. Under legally enforceable "secondary easement" rights, some such activities may occur outside SDG&E's easement if reasonably necessary for SDG&E's enjoyment of its easement rights to construct, install, maintain and operate its utility facilities, including electric transmission lines.

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[17] Attachment 46 (Easement 15813 at 1).
[18] Attachment 46 (Easement 15813 at 4).

Following the issuance of the Recirculated DEIR, SDG&E asked Energy Division for a copy of the "yet-to-be recorded conservation easement in the Talega Corridor," as described in therein.[19] Energy Division never responded to SDG&E's request. SDG&E has not seen the "yet-to-be recorded conservation easement in the Talega Corridor," as described in Recirculated DEIR. As set forth below, USFWS has informed SDG&E that its boundaries and permitted uses are not yet finalized. However, as a matter of law, a later-recorded easement cannot impair rights granted under the previously-recorded SDG&E ROW Easement. Therefore, this unrecorded easement cannot, and will not, prohibit any rights and uses granted in the SDG&E ROW Easement. Additionally, pursuant to the terms of the SDG&E ROW Easement, no easements shall be granted on, under or over the SDG&E ROW without the previous written consent of SDG&E, which has not been sought and would not be granted.

Therefore, the unrecorded conservation easement in the Talega Corridor does not conflict with SDG&E's Proposed Project activities that are authorized by the SDG&E ROW Easement, which are set forth above.

Section 4. With Refinements to Keep Structures within SDG&E's Easements, USFWS Does Not Object to Proposed Project Activities Outside of SDG&E's Easements (Witness Debbie Schafer)

The Recirculated RDEIR states: "The USFWS has indicated that establishing new ROW within the Talega Conservation Easement or impacting areas of the Prima Deshecha Landfill Conservation Easement that are outside of the applicant's existing ROW would directly conflict with the provisions of the aforementioned conservation easement(s), and thereby the provisions of the Orange County Southern Subregion HCP."[20] The Recirculated DEIR and USFWS thus recognize that SDG&E's exercise of its pre-existing rights under its ROW Easements does not conflict with the provisions of later-recorded or proposed conservation easements because such later conservation easements are subject to SDG&E's ROW Easements. Instead, USFWS' concern is SDG&E activities outside its existing easements and within areas covered by an existing Prima Deshecha Landfill Conservation Easement or proposed Talega Conservation Easement.

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[19] R. Giles (SDG&E) August 10, 2015 email to A. Barnsdale (CPUC Project Manager) and SDG&E's 07/17/15 Partial Response 1 to Energy Division's Data Request 11 (both seeking the referenced unrecorded easement).
[20] RDEIR at 2-77, 2-145.

Following publication of the Recirculated DEIR, SDG&E transmission engineering staff evaluated the possibility of refining the transmission and power line design (specifically for Segment 4) to minimize the need for new ROW. Segment 4 crosses an area that USFWS and Energy Division have said will be subject to the proposed, unrecorded Talega Conservation Easement. SDG&E prepared a preliminary design that would remove several structures and electrical transmission and power lines from one large area of Segment 4 and place all of them within existing SDG&E ROW, easements, and fee-owned property. See Attachment 48, Proposed Project Segment 4 Design Revision.[21] By relocating proposed structures to be within existing SDG&E ROW, the amount of new ROW potentially required in Segment 4 of the Proposed Project would be significantly reduced to small areas between two existing SDG&E easements and immediately adjacent to fee owned property.

SDG&E staff met with USFWS staff on September 11, 2015 to discuss SDG&E's existing easements and associated rights as well as USFWS concern whether the Proposed Project may conflict with existing or proposed conservation easements located in the vicinity of the Proposed Project. During the meeting, SDG&E reviewed a map showing SDG&E's easements and the path of the Proposed Project, refined as noted above, see Attachment 49 as well as the more detailed drawings discussed below.

As an initial matter, USFWS agreed that any activities conducted by SDG&E within existing SDG&E ROW, Easement, or fee-owned property would not cause a conflict with any subsequently recorded conservation easement or with the provisions of the Orange County Southern Region HCP.

With respect to the Prima Deschecha Landfill Conservation Easement, only a 210 square foot portion of an <u>existing road bed</u> is part of a proposed work area (for structure No. 26) which is located outside of SDG&E's easement. USFWS agreed that the scope of work anticipated for this location would not create a conflict between the Proposed Project and that Conservation Easement. The Proposed Project crosses the Prima Deschecha Landfill Conservation Easement at two locations, and contains one proposed new 230kV structure (No. 26), the removal of

[21] SDG&E has further engineering (civil and transmission) to perform to achieve a design level similar to the Proposed Project. Placing all structures in the existing ROW presents more challenges from an outage coordination and construction standpoint. Costs also are likely to increase due to the need for some 69kV undergrounding, additional retaining walls and outage constraints. These issues, and the final location and extent of work pads and stringing sites, will be addressed in final engineering.

existing 138kV structures, and the use of existing unpaved access roads. Attachment 50 shows the Proposed Project alignment, proposed new structures, and access roads in relation to the Prima Deshecha Landfill Conservation Easement.

The Proposed Project would require temporary work space for the construction of the new 230kV structure and permanent work space for the inspection and maintenance of the 230kV structure (No. 26) for the life of the project (refer to Attachments 51 and 52). All ground disturbing activities (e.g. grading, grubbing, and vegetation removal) will be contained within the limits of SDG&E's existing ROW. SDG&E would also utilize the existing access road network during construction and operation (see Attachment 50). As explained under Section 3 above, SDG&E's rights to its 150-foot ROW includes the ongoing use of the existing network of unpaved access roads that lead to and connect all existing structures, as well as existing structures owned and operated by SCE within its adjacent ROW.

In addition, as shown in Attachment 51 (Structure 26 Detail Map) and Attachment 52 (Structure 26 Aerial Photograph), the small portion (approximately 210 square feet) of Structure 26 work area that could extend outside of SDG&E's existing ROW is limited to the existing roadbed (access road), and no earthwork (grading, grubbing, clearing, etc.) would be required. This area could be used for the placement of construction equipment (such as a crane) or maintenance equipment (such as an aerial bucket truck). As existing road bed, this area is already disturbed. Following review of this information, USFWS agreed that the Proposed Project would not conflict with the Prima Deschecha Landfill Conservation Easement as work associated with the Proposed Project would be contained within SDG&E existing rights pursuant to SDG&E ROW Easement.

With respect to the proposed Talega Conservation Easement, as an initial matter, USFWS confirmed that such easement has not yet been finalized and is not recorded. Moreover, its boundaries are not yet set. For example, many of SDG&E's proposed permanent work pads occur within areas that are in between two existing SDG&E easements (see Attachment 48). When it was noted that some parcels being considered for inclusion in the Talega Conservation Easement are owned by the Transportation Corridor Agencies (TCA), USFWS commented that such parcels may not end up in the final boundaries of the Talega Conservation Easement as TCA may not approve such inclusion. Some of the parcels over which SDG&E is interested in acquiring an easement are owned by TCA.

Assuming that the proposed Talega Conservation Easement will cover some areas in Segment 4 of the Proposed Project, SDG&E shared with USFWS the minor refinements to the Proposed Project designed to eliminate potential conflict with such an easement. SDG&E and USFWS discussed the preliminary redesign shown in Attachment 48 and Attachment 49 (Sheet 1). This redesign involves all Proposed Project structures being located within SDG&E's existing easements. However, according to USFWS, there are portions of permanent work pads and some temporary string sites and other temporary work areas that would occur within potential areas of the proposed and unrecorded Talega Conservation Easement that are outside of SDG&E's existing easements. USFWS agreed that any activity that would occur within an existing road or work pad, and which would not require any ground disturbance, such as a pull/stringing site, would not require mitigation. USFWS stated that, based on the proposed redesign, they would be willing to work with SDG&E and the Talega Conservation Easement stakeholders to ensure that the remaining Proposed Project impacts would be mitigated to a level acceptable to both SDG&E and the USFWS.

As a result of the coordination meeting and review of the information above, USFWS proposed the following general procedure for ensuring that the Proposed Project would not conflict with the proposed and unrecorded Talega Conservation Easement. First, USFWS would work with the Talega Conservation Easement stakeholders (Grantor and Grantees) to temporarily suspend recording the easement while the Proposed Project re-design of Segment 4 is finalized. Once the design is finalized, the specifics of any temporary or permanent work areas located outside of existing SDG&E ROW would be incorporated into the Talega Conservation Easement as "allowed uses." USFWS and SDG&E would then agree on mitigation for the permanent and temporary impacts that occur outside of existing SDG&E ROW and within the finalized boundaries of the Talega Conservation Easement.

Even if SDG&E did not already have the right to proceed under Section 6.1 and Section 6.2.1 of its NCCP/HCP, this coordination with USFWS removes any possible conflict between the Proposed Project and the two known or proposed Conservation Easements discussed above, as any potential impacts would be mitigated to a level of less than significant. Furthermore, the process outlined above is consistent with Recirculated DEIR Mitigation Measure BR-10.

CHAPTER 4 THE RECIRCULATED DEIR'S "TRABUCO ALTERNATIVE" IS NOT FEASIBLE

Section 1. The RDEIR Trabuco Alternative (Witness John Jontry).

The Recirculated DEIR presents a new alternative to SDG&E's Proposed Project, identified as "Alternative J – SCE 230-kV Loop In to Trabuco Substation" (the "RDEIR Trabuco Alternative"). The Recirculated DEIR explains this alternative as follows:

> Under this alternative, the applicant would expand its existing 138/12-kV Trabuco Substation in Laguna Niguel into a 230/138/12-kV substation. The applicant would acquire approximately 2 acres of land, currently owned by AT&T, adjacent to the north side of the existing Trabuco Substation for the construction and operation of the 230-kV switchyard. The applicant would construct a 230- kV switchyard, including two 230-kV/138-kV transformers (one required and spare) with a capacity 392 MVA. The 230-kV/138-kV transformer would be housed in a 40- to 50-foot-high gas insulated substation building.
>
> A new underground, double-circuit 230-kV transmission line segment (approximately 0.5 miles long) would be constructed within new ROW that would loop the new substation into SCE's Santiago–SONGS 230-kV line. The new 230-kV transmission loop-in line would either exit the Trabuco Substation to the north in a new underground conduit along Camino Capistrano to connect to the Santiago–SONGS 230-kV line or exit the Trabuco Substation to the east overhead across Interstate 5, then into a new underground conduit along La Alameda, Los Altos, and Plaza and Bellogente roads to connect to the Santiago–SONGS 230-kV line (see Figure 3-5). The Santiago–SONGS 230-kV line would then become two new transmission lines: the Trabuco- SONGS 230-kV transmission line and the Trabuco-Santiago 230-kV transmission line.
>
> Major modifications to the existing Trabuco Substation would not be required as part of this alternative because the existing 138/12-kV equipment has not been identified as aging equipment by the applicant. It is anticipated that the Trabuco 130/12-kV system would remain operational while the new 230/138kV equipment is installed. Any potential disruptions of service would be limited to the time required to establish a physical connection between the new 230/138-kV equipment and the existing 138-kV equipment.
>
> Capistrano Substation would not be expanded as part of this alternative, but equipment at Capistrano Substation found to be inadequate would be replaced. The distribution circuit 315 (12-kV) would not be relocated. This alternative would not require any work at the existing Capistrano or Talega Substations. No 12-kV distribution lines or 138-kV transmission lines would require relocation or reconductoring.[22]

The Recirculated DEIR, Figure 3-5, provides a "Trabuco Substation Conceptual Site Plan" that appears to reflect Energy Division's proposed design of Trabuco Substation under the

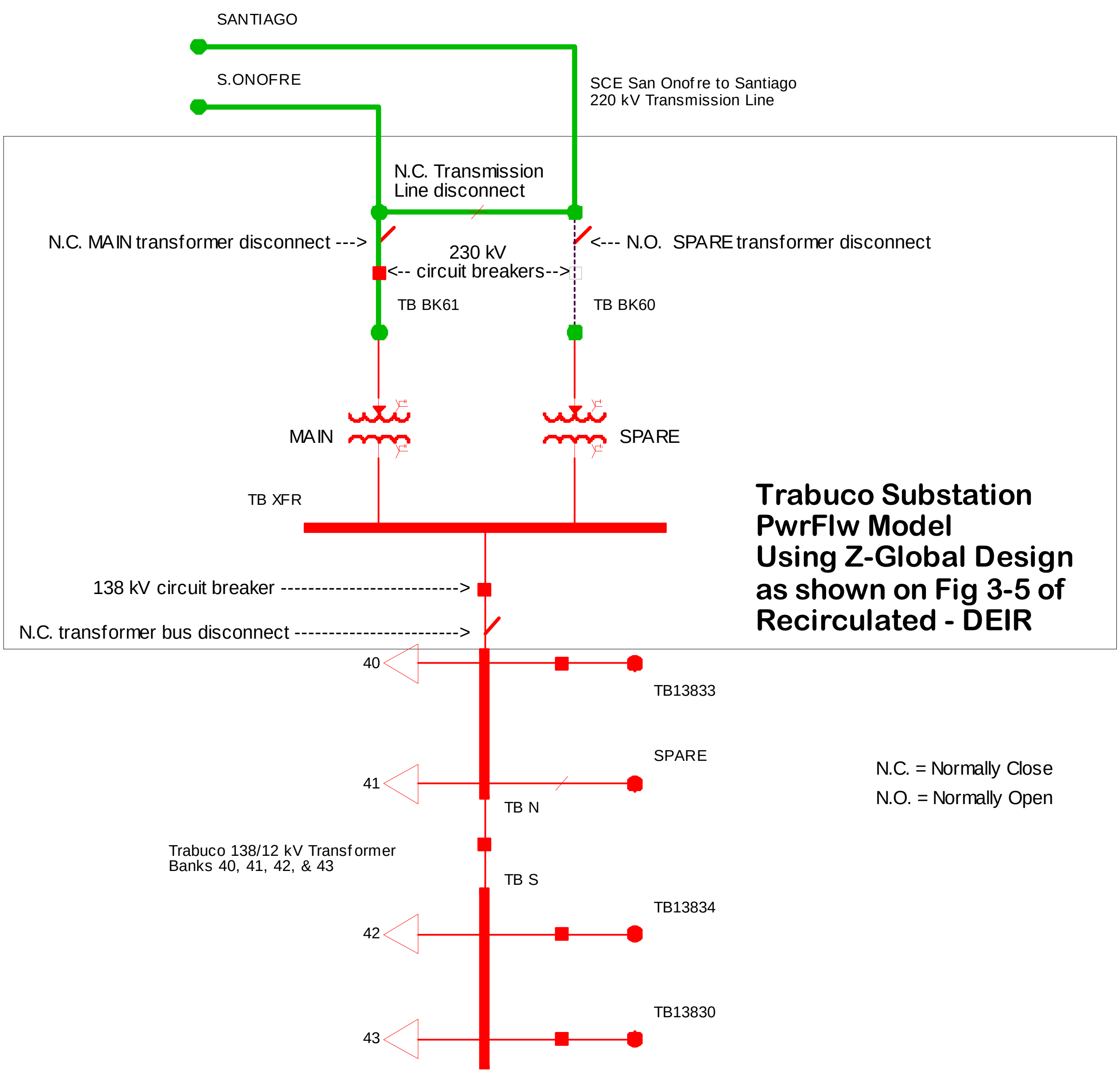
[22] RDEIR at 2-22.

RDEIR Trabuco Alternative. Despite the RDEIR text noted above, the “Conceptual Site Plan” does not include a “gas insulated substation building.” Similarly, the RDEIR lists the 230 kV equipment to be placed on the AT&T parking lot without mentioning a GIS building.[23] As a result, the Recirculated DEIR does not clearly describe Energy Division’s proposed design for a 230/138/12 kV Trabuco Substation.

Although the RDEIR does not provide an electrical one-line diagram of the RDEIR Trabuco Alternative, the electrical connectivity of this alternative may be inferred from RDEIR Fig. 3-5, Trabuco Substation Conceptual Site Plan. The one line diagram shown in Figure 4-1 was created by SDG&E using Figure 3-5 of the Recirculated DEIR.

[23] RDEIR at 2-171.

Figure 4-1 – Trabuco Substation One Line Diagram for ED Alternative J.



The RDEIR Trabuco Alternative is significantly and materially different from the Trabuco alternative proposed by ORA (the "ORA Trabuco Alternative"). As described in SDG&E's Rebuttal Testimony, Chapter 9, Section 5, SDG&E assumed the ORA Trabuco Alternative would include a properly designed substation, and thus modeled the ORA Trabuco Alternative using the following assumptions:

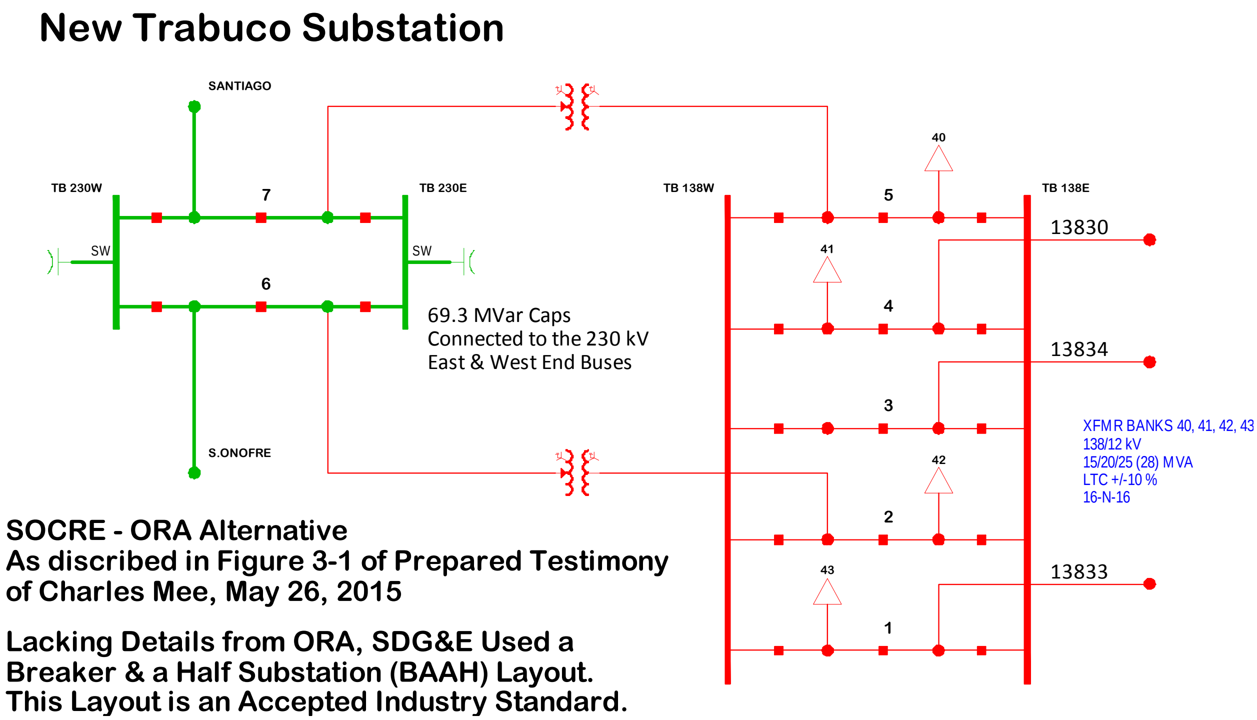
- The existing Trabuco 138 kV straight bus was re-configured into a breaker and a half bus.

- A new breaker and a half 230 kV bus was created for the new Trabuco Substation 230 kV connection.
- 60 MVar[24] capacitor banks were added to the end buses of the new Trabuco 230 kV breaker and a half bus.
- One of the two SCE 220 kV transmission lines which connect San Onofre to Santiago was opened and the ends connected to the new 230 kV bus at Trabuco Substation.
- Two 230/138 kV transformers were added to connect the Trabuco 230 kV bus to the Trabuco 138 kV bus.

The one-line diagram that SDG&E prepared for the ORA Trabuco Alternative is shown in Figure 4-2. Comparing Figure 4-1 to Figure 4-2, it can be seen that the layout used for the ORA Trabuco Alternative, which is similar to the Project's layout at Capistrano, contains more equipment than the RDEIR Trabuco Alternative. These are important differences. Circuit breakers isolate equipment which has failed. More circuit breakers in a design allow for better isolation of failed equipment. Isolating failed equipment from operating equipment leaves more equipment in-service following an equipment failure. With more equipment in-service following a failure, service continuity is preserved and customers continue to receive power. The RDEIR Trabuco Alternative does not use a standard BAAH substation layout at Trabuco and as such, does a poor job isolating failed equipment. This is a poor design.

[24] This is a reference to SDG&E's 69.3 MVar capacitor banks. The size of the capacitor banks shown in Figure 4-2 is correct. The model used 69.3 MVar capacitor banks on the 230 kV buses.

Figure 4-2 – Trabuco 230kV Substation One Line Diagram for ORA Alternative.



The salient drawbacks of the RDEIR Trabuco Alternative from a transmission planning standpoint are immediately evident and include the following:

1) Contrary to the RDEIR's description,[25] the SONGS-Santiago 230 kV line is not, in fact, "looped in" to the proposed Trabuco 230 kV substation, where it would form two two-terminal lines (SONGS-Trabuco and Trabuco-Santiago). Instead, it is configured as a three-terminal line (SONGS-Trabuco-Santiago) with one end terminating in the normally-closed 230/138 kV Trabuco transformer. The implication of this arrangement is that there is a single 230 kV transmission line serving the rebuilt Trabuco Substation under the RDEIR Trabuco Alternative. Any fault or maintenance outage on any segment of this line removes the 230 kV source from Trabuco.

2) The 230 kV bus in the RDEIR Trabuco Alternative is not actually a bus at all. It is simply a connection point for a three-terminal line that terminates into a single transformer. Taking either the 230 kV line, 230 kV breaker, or 230/138 kV transformer out of service disconnects the 230 kV source from Trabuco substation. The minimum SDG&E design standard for a 230 kV bulk power substation is a breaker-and-a-half (BAAH) arrangement, which in combination with a properly looped-in 230 kV line would prevent a single-element outage from disconnecting Trabuco from the 230 kV system.

[25] The RDEIR mistakenly asserts: "The Santiago-SONGS 230 kV line would then become two new transmission lines: the Trabuco-SONGS 230-kV transmission line and the Trabuco-Santiago 230-kV transmission line." RDEIR at 2-22 lines 33-35.

3) A similar BAAH arrangement would normally be expected for a 138 kV substation performing bulk power service; as the RDEIR Trabuco Alternative would be expected to be fully redundant to Talega Substation, which is nominally a BAAH arrangement on both the 138 kV and 230 kV voltage levels, a BAAH arrangement would be expected for Trabuco as well.

4) Neither the "normally closed" or "spare" 230/138 kV transformer can be isolated from the 138 kV bus, as there is no disconnect switch between the 138 kV transformer terminations and the 138 kV bus. In the event of a transformer failure or maintenance outage, it would be necessary to physically disconnect the faulted transformer from the 138 kV bus by removing jumpers or bus segments. The "spare" unit could not be energized until this was done, extending an outage from minutes to hours or possibly days.

5) The Trabuco 138 kV substation arrangement presented in the RDEIR Alternative is a single-bus, single-breaker arrangement. By inspection of Figure 4-1, which was created from Figure 3-5 of the Recirculated DEIR, it is immediately obvious that numerous faults or equipment failures will result in a complete loss of the 230 kV source at Trabuco. This is explained in detail in Sections 2 and 7 below. In contrast, a BAAH arrangement, as proposed for the 230/138/12 kV San Juan Capistrano substation in SDG&E's Proposed Project, would allow for loss of any one bus or breaker without loss of the connection to the 230 kV source.

Nonetheless, the Recirculated DEIR asserts that the RDEIR Trabuco Alternative is "potentially feasible from a technological, legal, and economic perspective," and that:

> This alternative would meet each of the project objectives as defined in Section 1.3.1. The CPUC's review of the applicant's power flow data indicates that Alternative J would ensure that each of the potential Category C (N-1-1) contingencies identified by the applicant and CAISO (Section 1.2.1) would be avoided through the 10-year planning horizon (Objective 1) Equipment at Capistrano Substation found to be inadequate would be replaced (Objective 2), and power flow within the applicant's South Orange County 138-kV system would be redistributed (Objective 3).[26]

The Recirculated DEIR is mistaken. The RDEIR Trabuco Alternative is not feasible as described, and does not meet the project objectives. As discussed in more detail below, the RDEIR Trabuco Alternative:

- Does not comply with mandatory NERC Reliability Standards, and will result in load shedding that would not occur with SDG&E's Project.

- Does not add 230 kV power at South Orange County's load center, thus requiring upgrades to SDG&E's South Orange County 138 kV system to redistribute the power to the distribution substations within South Orange County.

[26] RDEIR at 2-23.

- Would delay ensuring reliable electric service to SDG&E's South Orange County customers for years while the impacts of an interconnection to SCE's transmission system are studied under SCE's FERC-approved Transmission Owner's Tariff, pursuant to the CAISO Transmission Control Agreement, and in a WECC Path Rating group.

- Causes loop flows on SDG&E's South Orange County system that will impact not only SDG&E's system, but the flows between SDG&E's system and SCE's system. As a result, the SCE interconnection will not be allowed without construction of necessary Reliability Upgrades to SDG&E's South Orange County 138 kV system, on SCE's system, potentially elsewhere in the CAISO-controlled grid and potentially elsewhere in the WECC system. The scope of these Reliability Upgrades will be determined through the years-long study process by SCE, CAISO and WECC—only then will the Commission know the true cost of this alternative and be able to assess all of its environmental impacts.

- Does not rebuild the aging Capistrano Substation, which must be rebuilt to ensure reliable electric service. The Recirculated DEIR's failure to acknowledge that Capistrano Substation must be rebuilt, at least as a 138/12 kV substation, does not reflect what is reasonably expected to happen if the Commission approves the RDEIR Trabuco Alternative (or any other alternative that does not include rebuilding Capistrano Substation).

- Does not provide adequate space for construction and operation of an expanded 230/138/12 kV Trabuco Substation. As set forth in Section 7 below, the Recirculated DEIR provides a "Trabuco Substation Conceptual Site Plan" that is neither safe nor reliable, does not contain all necessary equipment, and requires a non-standard design that is far inferior in terms of reliability SDG&E's proposed San Juan Capistrano substation..

- The estimated cost of the known elements of the RDEIR Trabuco Alternative exceed the estimated costs of the Proposed Project—and such costs do not include the unknown costs of Reliability Upgrades caused by the SCE interconnection.

SDG&E addresses each of these issues below.

Section2. The Reconductoring Alternative Does Not Comply with Mandatory NERC Reliability Standards and Will Result In Load Shedding That Would Not Occur With SDG&E's Proposed Project (Witness Cory Smith)

A. Proposed Alternatives Must be Evaluated Pursuant to The FERC-Approved NERC Transmission Planning Standards

SDG&E, which has an obligation to provide reliable electric service to its South Orange County customers, must address the reliability issues in its system with a coherent and comprehensive plan of service. To do so, a potential plan of service must be evaluated in accordance with the mandatory requirements in the FERC-approved NERC Transmission

Planning Standards. The Recirculated DEIR does not state that the RDEIR Trabuco Alternative was evaluated pursuant to the NERC Transmission Planning Standards, much less that it passed such an evaluation. Therefore, SDG&E has performed the necessary power flow analysis as follows.

The NERC transmission planning standards, TPL-001-0.1, TPL-002-0b, TPL-003-0b, TPL-004-0a and the recently approved combined standard TPL-001-4, require the Planning Coordinator and the Transmission Planner to prepare a valid assessment of its portion of the transmission system. For the SDG&E service territory, the CAISO is the registered Planning Coordinator and SDG&E is the registered Transmission Planner.

In order for an assessment to be valid, it must test numerous contingencies under various critical conditions.[27] A single power flow analysis that looks at a single load level and does not consider the outage of critical equipment or changes in critical parameters is not a valid assessment. As part of the CAISO's FERC approved transmission planning process, CAISO and SDG&E complete a valid assessment of SDG&E's portion of the CAISO controlled transmission system each year. The South Orange County transmission network is part of the CAISO controlled transmission network, and is included in both the CAISO's and SDG&E's assessments. CAISO and SDG&E have completed independent assessments of the existing South Orange County transmission network. These assessments tested numerous contingencies at increasing load levels under different critical conditions making them valid NERC assessments.

Likewise, SDG&E completed a valid NERC assessment of the Trabuco 230kV Alternative J presented in the Recirculated DEIR. The following steps were taken:

1. A new model was created using the substation layout shown in Recirculated DEIR Fig 3-5. As shown in Section 1 on Figure 4-1 (within the box), a new 230 kV bus was added to existing Trabuco Substation model and one of the 220 kV SCE transmission lines which connects San Onofre to Santiago was connected to the new Trabuco bus. Two 230/138 kV transformers were added to connect the new 230 kV connection to the existing 138 kV Trabuco Substation. Circuit breakers and disconnects were added as shown in Figure 3-5 of the Recirculated DEIR.

2. Using the model created in 1) above, three scenarios were developed to simulate critical transmission system conditions,

    a. Moderate flow on Path 43 and Path 44. This is the non-stressed base condition from which the stressed power flow cases in b) and c) below are created. Path 43

[27] NERC TPL-002-0b and TPL-003-0b, Requirement R1 describes components of a valid assessment and NERC TPL-001-4 describes a valid assessment in section B.

is loaded to -141 MW (negative sign is the flow into San Onofre) and Path 44 is loaded to 123 MW. As discussed in SDG&E's Supplement Testimony, Chapter 5, Section 3, Path 43 is the group of four 220 kV transmission lines owned by SCE which emanate from San Onofre Substation and carry power north into SCE's service territory. The RDEIR Trabuco Alternative would tie into one of these transmission lines. Path 44 is the group of five 230 kV transmission lines owned by SDG&E which emanate from San Onofre Substation and carry power south into SDG&E's service territory. Two of these transmission lines are connected to Talega Substation.

b. High flows on Path 43. The non-stressed power flow case described in a) was adjusted to increase the amount of power flowing from SDG&E to SCE over Path 43 to 1550 MW.

c. High flows on Path 44. The non-stressed power flow case described in a) was adjusted to increase the amount of power flowing from SCE to SDG&E over Path 44 to 977 MW.

3. The three scenarios developed in 2) were simulated using power flow analysis to determine South Orange County's response to NERC Category B or C contingencies. For each of the three scenarios, power flow analysis was done for years 2016 to 2035. Load at the seven 138 kV substations in South Orange County was increased each year to match the load predicted for that year. Years 2016 to 2024 were adjusted to loads found in the 2015 load forecast and years 2025 to 2035 where adjusted using a MW/year growth rate found using the load forecast. For each year, SDG&E performed 1378 contingencies for total of 27,560 (20 x 1378) contingencies. This was done for each of the three scenarios.

Using specialized power flow software tools, in all, SDG&E simulated 82,680 (3 x 27,560) contingencies to assess the RDEIR Trabuco Alternative. The modeling assumed that all existing transmission equipment was in-service pre-contingency-- ten 138 kV transmission lines, four 230/138 kV transformers at Talega and one 230/138 kV transformer at Trabuco. Results are set forth in Attachment 53 and discussed below.

B. If Constructed As Set Forth in the RDEIR's Alternative J, "Trabuco Substation Conceptual Site Plan," the RDEIR's Trabuco Alternative Fails to Meet NERC Reliability Standards

With power flow on Path 43 increased as described above, power flow analysis found NERC violations. Table 4-1 lists Category C contingencies which lead to violation of TPL-003-0b. When load is above 450 MW, SDG&E's South Orange County system will be in violation of NERC standards without a project to mitigate the overloads. Every year beyond the date listed in the left column, the same element will overload for the same outage, but the percent above the Applicable Rating will increase over time. South Orange County load has been forecasted to reach a peak load of 450 MW as early as 2016.

Table 4-1: Violation of Applicable Ratings for RDEIR Alt J with Path 43 Stressed.

Year Element Reaches Limit	Load Level (MW)	Contingency	Overloaded Element
2016	450	C3:13831+13846	13836
2020	475	C3:13835+13846	13836
2023	488	C3:13831+13835	13816
2026	513	C3:13831+13833	13816
2030	536	C3:13835+13836	13846C
2031	542	C3:13831+13836	13846C
2032	548	C3:13831+13836	13846A
2032	548	C2:TA 8T	13846A
2032	548	C2:TA 8T	13846C

C. The RDEIR Trabuco Alternative Will Require Shedding Load Under Numerous NERC Contingencies.

The RDEIR Trabuco Alternative does not remove the need to shed load under a number of NERC contingencies. Power flow analysis with Path 43 stress as described above found that load would need to be shed for the contingencies listed in Table 4-2 starting in the year the load reaches the elements Normal Rating.

Table 4-2: Contingencies Requiring Load to be Shed with RDEIR Trabuco Alternative with Path 43 Stressed.

Year Element Reaches Normal Rating	Load Level (MW)	Contingency	Overloaded Element
2016	450	C2:TA 8T	13846A
2016	450	C2:TA 8T	13846C
2016	450	C3:TA BK 61+TA BK 63	TA BK 60
2016	450	C3:TA BK 61+TA BK 63	TA BK 62
2016	450	C3:13831+13836	13846A
2016	450	C3:13831+13836	13846C
2016	450	C3:13835+13836	13846C
2016	450	C3:13835+13846	13836
2016	450	C3:13836+13838	13846C
2016	450	C3:13838+13846	13836
2019	469	C3:13835+13836	13846A
2019	469	C3:13836+13838	13846A
2021	481	C3:13836+SANTIAGO2	13846C
2022	488	C3:13831+13835	13816
2024	500	C3:13846+SANTIAGO2	13836
2025	506	C3:13831+13833	13816
2029	531	C3:13816+13831	13833
2031	542	C3:TB61+13831	13830
2031	542	C3:13831+ SANTIAGO1[28]	13830
2032	548	C3:13831+Valley-Serrano 500	13830
2032	548	C3:13831+Perk-Mead	13830
2032	548	C3:CP41+13831	13830

Numerous overloads occur beyond year 2031. This is a result of high flows on Path 43, high South Orange County load and a lack of reactive support in the design. The STATCOM is in the model, but it is a dynamic device that is not used for continuous operation.

D. The RDEIR Trabuco Alternative Does Not Provide Reliable Second Source of Power for South Orange County In the Event of a Talega Substation Outage.

The RDEIR Trabuco Alternative does not provide a redundant source of power. SDG&E’s project objectives include adding a second source to South Orange County, and the need for such a second source is discussed extensively in SDG&E’s Opening, Supplemental, and

[28] The contingency SANTIAGO1 drops SCE’s transmission line between San Onofre and Santigo substations which, in turn, disconnects the Trabuco 230 kV substation.

Rebuttal Testimony. Power flow analysis has shown that the Trabuco Alternative J presented in the RDEIR is not a true redundant source. When the Talega 138 kV substation is out-of-service, South Orange County load would be supplied by the single 230/138 kV transformer located at Trabuco. The maximum amount of South Orange County load which can be supplied will be limited by the rating of the transformer; 392 MW. Figure 3-5 of the RDEIR shows a second transformer, but the transformer is labeled “SPARE”. This implies that it will not be in-service. Putting this aside and placing both transformers in service will only add an additional 77 MW of capability. The new limit will not be the combined transformer capability. Instead, the limit will be defined by a transmission line limitation. The outage of TL13837 will load TL13846B to its maximum rating. Therefore, at most, 469 MW can be served from Trabuco Substation with Talega Substation 138 kV out of service. To maintain this limit, load would be shed before the outage of TL13837 occurred. This is necessary to prevent damage to TL13834B.

Moreover, the RDEIR Trabuco Alternative substation design is unreliable and thus cannot serve as a reliable, redundant second source for South Orange County. A fault on a transmission line, which leads to the forced outage of the transmission line, is one of the most common failures in the electric utility industry. When Talega 138 kV is out-of-service, not only will the South Orange County load be limited to 469 MW, but it will be supplied by a single 230 kV transmission line, which supplies one (or two) 230/138 kV transformers at the rebuilt Trabuco Substation. Note the location of the circuit breakers on Figure 4-1. The two transformers share a single circuit breaker on the 138 kV side of the transformer. Without individual circuit breakers, the transformers cannot be isolated by from each other. When one transformer fails, both will be removed from service to isolate the fault.

The substation layout does not provide redundancy necessary for reliability. A single transmission line failure, transformer failure, bus fault or circuit breaker fault will drop all South Orange County load. SDG&E has identified 13 Equipment failures which will drop all South Orange County load when Talega Substation is out of service. The failures are presented below:

- Fault on the three terminal SCE 220 kV transmission line connecting San Onofre to Trabuco to Santiago substations;
- Fault on the MAIN Trabuco 230/138 kV transformer;
- Fault on the SPARE Trabuco 230/138 kV transformer. The 138kV terminal of the 230/138 kV transformer will be energized and even though the transformer is

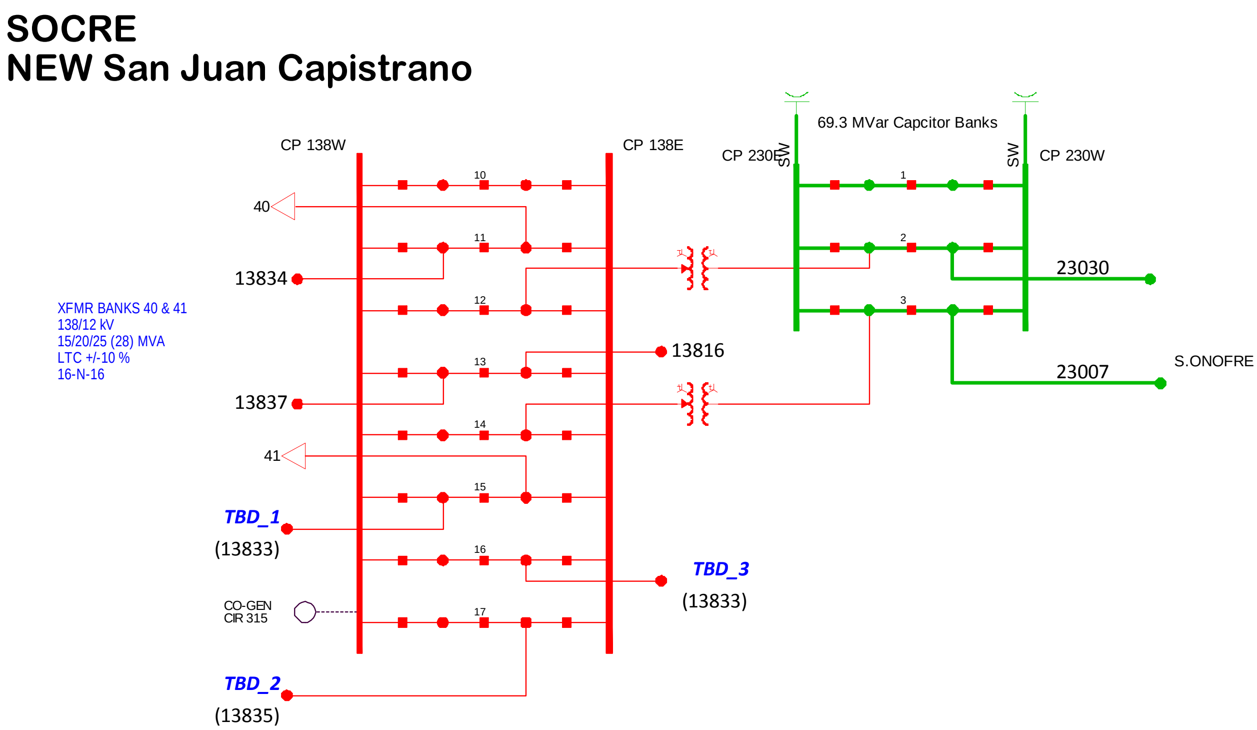
not carrying load, it will be exposed to a fault which would drop all South Orange County load;

- Fault on, or failure of, the 230 kV circuit breaker for Trabuco MAIN transformer;
- Fault on, or failure of, the 230 kV circuit breaker for Trabuco SPARE; transformer. Only if the normally open circuit breaker is closed and the circuit breaker is energized;
- Fault on, or failure of, the 138 kV circuit breaker connecting the Trabuco transformer bus (labeled TB XFR on Figure 4-1) to the 138 kV Trabuco North bus (labeled TB N on Figure 4-1);
- Fault on, or failure of, the 138 kV circuit breaker connecting the Trabuco North bus to Trabuco South bus (labeled TB S on Figure 4-1);
- Fault on, or failure of, the 138 kV circuit breaker connecting the Trabuco North bus to transmission line TL13833 (labeled TB13833 on Figure 4-1);
- Fault on, or failure of, the 138 kV circuit breaker connecting the Trabuco North bus to Trabuco Bank 40 transformer (labeled 40 on Figure 4-1);
- Fault on, or failure of, the 138 kV circuit breaker connecting the Trabuco North bus to Trabuco Bank 41 transformer (labeled 41 on Figure 4-1);
- Fault on the new Trabuco 230 kV bus;
- Fault on the Trabuco 138 kV transformer bus (TB XFR bus);
- Fault on the Trabuco 138 kV North bus (TB N bus);

By contrast, the SOCRE Project will have two 230/138 kV transformers in-service and be supplied by two 230 kV transmission lines at Capistrano. The Project will not only support 469 MW of load when Talega 138 kV substation is out-of-service, but , as shown in Figure 4-3, transmission lines and transformers at the rebuilt Capistrano Substation will be connected by breaker and a half configuration. Breaker and a half configurations are commonly used in the electric utility industry because they provide a high level of reliability for a moderate cost. Unlike the RDEIR Trabuco Alternative, the SOCRE Project allows the system to respond to a transmission line, transformer, bus or circuit breaker fault without dropping all South Orange County load when the Talega 138 kV substation is out of service. This is an important difference.

Expensive transmission projects that provide poor reliability are the result of poor planning practices and lead to an inefficient use of capital. The RDEIR Trabuco Alternative is just that kind of project. After spending over well over $500 million, SDG&E and its customers would be left with a South Orange County transmission system which is not fully redundant, will likely need additional upgrades in the future, require complicated maintenance programs, and require negotiation of new interconnection contracts. This is what is known. Unknowns could add more costs.

Figure 4-3 – New Rebuilt San Juan Capistrano Substation



E. Leaving Aside Necessary Reliability Upgrades Outside of South Orange County, SDG&E's 138 kV Transmission System Would Require Additional Work to Comply with NERC Transmission Planning Standards

In order to avoid violation of NERC TPL-003-0b and its successor TPL-001-4, SDG&E would pursue the following projects to prevent the overloads listed in Table 4-1 above. The list of transmission lines is repeated here below:

- Upgrade TL13836 to a higher rating: Talega Substation to Pico Substation;
- Upgrade TL13816 to a higher rating: Pico Substation to Capistrano Substation;
- Upgrade TL13846A to a higher rating: Pico Substation to TL13846 tap point;

- Upgrade TL13846C to a higher rating: Talega Substation to TL13846 tap point.

Further, to prevent MVar flow between South Orange County's 138 kV transmission system and SCE's 220 kV system, SDG&E will need to construct a new dynamic voltage control device (SVC, STATCOM or Synchronous Condenser) at the new Trabuco Substation at an estimated cost of $81 million to $99 million (with AFUDC, $89 million to $109 million). The new device will supply MVars to the SCE system at Trabuco 230 kV. Supplying MVars at Trabuco will stop the flow of MVars through South Orange County's 138 kV system. Additional analysis is needed to determine the size of equipment. To support voltage in South Orange County, SDG&E will also need to replace the Talega STATCOM when it reaches the end of its useful life or install a new dynamic voltage control device (SVC, STATCOM or Synchronous Condenser) at the rebuilt Capistrano Substation at that time. The estimated cost for doing so is another $81 million to $99 million (with AFUDC, $89 million to $109 million).

For the foregoing reasons, the RDEIR statement that "No 12-kV distribution lines or 138-kV transmission lines would require relocation or reconductoring"[29] is inaccurate.

Section 3. Without Additional Work, the RDEIR Trabuco Alternative Will Not Provide an Adequate Second Source for South Orange County (Witness John Jontry)

Without additional work, the RDEIR Trabuco Alternative does not provide an adequate second source for South Orange County because (a) it is not located at the load center for the area and thus 138 kV transmission line upgrades are needed to ensure that SDG&E's South Orange County distribution substations will receive adequate power in the event Talega Substation is out of service; and (b) as described in the Recirculated DEIR and shown on the RDEIR's "Conceptual Site Plan," the RDEIR Trabuco Alternative lacks the proper design and necessary equipment to reliably serve South Orange County in the event Talega Substation is out of service.

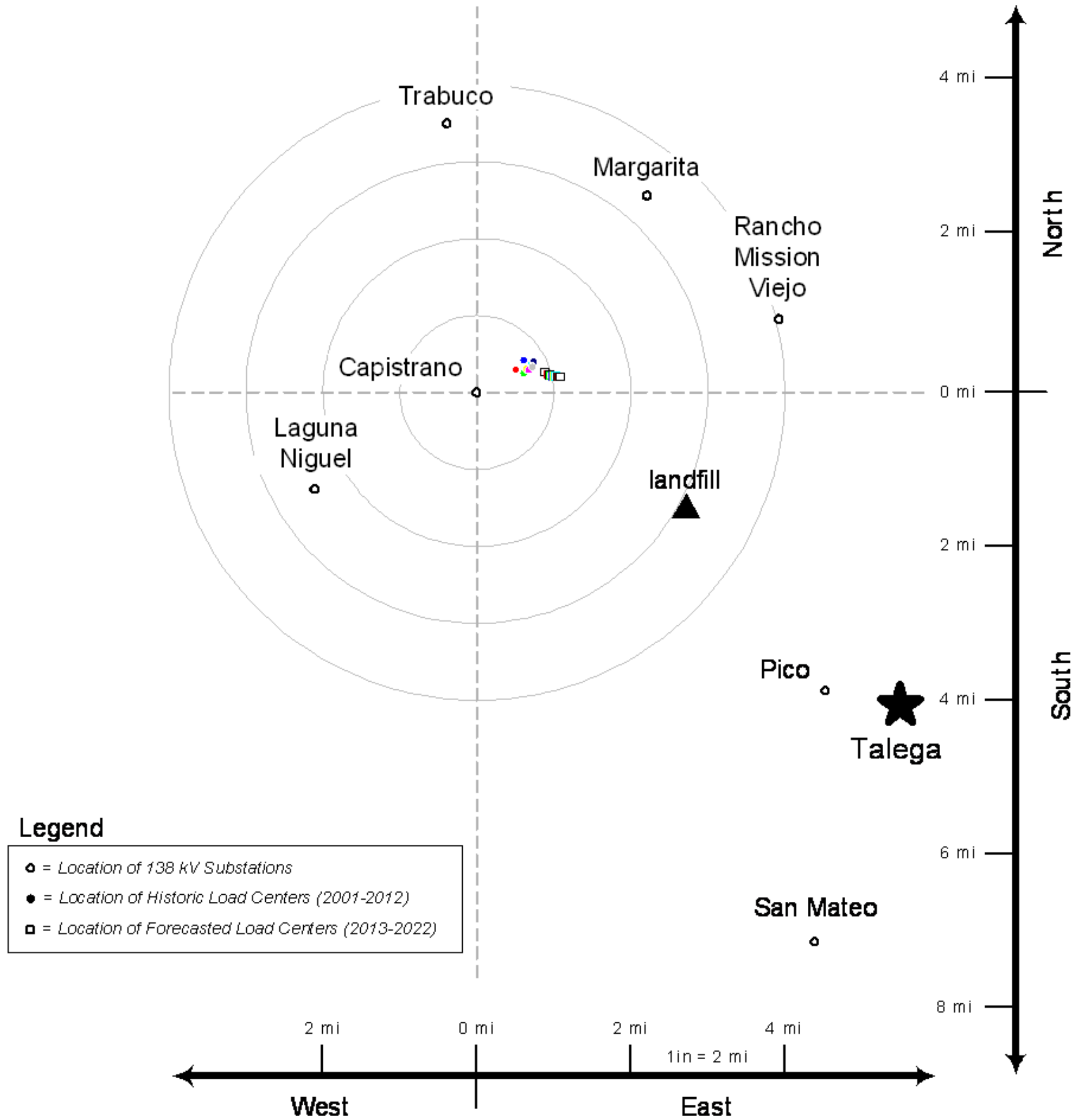
A. The RDEIR Trabuco Substation Alternative Does Not Add a 230 kV Source at the Load Center for South Orange County

As discussed in SDG&E's Rebuttal Testimony with respect to both Pico Substation Alternative and the ORA Trabuco Alternative, adding a 230 kV source at Capistrano Substation is more effective and efficient because of its close proximity to the center of load in South

[29] RDEIR at 2-22.

Orange County. Trabuco Substation is also not at the load center for South Orange County. Rather, it is located several miles north of the load center, with Capistrano Substation located between Trabuco and the calculated load center. See Fig. 4-4 below, which represents the load center analysis for South Orange County and indicates the relative proximity of all of the substations. Generally speaking, energy injected from the 230 kV system into the 138 kV system will then flow towards the load center, across the 138 kV network, before it can then flow out to serve customer load. Although Trabuco is located in a relatively better location than Pico to act as a second source to South Orange County (both closer to the load center and electrically removed from Talega), Capistrano is still the best of all existing locations as clearly demonstrated in Fig. 4-4.

Fig. 4-4 – South Orange County Load Center Analysis



Load Center based on Historic Loads		
Year	Miles North of CP	Miles East of CP
2001	0.299	0.506
2002	0.254	0.605
2003	0.419	0.605
2004	0.306	0.644
2005	0.293	0.681
2006	0.370	0.712
2007	0.410	0.728
2008	0.401	0.734
2009	0.401	0.734
2010	0.336	0.721
2011	0.337	0.721
2012	0.336	0.721

Load Center based on Forecasted Loads		
Year	Miles North of CP	Miles East of CP
2013	0.270	0.884
2014	0.234	0.924
2015	0.228	0.942
2016	0.221	0.959
2017	0.215	0.982
2018	0.211	1.003
2019	0.211	1.024
2020	0.210	1.045
2021	0.210	1.062
2022	0.205	1.083

B. Additional Work Would be Required for a Rebuilt Trabuco Substation To Serve As a 230 kV Source for South Orange County In the Event of a Talega Substation Outage

Also, Trabuco Substation is located adjacent to three 138 kV transmission lines, unlike the six lines that will terminate at Capistrano Substation upon completion of the SOCRE Project, and the four lines that currently terminate at Talega Substation. In order for a second 230/138 kV source located at Trabuco Substation to be fully redundant to the existing source at Talega, and given that two of the lines are located are located in a common transmission corridor south of Trabuco Substation and could be subject to a common-mode failure, it would be necessary to add at least one additional 138 kV line from Trabuco Substation to Capistrano Substation.

As discussed above, energy will tend to flow south from Trabuco towards the load center at Capistrano Substation. Following loss of Talega Substation, with Trabuco Substation acting as the sole source to South Orange County, this would result in several hundred megawatts of energy flowing south from Trabuco. As both lines south of Trabuco (TL13834 and TL13833) share a common transmission corridor and could be subject to a common-mode failure, it is possible for a single N-2 contingency to remove both lines from service. This would effectively cut off Trabuco from the bulk of the South Orange County load. As a result, substantial work is required on the 138 kV system to allow a 230 kV source at Trabuco Substation to serve South Orange County in the event of a service outage at Talega Substation.

C. The RDEIR Trabuco Alternative Does Not Provide Proper Design or Adequate Equipment for the Rebuilt Trabuco Substation to Serve as a Second Source in the Event of a Talega Substation Outage

As discussed in Section 1 above, the RDEIR Trabuco Alternative is inferior from a reliability standpoint to the proposed rebuilt Capistrano Substation. It is not a fully redundant source to Talega Substation for the following reasons:

1) It is served by a single 230 kV line.

2) It has a single-bus single-breaker topology that makes it vulnerable to single-element outages.

3) It has a single transformer in service at any one time that is not capable of carrying the full South Orange County customer load as of today, let alone as forecast ten years from now.

4) It does not have a sufficient number of 138 kV outlets (three lines, versus four from the existing Talega Substation and six from the proposed rebuilt Capistrano Substation)

As discussed in Section 7, it also is infeasible to construct a safe and reliable substation in the area prescribed by the RDEIR. To provide reliable service, SDG&E would need to construct a proper BAAH 230/138/12 kV substation on an expanded Trabuco site (including the existing site plus property to the north and south), as described in SDG&E's Rebuttal Testimony, Chapter 9, Section 6.

For the reasons discussed in Rebuttal Testimony, Chapter 5, a single 230/138 kV transformer at Trabuco is not a feasible alternative. The aggregate South Orange County peak load is forecast to exceed the capacity of SDG&E's standard 230/138 kV transformer (392 MVA). For a rebuilt Trabuco Substation to serve as a redundant second source, it would require at least two 392 MVA 230/138 kV transformers at Trabuco as well as a proper BAAH bus configuration, as discussed above. SDG&E also would reserve space for a future third transformer to enable enough capacity to feed the South Orange County load center at the system peak demand. The site for the transformers must be large enough to accommodate them.

Section 4. An Interconnection with SCE at Trabuco Substation Would Take Years to Accomplish (Witness John Jontry)

SDG&E's Supplemental Testimony, Chapter 5, Section 2 explained the required process for SDG&E to seek interconnection with SCE's system. "SDG&E would need to comply with SCE's Transmission Owner Tariff, the Transmission Control Agreement among transmission owners and the California Independent System Operator ("CAISO"), and the CAISO Tariff."[30] As described in more detail in SDG&E's Supplemental Testimony: "SDG&E estimates that it would take a minimum of twelve months and could take as long as twenty-four months to complete an interconnection application, System Impact Study, and a Facilities Study for an interconnection with SCE as described in the SCE Alternative."[31] SDG&E also would need to obtain CAISO approval.[32] "SDG&E believes that such an application would go through the normal annual transmission planning process. Depending when the CPUC provided such direction, and SCE completed its studies, it could be up to a year before CAISO would decide

[30] SDG&E Supplemental Testimony at 99.
[31] SDG&E Supplemental Testimony at 101.
[32] SDG&E Supplemental Testimony at 102-04.

whether to approve the Commission's preferred solution (and any "Reliability Upgrades" to SCE's or other systems determined to be necessary to permit the interconnection)."[33] The same process would apply if SDG&E were to seek an interconnection to SCE's system as part of the RDEIR Trabuco Alternative.

Until SCE performs a System Impact Study and any follow-on Facilities Study, the full scope of activities that would be required to implement the RDEIR Trabuco Alternative is unknown. The RDEIR Trabuco Alternative does not reflect any of the Direct Assignment Facilities or Reliability Upgrades that may be required by SCE and CAISO for SDG&E to implement the RDEIR Trabuco Alternative. And until SCE conducts a Facilities Study to determine the modifications to SCE's facilities necessary to permit interconnection, the construction activities, new structures and new lines that may be needed for such modifications is not known.

Further, to the extent that any of the Reliability Upgrades require CPUC approval, SDG&E and/or SCE would need to file applications with the CPUC for such approval, triggering further environmental review. SDG&E's Application for this Project has been pending since May 2012. The date when all required Reliability Upgrades are approved and constructed, before which time the interconnection to SCE will not be allowed under SCE's FERC-approved tariff, cannot be predicted accurately. None of this delay is necessary with SDG&E's Proposed Project.

Section 5. An SCE Interconnection at Trabuco Substation Will Have Impacts to Both the SCE and SDG&E Transmission Systems That Likely Would Need to be Mitigated with Other Reliability Upgrades Before An Interconnection Would be Allowed (Witness John Jontry).

As discussed extensively in SDG&E's Supplemental Testimony, Chapter 5, Section 3, and Rebuttal Testimony, Chapter 8, Section 4, such an interconnection with SCE would parallel a robust 230 kV path with a relatively weak 138 kV network. This would have the dual negative impacts of restricting the allowable flow on the 230 kV path while subjecting the 138 kV system to network flows for which it was not designed. Restricting allowable flow on the SCE lines in South Orange County could result in limiting the transfer capability between the SDG&E and SCE systems, resulting in reduced import capability for both utilities. In fact, such an interconnection may have a significant impact on Southern California's import capability.

[33] SDG&E Supplemental Testimony at 103.

SDG&E performed power flow analyses of several alternatives that include an SCE interconnection, and provided those results to Energy Division. See Attachment 54 (SDG&E Partial Response 1 to Energy Division Data Request 10). The power flow assessment shows that any connection to one of SCE's 220 kV transmission lines which make up Path 43 will result in SCE power flowing through South Orange County's 138 kV network. This "loop flow" will be carried by the South Orange County 138 kV transmission lines. These transmission lines are heavy loaded during peak load periods and the additional power flowing through them will result in post contingency overloads, which would not have existed without the SCE connection. SDG&E's Proposed Project does not provide a path for this loop flow.

SCE's System Impact Study is similarly likely to identify significant impacts to a number of important import paths and therefore require Reliability Upgrades to SCE's and SDG&E's systems at SDG&E's expense (which would be passed on to CAISO ratepayers). To properly assess the risk to the import limit, a WECC PRG (Path Rating Group) would be formed to determine any additional projects that would be needed to mitigate the impact to the import limit. These costs also would be attributed to SDG&E and then to CAISO ratepayers.

Because none of the Reliability Upgrades or WECC projects have been identified at this time (and would not be for at least several years), their environmental impacts have not been assessed.

Section 6. Rebuilding a 138/12 kV Capistrano Substation Is Necessary, and Would Have Similar Impacts as the Proposed Project (Witness Karl Iliev)

As set forth in SDG&E's Supplemental Testimony, Chapter 3, Section 3, Capistrano Substation must be rebuilt or overhauled to provide reliable electric service. Based upon careful analysis, SDG&E concluded that only replacing equipment in the existing Capistrano Substation will not provide adequate reliability for SDG&E's customers in the City and South Orange County. Adequate reliability can only be gained by a complete rebuild and expansion of the existing substation. Replacing aging infrastructure in kind and rebuilding a limited size substation in the existing yard will not achieve the improvements provided by the Proposed Project, and will not achieve SDG&E's goal to provide reliable electric service to its South Orange County customers.

The rebuild of the Capistrano Substation would expand to the lower yard within SDG&E-owned property and add a minimum of two spare 138kV positions for future needs that may arise outside of the planning time horizon, but within the expanded lifetime of the newly rebuilt substation. The substation cannot be rebuilt in its current location and needs to be built in the lower yard to maintain construction safety and station reliability during the rebuild project.

Moreover, for the reasons discussed in Section 2.D, SDG&E has concluded that a new 138kV transmission line from Trabuco to Capistrano would be needed to maintain reliability during a Talega Substation outage. There is no room at Capistrano for a new transmission connection. To connect a new transmission line into Capistrano Substation, a new position will be needed at Capistrano. This will require a new rebuilt substation at Capistrano.

If the second 230 kV source for South Orange County were to be moved to another site, then Capistrano Substation must be rebuilt as a 138/12 kV substation. If rebuilt as a stand-alone project, a Capistrano 138/12 kV substation is estimated to cost between $135 million to $165 million (including permitting, mitigation and AFUDC costs).

Section 7. The RDEIR Trabuco Alternative Is Infeasible As it Provides Insufficient Space to Construct a Safe and Reliable 230/138/12 kV Trabuco Substation (Witness Karl Iliev)

In SDG&E's Rebuttal Testimony, Chapter 9, Section 6, SDG&E explained that there was insufficient space at the existing Trabuco Substation to construct a 230/138/12 kV substation, as suggested by ORA's Trabuco Alternative. In that testimony, SDG&E also explained the property acquisition, phasing, and equipment that would be needed to construct a safe and reliable 230/138/12 kV substation on an expanded Trabuco Substation property, which would require acquiring property to the north and south of the existing substation.

As previously noted, although no preliminary engineering has been performed, the non-budgetary estimated cost to build a 230/138/12kV substation at Trabuco would be higher than the proposed 230/138/12 kV rebuilt Capistrano Substation because Trabuco has more existing equipment than Capistrano that would need to be replaced in the rebuilt substation. The estimated cost of constructing a 230/138/12 kV substation at Trabuco and the relocation of the existing distribution circuits is approximately $189- $231 million (including AFUDC). This cost does not include relocating the existing 138kV transmission, adding new 138kV and 230kV transmission lines, permitting, mitigation, property acquisition costs or the purchase of ROW. As noted above, the rebuilt Trabuco Substation also would need a voltage control device to control the flow of MVars between South Orange County and the SCE system, at an estimated cost of $81-$99 million (with AFUDC, $89 million to $109 million) (appropriate size and type to be determined).

The RDEIR Trabuco Alternative differs from the ORA's Trabuco Alternative by assuming that SDG&E will "acquire approximately 2 acres of land, currently owned by AT&T, adjacent to the north side of the existing Trabuco Substation for the construction and operation of the 230-kV switchyard."[34] The RDEIR then makes various assertions about what equipment would be placed on the acquired property and provides a "Trabuco Substation Conceptual Site Plan" that purports to diagram a 230 kV substation on the acquired property and how it would connect to SDG&E's existing Trabuco Substation.[35] The RDEIR Trabuco Alternative also states that "[m]odifications to the existing Trabuco Substation would not be required as part of this alternative" and "[n]o 12-kV distribution lines or 138-kV transmission lines would require relocation or reconductoring."[36] Based on this claim, the Recirculated DEIR does not attribute any environmental impacts to the performance of such work. In short, the RDEIR Trabuco Alternative does not permit the work that SDG&E identified as necessary to construct a safe and reliable 230/138/12 kV substation at and adjacent to the existing Trabuco Substation.

The substation proposed by Z-Global in the RDEIR Trabuco Alternative is neither safe nor reliable. It would create risks to SDG&E's electric customers that do not currently exist. It does not meet industry guidelines, regulatory requirements, or SDG&E's standards. SDG&E does not recommend construction of the substation proposed by the RDEIR Trabuco Alternative. If the Commission expressly requires SDG&E to do so, the decision must make clear that that the responsibility for the substation design lies with Z-Global and the Commission.

Below, SDG&E explains certain aspects of substation design, how SDG&E's proposed substation design achieved safety and reliability, and how the RDEIR's "Trabuco Substation Conceptual Site Plan" fails to provide adequate reliability, operational flexibility, capacity, and safe working conditions for required maintenance of equipment.

A. Safe and Reliable Substation Design

A substation is an assembly of electrical apparatus and physical structures for the purpose of control, regulation, subdivision, and transformation or conversion of electrical energy. It is

[34] RDEIR at 2-22.
[35] RDEIR, Figure 3-5.
[36] RDEIR at 2-22.

the connecting link between two or more sections of a transmission or distribution system, and performs the following:

- Directs flow of electrical energy in a power system;
- Voltage transformation; and
- Location for System Protection and Control and isolation devices (relays and circuit breakers).

Reliability, safety, and operational flexibility of a substation are created by building redundancy into the physical arrangement and protection designs. Although this "redundancy through design" requires more equipment, it provides greater reliability of electric service to customers, avoids unnecessary outages, and allows routine maintenance and/or trouble repairs to be worked in a safe and efficient manner. It also reduces the risk of customer interruptions during maintenance and repairs, and affords substation personnel appropriate work space and isolation points from energized equipment. In general, redundancy requires more physical space and equipment.

Physical redundancy in a substation is created by the bus arrangements and number of protective equipment (including circuit breakers) and isolating equipment (disconnects) installed as part of the bus arrangement.

- The substation bus is the conductor(s) serving as a common connection between circuits and the power flow in a substation.
- Circuit breakers are designed to break, make, and carry normal load current and to quickly interrupt high currents caused by failed/faulted elements and short circuits. Circuit breaker operation is typically automatic (as used in the application of removing faults from the electric system) or performed remotely to restore or redirect power flow.
- Disconnect switches are used to isolate a piece of equipment or segment a substation bus, transmission line, or distribution circuit for the purposes of personnel isolation intended for de-energized work. Disconnects are not load dropping devices and can only safely be opened when the equipment it is isolating is no longer carrying load. Properly sized disconnects are essential for personnel safety and are not typically operated automatically or remotely.

The purpose of installing a 230 kV switchyard at Trabuco Substation would be to provide a reliable second source of power via a 230 kV transmission line ("TL") into South Orange County. This 230 kV power would then be stepped down via 230/138kV transformer(s) and distributed to the 138 kV transmission grid serving the seven 138/12kV distribution substations within SDG&E's South Orange County ("SOC") electric grid. The voltage is then further stepped down from the 138 kV transmission voltage to the 12 kV distribution voltage circuits that serve the approximately 120,000 meters (roughly 300,000 people) in South Orange County.

The substation supplying the second source of power to the distribution substations must have the flexibility, capacity and reliability to serve SOC if the existing Talega Substation is out of service for any reason. It should also allow routine maintenance and/or trouble repairs to be performed in a safe and efficient manner, without high risk of customer outages or placing substation personnel at risk due to proximity to energized infrastructure.

(1) <u>Safety And Regulatory Considerations in Substation Design</u>

SDG&E designs new substations to meet SDG&E standards and industry guidelines for safety and reliability, and to meet regulatory concerns, by considering the following basic physical requirements:

- Electrical clearances (physical separation of energized exposed conductor to other exposed conductor, grounded surfaces, and or personnel walkable surfaces). SDG&E uses the following industry references in determining safe clearances for substation equipment:
    - IEEE Std. 1427 - Guide for Recommended Electrical Clearances and Insulation Levels in Air-Insulated Substations.
    - IEEE Std. C37.30 - Standard Requirements for High-Voltage Switches.
    - ANSI C37.32 - American National Standard for High-Voltage Air Disconnect Switches Interrupter Switches, Fault Initiating Switches, Grounding Switches, Bus Supports and Accessories Control Voltage Ranges—Schedule of Preferred Ratings, Construction Guidelines and Specifications.
    - IEEE Std. 1313.1 - Standard for Insulation Coordination – Definitions, Principals and Rules.
    - IEEE Std. 1313.2 - Guide for Application of Insulation Coordination.
    - NESC- C2 - National Electric Safety Code
- Safe access to equipment
    - Drive aisles shall be designed to accommodate regional standards for all safety vehicles.
    - A transmission substation's drive aisle in front of transformers should be approximately 40 ft to allow for placement/removal of transformers and required work on the transformer

- Drive aisles between an energized rack/bus, high voltage terminations and a fence/wall will be wide enough to allow safety and/or construction vehicles to safely turn, drive, and work– this is usually 25-30ft.

- Noise
  - The size of the site must allow transformer placements so that the decibel level at the property line meets the County noise requirements of the substation site or regulatory specifications.

- Fire safety (based on IEEE Std-979 IEEE Guide for Substation Fire Protection)
  - Access roads and gates must be at least 20 feet wide to accommodate emergency vehicles. Access roads inside the substation shall have adequate turning radius and access to all oil filled equipment.
  - Transmission Substations – transformers or oil containment (if required) should be a minimum of 50 feet to the wall or fence line. If this condition is not met, a fire barrier must be installed between the transformer and wall or fence.
  - Separation of a transmission bank should be at least 50 feet from the edge of the adjoining transformer's containment pit or a four hour fire barrier should be installed. The fire barrier should be placed a minimum of 4 feet away from the transformer radiators to allow for air cooling.

- Water Quality and Hydromodification
  - All new substation sites must meet space requirements for water quality and hydromodification management criteria as required by the Regional Water Quality Control Board. This is usually met through the use of underground infiltration tanks and above ground detention basins. SDG&E preliminary designs allow approximately 20-25% of space to meet these requirements until actual calculations can be done based on final site designs.

- Grounding
  - Ground studies must be done to determine the required ground grid that needs to be installed to safely dissipate fault current and allow for safe touch and step voltages for personnel and equipment protection. A smaller substation site may result in less area available inside the substation for the required ground grid, which may require additional mitigation and/or affect neighboring properties.

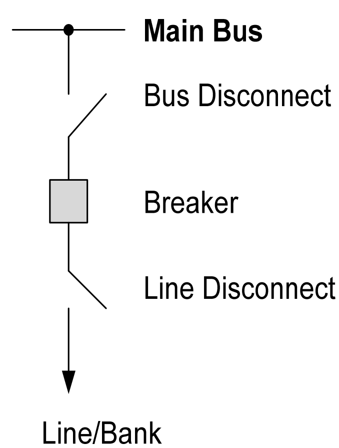
- Flexible operation.
  - Substation layout should include spacing to allow for safe construction and maintenance of all equipment allowing clear isolation points and proper clearance distances for these activities.
  - Substation layout should also include room for future growth due to unforeseen customer growth and/or potential large customer or generation interconnection.

(2) Reliable Design of Substation Bus Configuration

Substation designs are also influenced by the reliability requirements and the level of service continuity desired. As stated above, reliability, safety, and operational flexibility of a substation are created by building redundancy into the physical bus and circuit breaker arrangement. These arrangements also have implications for proper design of control and protection systems required to identify system disturbances and isolate them. Redundancy through design also allows routine maintenance and/or trouble repairs to be easily scheduled without major system impacts. Redundancy requires more equipment and therefore more cost. SDG&E seeks to balance cost and reliability by applying bus designs that escalate redundancy based on the magnitude of the impact the site has on potential customer outages.

IEEE, SDG&E, and industry standards commonly recognize five different types of substation bus designs. These designs (and the relevant considerations) are:

1. Single bus – single breaker (SBSB)
   a. Least reliable because each element is supplied through a single breaker and there is no way to offload the bus or breaker without dropping the load fed from the piece of equipment being de-energized.
   b. Least costly because it only requires one breaker per element
   c. Most problematic for maintenance as maintenance can't be done without offloading or dropping load on the element being removed from service.
   d. This configuration allows little reliability as any faulted piece of equipment fed from the bus will cause an outage to all elements fed from the bus (the bus itself or individual circuit breakers).



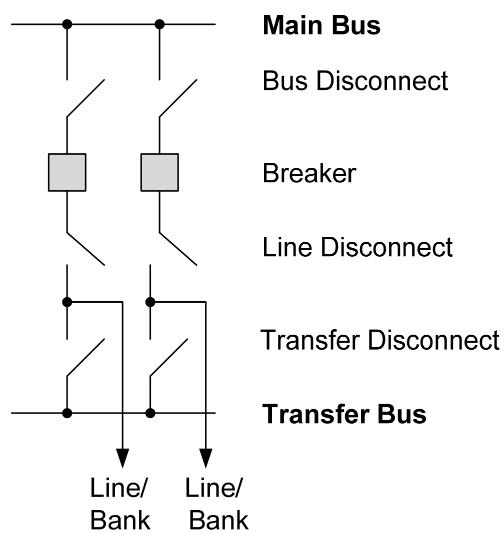
2. Main & Transfer Bus (MTB)

a. More reliable than SBSB design because an element may be offloaded onto the transfer bus under planned maintenance conditions, but there is still not a way to offload the main bus without dropping all load fed from that bus.

b. Inexpensive because it only requires one breaker per element but requires the added costs of a transfer bus and disconnects.

c. Usually used on distribution class bus designs.

d. This configuration allows little reliability as any faulted piece of equipment fed from the bus will cause an outage to all elements fed from the bus (the bus itself or individual circuit breakers).



3. Ring Bus (RB)

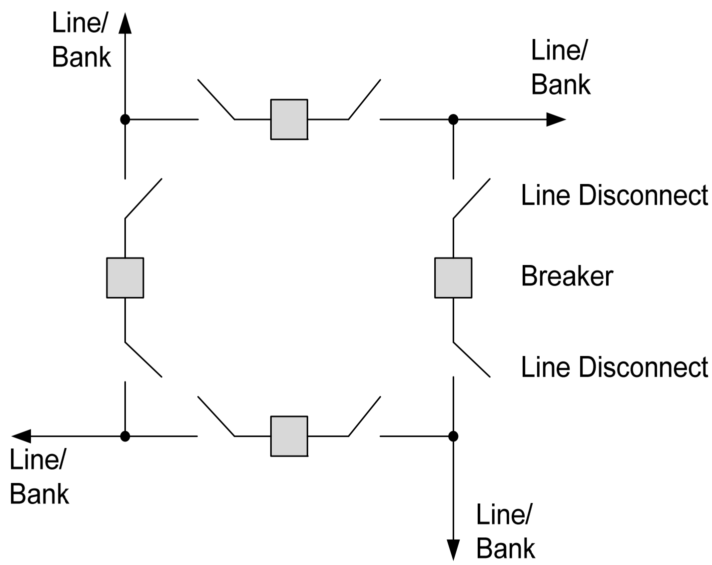
   a. More reliable than SBSB and MTB designs but much less reliable than a BAAH or DBDB because on a transmission bus, loop flow can be interrupted when more than one element is out of service.

   b. Less expensive because it requires one breaker for every single element.

   c. Usually limited in size to four element positions as reliability dramatically decreases the more elements are added.

   d. Will result in fragmented bus with two contingencies

   e. This design is not suitable as an ultimate arrangement for major transmission stations and SDG&E does not use this configuration for an ultimate design.



4. Breaker and a half (BAAH)

   a. Greater operating flexibility than a ring bus due to multiple feeds to each element

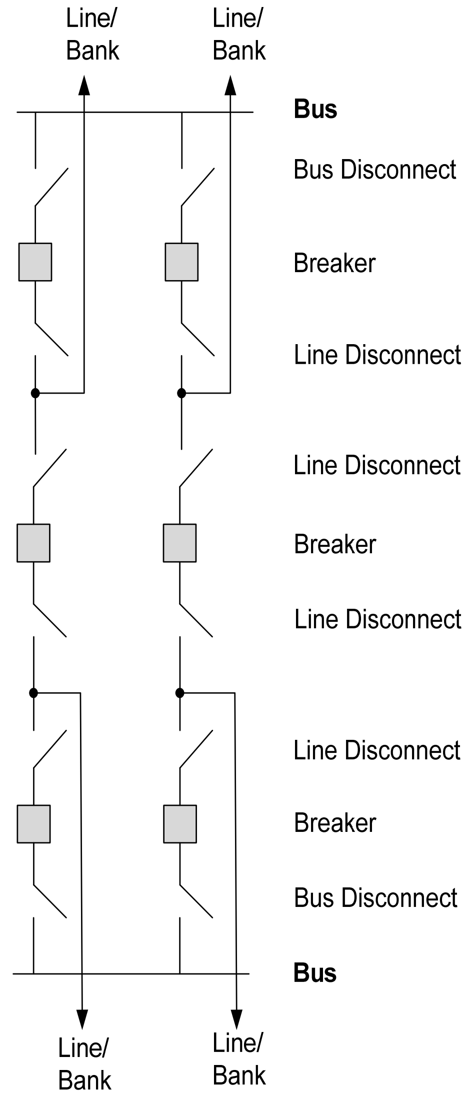
   b. Higher reliability than a ring bus due to redundancy in both busses and circuit breakers

   c. Redundant bus design allows the ability to isolate either main bus for maintenance and/or forced outages

   d. Bus fault does not interrupt service to any elements.

   e. Any single equipment failure (breaker) can only isolate a maximum of two elements providing reliability to stations with higher number of elements.

   f. Will eliminate fragmenting the station bus, which occurs during multiple outages in a ring bus design.



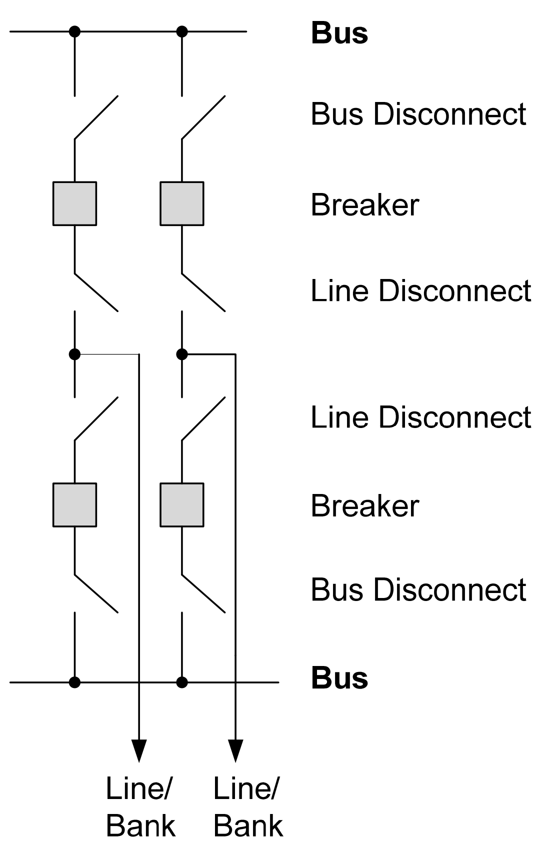
5. Double bus – double breaker (DBDB)

   a. This consists of two main buses with two breakers and disconnects per element – therefore it is considered the most reliable design as any single failure of a piece of equipment will only impact a maximum of one element.

   b. Any breaker or bus can be taken out of service without an interruption to service.

   c. Very costly and takes the largest amount of land as each bay position only holds one element (notice only two elements shown as compared to four in the BAAH diagram).

   d. SDG&E typically reserves this design for the most critical system elements such as generator buses and/or specific bulk power transformers.



B. SDG&E's Factors for Proper Substation Design

SDG&E takes into account IEEE, SDG&E, and industry standard practices when considering bus designs for a substation. SDG&E considers the following points when deciding what bus arrangement to design:

- Substation's intended purpose: Transmission (bulk power) versus distribution
- Safety
- Reliability requirements
    - Potential system impact of line faults
    - Potential system impact of bus faults
    - Potential system impact of Breaker failures including stuck breakers
- Simplicity of relaying requirements to protect the configuration
- Cost
- Ease of maintenance
- Flexibility of operation

- Limitations and layout impacts of connecting lines entry and exit from the substation
- Safety and reliability impacts of the bus electrical clearances towards meeting appropriate codes and guidelines.
- Physical arrangement of the station to allow access to equipment for maintenance and/or replacement due to failure and/or future upgrades.
- Current unique site limitations, SDG&E standards, general system operating practices.
- General capacity for future expansions and general redundancy to provide means for continuity of service during construction and maintenance.
- All bulk power transformer banks must be installed in a Breaker and Half or Double Breaker configuration
- Transformer bay position must be 1.5 times the rating of the normal transformer rating to account for short duration overload capabilities of the transformer.

C. The Substation Serving as the Second 230 kV Source for South Orange County Should Have a Safe and Reliable BAAH Design

SDG&E's Proposed Project, and any alternative meeting the project objectives, is intended to provide a reliable second source of power via a 230kV TL into a properly located substation in South Orange County. To provide reliable service to SDG&E's customers, this substation should have the flexibility, capacity and reliability to serve SOC if the existing Talega Substation is out of service for any reason. It should also allow routine maintenance and/or trouble repairs to be done in a safe and efficient manner, without risk of customer outages or to substation personnel.

SDG&E's Proposed Project would construct a 230/138/12 kV substation at the existing Capistrano Substation site, which, as set forth in Section 3A above, is at the load center for South Orange County. The proposed rebuilt Capistrano Substation would meet SDG&E standards and industry guidelines for the physical layout to meet the safety and regulatory considerations mentioned above.

To provide the appropriate level of reliability (continuity of service), SDG&E's proposed design for the 230/138 kV bulk power transmission substation (shown in the Proposed Project) requires a breaker and half (BAAH) configuration to meet operating and reliability criteria for a substation of this nature. As noted above, this configuration means each transmission bay has two elements connected to separate busses with a tie breaker between each element, allowing each element to be fed by either bus. This allows continuity of service to each element in the event of a bus outage. A BAAH configuration is more reliable and therefore preferred by SDG&E for large transmission stations since it limits any single point of failure to a maximum of two elements, minimizing transmission outage impacts. It is the most cost effective design to meet the reliability requirements of the proposed 230/138 kV substation.

Industry standards, e.g., IEEE Standard 605-2008, show that the BAAH configuration is the most suitable design for a major transmission (bulk power) substation. It has greater operating flexibility and higher reliability than the RDEIR Trabuco Alternative's proposed design. All switching is performed by circuit breakers, any circuit breaker can be isolated for maintenance without disrupting service to any element and each element can be fed by either bus. If a bus fault occurs, it does not interrupt service to any element during normal operation. It also allows proper electrical spacing so that each element can be safely taken out of service and grounded, as required for personnel safety during routine maintenance. All of these characteristics result in significantly less risk of isolating the transmission grid from the load, thus increasing the overall reliability of the feed. IEEE Standard 605-2008 recommends this arrangement for important 230kV substations and it is SDGE's standard design for bulk power transmission substations. A BAAH design reduces the risk of customer outages and the risk to substation personnel working on substation equipment.

In its Rebuttal Testimony regarding ORA's Trabuco Alternative, leaving aside power flow issues and assuming the feasibility of acquiring additional property and an SCE interconnection, SDG&E provided a preliminary design layout for a rebuilt 230/138/12 kV Trabuco Substation that would meet the above requirements. SDG&E's preliminary design provided for a physical layout that met necessary electrical clearances, access, fire safety, noise and RWQCB regulatory requirements, grounding and flexibility.

SDG&E's preliminary design for a rebuilt Trabuco Substation also provides for a BAAH bus design based on the following considerations (which also apply to the Proposed Project and any other alternative):

- Transmission (bulk power) versus distribution substation – The 230/138 kV substation required to supply the second 230kV source to SOC will be considered a bulk power transmission substation and should not be operated in a configuration normally found in a distribution class substation.

- Safety – The BAAH configuration allows for switching of each element with a breaker and safe grounding of the out-of-service element.

- Reliability requirements – The BAAH configuration allows continuity of service as follows:

    - Line faults – With a BAAH design, the 230kV lines into Trabuco would be properly "looped in" with both lines being terminated into their own bay positions with proper isolation. If one of the 230kV line were to trip, the transmission outage would only affect the damaged line, leaving the second 230kV line to feed the 138kV bus at Trabuco.

    - Bus faults – will allow elements to continue to be fed by the other bus.

    - Breaker failures – will trip only affected element and in case of a breaker failure, will still allow one bus to feed other elements. A breaker failure operation normally only trips a maximum of two elements, with the second element having an outage for a short duration to isolate the damaged breaker and restore service.

- Simplicity of relaying – SDG&E can use standard relaying schemes.

- Cost – more expensive than the proposed SBSB configuration proposed by Energy Division's RDEIR Trabuco Alternative, but provides proper reliability for the application.

- Ease of maintenance – allows for any element to be taken out without disrupting the bus or other elements. This is necessary to provide the redundancy necessary to perform routine maintenance work.

- Flexibility of operation – allows elements to be fed by either bus.

- Location of connecting lines – allows proposed 230 kV TLs to be located on the bus for optimum bus flow.

- For safety and reliability reasons, the bus electrical clearances must meet appropriate codes and recommendations – SDG&E has a standard BAAH design to meet these requirements.

- Buses must physically be arranged to allow access to equipment for maintenance and/or replacement due to failure or upgrades – SDG&E's standard BAAH design allows for access and maintainability on the equipment.

- Buses will be designed to meet all SDGE standards and operating practices.

- Bus arrangements should take into account future expansions and provide means for continuity of service during construction and maintenance – the SDG&E Proposed Project and the preliminary Trabuco Substation BAAH designs meet this requirement.

- All bulk power transformer banks must be installed in a Breaker and Half or Double Breaker configuration and sizing of the bay elements must allow for short duration overloads (usually 1.5 times the nominal transformer rating). The SDG&E Proposed Project and the preliminary Trabuco Substation BAAH designs meet this requirement.

As a result of attention and consistency to these considerations, SDG&E's Proposed Project and preliminary Trabuco Substation design would meet SDG&E's goals of safety, reliability, operation, maintenance, and flexibility (ignoring the non-substation issues with the proposed SCE interconnection at a rebuilt Trabuco Substation). As discussed below, the RDEIR Trabuco Alternative's proposed Trabuco Substation design would meet none of these requirements.

D. The RDEIR's "Conceptual Site Design" for Rebuilt Trabuco Substation Is Infeasible

(1) <u>RDEIR's "Conceptual Site Design" Is Not a Recognized IEEE or Industry Standard, and Does Not Meet SDG&E's Standards for Reliability or Safety</u>

(a) *The RDEIR's Proposed 230 kV Substation*

As noted above, the Recirculated DEIR states in its text that the 230 kV switchyard would include "two 230 kV/138 kV transformers (one required and spare) with a capacity 392 MVA. The 230-kV/138-kV transformer would be housed in a 40- to 50-foot-high gas insulated substation building."[37] The Recirculated DEIR, however, also provides a "Conceptual Site Plan" that does not include a GIS building and describes the new equipment for the 230 kV switchyard without a GIS building.[38] As the "Conceptual Site Plan" reflects Energy Division's effort to design a rebuilt Trabuco Substation that would fit on the AT&T parking lot and not require reconstruction of the 138 kV and 12 kV substations at Trabuco, SDG&E will focus on the flaws in the design depicted in the Conceptual Site Plan. However, constructing a safe and reliable 230 kV switchyard with a GIS building, particularly one containing two 230/138 kV transformers, on the AT&T parking lot along with other necessary air insulated equipment, is equally infeasible.

The Trabuco 230kV substation design shown in the Recirculated DEIR "Conceptual Site Plan" is not a recognized industry standard configuration. SDG&E does not know how the CPUC is proposing to operate this layout, i.e., what disconnects and/or breakers would normally

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[37] RDEIR at 2-22.
[38] RDEIR Figure 3-5 & 2-171.

be open, which is vital to evaluating the feasibility of the design. After review of every possible operating configuration, SDG&E assumes that Energy Division will operate the design under the configuration shown in the one line diagram in Figure 4-1 in testimony prepared by Cory Smith. SDG&E assumes the 230kV disconnect is normally closed in this diagram and modeled it as such in its power flow models. This is a reasonable assumption considering the location of the disconnect in relation to other equipment. When the 230 kV transmission line disconnect is opened[39] and the spare transformer disconnect open, the SCE transmission line connecting San Onofre Substation to Santiago Substation will be opened at Trabuco Substation. This would create two radial 220 kV transmission lines. One transmission line would supply power to Trabuco from San Onofre and the other transmission line would remain opened at Trabuco and carry no power. Consequently, the SCE transmission line would no longer carry power to SCE and SCE would lose one of its four 220 kV transmission line interconnections with SDG&E. SDG&E does not believe this was the intention of the Recirculated DEIR. Also, placing the spare transformer in service by closing the spare transformer disconnect and leaving the transmission line disconnect open will make matters worse. Power meant for SCE would flow through both the main and spare transformers to reach SCE's Santiago Substation. This would put unnecessary stress on the two Trabuco 230/138 kV transformers and be considered extremely poor design.

For these reasons, SDG&E assumes only one 230/138 kV transformer to be in service at the rebuilt Trabuco Substation with the transmission line disconnect closed. SDG&E notes that when both transformers are in-service, they are both connected together on the 138 kV side of the transformer with no isolation points (circuit breakers) to divide them. A single outage removes both transformers from service. With this design, SDG&E will be required to replace one (or both) of the aging 230/138 kV transformers at Talega. The Reciculated DEIR will lead to South Orange County be supplied by five 392 MVA 230/138 kV transformers; three in-service transformers at Talega, one in-service transformer at Trabuco and one spare out-of-service transformer at Trabuco. The Project uses four in-service 392 MVA 230/138 kV transformers; two at Capistrano and two at Talega.

At most, Energy Division's design is a modified single breaker, single bus design. However, Energy Division's design is not as reliable as a SBSB design because (a) the

[39] Labeled as "N.C. Transmission Line disconnect" on Figure 4-1.

transmission lines connect directly to the bus without a breaker (see Figure 4-4, Area A) and (b) both the transformers are protected off the low side bus by a single breaker (see Figure 4-4, Area B). The defects in this design are discussed more fully below.

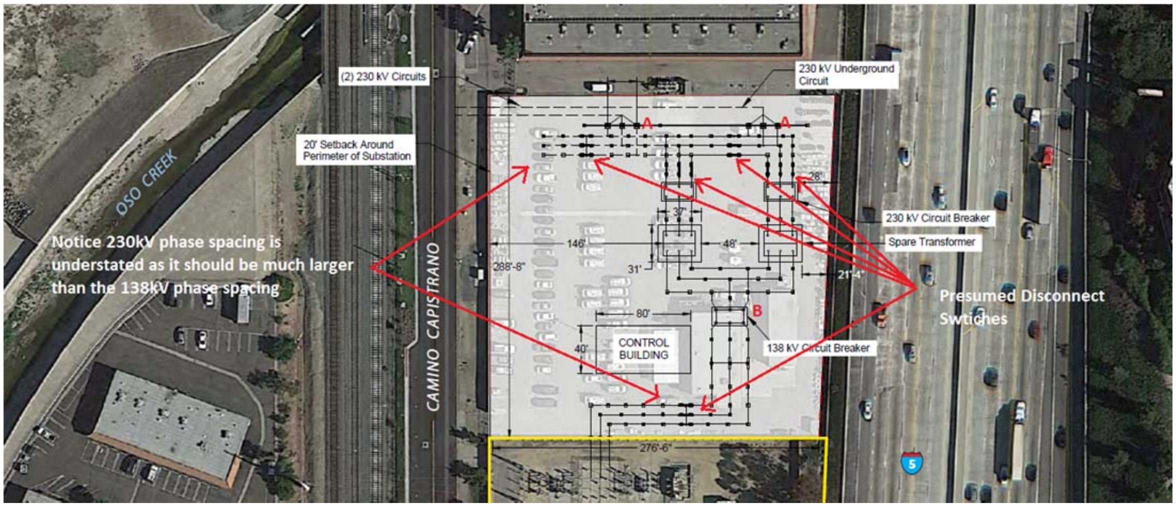

Figure 4-4 RDEIR Figure 3-5 Trabuco Substation Layout with SDG&E Comments

SDG&E notes that, even if Energy Division's design was a full SBSB, it would still be less reliable than the SDG&E Proposed Project and SDG&E preliminary Trabuco Substation BAAH designs.

Per IEEE Standard 605-2008 and SDG&E Standard SES-4402, a single breaker, single bus (SBSB) design has the lowest reliability of all standard bus designs. A bus or breaker fault causes loss of an entire bus, and in this case, the 230kV feed into Trabuco substation. Breaker maintenance under this configuration also requires the associated Transformer outage as there are no isolation points between the circuit breakers and transformers. While it requires the lowest cost and reduced land area, this comes at a large reliability risk.

Energy Division's design has less reliability than the already limited reliability of an SBSB design. The offered design does not meet any of the SDG&E requirements for bus design:

- This design would not normally be used in either a bulk power station or a distribution substation because of its poor reliability
- This design makes the substation less safe. Without having any 230kV breakers isolating the Transmission lines or serving as a 230kV bus tie breaker, isolation of the Transmission lines for standard maintenance on the 230kV bus, or to repair any damage on the line, becomes incredibly difficult as isolation normally requires de-energizing and grounding the required element. Strict procedures need to be written as isolation will require coordination between SCE and SDG&E. Isolation must first

occur at both SCE sites (San Onofre Substation and Santiago Substation) at the remote ends of the Transmission Lines feeding into the proposed 230kV switchyard at Trabuco, and at the Trabuco 230kV Transformer feeds, in order to safely isolate any work areas. The bus tie disconnect can only be operated safely after all areas are de-energized and isolated, requiring a much larger outage area than the area within which the maintenance or repair work will be performed. If the bus tie disconnect is operated outside of this procedure, there is a safety risk of de-energizing the 230kV transmission line cable, which typically carries capacitive charging current. Interrupting capacitive charge with a disconnect switch exceeds the current interruption rating of the switch. The typical failure mode of a disconnect switch under this condition causes the contact parts to melt. Human operators of the switch are located in close proximity to the switch and may be subject to burns and falling debris if this occurs. Additionally, damage to a switch renders it inoperable and an outage on the path would be required (typically multiple days) in order to replace the switch. Normally, additional circuit breakers are installed in the line and bus tie positions in order to afford on-site switching personnel the ability to locally isolate devices and equipment, and to alleviate communication and procedural errors that may lead to this scenario. Under Energy Division's design, there is no way to isolate any equipment without increasing outage requirements and following the mitigating procedure above.

- Reliability requirements
  - SDG&E's Supplemental Testimony discussed the potential events and durations that could force long duration outages at the Talega Substation. To add system redundancy to mitigate the effects of these outages, any alternative that serves as a redundant feed to Southern Orange County must have the capability to reliably feed the system for multiple months. The Energy Division's proposed design for the RDEIR Trabuco Alternative meets the need to add a second 230kV source to SOC, but fails in its attempt to reliably provide service during Talega Substation outages. The scenarios listed below outline the reliability problems if the RDEIR Trabuco Alternative were required to feed SOC in the event of a long-term Talega Substation outage.
    - **Transmission Line faults –** any fault on either of the two 230kV feeds into Energy Division's proposed Trabuco substation will isolate both lines, as there are no isolating devices to separate the two 230kV feeds. By de-energizing the entire 230kV bus, SOC will lose power, de-energizing all of SOC customer load. Troubleshooting will be hampered as any potential fault would have to be evaluated from relay event records at the SCE ends of both lines, rather than at the Trabuco site (as Energy Division did not include necessary instrument transformer infrastructure to be able to capture relay events at Trabuco). If the fault location is narrowed to either of the 230kV cables, all of the 230kV feed infrastructure would be de-energized in order to troubleshoot and find the fault location (which would take hours instead of minutes due to the safety procedures required). Once the cable was de-energized and tested, the good feed could be isolated and

used to restore service to SOC customers. Any line faults would likely cause outages to all of the 300,000 residents of SOC for several hours, depending on fault location and the damage.

- **138 kV or 230kV Bus faults –** Since there is no redundancy in bus design (SBSB versus a BAAH design), a bus fault on either the 230kV bus or the 138kV bus would isolate the entire 230kV feed into SOC, causing an immediate outage to all SOC customers for the duration of repairs to the bus, or restoration of Talega Substation (whichever is faster). Repairs could last from hours to days depending on the extent and location of the damage and the availability of spare parts.

- **Circuit Breaker/Transformer faults –** A 230kV Circuit breaker fault, fault on one or more of the 230/138kV transformers, or a fault on any of the 138kV breakers on the Trabuco North Bus, will isolate the 230kV feed into SOC and cause an outage to all customers in SOC. All of the 138kV circuit breakers on the Trabuco North Bus have isolating disconnects, and isolation and restoration of service from a failure on these circuit breakers would occur within an hour. Under Energy Division's Trabuco design, there are no isolation points between the 230/138kV main and spare transformer, and the 230kV and 138kV circuit breakers. Substation crews would have to de-energize, isolate, and ground this entire infrastructure and physically cut bus sections apart to isolate the damaged equipment, allowing at least one of the 392MVA transformers to be re-energized. This process would take several hours. If load was above the 392MVA limit, a portion of the customers in SOC would not be re-energized until either load in the system decreased, repairs were made to the faulted device, or service was restored at Talega substation (whichever is faster). Replacement of a faulted circuit breaker typically takes up to a week and replacement of a faulted transformer may take three to four weeks as mentioned in prior testimony. Lastly, if the single 138kV Circuit Breaker serving the two 230/138kV transformers failed, all of SOC customers would experience an outage until the circuit breaker was replaced or repaired (up to one week as mentioned above), or service at Talega substation is restored.

- As shown in the examples above, the configuration proposed in Energy Division's Trabuco substation design does not provide reliable service to SOC in the event of a Talega substation outage. SDG&E reiterates that a breaker and a half configuration is necessary to provide reliable service to Southern Orange County. SDG&E's Proposed Project includes a BAAH configuration.

- This design violates SDG&E and industry guidelines for protective relaying, which follows the principle that during a N-1 event, only the faulted element will be removed from service. More circuit breakers and relaying would be required to be able to isolate a single 230kV line and/or bus to make them into discrete elements (i.e. two separate 230kV transmission lines and a distinct 230kV bus). Because there is no isolation, the configuration is inaccurately described as two separate 230kV transmission lines feeding into the Trabuco site, as the system operates more like a single transmission line with a 230kV tapped transformer being fed off of it as John Jontry mentions in section 1 above

- Cost – assuming this bus design as compared to a breaker and a half design, this design will be lower cost for initial construction, but would cost more in reliability and operating expenses.

- Ease of maintenance:

    - Any maintenance on either 230kV TL will require both transmission lines to be de-energized and isolated per the safety procedure mentioned above. This will isolate the whole 230kV Trabuco feed for a few hours until the 230kV bus tie disconnect can be opened to restore service.

    - As mentioned above, Energy Division's design of the Trabuco substation places all 230/138kV transformers and 138kV and 230kV feeding circuit breakers together with no isolating devices from each other. Any maintenance performed would either take all of the infrastructure out of service for the duration of the outage or substation crews would have to take outages to physically cut bus sections apart to isolate them so that partial service can be restored. Normal transformer maintenance can last for up to one month, and circuit breaker maintenance can last as much as one week. This may get extended if damage is found inside the piece of equipment during inspection and parts are not readily available. Additionally, the 138kV breaker feeding both transformers will cause an outage on the whole 230kV Trabuco feed into SOC for the duration of any maintenance performed on it.

- Flexibility of operation – there is little to no flexibility in this design.

- Location of connecting lines – the location of the connecting 230 kV TLs is physically close, but may not be able to connect due to constraints in existing utilities in the street or having to cross Interstate 5.

- For safety and reliability reasons, the bus electrical clearances must meet appropriate codes and recommendations – this design does not appear to meet required clearances, but dimensions will have to be supplied to SDG&E to verify. It appears the 138kV bus spacing is larger than the 230kV bus spacing, meaning there is not sufficient spacing in the 230kV design to meet minimum requirements to prevent insulation breakdown of the air between energized phases, leading to a potential 230kV fault under normal operating conditions.

- Buses must physically be arranged to allow access to equipment for maintenance and/or replacement due to failure or upgrades – Energy Division's proposed design does not allow physical space for maintenance on the transformers and does not allow for electrical clearances required on equipment to perform maintenance.

- Buses must be designed to meet all SDG&E standards and operating practices – Energy Division's design does not meet SDG&E's operating practices, fire safety requirements, or allow for maintenance requirements.

- Bus arrangements should take into account future expansions and provide means for continuity of service during construction and maintenance – Energy Division's design does not allow for any additional connections for the required voltage control device, metering between SCE and SDG&E, and/or Station Light and Power transformers. It appears that Energy Division left a potential open position, but adding any element would require isolating breakers and disconnects on all elements already tied to the 230kV bus, which Energy Division did not leave enough space to accommodate. This means the 230k position that Energy Division designed could never be used.

- All bulk power transformer banks must be installed in a Breaker and Half or Double Breaker configuration and the transformer bay position must meet the overload capacity rating of 1.5 x transformer MVA rating. Energy Division's design does not meet any of these requirements as they seek to keep the existing 138kV bus that does not meet these ratings..

(b) *The RDEIR's Proposed 138 kV Bus Design*

The 138kV bus design proposed in the RDEIR is again a single beaker – single bus design since they are proposing connecting directly to the existing SDG&E Trabuco Substation 138kV bus. SDG&E constructed this bus as a SBSB design because it currently is a distribution substation and therefore does not require the reliability of a bulk power transmission substation.

For the same reasons mentioned above, the 138 kV bus connected to the 2nd 230 kV source for SOC should be a breaker and half design. This will allow the greatest reliability and results in significantly less risk of isolating the transmission grid from the load. The 138 kV system should be considered part of the bulk power transmission substation and be built accordingly.

Energy Division's proposed design, however, provides no requirement to reconstruct Trabuco Substation's 138 kV bus and expressly states that the "existing 138/12 kV substation equipment would not be modified, with the exception of connecting the new 138 kV circuit breaker and interconnecting bus work to the existing 138 kV system."[40] Extrapolating this decision, Energy Division's RDEIR Trabuco Alternative dictates that SDG&E may not increase the rating of its 138kV existing bus at Trabuco, which would limit the capacity of the 230kV as they are connected together. The lowered rating would leave Trabuco substation without enough

[40] RDEIR at 2-171.

capacity to carry SOC load, making it insufficient to act as a full and redundant feed into Southern Orange County.

In all events, even if the RDEIR Trabuco Alternative were amended to allow such work, none of it can be accomplished without an extended outage of the 138 kV bus in order for it to be replaced and upgraded to meet the capacity requirements of the 230/138kV transformers. This would expose customers to a higher probability of forced interruption of customer service fed from Trabuco substation. For that reason, and because of the space necessary to rebuild Trabuco in a more reliable BAAH design, SDG&E's preliminary Trabuco Substation design phased construction by reconstructing a new 138 kV substation on newly acquired property first, so that electric service could continue while the 230 kV substation was constructed. Instead, Energy Division's design for the RDEIR Trabuco Alternative dictates that SDG&E utilize an improper Trabuco Substation 138kV SBSB design that is not suited for major transmission substations.

Energy Division's Trabuco design jeopardizes SDG&E ability to construct a safe and reliable substation in accordance with prudent industry and SDG&E standards. As a result, the RDEIR Trabuco Alternative understates the necessary project scope, construction requirements to the existing Trabuco Substation, and the space required to build this alternative.

(c) *Physical layout and Missing Equipment*

The RDEIR's "Conceptual Site Plan" ignores what SDG&E considers basic design considerations of substation site layout requirements and the minimum equipment requirements required for the second source substation.

Also, as mentioned above, Energy Division's description of its plan does not match the drawing provided as Figure 3-5, "Trabuco Substation Conceptual Site Plan." Figure 3-5 shows an air insulated substation (AIS) design and the transformers in the drawing appear to be laid out in an AIS format. The text, however, states that the transformers will be housed in a 40 to 50 foot high gas insulated building.

If SDG&E were to assume that Energy Division would seek to house transformers in a GIS building, this would require GIS type transformers. If the transformers were to be housed in a GIS building, the building would need to be at least 50ft tall to meet clearances required to maintain the transformers. For fire safety requirements, the transformers should not be housed in the same building, however if they are, then the building would need independent roofing structures and a fire wall barrier between the two transformers. Each transformer would need access around each transformer for maintenance and/or construction, which would require the building to be a minimum of 75ft X 190ft long assuming SDG&E's standard 230/138kV transformers. Additional spacing may be required for the GIS terminations on the transformers.

As noted above, SDG&E considers numerous factors in substation layout design—and Energy Division's "Conceptual Site Plan" fails to meet many of them. Moreover, the RDEIR Trabuco Alternative, and the "Conceptual Site Plan" fail to include necessary equipment.

- Electrical clearances
  - o It can't be determined if the RDEIR's design meets these since SDG&E has not seen any specific detailed drawings. The RDEIR conceptual plan appears to show the 138kV spacing is larger than the 230kV spacing and the disconnects appears to be undersized as well (see Figure 4-4). If 230kV spacing is increased, the proposed design may not be feasible in the given space constraints that Energy Division proposes. See Figure 4-5 below to demonstrate how much more space is required for phase separation on 230kV as compared to 138kV.

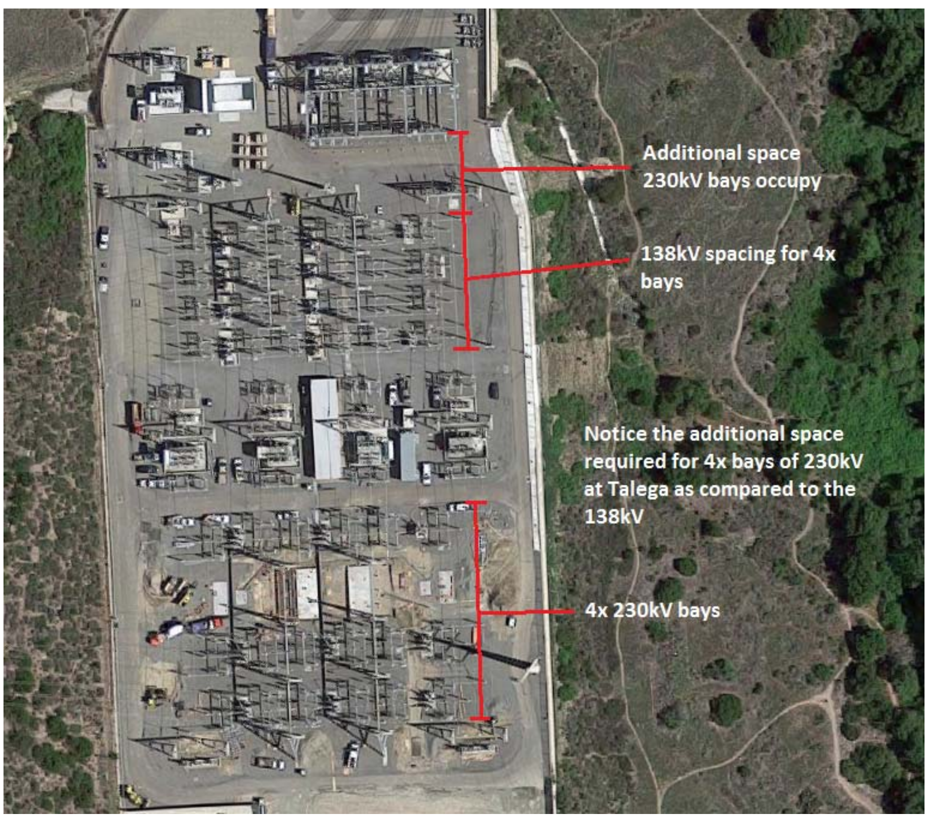

Fig 4-5 – Demonstration of 138kV vs. 230kV Phase spacing at Talega

- Safe access to equipment
  - o Drive aisles shall be designed to accommodate regional standards for all safety vehicles, consult local jurisdiction during design. The RDEIR's "Conceptual Site Plan does not allow safe vehicle access to the transformer on the east side and does not

allow any access to the middle of the bus to make repairs/modifications with lift equipment and cranes.

  - Transmission substation's drive aisle in front of transformers should be approximately 40ft to allow for placement/removal of transformers and required work on the transformer. The RDEIR's "Conceptual Site Plan does not allow enough drive access to the east transformer to enable a crane or boom truck to work on the transformer -SDG&E's boom trucks require 30ft of clearance to extend their stiff legs. The narrow space also would make it impossible to remove a transformer without demolition and replacement of existing infrastructure. This would extend outage times and costs unnecessarily because of the poor site planning.

  - Drive aisles - The RDEIR's "Conceptual Site Plan" spacing between the 230kV bus and north and east wall is questionable for safe access and drive-ability. This drive aisle should be between 25-30ft to allow safety and/or construction vehicles to safely turn, drive, and work.

- Noise

  - The size of the site and transformer placements should be placed so the decibel level at the property line meets county noise requirements for the county that the substation resides in and/or any other regulatory noise specifications. Based on SDG&E experience the transformer located on the East side of the property is located too close to the property line. There is insufficient space to install a noise barrier to mitigate these sound effects, but this may not be a major impact with the I-5 freeway near adjacent to the substation. Additional noise levels to the North, South and West would need to be studies to determine impacts from this design and if there is an impact then a noise barrier will have to be installed..

- Fire safety (based on IEEE Std-979 IEEE Guide for Substation Fire Protection)

  - Access roads and gates must be at least 20 feet wide to accommodate emergency vehicles. Access roads inside the substation shall have adequate turning radius and access to all oil filled equipment. The RDEIR's "Conceptual Site Plan spacing between the 230kV bus and north and east wall is questionable for safe access and drive-ability and will need to be further studied.

  - Transmission Substations – transformers or oil containment (if required) should be a minimum of 50 feet to the wall or fence line. If this condition is not met, a fire barrier must be installed between the transformer and wall or fence. The RDEIR's "Conceptual Site Plan does not allow space for the required fire wall on the East end of the property.

  - Separation of a transmission transformer bank should be at least 50 feet from the edge of the adjoining transformer's containment pit or a four hour fire barrier should be installed. The fire barrier should be placed a minimum of 4 feet away from the transformer radiators to allow for air cooling. No fire barriers are provided in Energy Division's design.

- Water Quality and Hydromodification
  - All new substation sites must meet space requirements for water quality and hydromodification management criteria as required by the Regional Water Quality Control Board which is usually met through the use of underground infiltration tanks and above ground detention basins. The RDEIR's "Conceptual Site Plan" does not provide any space for the necessary hydromodifications.
  - SDG&E has estimated it will take a minimum 15% of the entire property space (as a percentage of the total existing site and additional property) to be able to install the required hydromodification requirements. The existing Trabuco property will need to considered in the calculations since work will be done in the existing yard as part of the new construction, SDG&E's preliminary calculations indicate approximately 0,6 acres will be needed to meet this requirement.
- Grounding
  - Ground studies must be done to determine the required ground grid that needs to be installed to safely dissipate fault current and allow for safe touch and step voltages for personnel and equipment protection. A smaller substation site may result in less area inside the substation for required ground grid which may affect neighboring properties. Depending on grounding studies for the substation, additional property may be required or ground wells may need to be installed.
- Flexible operation.
  - Substation layout should be sized to allow for safe construction and maintenance of all equipment.
  - Substation layout's should include room for future growth.
- The "Conceptual Site Plan" does not include any allowance for required underground conduit sweeps – the proposed 230kV underground alignment may not be physically possible due to the radius required for underground 230kV cable and the space requirements for bundled 230kV underground cable. Further studies need to be performed to verify if the proposed design is feasible.
- The "Conceptual Site Plan" does not include any allowance required to safely maintain and operate equipment – this design does not allow enough access to the east side of the bus to easily maintain the transformer and its breaker. The drive aisles should be at least 25 ft and closer to 40ft next to the transformer. This allows oil processing equipment to be placed in close proximity to the transformer for normal prescribed maintenance activities.
- The "Conceptual Site Plan" does not include any allowance for the required voltage control device. SDG&E estimate this space to be up to approximately 00.75 acres for the equipment and access requirements.

- The "Conceptual Site Plan" does not include a BAAH configuration to provide proper reliability as a second source to Southern Orange County. The configurations lacks disconnect switches and current interrupting circuit breakers for proper isolation of system disturbances and to provide isolation for maintenance of each element eliminating operational flexibility and necessary redundancy.

- Allowances required for metering units if required at Trabuco Substation (required on at least one end of each 230kV interconnection with SCE).

- The RDEIR Trabuco Alternative states that "[n]ew substation componentry would be set back from the perimeter of the parcel by at least 20 feet."[41]   A 20ft setback around the perimeter of the substation would place the substation boundary nearly adjacent to the AT&T building and apparently block AT&T's ingress and egress to AT&T's building on its south side.. This would also most of their parking spaces on that side, significantly impacting the site operations.

- Additional allowances may be required to construct the east walls along the Interstate 5 freeway depending on Cal Trans' easements.

To construct the required 230kV and 138kV BAAH design, install the required voltage control equipment, hydromodifcation, and fire walls, and provide proper clearances and space for needed equipment, SDG&E's preliminary Trabuco 230/138/12kV substation12kV design set forth in its Rebuttal Testimony Chapter 9 estimated approximately 3-4 additional acres is required.

E. The RDEIR's Claims Regarding Construction of a 230/138/12 kV Trabuco Substation Are Inaccurate

For all of the reasons stated above, the RDEIR's "Trabuco Substation Conceptual Site Design" is infeasible. Energy Division's proposed layout appears designed solely to fit within a prescribed space, without regard for safety, reliability, adequate equipment or compliance with regulatory standards. SDG&E cannot construct a safe and reliable substation in the area dictated by the RDEIR's Trabuco Alternative.

In addition, the RDEIR mistakenly asserts:

> Major modifications to the existing Trabuco Substation would not be required as part of this alternative because the existing 138/12-kV equipment has not been identified as aging equipment by the applicant. It is anticipated that the Trabuco 130/12-kV system would remain operational while the new 230/138kV equipment is installed. Any potential disruptions of service would be limited to the time required to establish a physical

[41] RDEIR at 2-171.

connection between the new 230/138-kV equipment and the existing 138-kV equipment.[42]

Contrary to these statements, even if a safe and reliable 230 kV substation could be placed on the AT&T parking lot, which it cannot, the RDEIR is incorrect in assuming that no outages would be necessary on the existing Trabuco 138kV bus as part of the RDEIR Trabuco Alternative. Incorporating the emergency loading requirements to meet 150% the rated load of both 230/138kV transformers, the existing 138 kV bus would have to meet a rating of 1176 MVA, which exceeds its current ratings.

To increase the ratings of the existing Trabuco 138kV bus, all electrically conducting bus would have to be increased from the existing 2.5" Al Bus to larger than 6" al bus, which requires a new design that has never been built by SDG&E. Since SDG&E does not have a standard that fits this sizing, it is likely that all disconnect switches and structural supporting steel would have to be replaced to meet the new requirements. Appropriate equipment sizing would be based on studies that include seismic, short circuit, and normal flow analysis. Work (depending on scope) would take anywhere from one to several months to perform and emergency portable equipment would likely be brought in to support distribution station loading for the duration of the outage. As mentioned in the SDG&E's Opening Testimony, portable equipment is less reliable than normal equipment, leading to an increased risk of equipment failure and customer outage for the duration of this work. Additionally, the Trabuco 138kV North and South Bus outages would impact Transmission load flows by offloading the 138kV transmission lines fed from Trabuco. This impact would have to be studied to determine the outage feasibility based on the effects on the Southern Orange County transmission system.

This work would not address the lack of reliability arising from the failure to provide for a BAAH configuration for the 138 kV bus.

F. The Rebuilt Trabuco Substation under the RDEIR Trabuco Alternative Would Not Meet Industry Standards

IEEE 605-2008 reflects industry standards with respect to substation design. With respect to SBSB design, it states: "The single bus single breaker arrangement is generally applied in substations <u>from distribution voltage</u> through 121 kV to 161 kV and in locations <u>where system</u>

[42] RDEIR at 2-22.

reliability is not critical."[43] By contrast, with respect to BAAH design, it states: ""This arrangement is used for substations where reliability and service continuity is important. This arrangement is used extensively for voltage levels above 345 kV and some 230 kV substations due to the importance of these substations. Line switches can be added if required."[44]

The rebuilt Trabuco Substation design in the RDEIR Trabuco Alternative, which at most is a modified SBSB design, does not meet industry standards for substation design.

G. The RDEIR Does Not Address Issues Regarding Interconnection with SCE's Transmission System

The RDEIR Trabuco Alternative does not address issues involved with interconnecting SCE and SDG&E. Issues that will have to be resolved and that may affect the layout of the substation include:

1. Where will the interconnection point be? Typical interconnections between different entities include revenue metering at the point of change of ownership. Energy Division fails to identify the interconnection point in its design, and does not provide sufficient space for the equipment required for revenue metering.

2. If the interconnection point is in the substation, can SCE build the 230kV TL interconnection under SDG&E's permit? SCE may need to file an Application for its own permit to build the Transmission line unless it (a) relinquishes ownership to SDG&E of the line or portions of the line or (b) allows SDG&E to build SCE's portions of the line. Either option would have to be evaluated.

3. At any interconnection, SDG&E will have to request permission from SCE (and vice-versa) to perform any maintenance on the TLs and/or substation equipment, which may affect maintenance schedules and/or cost. As mentioned above, close coordination would have to occur to address safety, system operability, and reliability issues caused by Energy Division's proposed design.

Section 8. Transmission and Distribution Work that Would be Required by the RDEIR Trabuco Alternative (Witness Willie Thomas)

SDG&E has not had sufficient time to fully study and conduct an engineering study of the RDEIR Alternative J – SCE 230kV Loop In to Trabuco Substation. Based on Figure 3-5 in the RDEIR, the most feasible connection to SCE is the route along Camino Capistrano and West

[43] IEEE 605-2008 at 5 (emphasis added).
[44] IEEE 605-2008 at 9 (emphasis added).

of Interstate 5, which would require undergrounding 2-230 kV circuits southward along Camino Capistrano to the Trabuco Substation proposed 230kV yard north of the existing substation.

It is unknown if there is sufficient room in Camino Capistrano to accommodate the necessary trenching, conduit, and manholes required for the 230 kV undergrounding. Additional concerns arise from the bridge crossing over Oso Creek along Camino Capistrano. The feasibility of crossing the creek is unknown at this time, as two main point of concern include the available space for positioning of the 2-230kV lines and determining if the addition physical loading of the bridge can accommodate the additional weight. Structural analysis and consultation with the bridge owner would need to be done to address the feasibility of crossing the creek within or attached on the outside of the bridge (side or belly of bridge). Based on preliminary analysis there looks to be several attachments for other utilities within and on the outside of the bridge crossing Oso Creek. If the bridge cannot accommodate the additional 230kV lines an alternate route would need to be identifying to accommodate the creek crossing. Undergrounding techniques such as horizontal direction drilling may be needed and would adversely affect traffic due to spacing needed to perform the operation. This technique would also present potential environmental concerns such as frac-out during the drilling operation.

There would be other traffic issues on Camino Capistrano due to the lane closure requirements to construct the trench, conduit, vaults, and cable system installation (pulling, splicing, terminations). Distribution overhead and underground facilities may also need to be relocated to accommodate the routing of the underground and installation of the 230kV riser structures.

The proposed 230kV route in the RDEIR that crosses the Interstate 5 freeway is least desirable due to difficulty in obtaining Cal Trans permits to cross interstate 5, traffic control impacts along Interstate 5 during construction and maintenance, and acquisition of new easements to accommodate the routing east and west of Interstate 5. The stringing of transmission lines across the freeway involves shutting down all lanes of the freeway multiple times, once for each phase of conductors.

Additional concerns include the siting of the 230kV double circuit overhead structures on either side of Interstate 5. Referring to Figure 3-5, there looks to be limited room to locate a double circuit 230kV structure either inside the substation or adjacent to the substation and Cal Trans right of way. If a 230kV pole could be installed outside and adjacent to the north east corner of the expanded substation yard, as indicated in Figure 3-5, it is unclear if there would be enough electrical clearance between the 230kV pole and AT&T building as well as having enough working space to install and maintain the 230kV pole. This route would also require considerable undergrounding in the business/community area east of the freeway and there may be conflicts with other utilities (water, sewer, gas, telecom, etc…) that would conflict with two 230kV trench, conduit and manhole infrastructures.

Section 9. A Reliable RDEIR Trabuco Substation Alternative Would Cost More Than the Proposed Project (Witness Willie Thomas)

For all the reasons set forth above, the RDEIR Trabuco Alternative is infeasible. Even if the RDEIR Trabuco Alternative were altered to allow construction of a safe and reliable 230/138/12 kV substation, utilizing a BAAH configuration and the property north and south of the existing Trabuco Substation site, and to permit necessary 138 kV and 12 kV work, the RDEIR Trabuco Alternative would be more costly to ratepayers than SDG&E's Proposed Project.

- As discussed in SDG&E's Rebuttal Testimony, Chapter 9, Section 6.B, the estimated cost of constructing a 230/138/12 kV substation at Trabuco and the relocation of the existing distribution circuits is approximately $189 - $231million. This does not include the cost of acquiring the necessary property, which would include the cost of relocating two businesses and any AT&T communications infrastructure located at its facility. This cost also does not include relocating the existing 138kV transmission, adding new 138kV and 230kV transmission lines, permitting, mitigation, or acquiring ROW. Thus, this cost likely will be considerably more.

- To interconnect at rebuilt Trabuco Substation with an SCE transmission line, the likely path (without any engineering study) would be 0.5 miles of 230 kV double circuit underground down Camino Capistrano, at an estimated cost of $16 - $20 million (includes AFUDC and EMF mitigation).

- As set forth in Section 2 above, to supply MVars to SCE's system, a voltage control device at a rebuilt Trabuco Substation may cost as much as $81-$99 million (with AFUDC, $89 million to $109 million) (appropriate size and type will require further study).

- To support South Orange County voltage, SDG&E's Proposed Project includes two 230 kV capacitors at a rebuilt Capistrano 230 kV bus. The RDEIR Trabuco Alternative will require an additional voltage control device at either Capistrano or Talega when the existing Talega STATCOM reaches the end of its useful life at an additional cost of $81-$99 million (with AFUDC, $89 million to $109 million)

- As stated in Section 6 above, Capistrano Substation still must be rebuilt as a 138/12 kV substation to provide reliable electric service. The estimated stand-alone cost of rebuilding Capistrano Substation as a 138/12 kV substation, with the same configuration and location as proposed in the Proposed Project, is between $135 million and $165 million (including AFUDC, permitting and mitigation).

SDG&E's estimated cost for its Proposed Project is $384 million. The elements of the RDEIR Trabuco Alternative, modified as noted above and for which SDG&E has had time to estimate a cost, total $518 million to $634 million. This does not include additional costs for property acquisition and business relocation at the expanded Trabuco Substation, 138 kV upgrades to address NERC Category C violations and load shedding, 138 kV upgrades to mitigate the risk of forced outages during maintenance events, and 138 kV upgrades to make a rebuilt Trabuco Substation fully redundant for South Orange County in the event of a Talega service outage. As discussed in Sections 2 and 3 above, to avoid NERC violations and to make a 230/138 kV source at Trabuco fully redundant to Talega, SDG&E would have to:

- Upgrade TL13836 to a higher rating: Talega Substation to Pico Substation;
- Upgrade TL13816 to a higher rating: Pico Substation to Capistrano Substation;
- Upgrade TL13846A to a higher rating: Pico Substation to TL13846 tap point;
- Upgrade TL13846C to a higher rating: Talega Substation to TL13846 tap point;
- Add a third Trabuco-Capistrano 138 kV line;

As a result, SDG&E is confident that the RDEIR Trabuco Alternative will cost far more than the Proposed Project.

Section 10. The Reasonably Expected Actions If the RDEIR Trabuco Alternative Is Selected Will Have Greater Environmental Impacts Than the Proposed Project (Witness Scott Boczkiewicz).

The reasonably expected actions if the Commission selects the RDEIR Trabuco Alternative will have greater environmental impacts than SDG&E's Proposed Project. Although Energy Division was informed of the necessary work by SDG&E in response to data requests,[45] the Recirculated DEIR simply asserts that such work will not happen. Thus, the Recirculated DEIR erroneously asserts:

[45] See Attachment 54 (SOCRE ED 10-SDG&E Partial Response 1 dated July 10, 2015), 55 (SOCRE ED-08 SDG&E Response dated May 20, 2015), and 56 (SOCRE ED-10 SDG&E Partial Response 2 dated July 14, 2015).

> Existing infrastructure in the AT&T parking lot would be removed, and civil work would be conducted to establish a new pad for the 230/138-kV equipment. New equipment would include support structures for the 230-kV double circuit transmission line, a 230-kV bus, two 230-kV circuit breakers, two 230/138-kV transformers (one required and one spare), a 138-kV circuit breaker, and a new 80- x 40-foot control building. New substation componentry would be set back from the perimeter of the parcel by at least 20 feet (Figure 3-5). A small switchyard would be constructed to loop SCE's Santiago-SONGS 230-kV line into the Trabuco Substation. The existing 138/12-kV substation equipment would not be modified, with the exception of connecting the new 138-kV circuit breaker and interconnecting bus work to the existing 138-kV system.
>
> The SDG&E South Orange County 138-kV System would not require any reconductoring under this alternative. The Capistrano Substation would not be expanded, but equipment at Capistrano Substation found to be inadequate would be replaced. The distribution circuit 315 (12-kV) would not be relocated.[46]

Based upon these erroneous assertions, the Recirculated DEIR concludes that the the RDEIR Trabuco Alternative will have fewer and less significant environmental impacts than SDG&E's Proposed Project.

As stated above, Capistrano Substation must be rebuilt to provide reliable electric service. Unless the Commission directs SDG&E that it may not rebuild Capistrano Substation, Capistrano Substation will be rebuilt. By contrast, the Recirculated DEIR repeatedly states that certain impacts will be avoided because Capistrano Substation will not be rebuilt.[47] (The Recirculated DEIR, like the DEIR, makes this inaccurate assumption in assessing the environmental impacts of nearly all of the alternatives to SDG&E's Proposed Project.) This is incorrect and results in an inaccurate comparison of environmental impacts, as well as misinforming the Commission and the public.

As stated above, a safe and reliable 230/138/12 kV substation cannot be constructed on the existing Trabuco Substation plus the AT&T parking lot. Instead, SDG&E would have to

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[46] RDEIR at 2-171.

[47] RDEIR at 2-171 ("Because Alternative J does not include expanding the existing Capistrano Substation, the associated significant air quality impact that would result from exceeding the SCAQMD LST at the 6.4-acre construction site would be reduced"); 2-172 ("Alternative J is the Environmentally Superior Alternative for biological 1 resources (Table 5-1) compared to the other alternatives because it would only require about 6 acres of ground disturbance, mostly in previously disturbed areas."); 2-172 ("Alternative J does not include the expansion of the existing Capistrano Substation."); 2-172 ("Additionally, Alternative J does not include the expansion of the existing Capistrano Substation; therefore, the associated partial or full closures of Calle San Diego and Camino Capistrano (in the city of San Juan Capistrano) would not occur."); 2-173 ("Alternative J does not include the expansion of the existing Capistrano Substation; therefore, the associated partial closures of Camino Capistrano in the City of San Juan Capistrano would not occur and significant cumulative impacts would be avoided.")

acquire property both to the north and south of its existing Trabuco Substation, and engage in construction on all such property. By contrast, the Recirculated DEIR assumes that the work would occur in a much smaller area and require less new construction. Based upon Energy Division's method of analyzing impacts, these assumptions result in an inaccurate assessment of the impacts on air quality, biological resources, land use and planning.[48] This results in an inaccurate comparison of environmental impacts, as well as misinforming the Commission and the public.

As stated above, the RDEIR Trabuco Alternative will require upgrades to SDG&E's 138 kV system both to meet NERC reliability standards and to allow a rebuilt Trabuco Substation to serve South Orange County in the event of a Talega Substation outage. By contrast, the Recirculated DEIR asserts that no work on SDG&E's 138 kV transmission lines would be required. The Recirculated DEIR's erroneous assumption results in an inaccurate comparison of environmental impacts,[49] as well as misinforming the Commission and the public.

Further, the Recirculated DEIR fails to acknowledge the environmental impacts of the necessary Reliability Upgrades that will be required to mitigate the interconnection's impacts on SCE's system and the WECC Paths. Although it will require several years of study by SCE, CAISO and WECC to determine the necessary Reliability Upgrades in sufficient detail to determine their environmental impacts, the Recirculated DEIR does not even note that such Reliability Upgrades will be necessary and will have environmental impacts of uncertain scope. As a result, the Recirculated DEIR fails to inform the Commission and the public of the reasonably anticipated actions that would arise from selection of the RDEIR Trabuco Alternative (or any of the other alternatives that include an SCE interconnection).

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[48] RDEIR at 2-171 ("Based on the assumed disturbance acreages, the criteria pollutant emissions during construction of Alternative J would be approximately 88 percent below the construction emissions for the proposed project"); 2-171 (("Alternative J is the Environmentally Superior Alternative for biological 1 resources (Table 5-1) compared to the other alternatives because it would only require about 6 acres of ground disturbance, mostly in previously disturbed areas."); 2-172 (land use analysis wrongly assumes only a single GIS building).

[49] RDEIR at 2-171 to 2-172 (all comparisons based on "disturbed acreage" and "shorter length of transmission line work").

STATEMENT OF QUALIFICATIONS

JOHN M. JONTRY

My name is John M. Jontry. My business address is 8330 Century Park Court, San Diego, California, 92123. I am employed by San Diego Gas & Electric Company (SDG&E) as Transmission Planning Manager. I have been employed by SDG&E since 2005. For the past five years I have managed the Grid Planning group within the Transmission Planning department, with the primary responsibility of overseeing the annual grid reliability studies and the planning studies for major special projects such as the South Orange Country Reliability Enhancement project (SOCRE). Prior to working for SDG&E, I worked for electric utilities in Texas and Illinois and for the Midwest Independent System Operator (MISO) in Indiana in various engineering and operational roles for approximately fifteen years. I hold a bachelor's degree in Electrical Engineering from the University of Illinois and a master's degree in Industrial Technology from Eastern Illinois University. I am a Registered Professional Engineer in the states of Illinois and Texas.

I have previously testified before this Commission.

KARL ILIEV

My name is Karl Iliev and my business address is 8316 Century Park Court, San Diego, California 92123. I am the System Protection & Control Engineering Manager in the Electric Transmission & Distribution Engineering Department of San Diego Gas & Electric (SDG&E). My section's primary responsibities are to provide protective relay and control schemes, settings, and communication systems for a safe and reliable grid, including providing technical support, scoping advice, and review of substation electrical designs.

I began work at SDG&E in June 1999 as an Engineering Intern and have held positions around the company on both transmission and distribution sides ranging from planning to engineering to construction and operations. Since 2003, I've held positions of increasing responsibility related to substation design and construction including work in System Protection Engineering & Maintenance, Substation Construction & Maintenance, and Substation Engineering & Design. I was the Substation Engineering & Design Manager for over 4 years from 2009 into 2014 where my responsibities included cost estimatation, design specifications and scoping, material procurement, apparatus assessment, engineering review, substation drawing management, construction support, and real-time operational involvement for all of SDG&E's substations and substation related capital projects.

Immediately prior to obtaining full time employment with SDG&E in 2001, I graduated California State University of Sacramento with a Bachelor of Science in Electrical and Electronic Engineering with a concentration in Power Systems and a minor in Physics. In 2004, I earned my license as a Professional Engineer in the State of California.

I have previously testified before this Commission.

CORY SMITH

My name is Cory Smith and my business address is 8330 Century Park Court, San Diego, California 92123. I am employed as a Principal Engineer in the Transmission Planning Department of San Diego Gas & Electric where I have worked since 2008. My duties include assessing SDG&E's transmission system for compliance with NERC Transmission Planning Standards and creating technical models of SDG&E's high voltage transmission system to assess transmission system performance.

Prior to joining SDG&E, I was employed by Northeast Utilities in Berlin, Connecticut as a Senior Engineer. My duties included the creation of technical models and the application of specialized software to assess the reliability performance of the high voltage transmission system owned by Northeast Utilities. Before my employment with Northeast Utilities I was employed as an Engineer by the New York Independent System Operator in Schenectady, New York. My duties included reliability assessments of the high voltage transmission system serving the State of New York.

I received my Bachelor of Science degree in Electrical Engineering from Arizona State University in 1989, my Master of Engineering degree in Electric Power Engineering from Rensselaer Polytechnic Institute in 1994 and my Master of Business Administration degree from The College of Saint Rose in 2003. In addition, I am a Registered Professional Engineer in the states of California and New York.

I have not previously testified before the Commission in a proceeding.

WILLIE THOMAS

My name is Willie Thomas and my business address is 8316 Century Park Court, San Diego, California 92123. I am currently the manager of Electric Transmission Engineering and Design at San Diego Gas & Electric (SDG&E). My duties for the past two years include managing a diverse group of designers and engineers in the design, engineering, construction and management of electric transmission facilities in the SDG&E service territory. In addition, my duties include the development of specifications, cost estimates, budgeting, managing material and engineering service contracts, and ensuring the proper application of electrical codes, safety regulations, and regulatory agency requirements governing the design and installation of electric transmission facilities. My previous experience includes the design and engineering for the Sycamore Penasquitos 230kV project (CPCN), the transmission facility relocations for the County of Orange La Pata Avenue Gap Closure project (Advice Letter), and the South Bay Substation relocation project (PTC). I hold a Bachelor's of Science in Electrical Engineering from California Polytechnic University of San Luis Obispo in 2004. I am a licensed Professional Engineer (Electrical) in the State of California and an active IEEE member.

I have previously testified before this Commission.

SCOTT BOCZKIEWICZ

My name is Scott Boczkiewicz and my business address is 8316 Century Park Court, San Diego, California 92123. I am the Air and Water Team Lead in the Environmental Programs Group, within the Environmental Services Department of San Diego Gas & Electric (SDG&E). My primary responsibilities include administrative, supervisory and technical oversight of a team that ensures company compliance with all aspects of the Federal Clean Air and Clean Water Acts, as well as compliance with state and local regulations and ordinances that protect air and water quality. I administer technical review, permitting and environmental compliance programs for both capital projects and operations and maintenance programs.

I began work at SDG&E in June 2012 as a Senior Waters and Wetlands Specialist, and have held my current supervisory position with the Air and Water Team since November 2013. I have over 20 years of experience completing biotechnical project impact analysis and regulatory permitting for utility and commercial development projects, and specialize in wetlands science, compensatory mitigation planning and mitigation program implementation for large-scale projects. I worked as a professional consultant for 11 years in Southern California prior to joining SDG&E, and have comparable work experience from prior positons in Oregon, Washington, New Mexico, North Dakota and Wisconsin.

I graduated from the University of Wisconsin, Madison with a Bachelor of Science in Conservation Biology and a concentration in Restoration Ecology and Environmental Law.

I have not previously testified before the Commission in a proceeding.

JEFFREY SYKES

My name is Jeffery Sykes and my physical business address is 5057 Greencraig Way San Diego, CA 92123, my mailing address is PO Box 129831, SD1170, San Diego, CA 92112-9985. I am currently the Land Management Supervisor for the Land Services Department at San Diego Gas & Electric (SDG&E). I have been employed at SDG&E in the Land Department for over 15 years. Starting as a Land Management Representative my positions have subsequently included Lead Land Management Representative, Land Services Supervisor and Land Management Supervisor. My duties as a supervisor in Land Services have included supervising the acquisition of easements for SDG&E facilities, supervising the interpretation of SDG&E land rights, advising on SDG&E land rights and the enforcement of SDG&E land rights. SDG&E currently acquires over 500 distribution and transmission easements per year primarily using our in house staff. Our Land Management staff protects SDG&E's land rights so that those rights can be used for they were acquired for, generally the transmission and distribution of natural gas and electrical energy. SDG&E has in excess of 170,000 easements. I hold a Bachelor's of Science in Business Management from San Diego State University 1973, Masters of Business Administration from National University 2004. I am a licensed California Real Estate Broker and Licensed California General Contractor and an active member of the International Right of Way Association.

I have previously testified before this Commission.

ROBERT FLETCHER JR.

My name is Robert Fletcher Jr. and my business address is 8316 Century Park Court, San Diego, California 92123. I am the Natural and Cultural Resources Team Lead at San Diego Gas & Electric (SDG&E). As team lead my duties include managing a team of biologists and cultural resource specialists that review potential impacts to sensitive resources from existing and proposed gas and electric transmission and distribution facilities within the SDG&E service territory. In addition, my duties include managing the natural resources portion of multiple large, complex projects concurrently by providing technical support including the preparation of environmental documents for permitting. I also manage the implementation of project requirements, permit conditions, and mitigation activities before, during, and after construction.

My previous experience includes working as a Natural Resources Environmental Specialist with SDG&E, performing many of the same duties listed above. Prior to working for SDG&E, I worked as an environmental consultant with an independent environmental consulting firm. My primary responsibilities included managing the biological construction monitoring of multiple large transmission projects for SDG&E, including multiple Wood to Steel Replacement projects and the Sunrise Powerlink line. My duties also included the allocation and management of staff and resources, budget management and invoice preparation, threatened and endangered species surveys, biological assessments, reconnaissance level surveys, focused plant/animal/bird surveys, presence/absence surveys, habitat assessments, and report preparation and production.

I have not previously testified before the Commission in a proceeding.

DEBORAH SCHAFER.

My name is Deborah Schafer and my business address is 4940 Carlsbad Blvd., Carlsbad, California 92058. I am a Senior Environmental Specialist at San Diego Gas & Electric (SDG&E) and have been employed with SDG&E for 8 years. My duties as a Senior Environmental Specialist include reviewing documents and providing support within the field of natural science as it directly relates to existing and proposed gas and electric transmission and distribution facilities within the SDG&E service territory. Technical support is provided in the preparation of environmental documents for permitting under NEPA, CEQA, ESA and CESA. Overall support includes the facilitation of training for SDG&E employees as required by the SDG&E's Habitat Conservation Plan, the management of contract biologists and their associated field work and report writing, as well as the implementation of project requirements, permit conditions, and mitigation as it specifically relates to project impacts.

Prior to working for SDG&E, I worked as an environmental consultant with an independent environmental consulting firm for 8 years. My primary responsibilities included conducting a variety of biological surveys for utilities, researching, preparing and producing biological documents and training slides, monitoring construction, as well as managing staff biologists with similar responsibilities. My duties also included budget management and invoice preparation. I hold a Bachelor of Science in Natural Resources from Humboldt State University.

I have not previously testified before the Commission in a proceeding.

Attachment 42

CONFIDENTIAL

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Attachment 43

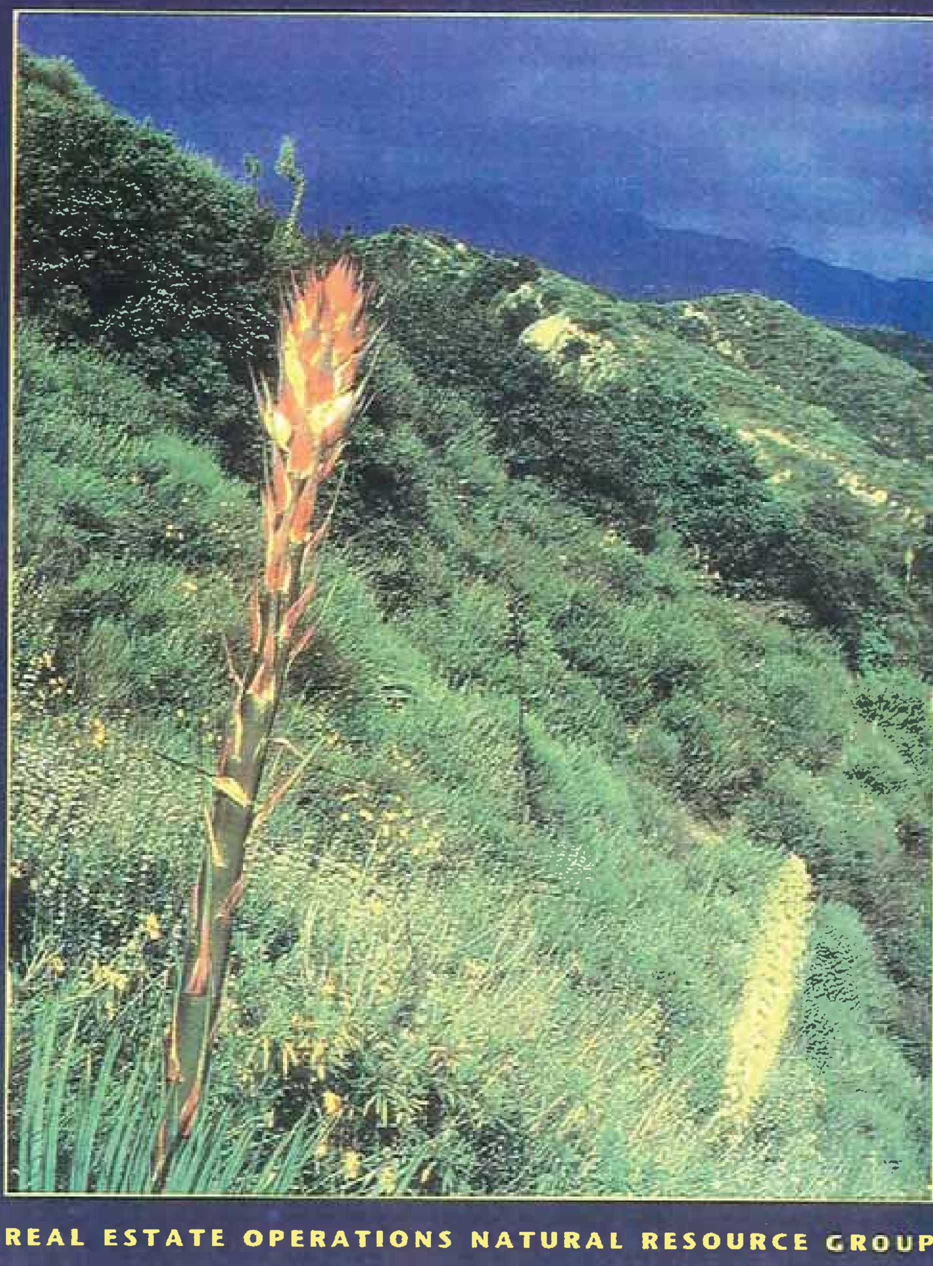
Chattel Report

Attachment 44

Subregional Natural Community Conservation Plan

SDGE
An Enova Company

Subregional Natural Community Conservation Plan



REAL ESTATE OPERATIONS NATURAL RESOURCE GROUP

San Diego Gas & Electric Company

Subregional Natural Community Conservation Plan

Prepared By:
San Diego Gas & Electric
Real Estate Operations Department
Last Edited: December 15, 1995

Cover photo courtesy of Mike Couffer

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Subregional Natural Community Conservation Plan

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San Diego Gas & Electric
P.O. BOX 1831 • SAN DIEGO, CA 92112-4150 • 619 / 696-2000

October 1995

FILE NO.

TO: READERS OF THIS DOCUMENT

There are many things that make San Diego a unique and desirable place to live: the weather, the topography, its proximity to Mexico, the beaches, the ocean, and its diverse environmental resources. Each of these things contribute to a quality of life that draws people to this region. SDG&E shares the belief with many San Diegans that growth should not result in destruction of the very qualities that make this community a desirable place to live. SDG&E also believes that our quality of life can be preserved while still providing opportunities for economic growth.

In recent years, protection of this region's environmental quality has become a major planning issue stimulating ballot initiatives, open space/preservation plans, and protective species "listings" under the State and Federal Endangered Species Acts. It has become apparent that environmental protection is a major public concern and will be with us for some time. SDG&E has recognized the importance of Environmental Protection and Enhancement by weighing it equally in our Corporate Goals to Quality Customer Service. The Company is standing behind our Environmental Protection and Enhancement goal by changing our maintenance and construction methods, by participating directly on all of the NCCP plans in the region, by making financial contributions to said plans, and by preparing this Subregional Plan that not only provides up front mitigation for future activities, but also allows the use of SDG&E's network of rights-of-way and other lands for conservation and preservation.

The primary purpose and ultimate objective of this Subregional Plan is not just to reduce regulatory hurdles, but to make a positive contribution toward the preservation and enhancement of San Diego's natural resources. This plan should be reviewed and evaluated by you, the reader, with that stated purpose and objective in mind. We, at the Company, feel that this Subregional Plan can fulfill our environmental objectives and still be good for business.

Sincerely,
San Diego Gas & Electric

Don L. Rose
Project Manager
Real Estate Management and Planning Section

EXECUTIVE SUMMARY

Background

With the proposed listing of the California Gnatcatcher, as a threatened species, the Endangered Species Act (ESA) suddenly became a significant constraint to all forms of development in southern California including the development of energy infrastructure. The State responded by using the recently legislated Natural Community Conservation Planning (NCCP) program as a tool to work with local communities to develop habitat conservation strategies to protect a wide variety of plants and animals which included the Gnatcatcher's coastal sage scrub habitat. One of the goals of the NCCP is to eliminate the need for future listings. The NCCP also allows for localized administration of the federal ESA and the California ESA (CESA) if certain steps are followed including the preparation of habitat conservation plans pursuant to the ESA and the NCCP.

San Diego Gas & Electric (SDG&E) saw the potential benefits offered by the NCCP to the region's resources and to the Company's ability to reduce regulatory processes typically involved with the maintenance and expansion of a gas and electric energy system. Therefore, the Company launched into preparation of its subregional habitat conservation plan also known as the 50-Year Permit. When approved, the Plan will provide for 25 years of ESA & CESA approvals with renewals to 50 years and possibly beyond.

Provision of the Plan

The Plan covers the following activities, as well as, estimates and defines the mitigation which may be required for the biological impacts of the installation, use, maintenance, and repair of the existing gas and electric system and typical expansions to that system. These activities are required to provide adequate, reliable, and safe service to existing customers and to meet the demands of new growth. The Plan does not cover extraordinary expansions to SDG&E's gas and electric system. The Plan also covers biological impacts (within the boundaries of the Plan area only), associated with new electric transmission lines including interconnections that do not project more that 30 miles outside of SDG&E's service territory, Rainbow to Santee natural gas transmission pipeline, new gas transmission lines under 30" in diameter and less than 20 miles in length, new substations and regulator stations with habitat impacts under 20 acres, and new natural gas compressor stations with habitat impacts under 10 acres. Projects not covered by the Plan will be evaluated on a case-by-case basis, but will be evaluated by the standards set forth in this plan.

Since the future cannot be accurately predicted, the Plan allows for up to 400 acres of impacts in natural areas before requiring a Plan amendment. However, based on current technology, construction methods and standards, population forecasts, and local agency General Plans, the Plan anticipates only 124 acres of grading impacts in natural areas as a result of typical expansion and maintenance activities over the next 25 years (areas which are "natural" are not paved and do not contain ornamental landscaping or otherwise urbanized uses). Impacted areas may be home to one or more of the 110 species covered by this Plan. To mitigate these impacts, the Plan provides the following forms of mitigation:

- The most important mitigation measure is avoidance of impacts whenever possible. To accomplish this, new Operational Protocols for working in the field were developed. There are 61 protocols, all listed in Chapter 7 of the Plan. In addition, field crews attend a series of on-going classes on how to behave and operate construction and maintenance equipment in environmentally sensitive areas.

- Certain fee-owned rights-of-way will be available for use as wildlife corridors in order to connect the region's conservation areas. SDG&E will also allow the use of certain rights-of-way held in easements for such corridors with the consent of the underlying land owner.

- Mitigation Credits of approximately 240 acres will be established upon commencement of the Subregional Plan. The bank will be debited to mitigate for actual impacts as projects are realized. The wildlife agencies will determine the extent and quality of any impact. If needed, the Mitigation Credits will be replenished.

- Restoration and enhancement are also available as mitigation measures, sometimes instead of debits to the Mitigation Credits, and other times in addition to such debits. Restoration will be used in some cases regardless of other forms of mitigation.

The benefits to SDG&E are that the permit processing typically required by the ESA & CESA will not be required. However, the wildlife agencies will still monitor projects, evaluate impacts, and prescribe mitigation in a much more time-efficient process. The Plan sets up a framework for the wildlife agencies to fulfill their regulatory responsibilities in an efficient manner and provides SDG&E with certainty over required mitigation.

Purpose of this Agreement is to Clarify the Vernal Pool Mitigation Measures of the Subregional Plan

SDG&E Subregional Plan – Clarification Document

1. Add to existing page vii of **Executive Summary**, before the section entitled Not Provided For:

A. In 2004, SDG&E amended its NCCP/HCP, which was originally approved in 1995, to incorporate minor modifications reflecting the Company's evolving approaches to resource management policy changes and the Company's many years of experience implementing the plan and permit. These changes are summarized as follows:

SDG&E and the Wildlife Agencies have developed a "vernal pool clarification" for provisions of the NCCP/HCP which provides a basis for SDG&E to carry out a range of utility activities without delay or disruption. This protocol addresses vernal pool resources located both on and off SDG&E access roads and establishes clear standards for avoidance, minimization, and mitigation of permanent and temporary impacts. As a result of these protocols, SDG&E and the Wildlife Agencies anticipate that SDG&E operations and maintenance activities, and the use of existing access roads associated with system expansion, development of new projects, and emergency repairs can be undertaken without the need for case-by-case analysis by, or negotiations with, the Service and/or the Department.

DEFINITIONS

Vernal Pool: A Vernal Pool is defined herein as consisting of both (1) the vernal pool basin, or ponding area, which provides the maximum area of ponded water (i.e., the inundation area when the pool is full), plus (2) the vernal pool watershed, which is the area surrounding the basin that provides sufficient hydrology to allow complete filling of the vernal pool basin in an average rainfall year.

Vernal Pool Basin (Ponding Area): The maximum area of vernal pool inundation, extending to and including the uppermost margins of the pool area that holds water when a pool is full (i.e., the ponding area itself exclusive of the surrounding watershed).

Vernal Pool Watershed: The area surrounding a vernal pool basin that provides sufficient hydrology, including adequate surface area and micro-topography, to enable complete filling of a vernal pool basin in an average rainfall year.

Vernal Pool Management Plan: A plan that provides a practical framework with specific management measures for restoring, enhancing, protecting, and maintaining vernal pool resources. The management plan shall include goals/objectives; methodology; success criteria and standards, including the control of invasive species which could threaten long-term persistence of the vernal pools; timelines; a minimum five year monitoring component (not to exceed seven years with at least one year in which the pool completely fills) to document the stability of populations and judge the success of restoration actions and the effectiveness of management practices; and a process and funding mechanism for managing adaptively, and in perpetuity, vernal pool habitat.

KEY ELEMENTS

The protocol set forth in this clarification document reinforces SDG&E's commitment to avoid permanent impacts to all vernal pools during construction of new facilities and confirms the assurance of the Wildlife Agencies that impacts to on – and off-road vernal pools associated with SDG&E operations and maintenance activities will be authorized. Furthermore, the Wildlife Agencies deem that the mitigation measures described in this protocol are consistent with the Subregional Plan.

- Under the SDG&E Subregional Plan impacts to vernal pools will be avoided during construction of new facilities, and new access roads, throughout the area covered by the Plan. Impacts to vernal pools related to other covered activities are authorized, including operations and maintenance activities occurring within and outside the footprint of existing access roads; use of existing access roads to support system expansion; and emergency repairs. In such cases, SDG&E will:

    1. Avoid impacts to the maximum extent practicable, including rerouting existing access roads when feasible.
    2. If avoidance of all impacts to vernal pools is not practicable, SDG&E will minimize impacts by implementing the measures described in this Clarification Document (Section 7.1.11).

- During operations and maintenance activities occurring outside the footprint of existing access roads, permanent and temporary impacts may occur. Permanent and temporary impacts to those vernal pools will be minimized and mitigated.

- Vernal pool surveys to determine if covered species are present or absent will not be conducted. During operations and maintenance activities occurring within and outside the footprint of existing access roads, permanent impacts will be mitigated at a 3:1 ratio. At SDG&E's discretion, some access roads containing road rut vernal pools will be graded on an as needed basis; other roads will be maintained on a regularly scheduled basis.

- Mitigation may be satisfied through either on-site restoration of vernal pools or the use of areas pre-approved by the Wildlife Agencies. Mitigation credits, as approved by the Wildlife Agencies, may be accumulated and used through advance creation, restoration, and enhancement of vernal pool basin area. The areas pre-approved by the Wildlife Agencies for creation, restoration, and/or enhancement of vernal pool basin area will be of high quality (e.g., Carmel Mesa and Otay Mesa) and will support species covered by the Plan. Pre-approved vernal pool mitigation areas must be managed and monitored pursuant to a Management Plan approved by the Wildlife Agencies.

2. Add the words "VERNAL POOLS" to the descriptive text in the bottom sketch in Figure 4. Add new drawings to Figure 4 that assist SDG&E in avoiding impacts to the pools. *SDG&E to provide.*

IX. Vernal Pools

This vernal pool protocol reinforces SDG&E's commitment to avoid permanent impacts to all vernal pools during construction of new facilities and new access roads, and confirms the assurance by the Wildlife Agencies that impacts to all vernal pools associated with SDG&E operations and maintenance activities are authorized under the Subregional Plan. Furthermore, the Wildlife Agencies deem that the mitigation measures described in this protocol are consistent with the Subregional Plan.

SDG&E intends to avoid impacts to vernal pools during new construction. During operations and maintenance activities occurring outside the footprint of existing access roads, permanent and temporary impacts may occur provided that they are mitigated consistent with this clarification document. Temporary and permanent impacts will be minimized. During operations and maintenance activities occurring within existing access roads, which may include grading and/or crowning of those roads, permanent impacts may occur. At SDG&E's discretion, some access roads containing vernal pools will be graded on an as needed basis; other roads will be maintained on a regularly scheduled basis.

Other than pre-activity surveys, no vernal pool surveys will be conducted to determine presence or absence of covered species. Mitigation for permanent impacts will be fixed at a 3:1 ratio for all impacts.

When required, mitigation may be satisfied through either on-site restoration of vernal pools or the use of areas pre-approved by the Wildlife Agencies. Mitigation credits, as approved by the Wildlife Agencies, may be accumulated and used through advance creation, restoration, and enhancement of vernal pool basin area. The areas pre-approved by the Wildlife Agencies for creation, restoration, and/or enhancement of vernal pool basin area will be of high quality (e.g., Carmel Mesa and Otay Mesa) and will support species covered by the Plan. Pre-approved vernal pool mitigation areas must be managed and monitored pursuant to a Management Plan approved by the Wildlife Agencies.

In the event that SDG&E Activities impact vernal pools, the following mitigation measures will be implemented:

Temporary Impacts

Off Road

SDG&E Activities, such as but not limited to, placement of structures, insetting poles, poles anchors and stubs, and underground facility access may have temporary impacts on off road vernal pools (Chapter 2, Proposed Activities, provides a complete list of SDG&E Activities). In those cases, SDG&E will restore those pools pursuant to the following protocols:

1. Seed from vernal pool indicator plants shall be collected from the pools that will be impacted when the plants have dried and before the seed disperses, and scattered in the affected vernal pool when the SDG&E Activity is completed. Seed collection may not be possible when precluded by weather or physical constraints, such as the Activity occurring at a time of year when no seed is present. If SDG&E needs to work in vernal pool areas under wet conditions, vehicular and foot traffic will be directed away from the pools. If vehicular and foot traffic cannot be directed away from the pools due to construction requirements, other impact minimization measures shall be used, such as the installation of steel plates or fabric mats. A qualified biologist will be present to ensure that all minimization measures are implemented.

2. Vernal pool *inoculum* shall be collected only when it is dry to avoid damaging or destroying fairy shrimp cysts. A hand trowel or similar instrument should be used to collect the sediment. Soil should be collected in chunks. Once the Activity is completed, the sediment will be replaced in the bottom of the disturbed pool.

3. If seed has been scattered and/or *inoculum* sediment has been replaced, a qualified biologist will monitor the vernal pool for successful restoration, for two subsequent wet seasons. Successful restoration will be determined/defined as the continued presence of vernal pool species (or threatened/endangered species if present) roughly comparable to the pre-disturbance condition. Furthermore, covered species identified in the pre-activity survey must be observed to fully mature, with fairy shrimp producing cysts and plant species producing seed. Unsuccessful restoration will be considered a permanent impact and will be mitigated at a 3:1 ratio at a pre-approved vernal pool mitigation area. If measures 1 and 2 above cannot be implemented, mitigation will occur at the pre-approved vernal pool mitigation area at a 3:1 ratio.

Within Road

During new construction activities, if vehicular traffic cannot be directed away from vernal pools due to construction requirements, impact minimization measures shall be used, such as the installation of steel plates or fabric mats. A qualified biologist will be present to ensure that all minimization measures are implemented.

Permanent Impacts

SDG&E Activities, such as, but not limited to road maintenance may have unavoidable permanent impacts on vernal pools (Chapter 2, Proposed Activities, provides a complete list of SDG&E Activities). To mitigate for those impacts, SDG&E will undertake the following measures:

1. Restoration Reporting[1] - If SDG&E does not mitigate at a pre-approved vernal pool restoration area, then Wildlife Agencies' concurrence on an acceptable mitigation site is required prior to any impacts to vernal pools. Recognizing that restoration efforts may vary somewhat, SDG&E shall prepare a vernal pool restoration plan for each Activity based on a generalized approach for vernal pool restoration, with which the Wildlife Agencies have previously concurred (Refer to Attachment 1). If further refinements to this generalized approach are necessary on a case-by-case basis, the Wildlife Agencies will respond to the restoration plan within 30 days. If the Wildlife Agencies do not comment within 30 days, SDG&E will proceed with its proposed Activities.

2. Mitigation Ratio – Impacts to vernal pools, with or without Covered Species present, will be mitigated at a 3:1 ratio for all impacts. Mitigation may occur onsite provided that a sufficient number of degraded pools exist in the vicinity and have been approved by the Wildlife Agencies for restoration and /or enhancement. Otherwise, mitigation will be implemented offsite at the pre-approved vernal pool restoration area. Mitigation credits, as approved by the Wildlife Agencies, may be accumulated and used through advance creation, restoration, and enhancement of vernal pool basin area. The areas pre-approved by the Wildlife Agencies for creation, restoration, and/or enhancement of vernal pool basin area will be of high quality (e.g., Carmel Mesa and Otay Mesa) and will support species covered by the Plan. Pre-approved vernal pool mitigation areas must be managed and monitored pursuant to a Management Plan approved by the Wildlife Agencies.

SDG&E may relocate an existing access road to minimize potential impacts to vernal pools. This rerouting would only be done if it was possible without compromising operational integrity and safety. The mitigation value of the rerouted road would be at

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[1] Restoration of degraded vernal pools on a pre-approved restoration area is considered appropriate as mitigation for permanent impacts. Steps will be implemented to ensure that hydrologic function is not significantly impaired.

1:1 level.[2] Under such circumstances, the mitigation requirement for impacts to vernal pools, with or without Covered Species present, will be the net of the total new impacts to vernal pools or pool complexes less the vernal pools or complexes being avoided within the existing roadway. The net impact will be mitigated at the pre-approved vernal pool mitigation area at a 2:1 ratio at least 1:1 ratio of which is creation.

Impacts to vernal pools with or without Covered Species present that occur on military lands will be mitigated at a pre-approved vernal pool mitigation area at a 3:1 ratio.

Monitoring and Reporting

Restoration of temporary impacts to vernal pools shall be accomplished by a qualified ecologist/biologist and managed (including monitoring) for two subsequent wet seasons.

Restoration for permanent impacts to vernal pools shall be accomplished by a qualified ecologist/biologist and managed and monitored for a minimum of five years, but not to exceed seven years with at least one year in which the pool completely fills.

SDG&E's Subregional Plan Annual Report will include a vernal pool section that tracks and reports the amount and type (temporary or permanent) of impacts to vernal pools, and reports the status of restoration/enhancement efforts.

4. Add new Avoidance and Minimization protocols to Chapter 7.1 as a new Section 7.1.11 Vernal Pool Complexes:

Avoidance and Minimization Measures:

62. SDG&E will avoid permanent impacts to vernal pools in the construction of all new Facilities, including new access roads, throughout the area covered by this Plan.

63. If the Wildlife Agencies recommend relocation of an access road that bisects a vernal pool area, SDG&E will take into account cost and operational considerations and determine within 30 days whether to relocate the road. When roads are relocated to avoid vernal pools, the realigned road will be clearly demarcated and barriers will be placed to prevent vehicle access on the old road.

64. For all construction activities occurring adjacent to vernal pools, SDG&E will work with a qualified biologist having local experience with vernal pool resources, to site roads or facilities in a manner that avoids potential impacts to vernal pools. (See Figure 4.) All vernal pools adjacent to the project footprint, plus a five-foot buffer (where feasible), will be fenced with orange safety fencing to ensure no people or equipment impact the vernal pools during construction activities. A silt fence will be installed along the base of the roadway to prevent

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[2] This language is consistent with and replaces paragraph 2 of Article IX Vernal Pools of the Subregional Plan.

increased erosion or sedimentation during construction in vernal pool areas. Gravel bags will be placed along the bottom of the fence to minimize erosion or sedimentation into vernal pools, and removed upon completion of construction.

65. During operations and maintenance activities occurring within the footprint of existing access roads, which may include grading and/or crowning of those roads, permanent impacts to vernal pools may occur. To prevent water from ponding on existing access roads, SDG&E will grade and crown roads using a grader. Other mechanisms may be employed that achieve the same result. Thereafter, the roads will be maintained on a regular basis as determined by SDG&E, to prevent future ponding, thereby minimizing native plant and animal species from becoming established. Roads in vernal pool complex areas within MCAS Miramar and the Torrey Hills, Otay Mesa, Carmel Mesa, Del Mar Mesa, and Tierrasanta communities in the City of San Diego may be less frequently graded to preserve habitat value, but will be graded as needed to preserve safe and reliable access to SDG&E facilities.

66. During modifications and maintenance of existing access roads, or the creation of new access roads adjacent to vernal pools, a qualified biological monitor, having local experience with vernal pool resources, shall oversee and monitor all such activities occurring adjacent to vernal pools. The biological monitor shall:

    - Hold a pre-construction meeting to brief the crew on the location of sensitive resources and construction boundaries.
    - Direct installation of protective fencing to prevent encroachment of people or equipment into vernal pools during construction activities and to ensure that no fence posts are placed within vernal pools.
    - If it is not feasible to place protective fencing without impacting vernal pools, during the dry season sandbags will be placed along the perimeter of the vernal pool and removed post-construction (or prior to the on-set of the wet season).

    An environmental surveyor will ensure that fencing to protect vernal pools is appropriately placed and is maintained in good condition for the duration of the project. (See Figure 4.)

67. When vernal pools are located above gas lines and repair work is necessary, work areas will be minimized and soil will be stockpiled for replacement after repairs.

68. During construction of new facilities, including access roads adjacent to vernal pools, a biological monitor will document all accidental or unanticipated impacts to vernal pools. The impacts will be provided to the Wildlife Agencies in a post-construction report with 30 days of project completion.

69. To the extent feasible, all construction equipment shall be fueled and maintained at least 100 feet from the nearest vernal pools.

SDG&E NCCP/HCP SUBREGIONAL PLAN

VERNAL POOL CLARIFICATION

This signature page is attached to the Final Vernal Pool Clarification document to identify that the Vernal Pool Clarification approved on May 26, 2004 by the United States Fish & Wildlife Service and California Department of Fish and Game shall be applied to SDG&E projects that have the potential to impact vernal pools within the Subregional Plan Area.

Date 7/26/04

Therese O'Rourke, Assistant Field Supervisor
U.S. Fish & Wildlife Service
Carlsbad Fish & Wildlife Office

Gail Presley Date 7/23/04

Gail Presley, Conservation Planning Program Manager
California Department of Fish and Game

Donald E. Haines Date 7/21/2004

Donald E. Haines
SDG&E
Manager, Land Planning & Natural Resources

Not Provided For

Projects which are currently subject to permits from the California Public Utility Commission (CPUC), Coastal Commission, Energy Commission, State Lands Commission and several other state and federal agencies will continue to be. Therefore, many projects will be subject to the California Environmental Quality Act & National Environmental Policy Act reviews. It is intended that the subsequent environmental reviews use this Plan to evaluate the impacts to covered species and their habitats.

1 Introduction

San Diego Gas & Electric Company (SDG&E) is a California public utility providing natural gas, electric, and other services to customers within its service territory, which includes San Diego County and portions of Orange and Riverside Counties. SDG&E's ability to provide these services depends upon the installation, operation, maintenance and repair of an evolving array of public utility facilities located throughout its service territory and, to a limited extent, beyond. For example, SDG&E's electric and natural gas service is provided by means of two essentially separate systems. The electric system includes steam electric generating plants, electric transmission lines, electric substations, and an electric distribution network (See Figure 1). The natural gas system includes compressor stations, transmission pipelines, regulator stations and distribution pipelines (See Figure 2). Regular maintenance and repair of these systems is performed to prolong their useful life and to ensure adequate, safe, and reliable service. The location and type of new Facilities is dependent upon the service demands of SDG&E's customers load centers while existing Facilities are not. However, both are subject to the regulatory authority and requirements of the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and various other federal and state agencies.

Over the past several years, the natural lands and wildlife habitats in San Diego County, Orange County, and Riverside County (Moreno Compressor Station only), have been subjected to increasing pressures from various land development activities. The Natural Community Conservation Planning Act (NCCP), authorizing comprehensive management and conservation of habitat and multiple wildlife species, is California's response to the ever increasing numbers of species protected and being considered for protection under the state and federal endangered species acts. In recognizing the need to develop a comprehensive management plan for the sensitive biological resources of the region, agency wildlife biologists, consulting and research biologists, landowners, businesses, and representatives of conservation groups have proposed a conservation strategy which includes the establishment of a habitat preserve system intended to ensure long-term habitat survival and individual species viability.

SDG&E's Activities may impact certain sensitive plant and animal species or their habitat which may include species listed as threatened or endangered by the United States Endangered Species Act (ESA) or the California Endangered Species Act (CESA). To ensure implementation of appropriate avoidance, minimization, or mitigation measures for these potential impacts, SDG&E has prepared this Subregional Plan following the multiple species and habitat conservation planning approach authorized by ESA and the California NCCP. The intent of this Subregional Plan is to identify SDG&E's existing and prospective Activities as a public utility which may have an impact upon Covered Species or their habitat and to define those measures SDG&E will employ to avoid, minimize or mitigate any such impacts. SDG&E's plan is a significant part of the overall regional conservation planning strategy for two reasons: 1) It will provide a net improvement in habitat values by providing foundational resources for the establishment of connecting corridors between habitat preserves; and 2) It can be used for other regional public service providers as a model.

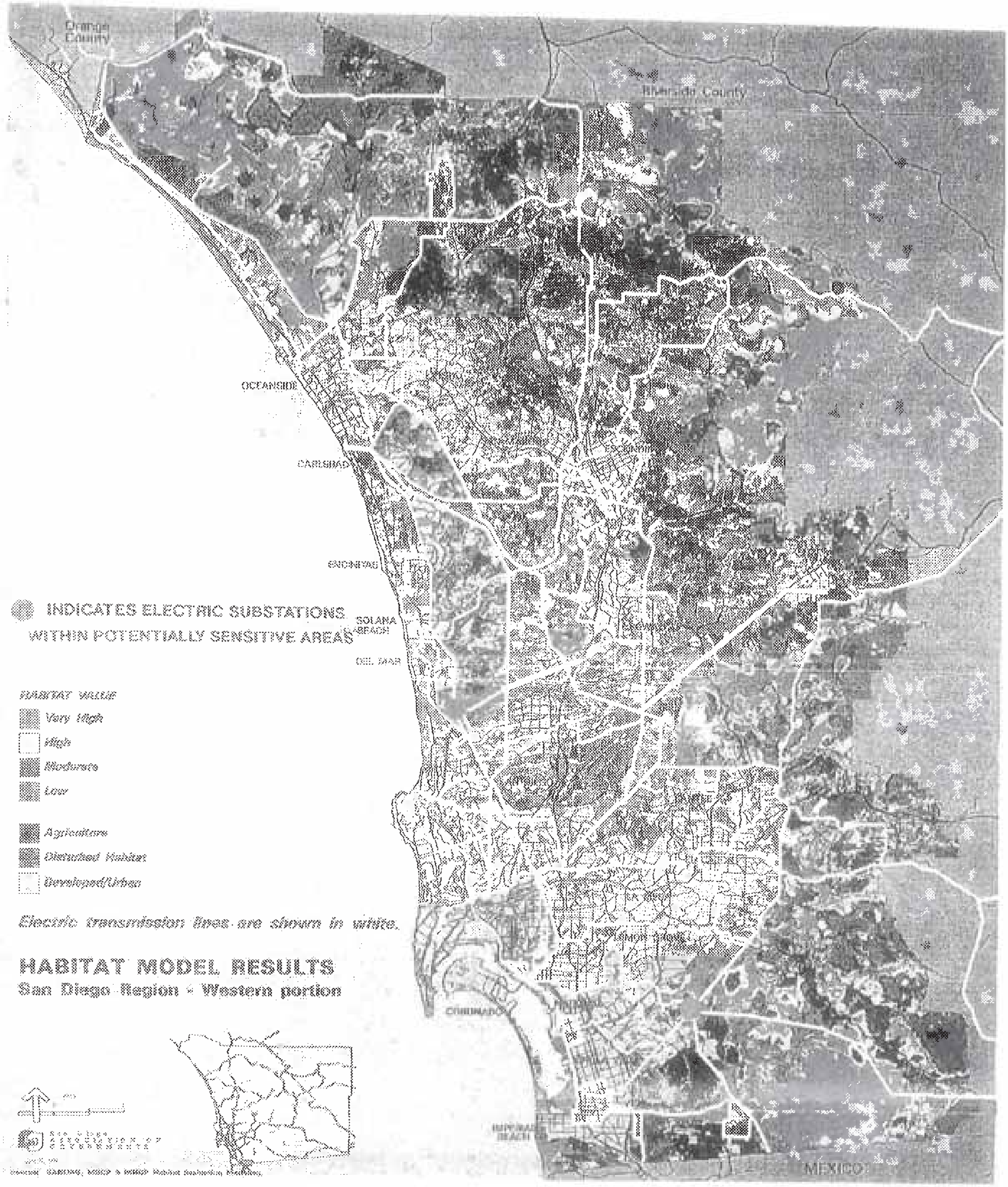
Over the last several years, a number of local governments have been working to develop comprehensive habitat and multi-species conservation plans within the boundaries of their respective jurisdictions, generally referred to as "Habitat Conservation Plans." Ultimately, a network of such plans will be implemented throughout much of the area which is or which may be affected by SDG&E's operations and covered by SDG&E's Subregional Plan (See Figure 3). Both SDG&E's Subregional Plan and the Habitat Conservation Plans will maximize the protection and conservation of wildlife and habitat by utilizing the comprehensive multi-species and habitat conservation approach. However, unlike the Subregional Plan, Habitat Conservation Plans otherwise address the unique municipal concerns of local government: local government's interest in local land development and other land use activities with federal and state wildlife conservation mandates.

In contrast, SDG&E's public utility operations and service span the jurisdictional boundaries of a large number of local governments and provide benefits to the State as a whole. SDG&E's operations as a public utility are, therefore, matters of statewide concern. To ensure uniform, adequate, safe, and reliable operations for the benefit of the State's citizens, SDG&E's operations are regulated at the state level primarily by the CPUC but also by various other state agencies, rather than at the local level. Accordingly, this Subregional Plan balances SDG&E's Activities necessary to meet the continuing and growing demands of its customers for electric and gas service with federal and state wildlife conservation mandates.

The applicability of Habitat Conservation Plans will be triggered by local permit applications filed by persons seeking to pursue projects falling within the regulatory authority of such local governments. However, because SDG&E's projects do not fall within the regulatory authority of local governments, none of the underlying Habitat Conservation Plans will be suitable to address the particular and unique issues raised by public utilities. SDG&E has resolved this problem by developing this Subregional Plan in coordination with the United States Fish and Wildlife Service (USFWS) and California Department of Fish & Game (CDFG) addressing SDG&E's activities and their potential impact upon Covered Species or their habitat throughout the area of its operations.

This Subregional Plan will cover all of SDG&E's Activities conducted within the area described in Figure 3 (Subregional Plan Area), and will function independently of the Habitat Conservation Plans of local governments, which may also cover any part of the Subregional Plan Area. This Subregional Plan takes into consideration the objectives of such local Habitat Conservation Plans and coordinates the implementation of this Subregional Plan with the proper functioning of such local Habitat Conservation Plans, as they become effective, to maximize the benefits to Covered Species and their habitat. This Subregional Plan will describe SDG&E's Activities that have the potential to impact Covered Species or their habitat and which will be subject to the provisions of this Subregional Plan. The nature and extent of such potential impacts will be identified together with those protective and conservation measures SDG&E will undertake to avoid such impacts and, where impacts are unavoidable, to minimize and mitigate the same. Protective and conservation measures will include (a) the implementation of Operational Protocols established in coordination with USFWS and CDFG, (b) assisting USFWS and CDFG to establish wildlife corridors which interconnect one habitat preserve or wildlife conservation area to another utilizing certain rights-of-way, and (c) by causing the conveyance of valuable habitat land to a wildlife management agency for conservation purposes.

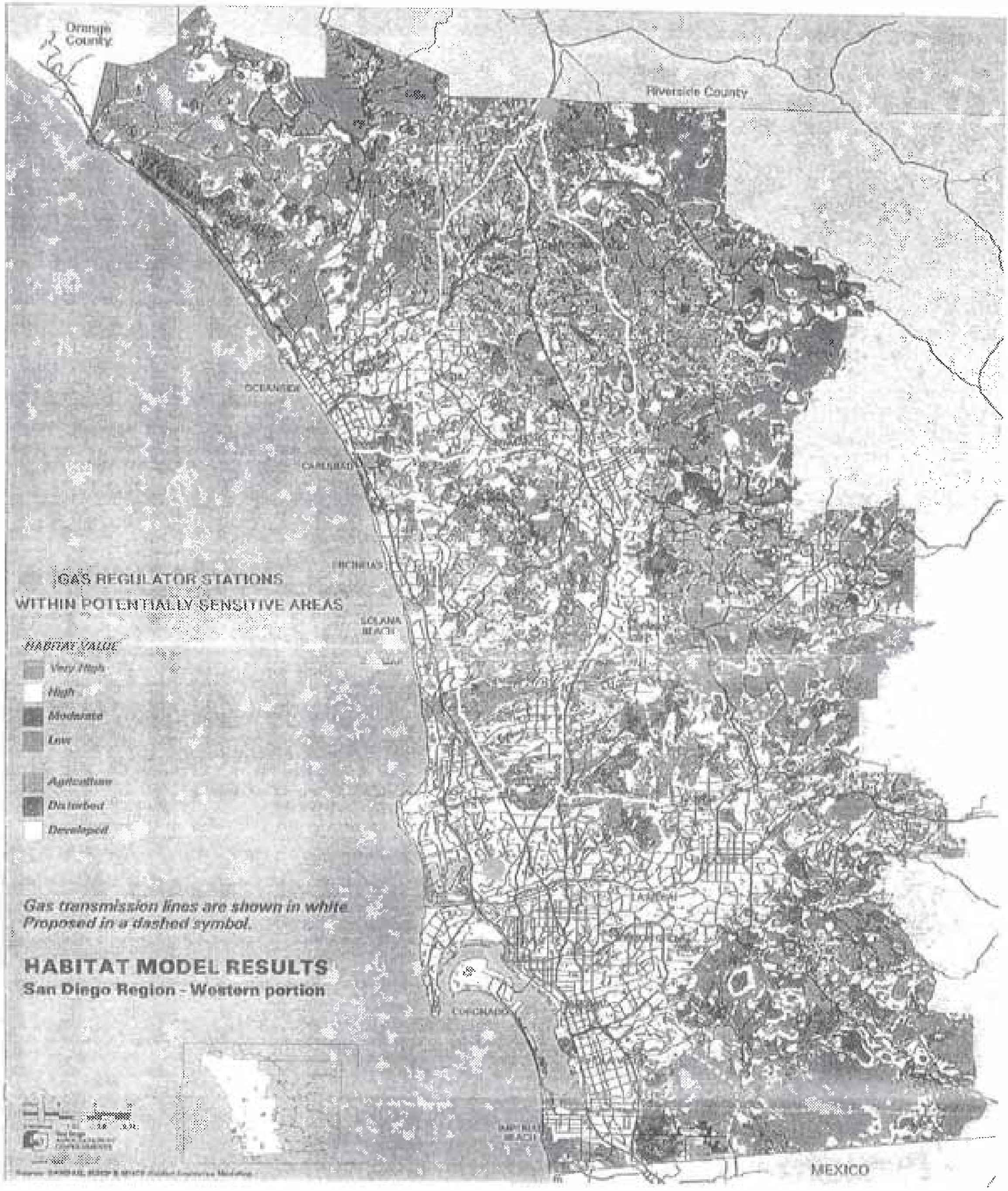
SDG&E, USFWS, and CDFG have, concurrent with the effective date of this Subregional Plan, entered into a long term Implementing Agreement which describes the legal rights and obligations of such parties regarding the implementation and maintenance of this Subregional Plan. The Implementing Agreement authorizes SDG&E to conduct its Activities within the Subregional Plan Area provided the same are performed in conformity with this Subregional Plan. Such authorizations are memorialized in permits issued by USFWS and CDFG, pursuant to ESA, CESA and NCCP. Such permits authorize SDG&E Activities and any resulting Incidental Take of Covered Species or impact to their habitat. The Subregional Plan and the Implementing Agreement can be amended to permit the addition of areas within which SDG&E conducts its operations and which are not yet covered by the Subregional Plan, such as the desert regions. Finally, the Implementing Agreement will provide assurances by USFWS and CDFG that, absent Unforeseen Circumstances, the terms and conditions of SDG&E's Activities authorization and Permits including, but not limited to, the required mitigation measures, will not change during the term of the Implementing Agreement. The long term duration and constancy of the Implementing Agreement and, therefore, of this Subregional Plan benefit SDG&E both by streamlining the permit process, enabling the early and efficient planning of avoidance and mitigation measures in project design, and by implementing a more cost-effective approach to wildlife conservation. Covered Species and their habitat will derive long term benefits from the implementation of the Subregional Plan.



SDG&E ELECTRIC FACILITIES IN ORANGE COUNTY ARE SHOWN ON FIGURE 9

SDG&E Electric Transmission System

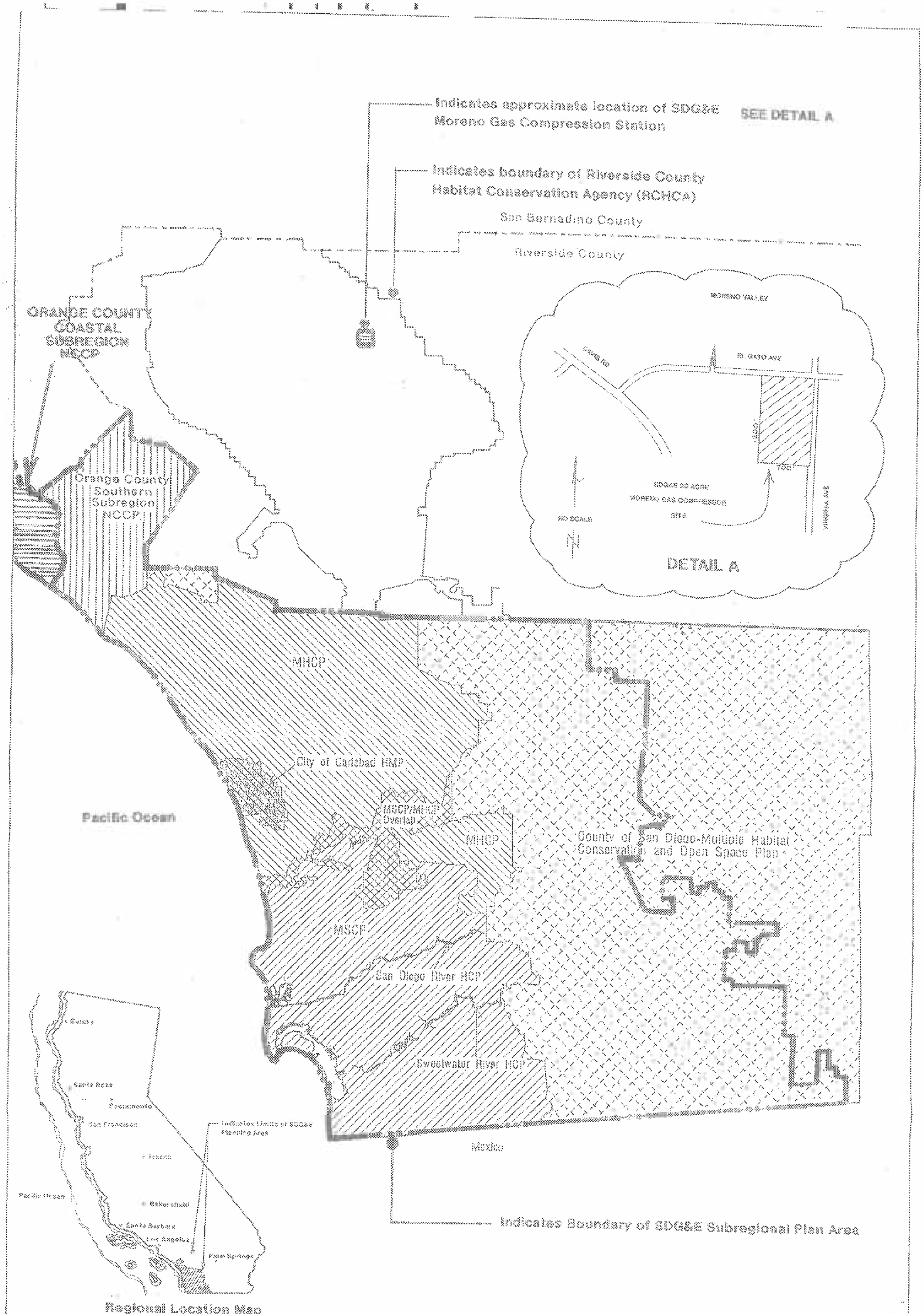
FIGURE 1



SDG&E GAS FACILITIES IN RIVERSIDE COUNTY ARE SHOWN ON FIGURE 10

SDG&E Natural Gas Transmission System

FIGURE 2



SDG&E Subregional Plan Area

Military Lands Contained Within This NCCP Are Treated Separately From NCCP Management Plans

FIGURE 3

1.1 Purpose

The purpose of this Subregional Plan is to establish and implement a long term agreement between SDG&E, USFWS and CDFG for the preservation and conservation of Covered Species and their habitat, while allowing SDG&E to develop, install, maintain, operate, and repair its Facilities which are or become necessary to provide electric, natural gas and other Services to the customers served by SDG&E within the Subregional Plan Area.

Because of the evolving and continuing nature of SDG&E's operations within the Subregional Plan Area, SDG&E, USFWS and CDFG have determined that a comprehensive multiple species and habitat conservation plan under ESA Section 10(a) and NCCP will most effectively preserve and enhance Covered Species and their native habitats. The long term multi species and habitat planning approach avoids the less effective, less efficient and more costly process of obtaining federal and state Incidental Take permits on a species-by-species, project-by-project basis.

This Subregional Plan is intended to meet the legal prerequisites of USFWS and CDFG for their issuance of ESA and CESA Incidental Take permits for all Covered Species and their habitat. Specifically, this Subregional Plan (a) authorizes the incidental take of listed and other covered species, such take being incidental to the otherwise lawful Activities of SDG&E, (b) minimizes and mitigates the impacts of such incidental take to the maximum extent possible, (c) assures adequate funding for the implementation of this Subregional Plan, (d) authorizes incidental take will not appreciably reduce the likelihood of the survival or recovery of any listed species or candidate species in the wild, (e) imposes measures to be implemented by SDG&E as requirements for or conditions of the authorization and permits granted herein which will be met by

SDG&E, (f) generally satisfies and fulfills all measures required by USFWS as being necessary or appropriate for the purposes of this Subregional Plan, including any measures determined to be necessary by the parties to deal with unforeseen circumstances, (g) will provide for the conservation and protection of Covered Species and their habitat within the Subregional Plan Area, as if each of the species, subspecies, or populations were listed under ESA, and (h) satisfies all legal requirements necessary for CDFG to issue a Management Authorization for Covered Species under Fish & Game Code Sections 2081 and 2835, and NCCP Section 2825.

1.2 Issues

Natural Resource Issues

Impact to Covered Species and their habitat is one of SDG&E's primary environmental concerns associated with its utility operations. The area of Southern California which includes the Subregional Plan Area contains the highest diversity of plant and animal life in the continental United States. As a result of the rapid pace of urbanization in the last half of the twentieth century, SDG&E's Subregional Plan Area also has the highest number of plants and animals in the continental United States which have become protected or are proposed for protection under ESA or CESA.

In the absence of multi-species and habitat conservation guidelines, continued urbanization and other land uses pose significant risks of extirpation or extinction of Covered Species. SDG&E's implementation of standard operating procedures to avoid or minimize impacts to natural resources is a major focus of this plan.

Land Use Issues

Several profound differences exist between the nature and extent of impacts to Covered Species or their habitat which may be caused by agricultural and typical urban development from those which may be caused by the operation of a gas and electric public utility like SDG&E. Agricultural and urban development usually occur on established parcels of land with generally permanent impacts to Covered Species and their habitat as the same are replaced with the project. Agricultural and urban development occurs in checkerboard fashion over the available land. With some limited exceptions (e.g., the infrequent installation of electrical substations or natural gas regulator stations), most utility projects are linear in nature requiring limited grading; therefore, impacts upon Covered Species and their habitats caused by the operations of an electric and gas public utility like SDG&E are avoided entirely or are only minimal or temporary. The potential exists, however, for slight habitat fragmentation by virtue of the presence of the utility and its access roads which may facilitate unapproved intrusion into an ecosystem.

In addition to San Diego County, southern Orange and Riverside Counties continue to experience strong socio-economic growth pressures, causing equally strong pressures to be exerted on the regional ecosystem's long term viability. Consequently, the following land use and operational issues were examined within the Subregional Plan Area in the preparation of this document:

- Impacts of adjacent land uses, particularly real estate development, on the Covered Species and their habitat which exist in SDG&E's easements and fee-owned rights-of-way and other land holdings.
- Existing conditions in SDG&E's easements and fee-owned rights-of-way and other land-holdings of natural resources and degree of habitat protection and conservation.
- Land use compatibility.
- Coordination with Habitat Conservation Plans.
- SDG&E's Subregional Plan strategies which include avoidance, minimization, mitigation, and plan implementation strategies.
- Impacts to Covered Species from operation & maintenance activities.
- Impacts to Covered Species from new construction.

1.3 Approach

Neither CESA nor ESA had been enacted when much of the SDG&E public utility Facilities were planned and constructed. In 1993, SDG&E cooperated with USFWS and CDFG to develop and implement Operational Protocols designed to avoid impacts to specified species and their habitat. However, certain installation, maintenance, operation and repair Activities could not be modified to avoid an Incidental Take of Listed Species. For these Activities, Incidental Take permits were either sought by SDG&E from USFWS and CDFG through either ESA Section 7 and CESA Section 2090 consultation procedures where the appropriate federal or state nexus occurred, or through the ESA Section 10 or CESA Sections 2081/2084 process.

The protection, preservation and conservation of endangered, threatened, candidate species, and other sensitive species and their habitats under ESA, CESA, NCCP and other wildlife acts on a species-by-species basis has resulted in limited success. For SDG&E, such an approach is far too cumbersome and incomplete to adequately identify and conserve the biological and physical resources upon which each such species is dependent. In fact, the implementation of specific protective measures for one species, in the species-by-species/project-by-project approach, may actually cause deleterious conditions to another species. Habitat Conservation Plans, such as the SDG&E Subregional Plan which incorporates comprehensive protection or conservation measures needed for multiple species and their habitat, will most closely approximate an ecosystem conservation approach. It is intended that the biological and physical resources comprising sensitive habitats (ecosystems) be preserved intact to the greatest extent possible. All species within managed habitats will be afforded greater protections than before.

1.4 Scoping

Applicable Law

Federal

The federal Endangered Species Act (ESA), 15 U.S.C. Section 1531 et seq., provides for the protection and conservation of fish, wildlife and plants which have been listed as threatened or endangered. Activities otherwise prohibited by ESA Section 9 and subject to the civil and criminal enforcement provisions of ESA Section 11 may be authorized for appropriate federal agency action pursuant to ESA Section 7 and for other non-federal actions pursuant to ESA Section 10.

Other federal laws enacted with the intent to protect and conserve Listed Species of fish, wildlife, plants, and their habitats include, but are not limited to, the following:

- The Migratory Bird Treaty Act (including the protective provisions for game and wild birds), The Migratory Bird Conservation Act, and the Migratory Bird Hunting Stamp Act, 16 U.S.C. Section 701 et seq., are intended to protect birds and restore their necessary habitat. Otherwise unlawful activities which may impact such birds or their habitat may be authorized in accordance with applicable regulation, by permit or other entitlement, as appropriate.

- The National Environmental Policy Act, 42 U.S.C. Section 4321 et seq., mandates that federal agencies consider the environmental impacts of their actions, with the intent of avoiding or minimizing any such impact prior to conducting federal projects (including the authorization of private projects).

- The Federal Water Pollution Control Act, 33 U.S.C. Section 1251 et seq., provides for certain protections to wildlife relating to the discharges of pollutants into the waters of the United States.

State

Similarly, the California Endangered Species Act (CESA), California Fish and Game Code, Section 2050 et seq., provides for the protection and conservation of fish, wildlife and plants which have been listed by the State of California as threatened, endangered, or as candidate species. Activities prohibited by Section 2080 and subject to the civil and criminal enforcement provisions of Section 12000 et seq., may be authorized for appropriate state actions pursuant to CESA Section 2090 et seq. and for other persons pursuant to CESA Sections 2081 and 2084.

Other state laws enacted with the intent of protecting and conserving fish, wildlife, plants, and their habitats include, but are not limited to, the following:

- Fish and Wildlife Protection and Conservation, California Fish and Game Code, Section 1600 et seq., requires that state agencies, public utilities, and other persons notify CDFG before conducting any project which may adversely affect aquatic habitats of fish or wildlife.

- Native Plant Protection Act (NPPA), California Fish and Game Code, Section 1900 et seq., is intended to preserve, protect and enhance endangered or rare native plants.

- Natural Community Conservation Planning Act (NCCP), California Fish and Game Code Section 2800 et seq. authorizes agreements between CDFG and any person for the comprehensive management and conservation of habitat and multiple wildlife species and permit, as appropriate, as a part of such plan, the Incidental Taking of Listed Species and candidate species under Sections 2830 and 2835.

- California Environmental Quality Act (CEQA), California Public Resources Code Section 21000 et seq., is intended to require state agencies to consider environmental qualitative factors, including the conservation of fish, wildlife and plant species and the preservation of representations of all plant and animal communities for future generations prior to conducting any project.

Pursuant to ESA Section 10(a), USFWS may issue permits, under such terms and conditions as the Secretary may prescribe, for acts otherwise in violation of ESA Section 9 to enhance the propagation or survival of any affected species or for the taking of any species incidental to an otherwise lawful activity. Further, for threatened species, the Secretary may issue such regulations as necessary to provide for the conservation of such species under ESA Section 4(d). Similarly, CESA Section 2081 enables CDFG to grant management authorization for the take of threatened, endangered or candidate species subject to such terms and conditions as it may prescribe. NCCP authorizes CDFG to enter into agreements with any person to develop and implement a natural community conservation plan to provide comprehensive management and conservation of multiple wildlife species and their habitat. Any such plan may authorize the taking of candidate, threatened or endangered species whose protection and conservation is provided for in any such plan pursuant to NCCP Sections 2830 and 2835.

1.4.2 Coordination

As a result of urbanization, agriculture and other development, the amount of habitat remaining to support Covered Species is rapidly dwindling. The effective protection, preservation and conservation of Covered Species is dependent upon the implementation of effective and properly functioning conservation plans for the habitats and ecosystems essential to the survivability of such species.

Habitat Conservation Plans are now being prepared by various local governments or government entities within the Subregional Plan Area such as the City of San Diego's Multiple Species Conservation Program, San Diego Association of Governments' Multiple Habitat Conservation Program, the County of San Diego's Multiple Habitat Conservation and Open Space Plan, and the South Orange County NCCP Subregional Plan.

Local land development is regulated by local government through enactments of land use, zoning and permitting ordinances pursuant to their police powers derived from the California Constitution. Local Habitat Conservation Plans will be adopted, implemented and enforced pursuant to these same laws. Persons whose development activities fall within the jurisdiction of these local governments will then be authorized to take species/habitats caused by their activities. Local government authority to take species/habitat comes from the issuance of take authorization issued by USFWS and CDFG, pursuant to the State and Federal ESA and the NCCP. Developer compliance will be supervised by local government, USFWS, and CDFG.

SDG&E's land use Activities, the regulation of such Activities, and its Subregional Plan, are unique. The California Constitution, through Article

XII, created and empowered the CPUC with the exclusive jurisdiction to regulate the affairs and operations of public utilities. Pursuant to Section 8 of Article XII, the enactments of local governments which attempt to regulate public utility operations, in matters over which the CPUC has the power to regulate, are invalid.

The CPUC's exclusive jurisdiction to regulate public utilities recognizes the statewide interest in preserving for the benefit of the State's citizens uniform, safe, and reliable utility service. Were the converse true, and if local governments were allowed to regulate the activities of public utilities, public utilities would be subject to a mosaic of divergent local requirements from as many local governments as there are in the Subregional Plan Area. SDG&E serves a statewide interest.

This Subregional Plan and the Habitat Conservation Plans govern different activities and different persons, often in the same area. The identified Activities in the Subregional Plan are regulated by various state agencies, primarily the CPUC, while the activities identified in the Habitat Conservation Plan are subject to local regulation. In effect the Subregional Plan, governing Activities serving a statewide interests, acts as an overlay across areas also covered by Habitat Conservation Plans, thereby governing activities of municipal concern. As a result of the cooperative efforts of various local governments and public bodies within San Diego, Orange, and Riverside Counties, a reserve of habitat is being established which includes reserve core areas, narrow endemic reserves, and connecting corridors. These reserve areas would be managed primarily for listed plants and animals, with a varying goal of maintaining at least 60 - 90% of the natural lands as high quality habitat, depending on the subregional plan and jurisdiction. The corridors are designed to maintain connections between the primary reserves and to support supplemental populations between reserves. This Subregional Plan is designed to be consistent with the local habitat conservation plans and the overall preserve planning effort.

1.4.3 Activities Covered by Plan and Those Requiring Further CEQA/NEPA Coverage

There are two broad categories of activities covered in the Plan: Operation and Maintenance (O&M) and new construction. O&M pertains to existing facilities and does not require permits; therefore, CEQA/NEPA review is also not required. The Plan recognizes that O&M activities can, at times, have impacts. To mitigate for O&M impacts the Plan contains an extensive list of field protocols designed to minimize disturbance to habitat. The company has also committed to allow use of selected transmission rights-of-way for wildlife corridors. This use of rights-of-way for corridors is specifically intended to mitigate O&M activities and nothing else.

New construction may be subject to CEQA pursuant to the Public Utilities Commission (PUC) rules, in particular the new General Order 131-d. This Plan is intended to cover typical expansions of the system needed to serve new load, insure reliability, modernize older less efficient facilities, underground existing overhead lines, and to comply with new safety, air, and water quality standards, as well as other retrofits imposed by new government regulations. Those aforementioned activities that would normally be addressed by CEQA will still be subject to CEQA.

This Plan is not intended to exempt such projects from CEQA or NEPA, should the State or Federal Act pertain.

The Plan covers the following activities, as well as, estimates and defines the mitigation which may be required for the biological impacts of the installation, use, maintenance, and repair of the existing gas and electric system and typical expansions to that system. These activities are required to provide adequate, reliable, and safe service to existing customers and to meet the demands of new growth. The Plan does not cover extraordinary expansions to SDG&E's gas and electric system. The Plan also covers biological impacts (within the boundaries of the Plan area only), associated with new electric transmission lines including interconnections that do not project more that 30 miles outside of SDG&E's service territory (200 kV and less), Rainbow to Santee natural gas transmission pipeline, new gas transmission lines under 30" in diameter and less than 20 miles in length, new substations and regulator stations with habitat impacts under 20 acres, and new natural gas compressor stations with habitat impacts under 10 acres. Projects not covered by the Plan will be evaluated on a case-by-case basis, but will be evaluated by the standards set forth in this plan.

Since the future cannot be accurately predicted, the Plan allows for up to 400 acres of impacts in natural areas before requiring a Plan amendment. However, based on current technology, construction methods and standards, population forecasts, and local agency General Plans, the Plan anticipates only 124 acres of grading impacts in natural areas as a result of typical expansion and maintenance activities over the next 25 years (areas which are "natural" are not paved and do not contain ornamental landscaping or otherwise urbanized uses). Impacted areas may be home to one or more of the 110 species covered by this Plan. To mitigate these impacts, the Plan provides the following forms of mitigation:

- The most important mitigation measure is avoidance of impacts whenever possible. To accomplish this, new Operational Protocols for working in the field were developed. There are 61 protocols, all listed in Chapter 7 of the Plan. In addition, field crews attend a series of on-going classes on how to behave and operate construction and maintenance equipment in environmentally sensitive areas.

- Certain fee-owned rights-of-way will be available for use as wildlife corridors in order to connect the region's conservation areas. SDG&E will also allow the use of certain rights-of-way held in easements for such corridors with the consent of the underlying land owner.

- Mitigation Credits of approximately 240 acres will be established upon commencement of the Subregional Plan. The credits will be debited to mitigate for actual impacts as projects are realized. The wildlife agencies will determine the extent and quality of any impact. If needed, the Mitigation Credits will be replenished by additional land conveyance.

- Restoration and enhancement are also available as mitigation measures, sometimes instead of debits to the Mitigation Credits, and other times in addition to such debits. Restoration will be used in some cases regardless of other forms of mitigation.

1.4.4 Term of Plan

The Plan covers a term of 25 years with options for renewal. Involved parties agreed that 25 years should be the maximum term because of possible major changes in technology, development patterns, and projections and legislation affecting land use and the environment. After 25 years, the Plan will be reevaluated, and, if appropriate, extended. The Mitigation Credits will be replenished as needed.

The program anticipates approximately 124 acres of Covered Species habitat will be temporarily or permanently impacted under this program. A maximum of 400 acres of Covered Species habitat could be temporarily or permanently impacted under the 10(a) permit for this program.

2 Proposed Actions

2.1 Maintenance and Construction Activities

SDG&E constructs new utility infrastructure on an ongoing basis to maintain uniform, adequate, safe, and reliable electric and gas service. SDG&E also conducts maintenance and repair activities on existing Facilities. Typical construction, maintenance and repair activities for each type of Facility are described in this section. Operational Protocols to be used by SDG&E field personnel to avoid and minimize the potential impacts of installation, maintenance and repairs for each type of facility are contained in Section 7.1[2]

2.1.1 Overhead Facilities

Overhead Facilities are utilized in the transmission and distribution of electricity. Generally, overhead conductors (wires) are supported by wood or steel poles, or by steel lattice towers.

2.1.1.1 New Overhead Facility Alignment

New overhead facilities will, to the extent possible, be designed to minimize habitat fragmentation and disruption of wildlife movement and breeding areas. This will be accomplished by avoiding siting of Facilities in habitat and by utilizing dead-end/spur roads rather than linking facilities tangentially, to the extent possible[3]. When

[2] Extensions of SDG&E gas and electric transmission and distribution facilities provided to serve a particular customer constitute a project of that customer and are not subject to this Subregional Plan, the Implementing Agreement, or the Permits.
[3] "to the extent possible" means without violating CPUC standards or jeopardizing the structural and operational integrity of the facility

facilities must be sited in undisturbed or habitat areas, they will, to the extent possible, be sited in lower quality habitat (See Figure 4).

2.1.1.2 Placement of Structures

Steel lattice towers are installed using concrete foundations. Wood poles are installed using direct burial or concrete foundations. Maintenance will be performed and repairs may be required to restore structural integrity or inadequacies in a foundation or transmission structure caused by erosion or other occurrences.

2.1.1.3 Placement of Electrical Equipment on Structures

Towers and poles support a variety of electrical equipment including insulators and conductors. Insulators are attached directly to poles, or to arms mounted on the structures. The insulators are installed by workers who climb the structure or access the structure in bucket trucks. Once the insulators are installed, a helicopter is often used to install a small rope. The small rope is used to pull in a bigger rope or cable which is then used to pull in the conductor.

2.1.1.4 Insetting Poles

"Pole insetting" places poles in-line between existing structures. The new poles provide additional strength to support new or heavier conductors. The new poles are also used to achieve necessary wire clearances. Insetting is an effective method of fully utilizing existing electric line structures and alignments which often defers the need for new structures, lines and alignments.

2.1.1.5 Equipment Repair and Replacement

Poles or towers may support a variety of equipment such as conductors, insulators, switches, transformers, lightning arresters, line junctions, and other electrical equipment. This type of equipment may need to be added, repaired, or replaced in order to maintain uniform, adequate, safe, and reliable service. Due to damage, changes in conductor size, or the like, an existing transmission structure will be removed and replaced with a larger/stronger structure at the same or nearby location.

2.1.1.6 Pole Anchors and Stubs

Anchors, guy wires, and stubs are used to support poles. Generally one end of a guy wire attaches to the upper portion of a wood pole. The other end attaches to the top of a stub or to an anchor buried in the ground. These anchors can be in or out of alignment with the pole line. In order to maintain pole stability, new anchors or stubs, replacement anchors or stubs may be needed. Stubs can either be made of wood or steel and sometimes require concrete foundations.

2.1.1.7 Insulator Washing

In some areas prone to atmospheric moisture, condensation combines with dust on porcelain insulators can create an electrical discharge. This discharge, known as "arcing", poses a significant risk of service outages. This risk can be substantially reduced by periodic washing of the insulators. The process of washing insulators involves driving a water truck to within 60 feet of the facility. A high pressure hose is used to spray water at the insulator.

2.1.1.8 Tree Trimming

Tree trimming plays a critical role in maintaining reliable electrical power. Tree limb contact with electrical lines is a potential cause of power outages and is also a source of possible ignition and as such a potential fire hazard. Constant vigilance in tree trimming practices, regardless of habitat type, is necessary to maintain proper line clearances.

2.1.1.9 Use of Helicopters

Helicopters are used in the visual inspection of overhead facilities. Each electric transmission line is inspected several times a year via helicopter. Helicopters are also occasionally used to deliver equipment, position poles and towers, string lines and position aerial markers as required by Federal Aviation Administration regulations.

2.1.2 Underground Facilities

Underground Facilities are primarily utilized in the transmission and distribution of natural gas. Conduit containing electrical conductor may also be placed underground. New electric distribution lines are almost always placed underground in public streets.

2.1.2.1 New Underground Facility Alignment

New underground facilities will be designed to minimize habitat fragmentation and disruption of wildlife movement and breeding areas by avoiding siting facilities in habitat and by utilizing dead-end/spur roads to the extent possible. When facilities must be sited in undisturbed areas, they will, to the extent possible, be sited in lower quality habitat.

2.1.2.2 Underground Facility Access

Underground Facilities are regularly inspected visually and mechanically for any conditions which can potentially impair their function. Inspections involve driving along the top of/or parallel to the underground Facility. Access roads from public streets are utilized to reach the underground alignment. Access road maintenance is therefore a key component in installing, maintaining and inspecting underground Facilities.

2.1.2.3 Protection of Underground Facilities in Waterways

Underground infrastructure may cross a variety of shallow waterways ranging from blue-line streams designated on United States Geological Service maps to agricultural irrigation ditches. When the integrity of the Facility is threatened due to scouring, measures to protect the Facility and to minimize future erosion must be taken. Typical maintenance activities utilized to protect the underground Facilities include grading, addition of fill material to repair erosion damage, repair of adjacent slopes with placement of rip-rap or concrete, compaction of soil, vegetation control of species with invasive root structures, and other activities as necessary. These measures may be accomplished by hand or by equipment or machinery. Vegetation is allowed to grow over the underground Facility where it will reduce erosion by wind and water, and stabilize the soil.

2.1.2.4 Trenching

Trenching is required in order to install, replace, reposition, or repair underground Facilities. The width of the trench is dependent on the depth of the underground Facility and the stability of the side slopes. Underground Facilities are typically buried 3' to 5' deep. Facilities which are buried over 5' deep require side slopes of 1:1 or the use of shoring.

2.1.2.5 Line Markers

Underground infrastructure installed on private property or out of the public right-of-way is marked above the ground through a variety of methods, including "Transmission Line Markers" (paddle-shaped markers attached at eye level to steel posts). In addition to marking the location of the underground facilities, the markers contain safety warning messages for digging contractors and the general public. Underground alignment occasionally runs perpendicular to a waterway or other terrain which prevents walking or driving along the alignment for inspection purposes. In these instances, a line-of-site free from vegetation from marker to marker must be maintained for visual inspections at a distance.

2.1.2.6 Use of Helicopters and/or Fixed Wing Aircraft for Visual Inspection

Gas transmission lines are inspected by ground patrol or from the air.

2.1.3 Other Ground Disturbance

Many types of ground disturbance are necessary in order to install, protect, maintain and repair Facilities. These types of disturbances generally occur in, but are not limited to, the utility rights-of-way and existing access roads.

2.1.3.1 Access Roads

Access roads comprise part of SDG&E's Facilities. Cost-effective and efficient installation, maintenance, and repair of its Facilities depend upon the availability of adequate access roads. Most gas and electric transmission facilities, and some distribution facilities, require access roads. New access roads will, to the extent possible, be designed to minimize habitat fragmentation and disruption of wildlife movement and breeding areas through the utilization of dead-end/spur roads rather than linking facilities tangentially. When new access roads must be sited in undisturbed areas, they will, to the extent possible, be sited in lower quality habitat (See Figure 5).

2.1.3.2 Access Roads Crossing Waterways

Access roads may cross a variety of shallow water ways ranging from blue-line streams designated on United States Geological Service maps to agricultural irrigation ditches. Culverts may be added when utilization of an unculverted access road would alter the natural flow of a waterway. When the integrity of the access road is threatened, the culverts will be kept clear of vegetation, sediment, and debris to protect the access road. Sediment deposited in the area will be removed by hand or through the use of earth moving equipment. Other construction and activities include bank stabilization and repair of subsidence damage. These activities may be accomplished through the placement of rip-rap and through the use of earth moving equipment within the access road area.

NOTE: A Streambed Alteration Agreement is still required from CDF&G, however, no additional biological mitigation other than what is defined by this Plan shall be required for Covered Species. Refer to Implementing Agreement and clearance by ACOE/404 permit.

2.1.3.3 Slopes

Cut and fill slopes are constructed to create pads/foundations for utility structures or access roads. Slopes may require erosion repair.

2.1.3.4 Staging & Other Work Areas

Staging areas are for the temporary storage of large construction equipment and materials used in construction, maintenance, and repair activities. They can also serve as equipment turn-around areas, wire pulling sites, equipment parking areas, component assembly areas, equipment laydown areas, equipment and material storage sites, and temporary soil stockpile sites.

2.1.3.5 Geotechnical Remediation

Geotechnical remediation is necessary when geotechnical failure which may threaten the integrity of a Facility such as an electrical structure or a pipeline is imminent or has occurred.

2.1.3.6 Geotechnical Testing

Geotechnical tests are conducted to determine soil stability, depth of water table, engineering design values, and for the presence of hazardous waste. Testing may involve sample drilling, monitoring wells, excavation pits, or trenches.

Access roads are required for this equipment over existing or potential project sites.

2.1.3.7 Pest Control

Pest control at electric and gas facilities is necessary to ensure system integrity. Facilities requiring pest control are electric substations, gas regulator stations, gas valve boxes, and utility equipment yards (pest control is not necessary within electric transmission rights-of-way). Non-native rats, mice, and other rodents have been known to cause electrical shorts within substation transformers, eat through gas metering equipment, and eliminate the effectiveness of gas valve boxes. Fortunately, SDG&E facilities are not normally attractive to these pests. Therefore, a limited program of pest control is able to keep the rodent population down. Pest control is more common to facilities located adjacent to urbanized areas where food is more plentiful. When necessary, pest control measures will be used in accordance with the written recommendation of a licensed, registered Pest Control Advisor. Pesticides will only be applied by a licensed applicator in accordance with label precautions and applicable law in a manner that does not harm native plants or animals.

2.1.3.8 Fire Control Areas

A clearing of 10 feet in any direction, measured horizontally, from the outer circumference of any pole or tower is needed for construction and is required by law to be maintained for fire protection after construction. This clearing forms an imaginary cylindrical space surrounding each pole or tower. At ground level, all flammable materials that will propagate fire are removed. Within such 10' radius and to height of to 8' from the ground, dead or dying trees or foliage, or the dead, diseased, or dying limbs or foliage are removed. Where such trimming results in the removal of more than 50% of any such tree or foliage to meet fire safety requirements, such tree or foliage is entirely removed. These fire control measures can aid in the prevention of fire caused by arcing and can protect the Facilities from failure due to a fire in a surrounding area. Areas cleared of vegetation are also required around gas line valve complexes and cathodic test stations for fire protection.

2.1.3.9 Vegetation Control

Vegetation must be controlled on access roads, road shoulders, drainage structures, around transformers, buildings, fuel tanks, switch and transformer yards, substations, regulator stations, and other Facilities. Vegetation is controlled to facilitate the construction and use of roads, to allow inspection and maintenance of infrastructure and Facilities, to expose hazards such as ruts to drivers, eliminate noxious weeds, prevent fires, and to provide safe working areas.

2.1.3.9.1 Mechanical Removal

The simplest method of removing vegetation is by hand, such as the removal of isolated large shrubs or trees growing in areas where the roots could damage Facilities or where vegetation size restricts visual inspection. Raking is a means of removal usually used only to gather debris in preparation for disposal. Mowing will be used to control vegetation where low vegetation is desirable for erosion control. Clearing an area of vegetation by grading will also be used where no other means are appropriate.

2.1.3.9.2 Herbicide Spraying

Herbicide spraying, although not commonly employed by SDG&E, may be used around buildings and where bare ground is required for fire control. Herbicide spraying will not be conducted where it will damage known populations of Covered Species of plants. The typical regimen for herbicide use includes the application of pre-emergent herbicides during the fall and winter and spot application of contact herbicides during the growing season. All herbicides will be applied by a registered applicator in accordance with label precautions and applicable law.

2.1.4 Substations and Regulator Stations

Electric Substations connect the electrical transmission system to the electric distribution system, and reduce the electrical voltage to the distribution system in order to maintain safe reliable electric service. Substations are designed and operated to meet the safety standards required in the CPUC General Order 131-D for electrical systems. Regulator stations connect the natural gas transmission system to the natural gas distribution system, and regulate the supply of gas to that distribution system in order to maintain safe, reliable natural gas service. Regulator stations are designed and operated to meet the safety standards required in the CPUC General Order 112-D for natural gas systems. This Plan mitigates up to 20 acres of habitat impacts associated with new substations and regulator stations.

2.1.4.1 Substation and Regulator Siting

To the extent possible, new substations and regulator stations will be sited to avoid natural areas in order to minimize habitat fragmentation and disruption of wildlife movement and breeding areas. When natural areas must be disturbed, facilities will, to the extent possible, be sited in lowest quality habitat. When facilities must be sited in a preserve area they will, to the extent possible, be sited at the outer boundary of the preserve rather than in the center (See Figure 6).

2.1.4.2 Staging and Other Work Areas

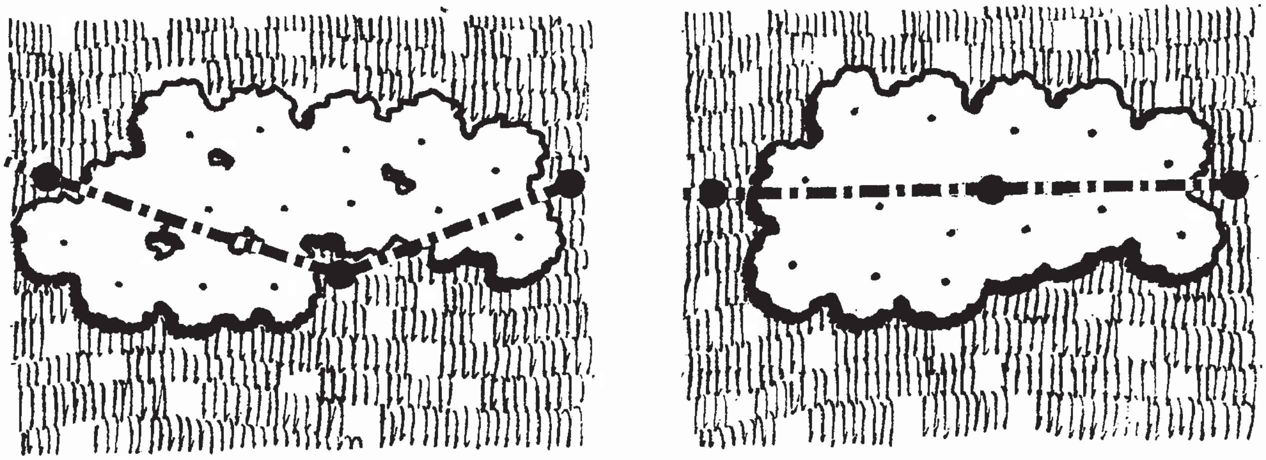
The disturbed areas within the property line of a substation or regulator station may be used as a staging area for the temporary storage of large construction equipment used in construction and maintenance activities. This property may also serve as equipment turn-around areas, wire pulling sites, equipment parking, assembly, and storage sites. Staging areas are used for equipment lay-down areas and pads for equipment positioning during construction. This utilization is intended to be temporary.

2.1.4.3 Fire Control Areas

Brush management around substations and regulator stations consisting of a 30'-wide fire break free from natural vegetation is desirable. Fire-control clearances are maintained on a yearly basis.

2.1.4.4 Geotechnical Failure Protection and Remediation

Geotechnical remediation is necessary when geotechnical failure is eminent or has occurred, and threatens the integrity of a Facility such as a substation or a regulator station. Preventative maintenance includes slope reconstruction and the repair or addition of drainage structures and retaining walls. Access is needed to various sites proposed for electrical substations and gas regulator stations for the purpose of obtaining engineering design information on the soils.



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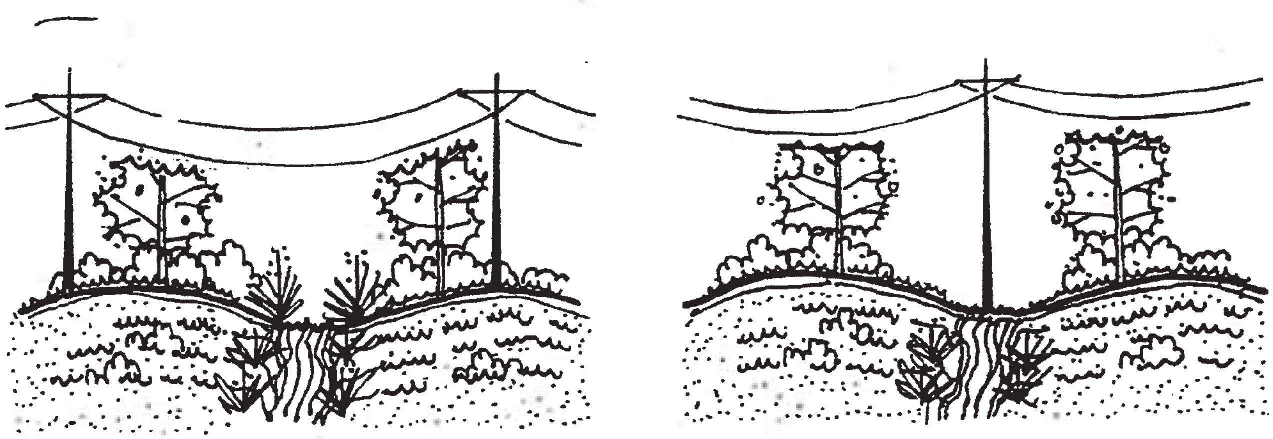
PLACEMENT OF OVERHEAD POLES SHOULD AVOID HABITAT AREAS



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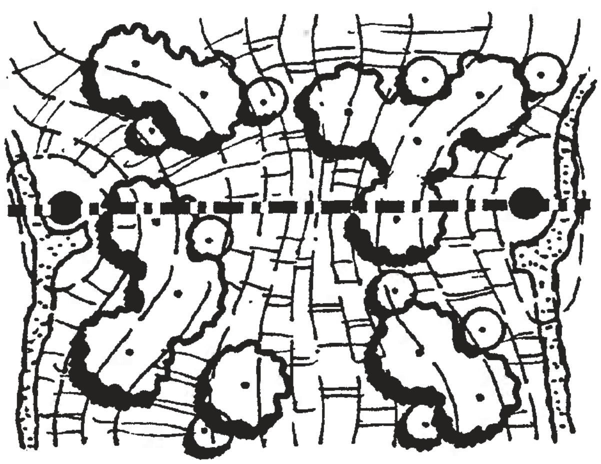
OVERHEAD POLES SHOULD NOT BE PLACED IN RIVERS, STREAMS, OR CREEKS

FIGURE **4**

Operational Protocol Diagrams



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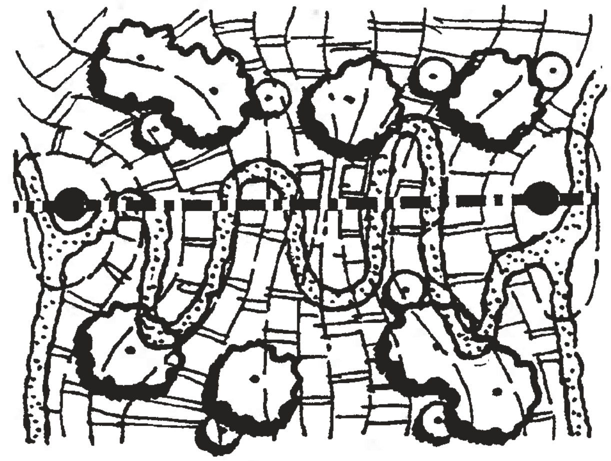

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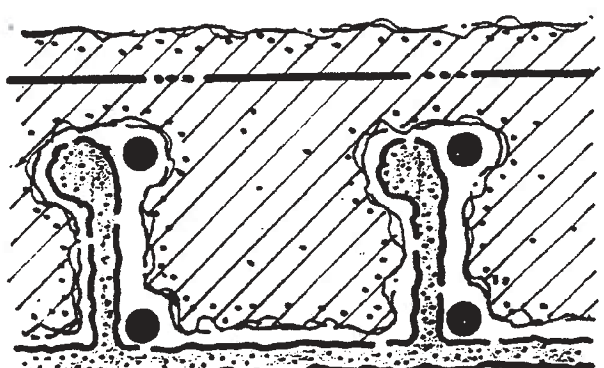
NEW ACCESS ROADS SHOULD AVOID SENSITIVE AND CANYON AREAS



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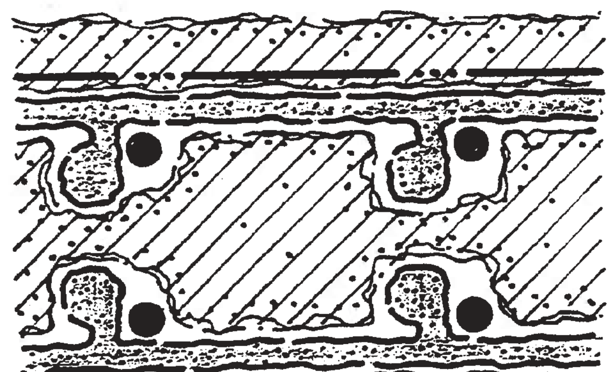

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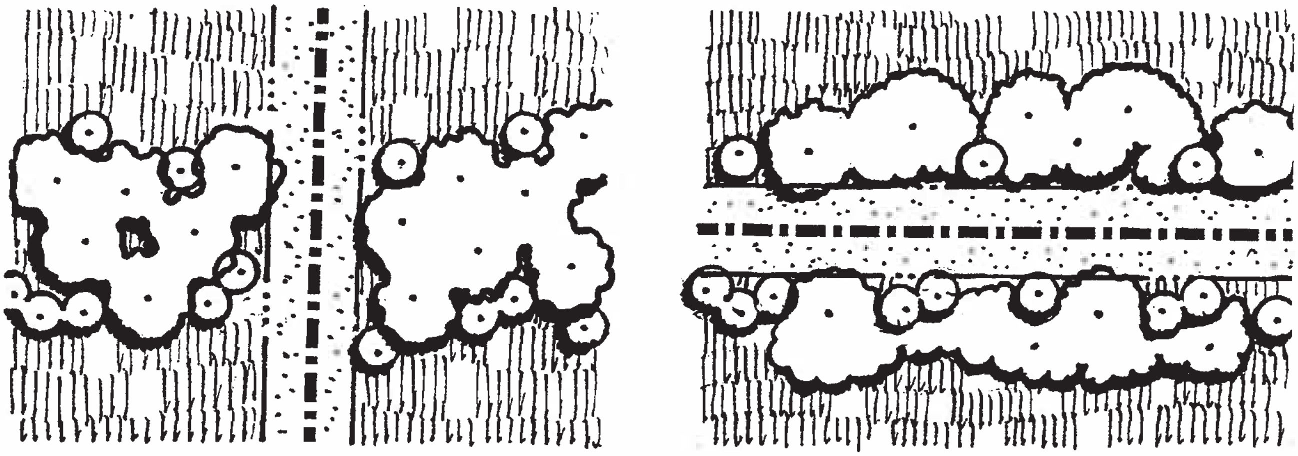
STUBS FROM EXISTING ACCESS ROADS SHOULD BE USED TO REACH NEW LINES

FIGURE 5

Operational Protocol Diagrams



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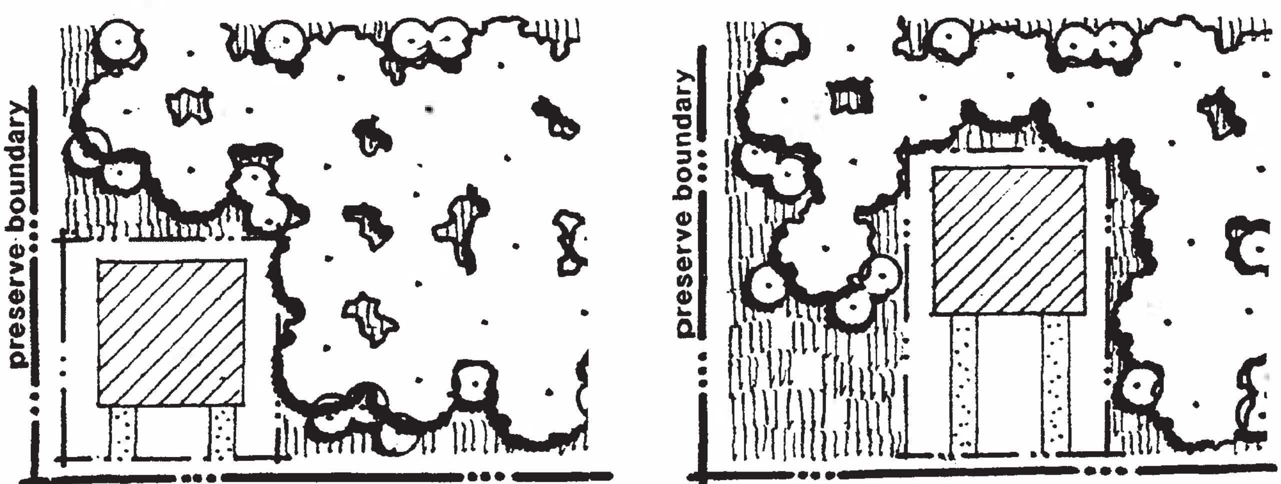
UTILITY LINES SHOULD MAKE PERPENDICULAR CROSSINGS THROUGH HABITAT AREAS



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SUBSTATIONS SHOULD BE SITED AT THE EDGES OF HABITAT PRESERVES

FIGURE 6

Operational Protocol Diagrams

2.2 Emergencies

As a result of natural disaster, stochastic factors or vandalism, emergency repairs to Facilities may be warranted. Emergency repairs may also be required to prevent the occurrence of a Facility failure. Conditions in this category are those that potentially or immediately threaten the integrity of the SDG&E system including: broken/leaking pipes, downed lines/poles, slumps, slides, surface fault ruptures, erosion, major subsidence, or other natural disaster. Emergency repairs will be taken immediately as required. As a result, in considering potential impact to Covered Species or their habitat, adjustments for time of day or seasonal constraints may not be possible in the interest of system integrity and public health and safety.

Emergency work will be performed by SDG&E crews and/or contract crews under the direction of SDG&E and in accordance with the Operational Protocols and mitigation contained in Section 7.

3 Biology

This section describes the biological information used to assess potential impacts of this Subregional Plan. It identifies the habitats that are the subject of the Subregional Plan and provides a description of potential impacts to Covered Species or their habitat caused by Activities.

The biological data utilized in the development of the Subregional Plan are derived from a variety of sources, including a number of conservation programs being prepared by local governments in Southern California. The sources of SDG&E's biological data and information are set forth in Section 3.1.

Table 3.1 lists the species and habitats for which this Subregional Plan is intended to provide protective and conservation measures over the term of the Implementing Agreement.

3.1 Data Base References

The data bases for the regional conservation programs covering all of San Diego County and parts of Riverside and Orange Counties provide the biological basis for this Subregional Plan. Vegetation and habitat evaluation maps were used to provide the basis for decision-making on potential preserve boundaries. The three habitat conservation planning areas in San Diego are shown on Figure 7.

For the purposes of this Subregional Plan, the term Covered Species is as defined in the Implementing Agreement. Covered Species which are not listed are included because in most cases they will benefit from the habitat conservation actions to protect Listed Species. Furthermore, if any of the unlisted species are listed in the future, they will be protected as a function of the Implementing Agreement associated with the Subregional Plan.

Covered Species are listed in Table 3.1 Figures 3.1a - 3.1i follow Table 3.1 and indicate the approximate locations of selected sensitive species near SDG&E rights-of-way. These figures are to provide a rough indication of potential areas of impact for workers conducting preactivity surveys consistent with the Operational Protocols (see also § 7.1). These maps will be periodically revised as the quality of data improves.

3.1.1 Multiple Species Conservation Program (MSCP)

The biological data base and information which comprise the scientific basis for the City of San Diego's Multiple Species Conservation Program (MSCP) were developed over six years, beginning in 1989. It will be updated periodically as the research and monitoring programs which accompany the implementation of the MSCP are carried out. The MSCP covers about 581,000 acres in southwestern San Diego County. The MSCP biological data base was developed by Ogden Environmental in cooperation with the USFWS, CDFG, local jurisdictions in the San Diego, and various consulting and academic biologists. It also relies in part on the California Natural Diversity Data Base and other records of survey. The Subregional Plan is based in part upon this data base. A map of the draft preserve plan area is attached as Figure 8a. The vegetation map is attached as Figure 8b.

3.1.2 Multiple Habitat Conservation Program (MHCP)

This data base was developed under a similar process to the MSCP data base. The study area covers approximately 658,000 acres in the northwestern portion of San Diego County. The vegetation map is attached as Figure 8c.

3.1.3 San Diego County Multi-Habitat Conservation and Open Space Plan (MHCOS)

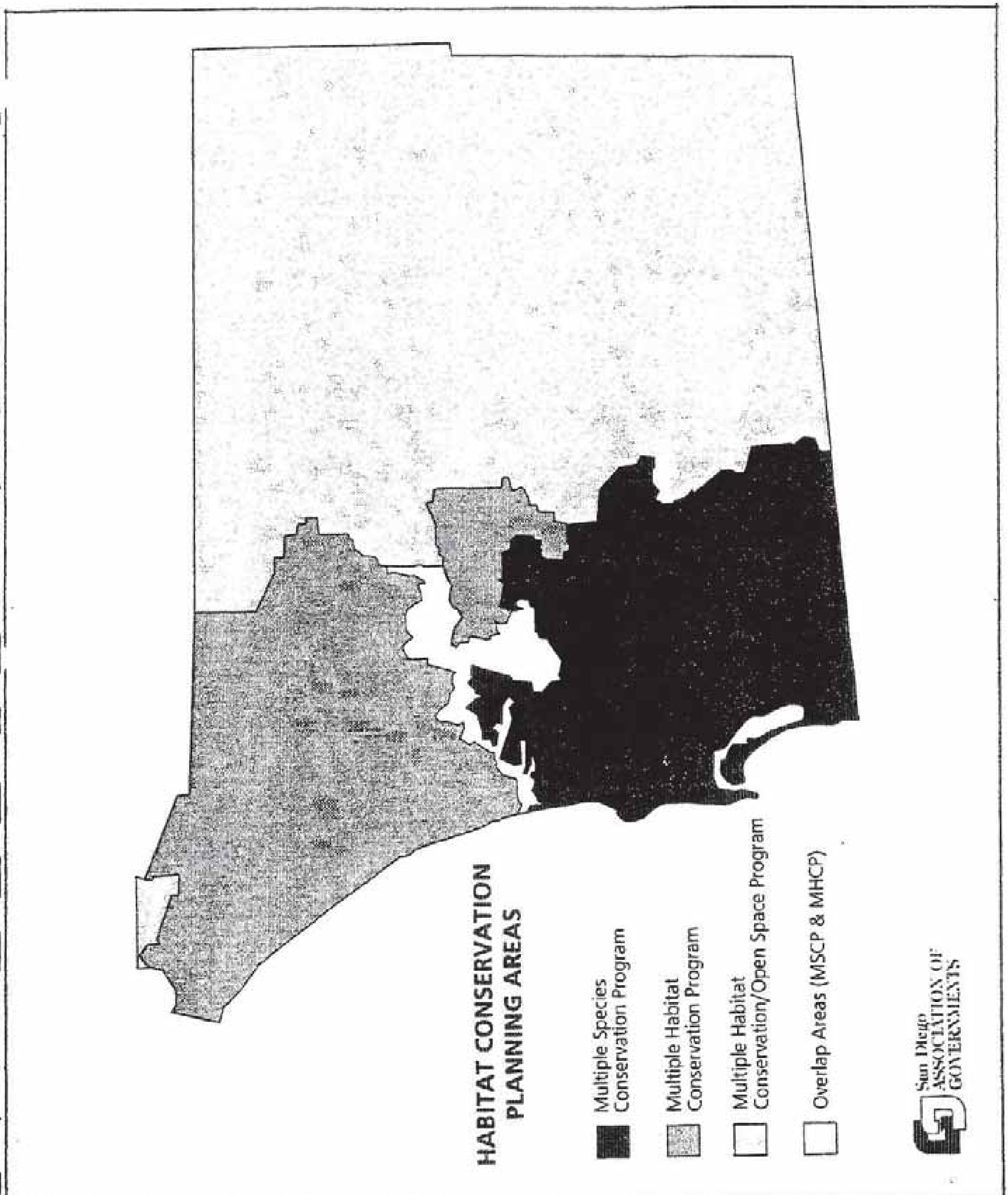
This data base remains under development, though basic biological information has been gathered on habitat types and other baseline information. This data base is being developed under a similar process to the MSCP data base. It covers the central mountainous section of San Diego County west of the desert. The vegetation map is attached as Figure 8d.

3.1.4 South Orange County NCCP Subregional Data Base

This data base was also developed under a similar process as the MSCP data base. It covers the southern section of Orange County, largely comprising the Rancho Santa Margarita Company property and adjacent conservation lands, and adjoining the Camp Pendleton Marine Corps Base west of Riverside County. A map of the draft plan area is attached as Figure 9.

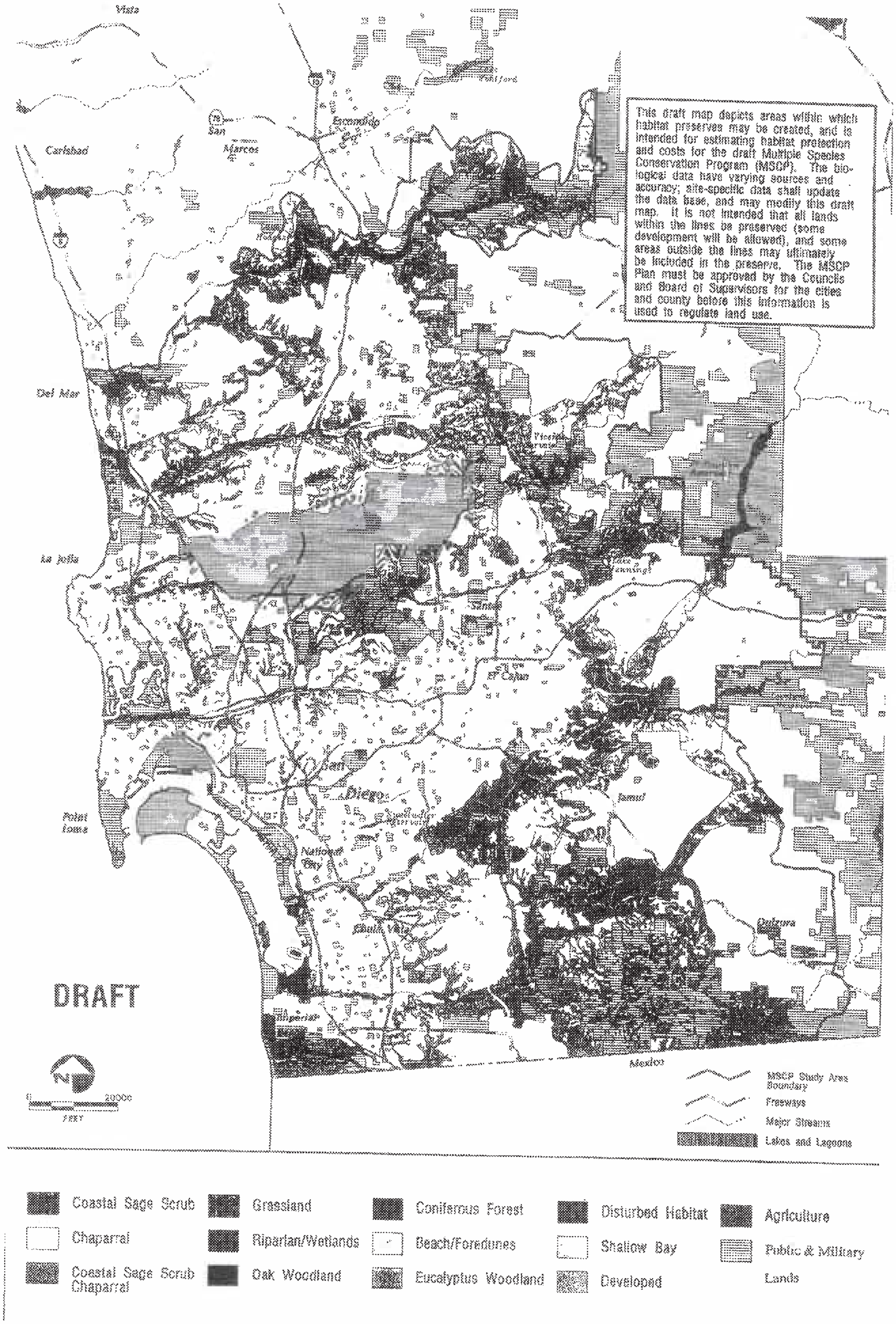
3.1.5 Riverside County Habitat Conservation Plan (RCHCP)

This database was developed to address the recovery plan for the Stephen's Kangaroo Rat. A small portion of SDG&E's system is in this Plan area. The RCHCP intends to expand its scope into a multi-species program. A map of the draft plan area is attached as Figure 10.


HABITAT CONSERVATION PLANNING AREAS
Multiple Species Conservation Program
Multiple Habitat Conservation Program
Multiple Habitat Conservation/Open Space Program
Overlap Areas (MSCP & MHCP)
San Diego ASSOCIATION OF GOVERNMENTS

FIGURE

7



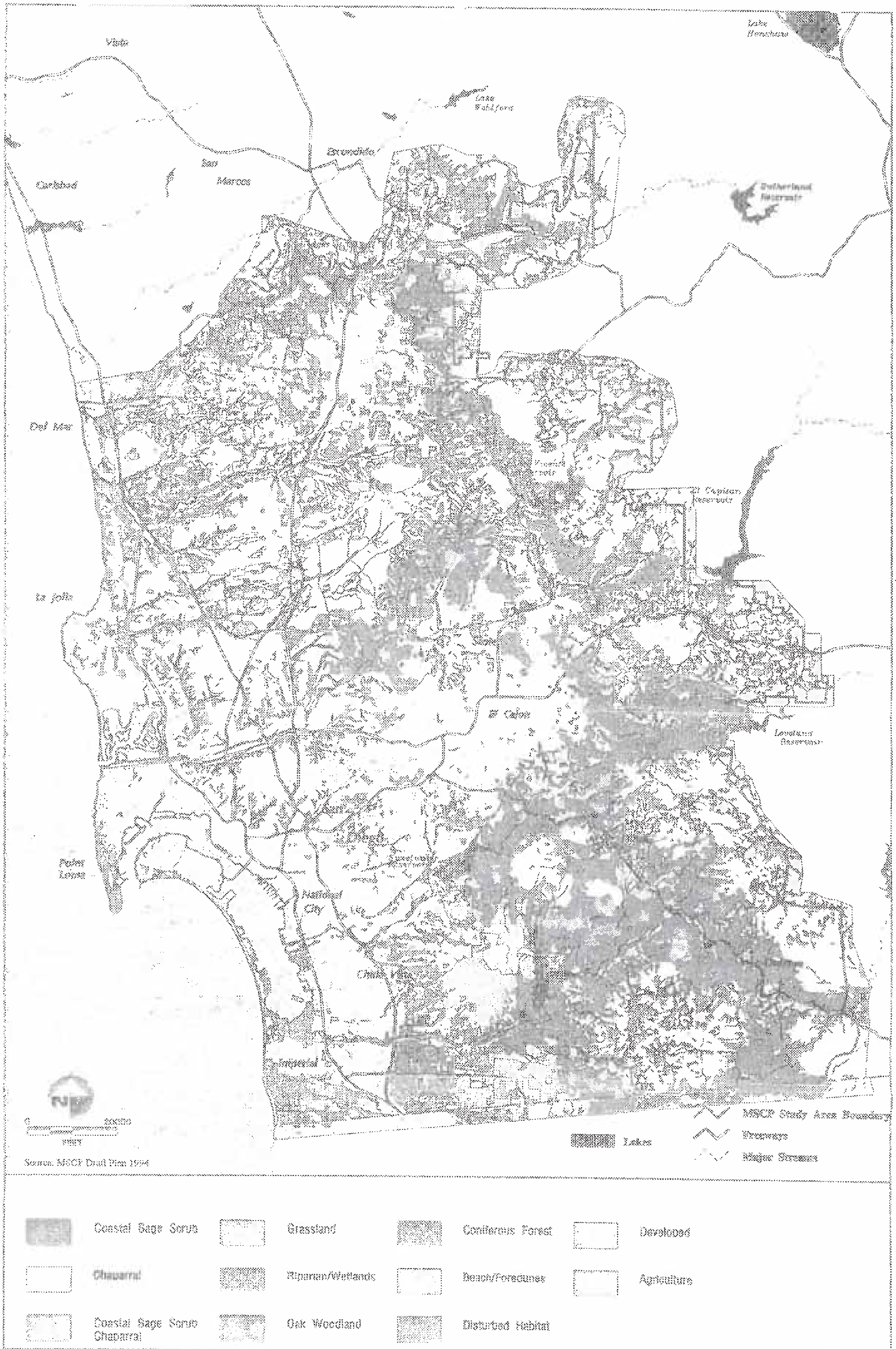
OGDEN

Multiple Habitat Planning Area (MHPA) For The MSCP

FIGURE 8a

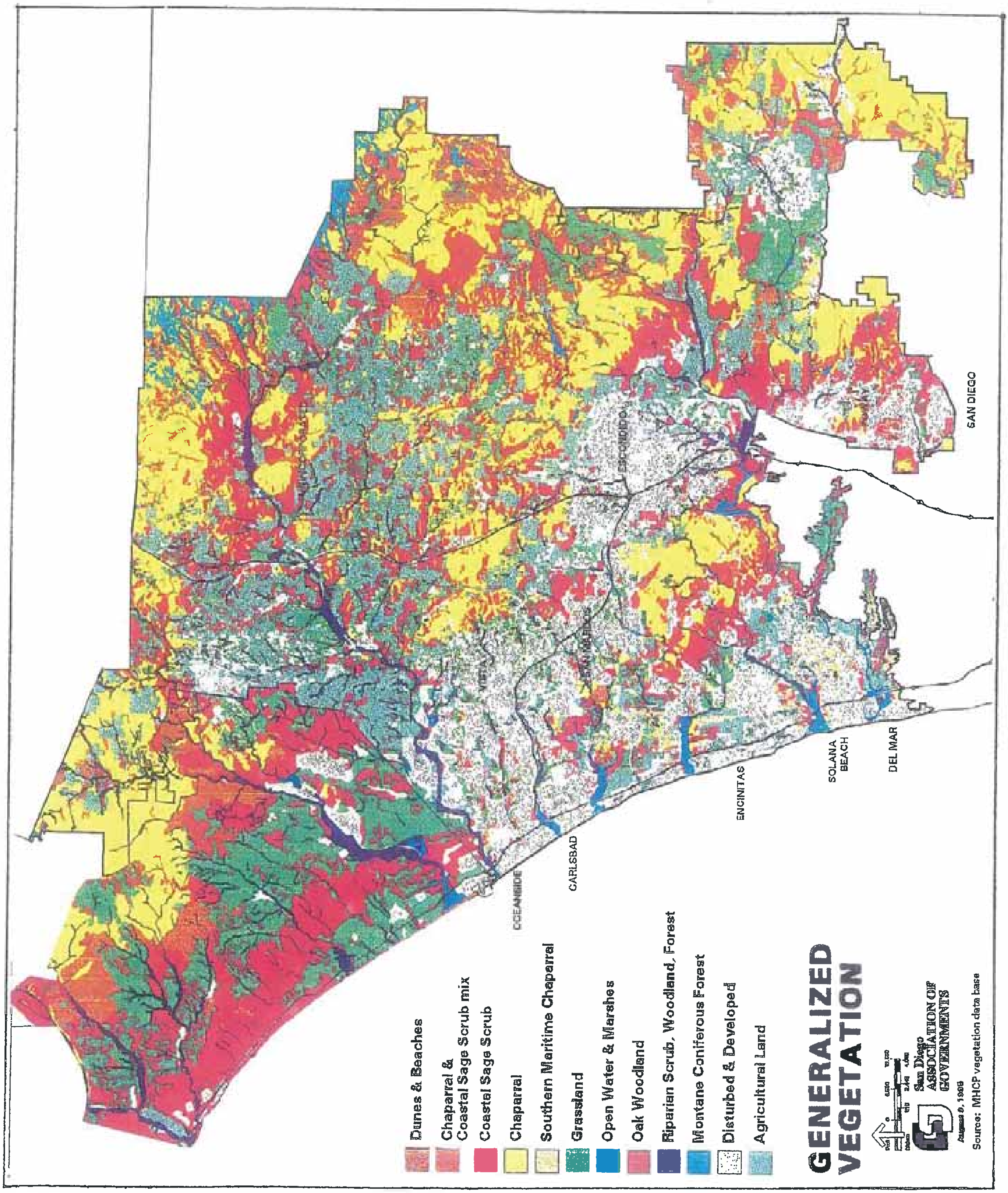
SDG&E

Subregional Natural Community Conservation Plan



Vegetation Communities for MSCP Study Area

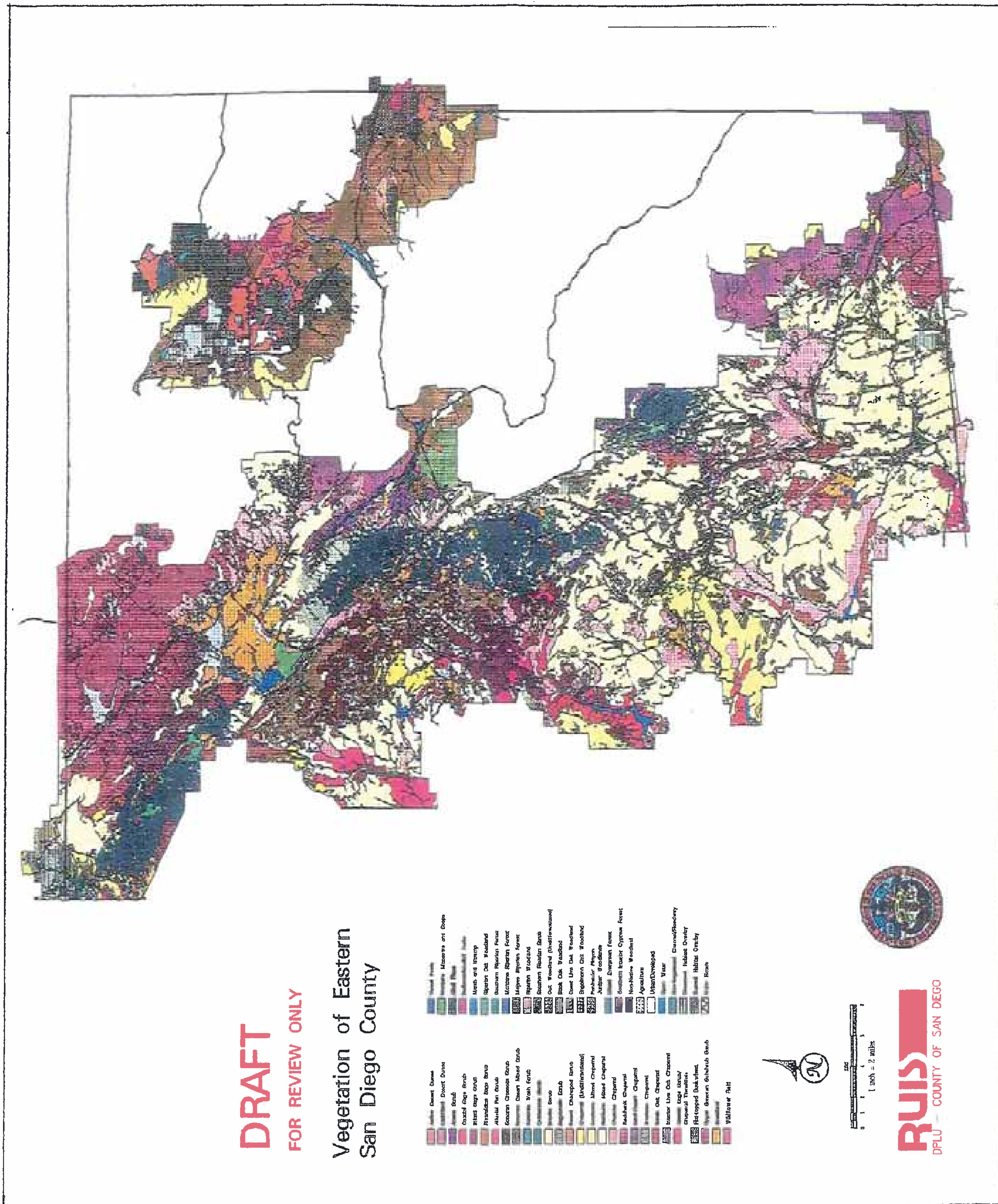
FIGURE 8b



FIGURE

8c

Multiple Habitat Conservation Program MHCP



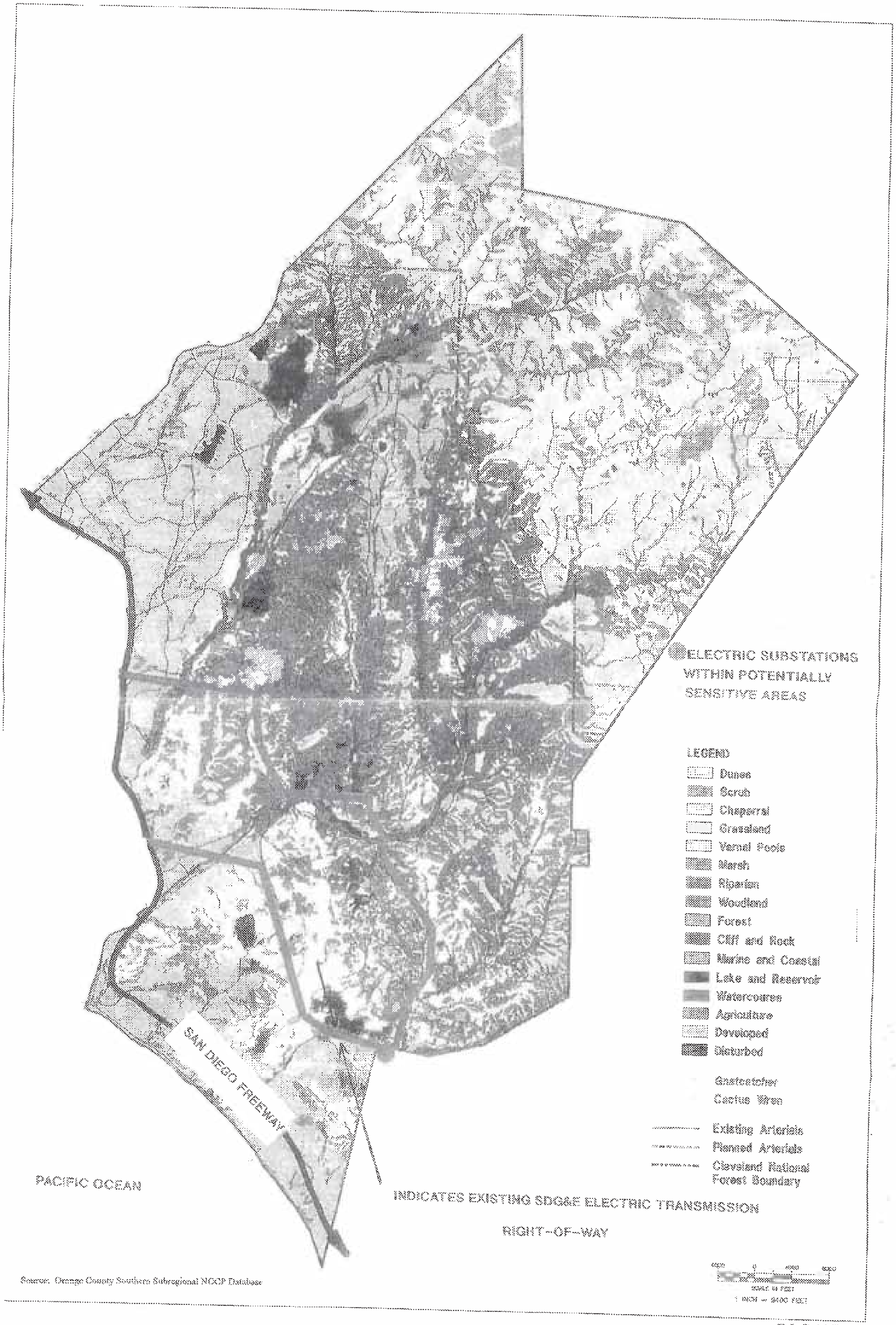
FIGURE

8d

Multiple Habitat Conservation and Open Space Program MHCOS

SDGE

Subregional Natural Community Conservation Plan



Orange County Southern Subregion NCCP

FIGURE 9

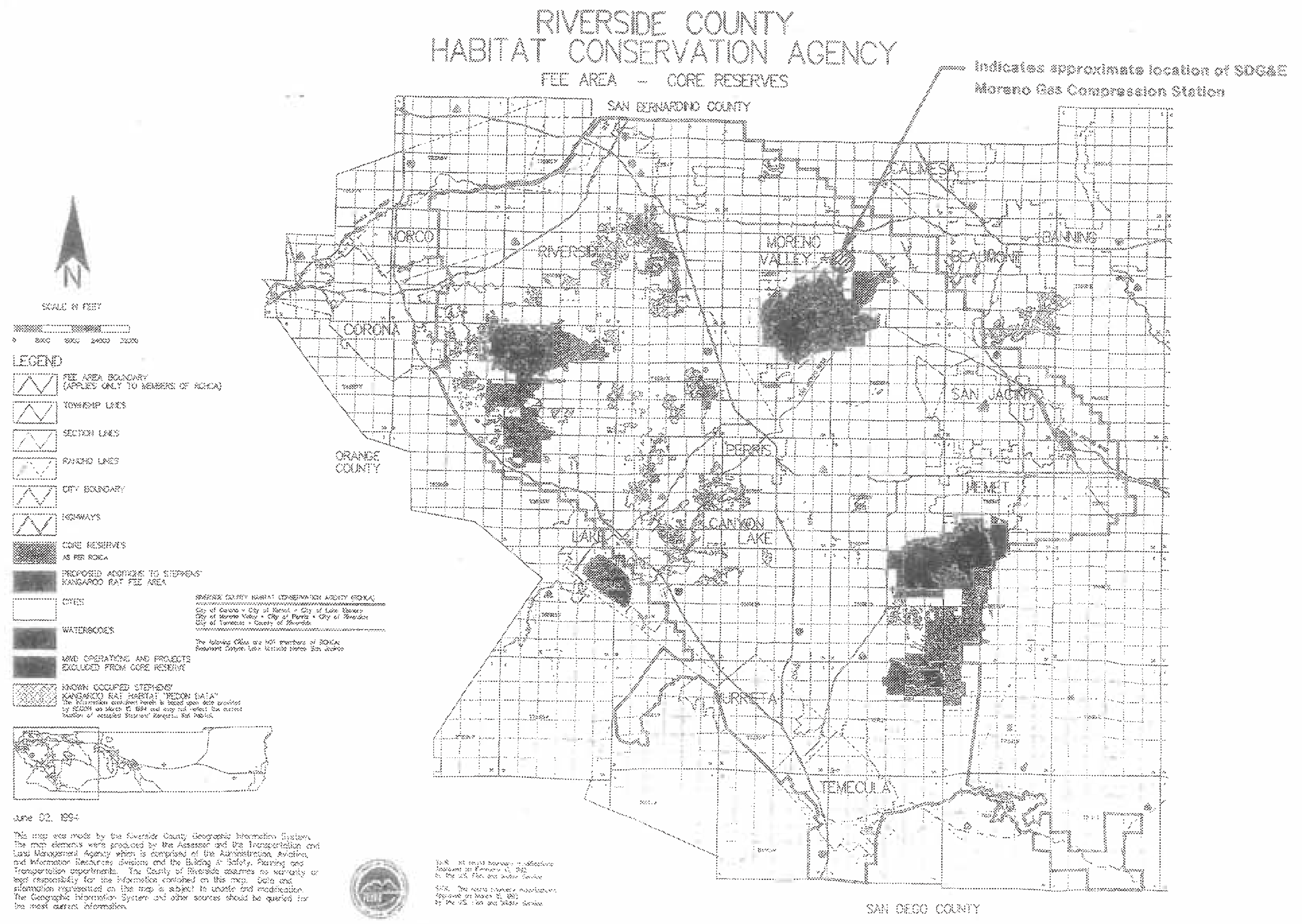

RIVERSIDE COUNTY
HABITAT CONSERVATION AGENCY
FEE AREA - CORE RESERVES
Indicates approximate location of SDG&E
Moreno Gas Compression Station
SAN BERNARDINO COUNTY
ORANGE COUNTY
SAN DIEGO COUNTY
NORCO
RIVERSIDE
CORONA
MORENO VALLEY
CALIMESA
BEAUMONT
BANNING
SAN JACINTO
PERRIS
HEMET
CANYON LAKE
LAKE
MURRIETA
TEMECULA
N
SCALE IN FEET
LEGEND
FEE AREA BOUNDARY (APPLIES ONLY TO MEMBERS OF RCHCA)
TOWNSHIP LINES
SECTION LINES
RANCHO LINES
CITY BOUNDARY
HIGHWAYS
CORE RESERVES AS PER RCHCA
PROPOSED ADDITIONS TO STEPHENS' KANGAROO RAT FEE AREA
CITIES
WATERBODIES
MINE OPERATIONS AND PROJECTS EXCLUDED FROM CORE RESERVE
KNOWN OCCUPIED STEPHENS' KANGAROO RAT HABITAT "PEDON DATA"
RIVERSIDE COUNTY HABITAT CONSERVATION AGENCY (RCHCA)
June 02, 1994

FIGURE 10

TYPES OF HABITAT WITHIN SUBREGIONAL PLAN AREA

- *Southern Foredunes*
- *Southern Coastal Bluff Scrub*
- *Maritime Succulent Scrub*
- *Coastal Sage Scrub*
- *Alluvial Fan Scrub*
- *Chaparral*
- *Southern Maritime Chaparral*
- *Coastal Sage/Chaparral Mix*
- *Grassland*
- *Meadow/Seep*
- *Southern Coastal Salt Marsh*
- *Alkali Marsh*
- *Freshwater Marsh*
- *Coast Live Oak Riparian Forest*
- *Riparian Forest*
- *Riparian Woodland*
- *Riparian Scrub*
- *Open Oak Woodland*
- *Open Engelmann Oak Woodland*
- *Dense Engelmann Oak Woodland*
- *Coast Live Oak Forest*
- *Black Oak Forest*
- *Torrey Pine Forest*
- *Mountain Conifer Forest*
- *Coulter Pine Forest*
- *Big Cone Spruce*
- *Jeffrey Pine*
- *Eucalyptus Forest*

- ***Tecate Cypress Forest***
- ***Inland Water***
- ***Shallow Bays***
- ***Disturbed Wetlands***
- ***Non-Vegetated Floodchannel***
- ***Beach-Saltpan***
- ***Disturbed Habitat***
- ***Agricultural***

MITIGATION

I. Scrub & Chaparral Species

See Protocols (Section 7.1) and Habitat Enhancement Measures (Section 7.2)

II. Grassland Species

Native grasslands: Over gas lines, same as vernal pool, except remove bunch grasses and replant, otherwise span with distribution and transmission lines.

Non-native grasslands: See Protocols (Section 7.1) and Habitat Enhancement Measures (Section 7.2).

III. Beach, Marsh, and Wetland Species

Construction in marsh areas, soft sand, or open water in most cases will be accomplished through the use of helicopters for the delivery of materials, poles, personnel, and platforms. Roads should be avoided to the extent feasible.

IV. Narrow Endemic Species

Take of certain narrow endemic Covered Species is to be avoided. Take authorizations for these species will be limited to emergencies and unavoidable impacts from repairs to existing facilities. The first priority is avoidance, if impact is unavoidable, then state-of-the-art conservation practices will be utilized to determine best mitigation method consistent with Operational Protocols. For repairs to existing facilities which could result in an impact, a biologist would be called in. Take of the "species to be avoided" may not occur for non-emergency repair work without first conferring with the USFWS and CDFG. For new projects, kill or injury of such animal species or destruction of such plants or their supporting habitat would not be covered by the Plan and Implementing Agreement.

V. Riparian Species

See Protocols (Section 7.1, especially 7.1.7)

VI. Forest Species

See Protocols, same as Riparian (Section 7.1, especially 7.1.7)

VII. Open Water Species

When working in open water: Typically, a wooden platform is fabricated on dry land then delivered by helicopter. The platform, in two pieces, has a 1/2 circle for the pole cut into the edge of each. The platform has "feet" to keep it above the water. The platform would have other holes to prevent suction during removal. Personnel, materials, tools, and replacement poles would also be delivered to the platform by air.

Temporary disturbances in the work area would be limited to a 10' radius around the pole hole.

VIII. Raptor Species

SDG&E will coordinate with wildlife agencies when new or expanded facilities are planned in significant bird movement corridors. The following methods will be considered for implementation on a case by case basis for use in the protection of raptors from electrocution associated with perching/nesting activities on distribution and transmission structures: Pole mounted bird perches, inverted "V" raptor guards, Bird-be-Gone™, saw-toothed metal bird guards, insulated jumpers, or others. These methods will be employed on select structures in areas known to be inhabited by sensitive raptor species when the likelihood of electrocution is high or has been historically documented. Where nests interfere with safe operation of transmission system, avoid removal in months January - June.

<u>Wood Poles</u>
Pole Mounted Bird Perch

- Construction from 2" x 6" treated lumber, attached to the top of wood pole carrying voltages from 12kV - 138kV (PacifiCorp EV 101)

Inverted "V" Raptor Guard

- Constructed of poly pipe and attached to cross arm between insulators with galvanized steel clamps

<u>Wood or Steel Poles</u>
Bird-be-Gone

- 4' long rows of plastic spikes attached to cross arms

Sticky Solution

- Sticky solution on cross arms or wires, birds don't like the feel

<u>Steel Lattice Towers</u>
Metal Bird Guard

- Saw-toothed bird guard, of 22-gauge sheet metal, attached to the cross arms of terminal, tangent, and angle towers, carrying voltages of 69kV and above

IX. Vernal Pools

SDG&E will avoid vernal pools and their watersheds in the construction of new facilities, including roads. When pools are located above gas lines and repair work is necessary, work areas should be minimized and soil should be stockpiled for replacement after repairs. For new gas lines, avoid through routing changes. For access roads, stay within existing footprint, no new roads through vernal pool areas.

Under certain circumstances, SDG&E is prepared to consider rerouting an existing access road which passes through a vernal pool area as potential mitigation for the impacts of utility Activities on vernal pools that cannot be otherwise avoided pursuant to the Operational Protocols in the Plan, such as in an emergency. This rerouting would only be done if it was possible without compromising operational integrity and safety. The mitigation value of the rerouted road would be at 1:1 level.

X. Stephens' Kangaroo Rat

Take of the Stephens' Kangaroo Rat (SKR) is only permitted for SDG&E in the Multiple Habitat Conservation Program (MHCP) planning area in northern San Diego County for operation and maintenance activities until the MHCP is approved. After that time, and provided that SKR is conserved within MHCP, Take for new construction Activities will be permitted under the terms of this Plan. This condition only applies to the SKR populations in San Diego County; Riverside County has an approved Take process and mitigation protocol. Furthermore, SDG&E's facilities in Riverside County already exist, and no new impacts are expected.

Note: Operational Protocols (Section 7.1) and Habitat Enhancement Measures (Section 7.2) are generally applicable to all of the habitat.

TABLE 3.1 COVERED SPECIES LIST

#	SPECIES NAME & STATUS	HABITAT TYPES	RANGEWIDE AND LOCAL DISTRIBUTION OF SPECIES	DEGREE OF EXISTING PROTECTION	CONSERVATION PLANNING IMPLICATIONS	MITIGATION
	PLANTS					
1	San Diego thornmint (*Acanthomintha ilicifolia*) C1/PE/List 1B, R-E-D 2-3-2	Clay soils in chaparral, coastal sage scrub, valley and foothill grasslands, and vernal pools.	San Diego County and Baja California, Mexico. Known currently from approximately 30 populations that are typically small and endangered by urban pressures.	CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, IV, IX
2	Shaw's agave (*Agave shawii*) Regionally sensitive species/List 2, R-E-D 3-3-1	Coastal bluff scrub and coastal sage scrub.	San Diego County and Baja California, Mexico. Only three, small, disjunct populations occur naturally in the U.S. Has been introduced to other localities.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs.	I, IV
3	San Diego ambrosia (*Ambrosia pumila*) Regionally sensitive species/List 1B, R-E-D 3-3-2	Chaparral, coastal sage scrub, valley and foothill grasslands, and vernal pools. Often in disturbed areas.	Riverside and San Diego counties and Baja California, Mexico. In San Diego County, currently known from 4 scattered populations.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, II, IV, IX
4	Aphanisma (*Aphanisma blitoides*) Regionally sensitive species/List 1B, R-E-D 2-2-2	Sandy areas in coastal bluff scrub and coastal sage scrub.	Central California coast to Baja California, Mexico. May be extirpated in San Diego County and severely declining throughout its mainland U.S. range.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts to San Diego County populations will be avoided unless deemed necessary for emergencies or repairs.	I, IV
5	Otay manzanita (*Arctostaphylos otayenis*) Regionally sensitive species/List 1B, R-E-D 3-2-3	Volcanic soils in chaparral and cismontane woodland.	Scattered populations occur on Otay, San Miguel, and Jamul, mountains in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I, VII
6	Del Mar manzanita (*Arctostaphylos glandulosa* var. *crassifolia*) PE/List 1B, R-E-D 3-3-2	Southern maritime chaparral.	Infrequent in coastal San Diego County from Del Mar to Carlsbad.	FESA (assuming federal action associated with take), CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves populations and habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I
7	Coastal dunes milk-vetch (*Astragalus tener* var. *titi*) C1/PE/List 1B, R-E-D 3-3-3	Coastal bluff scrub and coastal dunes.	Historically occurred in San Diego, Monterey, and Los Angeles counties. Presumed extirpated in San Diego and Los Angeles counties.	CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs.	III, IV
8	Encinitas baccharis (*Baccharis vanessae*) PE/CE/List 1B, R-E-D 2-3-3	Sandstone soils in chaparral.	San Diego County endemic. Restricted to approximately 13 known localities.	FESA (assuming federal action associated with take), CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs.	I, IV
9	Nevin's barberry (*Berberis nevinii*) C1/PE/List 1B, R-E-D 3-3-3	Sandy or gravelly soils in chaparral, cismontane woodland, coastal sage scrub, and riparian scrub.	Los Angeles County south to Riverside, San Bernardino, and San Diego counties. Populations are relatively stable although few in number. No extant native populations are known in San Diego County.	CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, IV, VI
10	Thread-leaved brodiaea (*Brodiaea filifolia*) PT/CE/List 1B, R-E-D 3-3-3	Clay soils in coastal sage scrub, cismontane woodland, valley and foothill grasslands, and vernal pools.	Interior valley regions of Riverside and San Diego counties. Fifteen populations are known from San Diego County, 6 from Riverside County, 2 from San Bernardino County, and 1 each from Los Angeles and Orange counties.	FESA (assuming federal action associated with take), CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves populations and habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species. Vernal pool populations will be adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, II, VI, IX

TABLE 3.1 COVERED SPECIES LIST

#	SPECIES NAME & STATUS	HABITAT TYPES	RANGEWIDE AND LOCAL DISTRIBUTION OF SPECIES	DEGREE OF EXISTING PROTECTION	CONSERVATION PLANNING IMPLICATIONS	MITIGATION
	PLANTS					
11	Orcutt's brodiaea (*Brodiaea orcuttii*) Regionally sensitive species/List 1B, R-E-D 1-3-2	Clay soils in close-coned coniferous forests, chaparral, cismontane woodlands, meadows, valley and foothill grasslands, and vernal pools.	Riverside and San Bernardino counties to Baja California, Mexico. Found in numerous localities in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species. Vernal pool populations will be adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, VI, IX
12	Dense reed grass (*Calamogrostis koelerioides*) Regionally sensitive species	Chaparral.	Orange and San Diego counties. Known from approximately 25 localities in San Diego County and approximately 3 localities in Orange County.	Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitat. The Plan also preserves habitat to maximum extent practicable and preserves corridors connecting habitat thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitat that may include the species.	I
13	Dunn's mariposa lily (*Calochortus dunnii*) CR/List 1B, R-E-D 2-2-2	Gabbroic and metavolcanic soils in close-coned coniferous forests and chaparral.	Southern Peninsular Range of San Diego County and adjacent Baja, California, Mexico. Known from approximately 8 localities in San Diego County.	CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves populations and habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I, VI
14	Payson's jewelflower (*Caulanthus simulans*) Regionally sensitive species/List 4, R-E-D 1-2-3	Sandy, granitic soils in chaparral and coastal sage scrub.	Riverside and San Diego counties. Known from approximately 19 localities in San Diego County and 4 localities in Riverside County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I
15	Slender-pod jewelflower (*Caulanthus stenocarpus*) CR	Chaparral, especially on burns.	San Diego County to northern Baja California, Mexico. Widespread but sporadic distribution.	CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves populations and habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I
16	Lakeside ceanothus (*Ceanothus cyaneus*) Regionally sensitive species/List 1B, R-E-D 3-2-2	Acid igneous rockland in close-coned coniferous forests and chaparral.	Western San Diego County to Baja California, Mexico. Restricted to Crest and El Cajon Mountain region in San Diego County. Specimen collected from Baja California, Mexico may be a hybrid.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I, VI
17	Wart-stemmed ceanothus (*Ceanothus verrucosus*) Regionally sensitive species/List 2, R-E-D 1-2-1	Chaparral.	San Diego County and Baja California, Mexico. Currently known from approximately 17 localities in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitat. The Plan also preserves habitat to maximum extent practicable and preserves corridors connecting habitat thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitat that may include the species.	I
18	Orcutt's spineflower (*Chorizanthe orcuttiana*) PE/CE/List 1B, R-E-D 3-3-3	Chaparral, close-coned coniferous forests, and coastal sage scrub.	Endemic to San Diego County. Only one site known to be extant: Oak Crest Park in Encinitas.	FESA (assuming federal action associated with take), CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs.	I, IV, VI

TABLE 3.1 COVERED SPECIES LIST

#	SPECIES NAME & STATUS	HABITAT TYPES	RANGEWIDE AND LOCAL DISTRIBUTION OF SPECIES	DEGREE OF EXISTING PROTECTION	CONSERVATION PLANNING IMPLICATIONS	MITIGATION
	PLANTS					
19	Orange County Turkish rugging (*Chorizanthe staticoides* ssp. *chrysacantha*) Regionally sensitive species	Ocean bluffs, coastal sage scrub.	San Diego and Orange counties. Two known localities in San Diego County and 11 known in Orange County.	Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I
20	Salt marsh bird's-beak (*Cordylanthus maritimus* spp. *maritimus*) FE/CE/List 1B, R-E-D 2-2-2	Coastal dunes and coastal salt marshes.	San Luis Obispo County south to Baja California, Mexico. Restricted to 2 extant populations in San Diego County and possibly 2 in Orange County.	FESA (assuming federal action associated with take), CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III, IV
21	Orcutt's bird's-beak (*Cordylanthus orcuttianus*) Regionally sensitive species/List 2, R-E-D 3-3-1	Coastal sage scrub.	Endemic to San Diego County and Baja California, Mexico. Restricted to a few localities in southwestern San Diego County. Otay River populations are only vigorous, extant U.S. populations.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitat. The Plan also preserves habitat to maximum extent practicable and preserves corridors connecting habitat thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitat that may include the species.	I
22	Tecate cypress (*Cupressus forbesii*) Regionally sensitive species/List 1B, R-E-D 3-2-2	Close-coned coniferous forests and chaparral.	Orange County, San Diego County, and Baja California, Mexico. Known from 6 localities in San Diego County and 6 localities in Orange County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	VI
23	Short-leaved dudleya (*Dudleya blochmaniae* ssp. *brevifolia*) PE/CE/List 1B, R-E-D 3-3-3	Torrey sandstone in chaparral and coastal sage scrub.	Between La Jolla and Del Mar in San Diego County. Known from approximately 6 but not more than 8 localities.	FESA (assuming federal action associated with take), CESA,NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs.	I, IV
24	Many-stemmed dudleya (*Dudleya multicaulis*) Regionally sensitive species/List 1B, R-E-D 1-2-3	Often clay soils in chaparral, coastal sage scrub, and valley and foothill grasslands.	Los Angeles, Orange, Riverside, San Bernardino, and San Diego counties. Known only from Marine Corps Base Camp Pendleton in San Diego County, numerous localities in Orange County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I, II
25	Variegated dudleya (*Dudleya variegata*) Regionally sensitive species/List 1B, R-E-D 2-2-2	Chaparral, cismontane woodlands, coastal sage scrub, valley and foothill grasslands, and vernal pools.	Southern San Diego County and northwestern Baja California, Mexico. Known from approximately 60 localities in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species. Vernal pool populations will be adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, II, VI, IX
26	Sticky dudleya (*Dudleya viscida*) C1/List 1B, R-E-D 3-2-3	Rocky areas in coastal bluff scrub, chaparral, and coastal sage scrub.	San Diego, Orange, and Riverside counties. Known from 10 populations in San Diego County, 4 localities in Orange County, and 1 location in southwestern Riverside County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I

TABLE 3.1 COVERED SPECIES LIST

#	SPECIES NAME & STATUS	HABITAT TYPES	RANGEWIDE AND LOCAL DISTRIBUTION OF SPECIES	DEGREE OF EXISTING PROTECTION	CONSERVATION PLANNING IMPLICATIONS	MITIGATION
	PLANTS					
27	Palmer's ericameria (*Ericameria palmeri* ssp. *palmeri*) Regionally sensitive species/List 2, R-E-D 2-2-1	Coastal sage scrub.	Southern San Diego County and Baja California, Mexico. Known from 10 populations in San Diego County.	Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs.	I, IV
28	San Diego button-celery (*Eryngium aristulatum* var. *parishii*) FE/CE/List 1B, R-E-D 2-3-2	Coastal sage scrub, valley and foothill grasslands, and vernal pools.	San Diego and Riverside counties and Baja California, Mexico. Known from 65 localities in San Diego County; many of these are remnants of once larger populations.	FESA (assuming federal action associated with take), CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves populations and habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species. Vernal pool populations will be adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, II, IX
29	Coast wallflower (*Erysimum ammophilum*) Regionally sensitive species/List 1B, R-E-D 2-2-3	Coastal dunes.	San Diego County, Santa Rosa Island, Santa Cruz and Monterey counties. Known from approximately 7 localities in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs.	III, IV
30	San Diego barrel cactus (*Ferocactus viridescens*) Regionally sensitive species/List 2, R-E-D 1-3-1	Chaparral, coastal sage scrub, maritime succulent scrub, and valley and foothill grasslands.	San Diego County and Baja California. Persists in numerous, fragmented populations in San Diego County. Its highest densities occur on Otay Mesa, particularly northeast of Brown Field and at the east end of Wruck Canyon.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I, II
31	Palmer's grapplinghook (*Harpagonella palmeri*) Regionally sensitive species/List 2, R-E-D 1-2-1	Clay soils in chaparral, coastal sage scrub, and valley and foothill grasslands.	Los Angeles, Orange, Riverside, and San Diego counties, on San Clemente Island, in Arizona, Baja California, and Sonora, Mexico. In San Diego County several thousand individuals grow on the slopes of Table Mountain near Jacumba. Otherwise most populations are small and scattered along the coast.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I, II
32	Otay tar plant (*Hemizonia conjugens*) PE/CE/List 1B, R-E-D 3-3-2	Clay soils in coastal sage scrub and valley and foothill grasslands.	Southern San Diego County and northwestern Baja California, Mexico. Most U.S. localities for this species occur in the vicinity of Chula Vista.	CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves populations and habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I, II
33	Heart-leaved pitcher sage (*Lepechinia cardiophylla*) Regionally sensitive species/List 1B, R-E-D 3-2-2	Close-coned coniferous forests, chaparral, and cismontane woodlands.	Orange, Riverside, San Diego counties and Baja California, Mexico. Restricted to one population on Iron Mountain in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I, VI
34	Gander's pitcher sage (*Lepechinia ganderi*) Regionally sensitive species/List 1B, R-E-D 3-1-2	Close-coned coniferous forests, chaparral, coastal sage scrub, and valley and foothill grasslands.	San Diego County and Baja, California, Mexico. Known from four localities in San Diego County (Otay Mountain, the Jamul Mountains, San Miguel Mountain, and Donohoe Mountain).	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species. Three of the 4 populations are currently in designated open space.	I, II, VI

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	PLANTS					
35	Del Mar Mesa sand aster (*Corethrogyne filaginifolia* var. *linifolia*) PT/List 1B, R-E-D 3-2-3	Chaparral and coastal sage scrub.	San Diego County. Restricted to a few, disjunct populations between Los Penasquitos Canyon and Encinitas (possibly Carlsbad).	FESA (assuming federal action associated with take) and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves populations and habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I
36	Nuttall's lotus (*Lotus nuttallianus*) Regionally sensitive species/List 1B, R-E-D 3-3-2	Coastal dunes and coastal sage scrub.	Southern San Diego County to northern Baja California, Mexico. Restricted to approximately 6 localities along the immediate coast in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I, III
37	Felt-leaved monardella (*Monardella hypoleuca* ssp. *lanata*) Regionally sensitive species/List 1B, R-E-D 2-2-2	Chaparral and cismontane woodland.	Orange and San Diego counties to Baja California, Mexico. Known from approximately 30 localities in San Diego County and possibly 1 locality in Orange County.	Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I, VI
38	Willowy monardella (*Monardella linoides* ssp. *viminea*) PE/CE/List 1B, R-E-D 2-3-2	Close-coned coniferous forests, chaparral, riparian forests, riparian scrub, and riparian woodland.	San Diego County to Baja California, Mexico. Known from approximately 16 localities in San Diego County.	CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, IV, V, VI
39	San Diego golden star (*Muilla clevelandii*) Regionally sensitive species/List 1B, R-E-D 2-2-2	Chaparral, coastal sage scrub, valley and foothill grasslands, and vernal pools.	San Diego County to Baja California, Mexico. Known from approximately 112 localities in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitat that may include the species. Vernal pool populations will be adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, II, IX
40	Little mousetail (*Myosurus minimus* ssp. *apus*) Regionally sensitive species/List 3, R-E-D 2-3-2	Vernal pools (alkaline).	Riverside, San Bernardino, San Diego, Butte, Alameda, Contra Costa, Colusa, Solano, Stanislaus, and Kern counties; Oregon; Baja California, Mexico. Restricted to several vernal pool complexes on the mesas north of San Diego and on Otay Mesa in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	IX
41	Prostrate navarretia (*Navarretia fossalis*) PT/List 1B, R-E-D 2-3-2	Vernal pools.	Riverside, San Diego counties to Baja California, Mexico. Restricted to populations on Otay Mesa, Camp Pendleton, and Ramona in San Diego County.	FESA (assuming federal action associated with take) and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	IX

TABLE 3.1 COVERED SPECIES LIST

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	PLANTS					
42	Snake cholla (*Opuntia parryi* var. *serpentina*) Regionally sensitive species/List 1B, R-E-D 3-3-2	Chaparral, coastal sage scrub, and maritime succulent scrub.	Southwestern San Diego County into northwestern Baja California, Mexico. In San Diego County is known from approximately 14 localities.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs.	I, IV
43	California Orcutt grass (*Orcuttia californica*) FE/CE/List 1B, R-E-D 3-3-2	Vernal pools.	Riverside and San Diego counties and in Baja California, Mexico. Known from approximately 10 localities in San Diego County and approximately 3 localities in Riverside County.	FESA (assuming federal action associated with take), CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	IIX
44	Torrey pine (*Pinus torreyana*) Regionally sensitive species/List 1B, R-E-D 3-2-3	Sandstone in close-coned coniferous forests and chaparral.	Along the coast near Del Mar in San Diego County and on Santa Rosa Island. Known only from these two localities as natives.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I
45	San Diego mesa mint (*Pogogyne abramsii*) FE/CE/List 1B, R-E-D 2-3-3	Vernal pools.	San Diego County (Los Peñasquitos Canyon, Miramar, and San Diego). Restricted to these vernal pool complexes.	FESA (assuming federal action associated with take), CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	IX
46	Otay mesa mint (*Pogogyne nudiuscula*) FE/CE/List 1B, R-E-D 3-3-2	Vernal pools.	Southwestern San Diego County and Baja California, Mexico. Restricted to 3 to 5 vernal pool complexes on Otay Mesa in San Diego County.	FESA (assuming federal action associated with take), CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	IV, IX
47	Small-leaved rose (*Rosa minutifolia*) CE/List 2, R-E-D 3-3-1	Chaparral.	San Diego County to Baja California, Mexico. In San Diego County, restricted to 1 thicket on northwestern Otay Mesa.	CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves populations and habitat to maximum extent practicable and preserves corridors connecting habitat thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitat that may include the species.	I
48	Dehesa beargrass (*Nolina interrata*) PT/CE/List 1B, R-E-D 3-3-2	Chaparral (gabbroic and serpentinite)	San Diego County to Baja California, Mexico. Known from approximately 9 localities in San Diego County.	CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves populations and habitat to maximum extent practicable and preserves corridors connecting habitat thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitat that may include the species.	I

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	PLANTS					
49	San Miguel savory (*Satureja chandleri*) Regionally sensitive species/List 4, R-E-D 1-2-2	Chaparral, cismontane woodland, coastal sage scrub, riparian woodland, and valley and foothill grasslands.	Northern Baja California, Mexico; San Diego County; and adjacent Orange and western Riverside counties. An extremely rare shrub with very few recent reports.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, II, V, VI
50	Gander's butterweed (*Senecio ganderi*) CR/List 1B, R-E-D 3-2-3	Chaparral (burned areas, gabbroic outcrops).	San Diego and Riverside counties. Known from approximately 11 localities in San Diego County.	CESA, NPPA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves populations and habitat to maximum extent practicable and preserves corridors connecting habitat thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitat that may include the species.	I
51	Narrow-leaved nightshade (*Solanum tenuilobatum*) Regionally sensitive species	Chaparral.	Southern San Diego County to Baja California, Mexico. Otay Mountain is a focus for populations of this species. Known from approximately 30 localities in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitat. The Plan also preserves habitat to maximum extent practicable and preserves corridors connecting habitat thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitat that may include the species.	I
52	Parry's tetracoccus (*Tetracoccus dioicus*) Regionally sensitive species/List 1B, R-E-D 3-2-2	Chaparral and coastal sage scrub.	San Diego and Riverside counties and Baja California, Mexico. Approximately 32 known localities but rare in the southern portions of San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I

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#	SPECIES NAME & STATUS	HABITAT TYPES	RANGEWIDE AND LOCAL DISTRIBUTION OF SPECIES	DEGREE OF EXISTING PROTECTION	CONSERVATION PLANNING IMPLICATIONS	MITIGATION
	ANIMALS					
1	Cooper's hawk (*Accipiter cooperii*) SSC	Riparian woodlands.	Throughout the continental U.S. excluding Alaska, parts of Montana, and parts of the Dakotas. Winters south to Mexico and Honduras. Uncommon migrant, winter visitor, and summer resident in San Diego County. Breeds in San Diego County.	CEQA and MBTA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan are discountable because the species has such a widespread distribution. Also, the Plan preserves its habitats to the maximum extent practicable. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	VIII
2	Tricolored blackbird (*Agelaius tricolor*) SSC	Croplands, edges of fields, and edges of ponds.	California's Central Valley, west of the Sierra Nevada Mountains from San Diego County north to Lake County. Breeding populations in California in Siskiyou and Modoc counties and in southern Oregon. Very common to abundant, but localized, resident in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III
3	Southern California rufous-crowned sparrow (*Aimophila ruficeps canescens*) SSC	Coastal sage scrub and chaparral.	Ventura County southeast through Los Angeles, Orange, Riverside and San Diego counties to northwestern Baja California, Mexico. Uncommon to fairly common, but localized, resident in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	I
4	Grasshopper sparrow (*Ammodramus savannarum*) Regionally sensitive species	Grasslands.	Southern Canada to the southern U.S., West Indies, and Mexico to Ecuador. Uncommon and localized summer resident; may be very rare in winter.	Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, the species has a somewhat broad distribution, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats thereby providing for genetic material exchange and opportunities for natural population expansion. It may also restore and reclaim habitats that may include the species.	II
5	Golden eagle (*Aquila chrysaetos*) BEPA/SSC	Rolling foothills, mountains, sage-juniper flats, and desert.	Mountain regions of the Northern Hemisphere. Throughout California except the center of the Central Valley. Uncommon resident in San Diego County. As of 1981, the number of breeding pairs(38) within the western half of the County had decreased by 33% from 1928 levels.	BEPA and CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan are discountable because the species is an uncommon resident in San Diego County, and any impacts would be extremely small relative to the large range of the species. Also, the Plan preserves its habitats to the maximum extent practicable.	VIII
6	Canada goose (*Branta canadensis*) Regionally sensitive species	Fresh, emergent wetlands, moist grasslands, croplands, pastures, and meadows.	Alaska, Canada, northern U.S. Winters to northern Mexico. Central Valley, Salton Sea, and northeastern California. Abundant but localized winter visitor. Wintering populations have declined in San Diego County due to wetland habitat loss.	MBTA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, the species has a somewhat broad distribution, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	II, III
7	Ferruginous hawk (*Buteo regalis*) SSC	Grasslands, sagebrush flats, desert scrub, low foothills surrounding valleys, and pinyon-juniper habitats.	Southwestern Canada and the western U.S. Winters in the southwestern U.S. and northern Mexico. Uncommon winter visitor.	CEQA and MBTA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan are discountable because the species is an uncommon winter visitor in San Diego County, and any impacts would be extremely small relative to the large range of the species. Also, the Plan preserves its habitats to the maximum extent practicable.	VIII

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	ANIMALS					
8	Swainson's hawk (*Buteo swainsoni*) CT	Juniper-sage flats, riparian areas, oak savannah, and grasslands.	Northwestern North America to northern Mexico. Winters to Argentina. Spring and fall transient in southern California. Uncommon breeding resident in northeastern California and the Central Valley. Uncommon spring migrant; very rare fall migrant.	CESA, CEQA, and MBTA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan are discountable because the species is an uncommon spring migrant and very rare fall migrant in San Diego County, and any impacts would be extremely small relative to the large range of the species. Also, the Plan preserves individuals and habitats to the maximum extent practicable. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	VIII
9	Coastal cactus wren (*Campylorhynchus brunneicapillus*) SSC	Coastal sage scrub and maritime succulent scrub.	Southern Orange County south through San Diego County into northwestern Baja California, Mexico. San Diego County population estimated to be less than 300 pairs with highly disjunct distribution and small, fragmented populations.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided; no direct killing or injury to individuals will occur unless deemed necessary for emergencies or repairs.	I, IV
10	Western snowy plover (coastal) (*Charadrius alexandrinus nivosus*) FT/SSC	Sandy marine and estuarine shores.	Breeds throughout the western U.S.; Baja California, Mexico; the coastal southeastern U.S.; and the Bahamas. In winter, migrates to coastal areas and south to Central and South America. Common migrant, winter visitor, and localized breeding resident in San Diego County.	FESA, CEQA, and MBTA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves individuals and habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III, VII
11	Mountain plover (*Charadrius montanus*) SSC	Grasslands and plowed fields.	Breeds in the U.S. west of 95° W longitude in the Great Plains and Rocky Mountain states. Winters from the southwestern U.S. to Mexico, including the Baja California, Mexico. Common to very common, but extremely localized, winter visitor.	CEQA and MBTA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, the species has a somewhat broad distribution, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	II
12	Northern harrier (*Circus cyaneus*) SSC	Meadows, grasslands, open rangelands, desert sinks, and fresh and saltwater emergent wetlands.	Widespread throughout the temperate regions of North America and Eurasia. Uncommon to fairly common migrant and winter visitor, rare and local summer resident in San Diego County.	CEQA and MBTA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan are discountable because the species is an uncommon to fairly common migrant and winter visitor but a rare and local summer resident in San Diego County. Any impacts would be extremely small relative to the large range of the species. Also, the Plan preserves its habitats to the maximum extent practicable. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	VIII
13	Reddish egret (*Egretta rufescens*) Regionally sensitive species	Brackish marshes, shallow, coastal habitats, and mangroves.	Breeds on southeast coast of the U.S.; east and west coasts of Baja California, Mexico; other parts of Mexico; and on some Carribean islands. Winters throughout its breeding range, but extends its range south to include Central America to El Salvador. A few reddish egrets (1-4 individuals) are typically found along the southern San Diego County coast. Most occurrences are in fall and winter. There are no breeding records for the County.	CEQA and MBTA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan are discountable because the species is found in very small numbers (1-4 individuals) in the fall and winter in San Diego County. Also, the Plan preserves its habitats to the maximum extent practicable. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III
14	Southwestern willow flycatcher (*Empidonax traillii extimus*) FE/CE	Breeds in thickets of willows or other riparian understory, along streams, ponds or lakes, or in canyon drainage bottoms. Migrants may be located among any of the larger trees or shrubs in the County of San Diego but seem to prefer damp areas.	U.S. breeding range is so. California, Arizona, Utah, Nevada, New Mexico, and Texas. Small, breeding populations persist in major river valleys in San Diego County.	FESA, CESA, CEQA, and MBTA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves individuals and habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	V
15	American peregrine falcon (*Falco peregrinus anatum*) FE/CE	Open grasslands and scrublands, cliffs and steep terrain, sometimes urban areas. Often found along the coast or near lagoons and ponds where waterfowl gather.	Southern California as a rare visitor, primarily along the coast. Only one pair has bred in San Diego County since the 1950s. In winter, occurs along coastal areas and at reservoirs in the County.	FESA, CESA, CEQA, and MBTA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan are discountable because the species is a rare visitor along the coast in San Diego County, and any impacts would be extremely small relative to the large range of the species. Also, the Plan preserves individuals and habitats to the maximum extent practicable. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	VIII

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	ANIMALS					
16	Bald eagle (*Haliaeetus leucocephalus*) (BEPA) FE/CE	Coasts, rivers, large lakes, mountains, and open country.	Alaska, Canada to southern U.S. Inland waters in winter in southern California. Uncommon winter visitor to San Diego County.	BEPA, FESA, CESA, CEQA, and MBTA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan are discountable because the species is an uncommon winter visitor in San Diego County. Also, the Plan preserves individuals and habitats to the maximum extent practicable. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	VIII
17	Long-billed curlew (*Numenius americanus*) SSC	Rangeland, cultivated land, tideflats, beaches, and salt marshes.	Southwestern Canada, western U.S. Winters to Guatemala. Common migrant and winter visitor to San Diego County; no breeding records.	CEQA and MBTA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, the species has a somewhat broad distribution, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III
18	Belding's savannah sparrow (*Passerculus sandwichensis beldingi*) CE	Restricted to salt marshes around coastal lagoons that are dominated by pickleweed (*Salicornia* spp.)	Santa Barbara County south to El Rosario, Baja California, Mexico. Localized, permanent resident in San Diego County.	CESA and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves individuals and habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III
19	Large-billed savannah sparrow (*Passerculus sandwichensis rostratus*) SSC	Open fields, meadows, salt marshes, dunes, and shores.	Alaska, Canada to Guatemala. Winters to Honduras, West Indies. Scarce along the southern California coast.	CEQA and MBTA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan are discountable because the species is scarce along the southern California coast. Also, the Plan preserves its habitats to the maximum extent practicable. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III
20	California brown pelican (*Pelecanus occidentalis californicus*) FE/CE	Open salt water, bays, and beaches.	West coast of the U.S. and Baja California, Mexico. Common to very common non-breeding visitor to San Diego County.	FESA, CESA, CEQA, and MBTA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves individuals and habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III, VII
21	White-faced ibis (*Plegadis chihi*) SSC	Freshwater marshes, irrigated land.	Western U.S. to Argentina. In San Diego County, uncommon migrant and winter visitor; rare in summer.	CEQA and MBTA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan are discountable because the species is an uncommon migrant and winter visitor and is rare in summer in San Diego County. Also, the Plan preserves its habitats to the maximum extent practicable. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III
22	Coastal California gnatcatcher (*Polioptila californica californica*) FT/SSC	Coastal sage scrub.	Southern Los Angeles, Orange, western Riverside, and San Diego counties south into Baja California, Mexico. In 1990, Atwood estimated that approximately 1,819 to 2,262 pairs occurred in southern California.	FESA and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves individuals and habitat to maximum extent practicable and preserves corridors connecting habitat. It may also restore and reclaim habitat that may include the species.	I
23	Light-footed clapper rail (*Rallus longirostris levipes*) FE/CE	Saltwater and brackish marshes.	Central and southern California; Baja California, Mexico; and the Gulf of California. The total California population was estimated to be 235 pairs in 1991.	FESA, CESA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves individuals and habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III
24	Western bluebird (*Sialia mexicana*) Regionally sensitive species	Scattered trees; open, coniferous forests; and farms. In winter, brush and deserts.	Southern British Columbia and western U.S. to the mountains of central Mexico. Common to very common resident and winter visitor in San Diego County.	Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, the species has a somewhat broad distribution, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	VI

TABLE 3.1 COVERED SPECIES LIST

#	SPECIES NAME & STATUS	HABITAT TYPES	RANGEWIDE AND LOCAL DISTRIBUTION OF SPECIES	DEGREE OF EXISTING PROTECTION	CONSERVATION PLANNING IMPLICATIONS	MITIGATION
	ANIMALS					
25	Western burrowing owl (*Speotyto cunicularia hypogea*) SSC	Open grasslands, prairies, farmlands, and airfields.	Southwestern Canada, western U.S. Uncommon and rapidly declining in California.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided; no direct killing or injury to individuals will occur unless deemed necessary for emergencies or repairs.	II, IV
26	California least tern (*Sterna antillarum browni*) FE/CE	Sea beaches, bays, large rivers, bars.	Temperate and tropical oceans. Winters south of the U.S. In San Diego County the number of nesting pairs was 500 in 1991.	FESA, CESA, CEQA, and MBTA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves individuals and habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III
27	Elegant tern (*Sterna elegans*) SSC	Shallow ocean waters, bays, and lagoons. Strictly associated with salt water.	Breeds on islands off Baja California, Mexico and near San Diego. Winters from Peru to Chile. Irregularly wanders north to San Francisco Bay. Abundant summer resident in the single nesting colony at the south end of the San Diego Bay.	CEQA and MBTA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III
28	Least Bell's vireo (*Vireo bellii pusillus*) FE/CE	Riparian woodlands.	Formerly common and widespread in California and northwestern Baja California, Mexico. Known to winter only in southern Baja California, Mexico. Over 460 breeding pairs or territorial males were documented in San Diego County in 1991.	FESA, CESA, CEQA, and MBTA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves individuals and habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	V
29	Thorne's hairstreak butterfly (*Mitoura thornei*) Regionally sensitive species	Closed-cone pine forest.	Restricted to the same distribution of the larval food plant, Tecate cypress (*Cupressus forbesii*). in three locations in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitat. The Plan also preserves habitat to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitat that may include the species.	VII
30	San Diego fairy shrimp (*Branchinecta sandiegoensis*) PE	Seasonally astatic pools which occur in tectonic swales or earth slump basins in patches of grassland and agriculture interspersed in coastal sage scrub and southern mixed chaparral vegetation.	Occurs throughout San Diego County.	FESA and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	IX
31	Salt marsh skipper (*Panoquina errans*) Regionally sensitive species	Tidelands and estuaries.	Santa Barbara County to the southern tip of Baja California, Mexico. Associated with nearly every coastal lagoon in San Diego County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided; no direct killing or injury to individuals will occur unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	III, IV
32	Riverside fairy shrimp (*Streptocephalus woottoni*) FE	Seasonally astatic pools occurring in tectonic swales or earth slump basins in patches of grassland and agriculture interspersed in coastal sage scrub.	Known only from five vernal pools in western Riverside County in the vicinity of Temecula and Rancho California, from one pool on Otay Mesa in San Diego County, and from one pool at an undisclosed location in northern Baja California, Mexico.	FESA and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts to vernal pools will be avoided unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	IX
33	Coronado skink (*Eumeces skiltonianus interparietalis*) SSC	Grasslands, coastal sage scrub, open chaparral, pine oak woodland, and coniferous forests.	Southwestern California from Los Angeles County south into northwestern Baja California, Mexico. Also occurs on several islands off the Pacific coast including Los Coronados Islands. Relatively limited distribution.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I

TABLE 3.1 COVERED SPECIES LIST

#	SPECIES NAME & STATUS	HABITAT TYPES	RANGEWIDE AND LOCAL DISTRIBUTION OF SPECIES	DEGREE OF EXISTING PROTECTION	CONSERVATION PLANNING IMPLICATIONS	MITIGATION
	ANIMALS					
34	Stephens' kangaroo rat (*Dipodomys stephensi*) FE/CT	Grasslands, coastal sage scrub or sagebrush with sparse canopy cover, and disturbed areas.	Around San Jacinto Valley from Riverside County south to the vicinity of Vista in San Diego County. Geographic range is estimated to encompass 708,641 acres, which is unusually small for rodents, particularly kangaroo rats.	FESA, CESA, and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided; no direct killing or injury to individuals will occur unless deemed necessary for emergencies or repairs.	X
35	San Diego desert woodrat (*Neotoma lepida intermedia*) SSC	Favors xeric habitats. Coastal habitats include open chaparral and coastal sage scrub.	Restricted to the coastal slope of southern California, from San Luis Obispo County south into northwestern Baja California, Mexico. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I
36	Pacific little pocket mouse (*Perognathus longimembris pacificus*) FE/SSC	Near the ocean where the substrate consists of fine, alluvial sands, and the dominant vegetation is coastal sage scrub or weeds.	Historically recorded from Marina del Rey/El Segundo south along the coast to the Tijuana River Valley north of the international border in San Diego County. May occur at other localities. Only three currently recorded localities remain out of eight historic localities: Dana Point, Orange County and Marine Corps Base Camp Pendleton, San Diego County.	FESA and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided; no direct killing or injury to individuals will occur unless deemed necessary for emergencies or repairs.	I, IV
37	Northwestern San Diego pocket mouse (*Chaetodipus fallax fallax*) SSC	Coastal sage scrub and weedy growth, often on sandy substrates.	Southwestern San Bernardino, western Riverside, eastern Los Angeles, and San Diego counties south into Baja California, Mexico. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I
38	Pallid San Diego pocket mouse (*Chaetodipus fallax pallidus*) SSC	Chamise-redshank and mixed chaparrals, sagebrush, desert wash, desert scrub, pinyon-juniper, and annual grassland .	Eastern Los Angeles, southwestern San Bernardino, central Riverside, eastern San Diego, and western Imperial Counties. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I, II
39	Dulzura pocket mouse (*Chaetodipus californicus femoralis*) SSC	Primarily associated with mature chaparral and is less common in open stands of this vegetation. Has been trapped in mulefat scrub.	Santa Margarita River south to northern Baja California, Mexico. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I, V
40	Southern grasshopper mouse (*Onychomys torridus ramona*) SSC	Wide variety including various scrublands. May be associated with clumps of cactus or yucca.	Northern Los Angeles County along the coastal slope to extreme northwestern Baja California, Mexico. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I
41	Los Angeles pocket mouse (*Perognathus longimembris brevinasus*) SSC	Coastal sage scrub and sagebrush.	Los Angeles, southwestern San Bernardino, and western Riverside counties. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I
42	Jacumba pocket mouse (*Perognathus longimembris internationalis*) SSC	Sagebrush.	San Diego County. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitat. The Plan also preserves habitat to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitat that may include the species.	I
43	San Diego black-tailed jackrabbit (*Lepus californicus bennettii*) SSC	Coastal sage scrub, chaparral, grasslands, croplands, and open, disturbed areas provided there is at least some scrub cover present.	Southern Santa Barbara County, south on the coastal slope to the vicinity of San Quintin, Baja California, Mexico. Localities on the eastern edge of its range include Jacumba and San Felipe Valley in San Diego County. Relatively common in open areas in coastal southern California.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I, II

TABLE 3.1 COVERED SPECIES LIST

#	SPECIES NAME & STATUS	HABITAT TYPES	RANGEWIDE AND LOCAL DISTRIBUTION OF SPECIES	DEGREE OF EXISTING PROTECTION	CONSERVATION PLANNING IMPLICATIONS	MITIGATION
	ANIMALS					
44	Mountain lion (*Felis concolor*) Regionally sensitive species	Nearly all habitats.	In California, sea level to alpine meadows, except xeric regions of the Mojave and Colorado deserts not supporting mule deer (*Odocoileus hemionus*) populations. Relatively common and most abundant in riparian areas and brushy stages of most habitats.	Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	None
45	Southern mule deer (*Odocoileus hemionus fuliginata*) Game species	Coastal sage scrub, riparian and mountain forests, chaparral, grasslands, croplands, and open, disturbed areas provided there is at least some scrub cover present.	Southern Riverside County (Tahquitz Valley), south on the coastal slope to the vicinity of San Quintin, Baja California, Mexico. Relatively common along the coastal foothills of southern California.	Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	None
46	American badger (*Taxidea taxus*) SSC	Drier, open stages of most shrub, forest, and herbaceous habitats with friable soils.	Central and southwestern North America. Throughout most of California except the North Coast area. Widespread but thought to be declining in California.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	II
47	Arroyo southwestern toad (*Bufo microscaphus californicus*) FE/SSC	Restricted to rivers with shallow, gravelly pools adjacent to sandy terraces.	Formerly distributed from southern California to the northwestern coastal region of Baja California, Mexico. Most remaining populations occur within, or adjacent to, the Cleveland National Forest. Only 6 of the 22 extant populations south of Ventura are known to contain more than a dozen adults.	FESA and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan prioritizes avoidance, minimization, and mitigation (in that order) for any potential impacts. The Plan preserves individuals and habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	V
48	Western spadefoot toad (*Scaphiopus hammondi*) SSC	Occurs primarily in grassland situations, but occasional populations occur in valley-foothill hardwood woodlands.	In California, throughout the Central Valley and adjacent foothills from Santa Barbara County south to the Mexican border. Usually quite common where it occurs.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I
49	Southwestern pond turtle (*Clemmys marmorata pallida*) SSC	Wetland habitats including freshwater marshes, creeks, ponds, and reservoirs.	Vicinity of Monterey south into northwestern Baja California, Mexico. Primarily west of the major mountain ranges in southern California, but there is a population along the Mojave River in San Bernardino County. Very few viable populations left south of Santa Barbara County.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	V
50	Orangethroat whiptail (*Cnemidophorus hyperythrus beldingi*) SSC	Coastal sage scrub, chaparral, edges of riparian woodlands, and washes; and in weedy, disturbed areas adjacent to these habitats.	Southern Orange County and southern San Bernardino County (Colton), south to the cape of Baja California, Mexico. Locally common.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I
51	San Diego banded gecko (*Coleonyx variegatus abboti*) Regionally sensitive species	Chaparral and coastal sage scrub in areas with rock outcrops.	Southern slopes of the San Gabriel Mountains of Los Angeles County, south throughout cismontane and coastal southern California into northwestern Baja California, Mexico. Also found on Cedros Island off the Pacific coast of Baja California, Mexico. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I

#	SPECIES NAME & STATUS	HABITAT TYPES	RANGEWIDE AND LOCAL DISTRIBUTION OF SPECIES	DEGREE OF EXISTING PROTECTION	CONSERVATION PLANNING IMPLICATIONS	MITIGATION
	ANIMALS					
52	Northern red rattlesnake (*Crotalus ruber ruber*) SSC	Chaparral, woodland, and arid habitats in rocky areas and dense vegetation.	Extreme southeastern Los Angeles County (Diamond Bar) into southern San Bernardino County and south into southern Baja California, Mexico. Relatively common in the foothill zone and on the desert slopes.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I
53	San Diego ringneck snake (*Diadophis punctatus similis*) Regionally sensitive species	Oak woodlands and canyon bottoms. Sometimes encountered in grassland, chaparral, and coastal sage scrub.	Southwestern San Bernardino County south along the coastal slope into northwestern Baja California, Mexico. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I
54	Coastal rosy boa (*Lichanura trivirgata roseofusca*) Regionally sensitive species	In or near rocky areas in coastal sage scrub, chaparral, and desert scrub.	Transverse Ranges in Los Angeles and San Bernardino counties south into northwestern Baja California, Mexico. It also ranges east to the lower desert slope. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I
55	San Diego horned lizard (*Phrynosoma coronatum blainvillei*) SSC	Coastal sage scrub, chaparral, open oak woodlands and open coniferous forests in the mountains.	Southern California, west of the deserts, and ranges south into northern Baja California, Mexico. Relatively common in foothill areas that contain large expanses of good habitat.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I
56	California red-legged frog (*Rana aurora draytonii*) PE/SSC	Dense shrubby, emergent riparian vegetation closely associated with deep, still, or slow moving water.	Central and southern California. Has been extirpated from 75% of its former range.	FESA and CEQA. Plan's Operational Protocols would not be in place to avoid impacts as a first priority during SDG&E activities.	Adequately conserved by the Plan because impacts will be avoided; no direct killing or injury to individuals will occur unless deemed necessary for emergencies or repairs. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	IV, V
57	Coast patch-nosed snake (*Salvadora hexalepis virgultea*) SSC	Primarily chaparral, but also coastal sage scrub and areas of grassland mixed with scrub.	Santa Barbara County south to northwestern Baja California, Mexico. Population information lacking.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species.	I
58	Two-striped garter snake (*Thamnophis hammondii*) Regionally sensitive species	Along permanent creeks, streams, vernal pools and along intermittent creeks. Occasionally found in chaparral or other habitats relatively far from permanent water.	Monterey County south through the coastal ranges into northwestern Baja California, Mexico. Rare or extirpated from many areas where it was formerly common.	CEQA. Plan's Operational Protocols would not be in place to minimize or mitigate impacts as a first priority during SDG&E activities.	Effects of Plan on species are considered insignificant because impacts would generally be very small, and the Plan minimizes or mitigates (in that order) any potential impacts that occur to the species' habitats. The Plan also preserves habitats to maximum extent practicable and preserves corridors connecting habitats. It may also restore and reclaim habitats that may include the species. Permitting pursuant to Section 404 of the federal Clean Water Act and/or Section 1600 of the California Fish and Game Code may be necessary for impacts to ACOE and/or CDFG jurisdictional areas.	I

STATUS
SSC = CDFG Species of special concern
CE = California endangered
CT = California threatened
CR = California rare
FE = Federally listed endangered
FT = Federally listed threatened
PE = Federally proposed endangered
PT = Federally proposed threatened
C1 = Enough data to support federal listing

List 1B = Rare and endangered in California and elsewhere
List 2 = Rare and endangered in California but more common elsewhere
List 3 = More information needed
List 4 = Limited distribution (a watch list)

R (Rarity)
1 = Rare but found in sufficient numbers and distributed widely enough that potential for extinction or extirpation is low at this time.
2 = Occurrence confined to several populations or one extended population.
3 = Occurrence limited to 1 or a few highly restricted populations or present in such small numbers that it is seldom reported.

E (Endangerment)
1 = Not endangered
2 = Endangered in a portion of its range
3 = Endangered throughout its range

D (Distribution)
1 = More or less widespread outside of California
2 = Rare outside California
3 = Endemic to California

ABBREVIATIONS
ACOE = U.S. Army Corps of Engineers
BEPA = Bald Eagle Protection Act
CDFG = California Department of Fish and Game
CEQA = California Environmental Quality Act
CESA = California Endangered Species Act
FESA = Federal Endangered Species Act
MBTA = Migratory Bird Treaty Act
NPPA = Native Plant Protection Act

MITIGATION
I. Scrub and chaparral species
II. Grassland species
III. Beach, marsh, and wetland species
IV. Narrow endemic plant and animal species
V. Riparian species
VI. Forest (woodland) species
VII. Open water species
VIII. Raptor species
IX. Vernal pool species
X. Stephens' kangaroo rat

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SDG&E Subregional NCCP

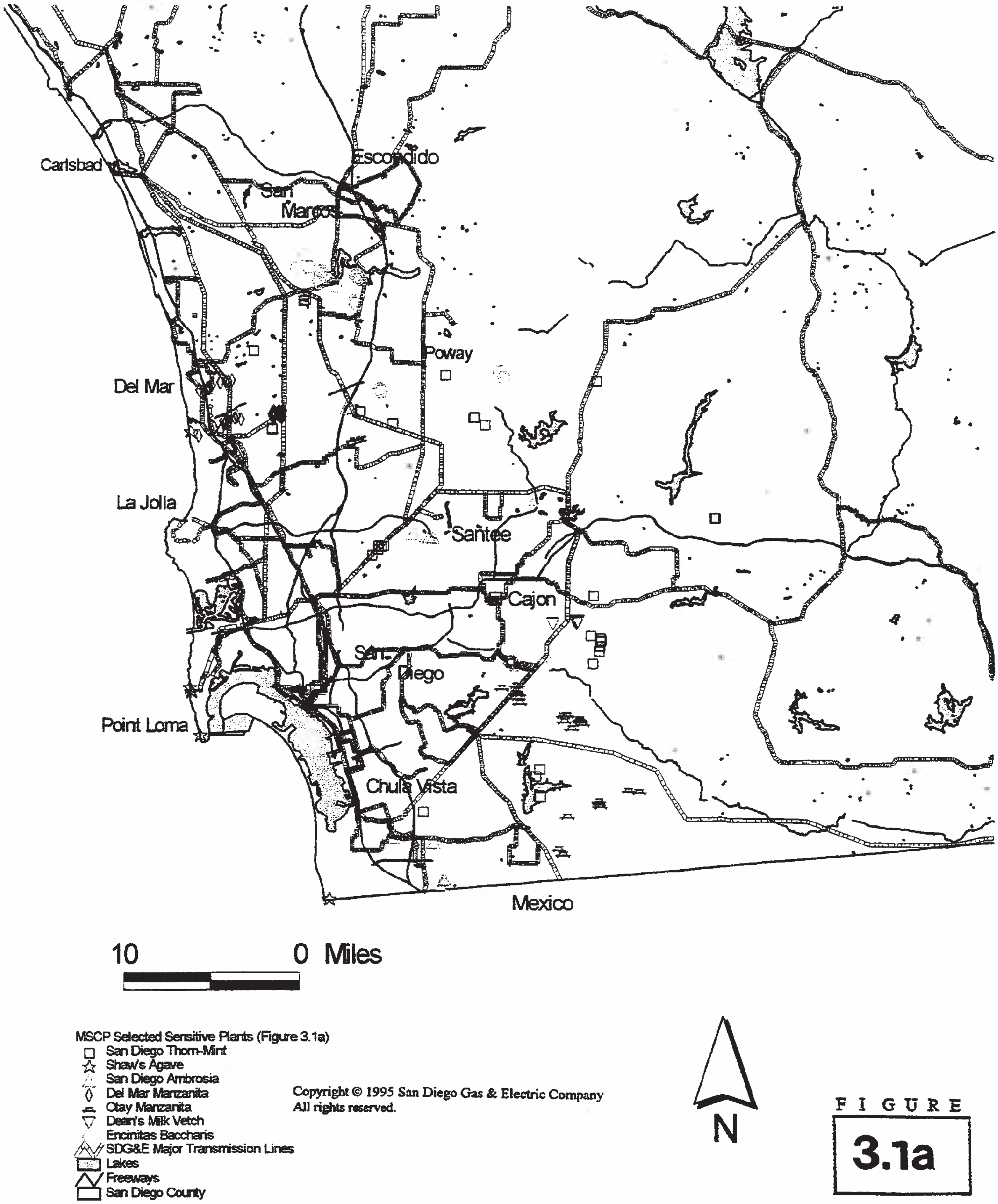
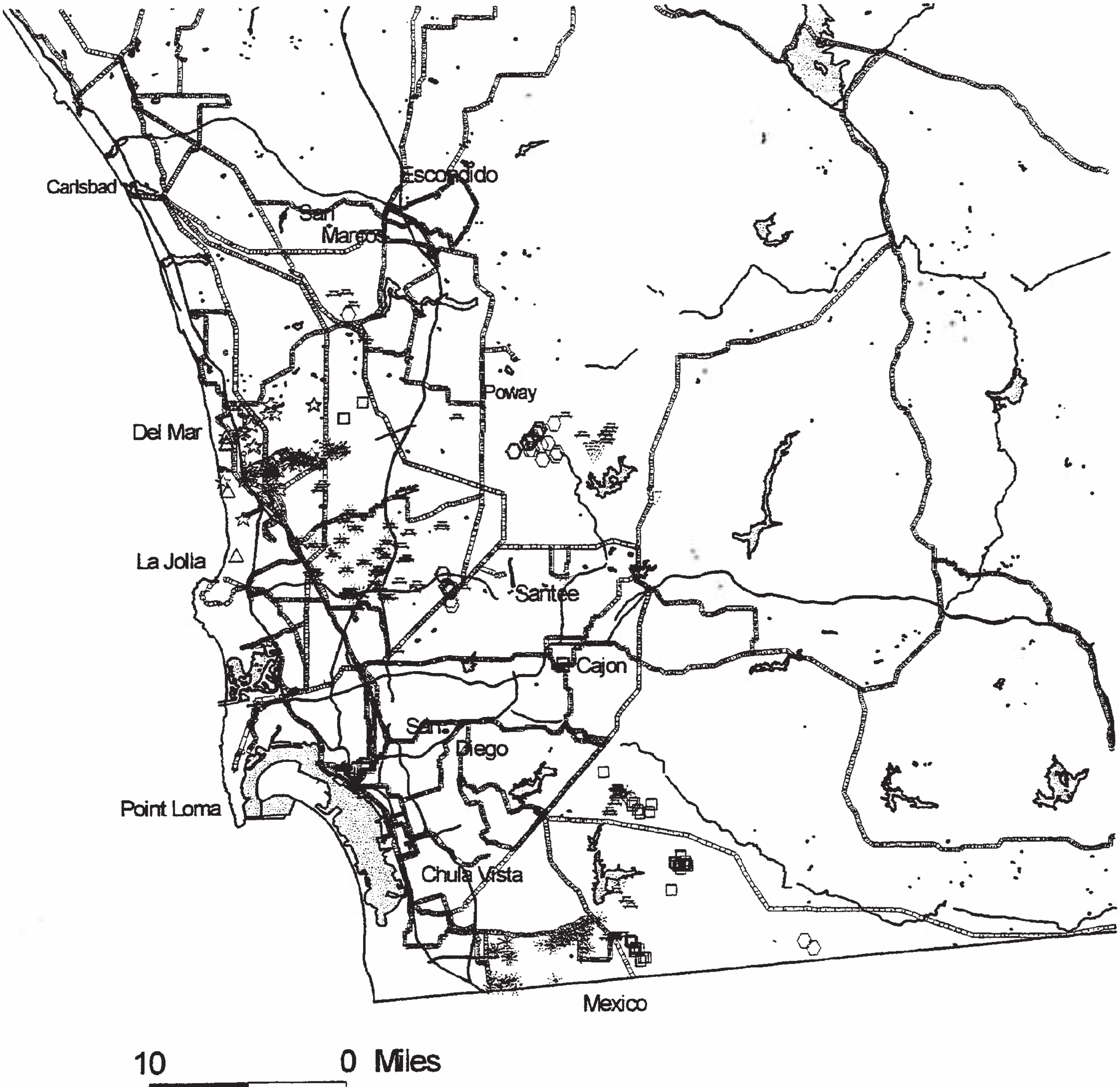


FIGURE 3.1a

SDGE Subregional Natural Community Conservation Plan

SDG&E Subregional NCCP



MSCP Selected Sensitive Plants (Figure 3.1b)
- Orcutt's Brodiaea
- Dunn's Mariposa Lily
- Slendor-Pod Jewelflower
- Lakeside Ceanothus
- Del Mar Mesa Sand Aster
- Short-Leaved Dudleya
- Sticky Dudleya
- San Diego Button-Celery
- SDG&E Major Transmission Lines
- Lakes
- Freeways
- San Diego County

N

FIGURE
3.1b

SDG&E Subregional NCCP

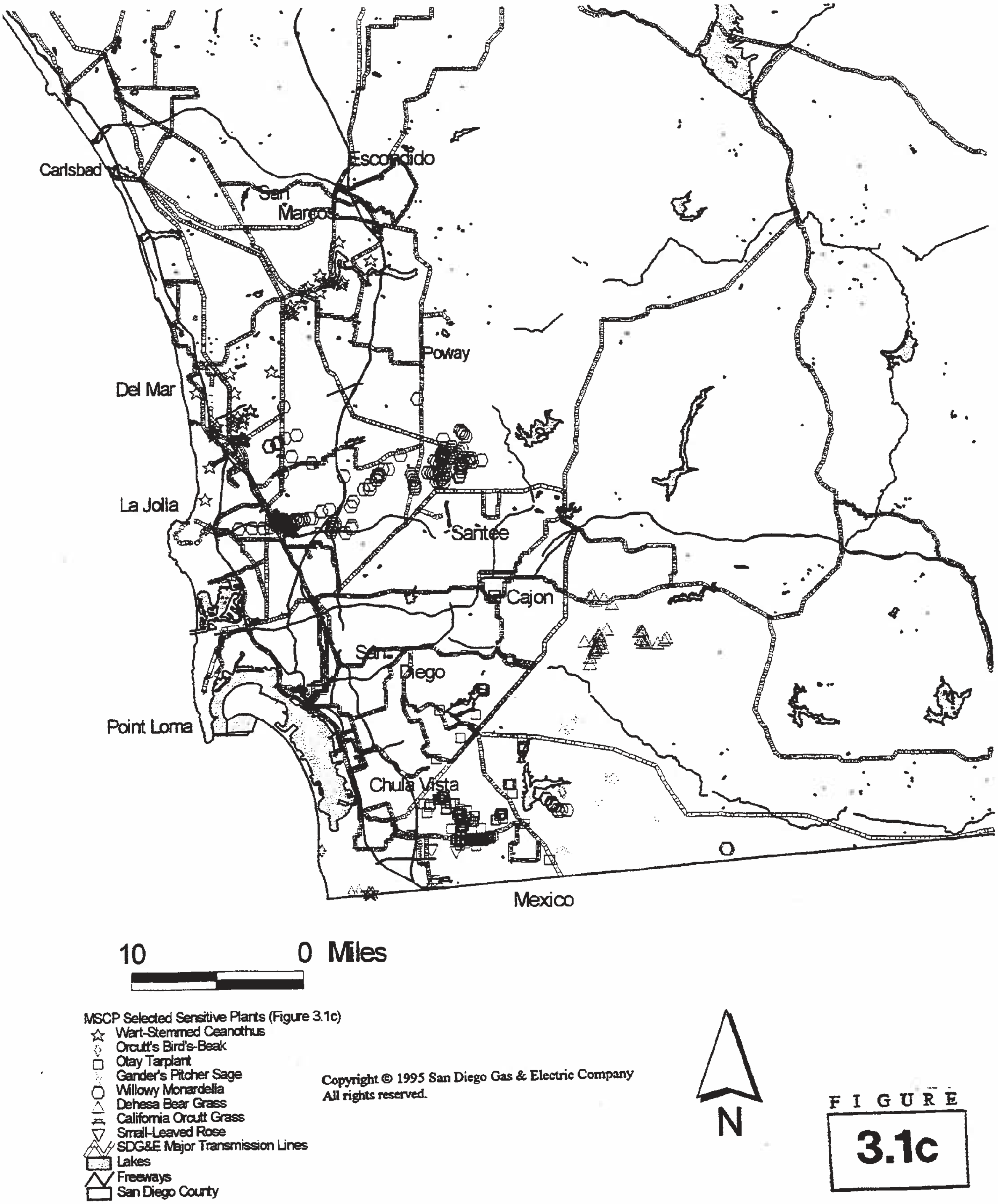


FIGURE 3.1c

SDGE Subregional Natural Community Conservation Plan

SDG&E Subregional NCCP

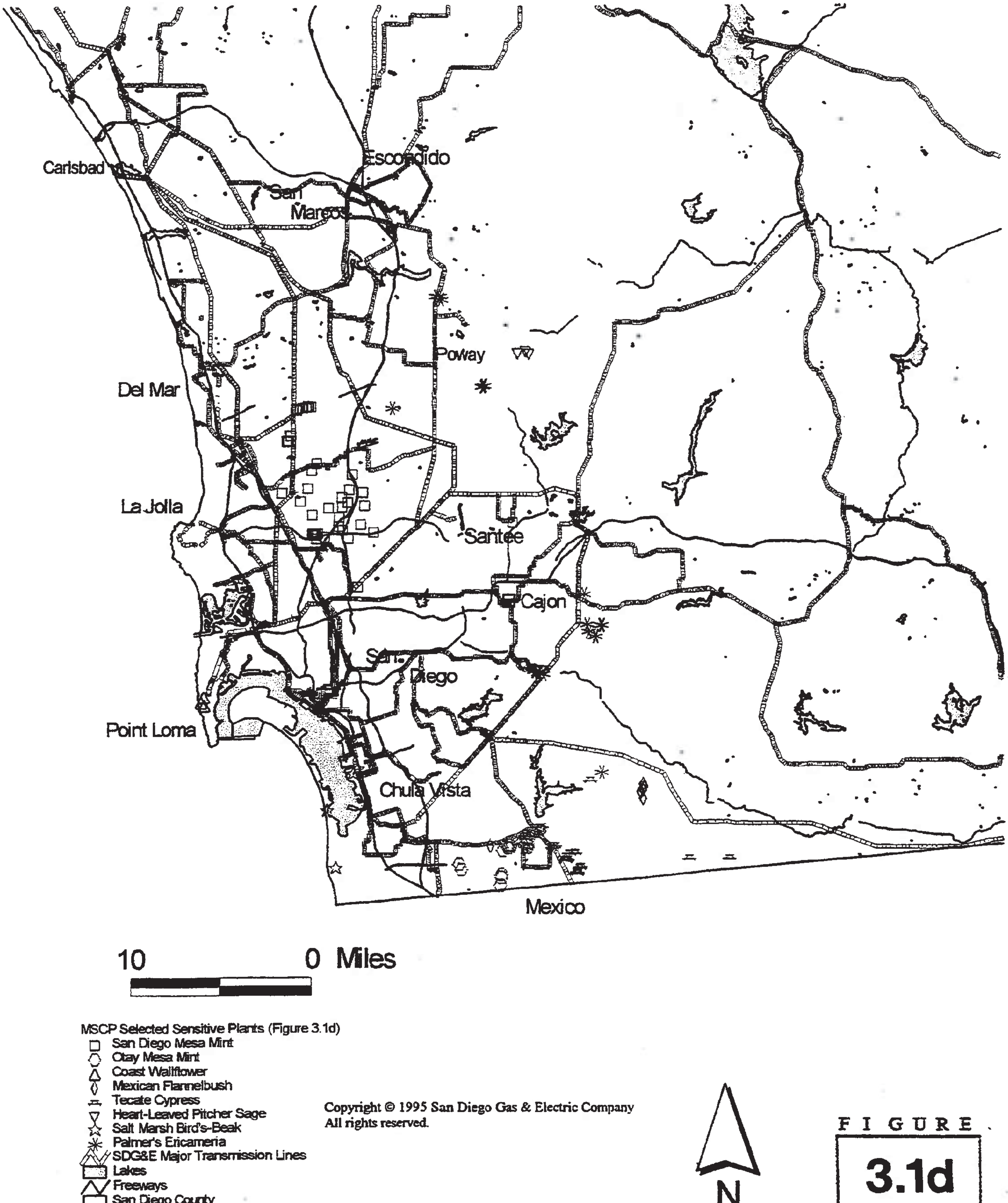


FIGURE
3.1d

SDG&E Subregional NCCP

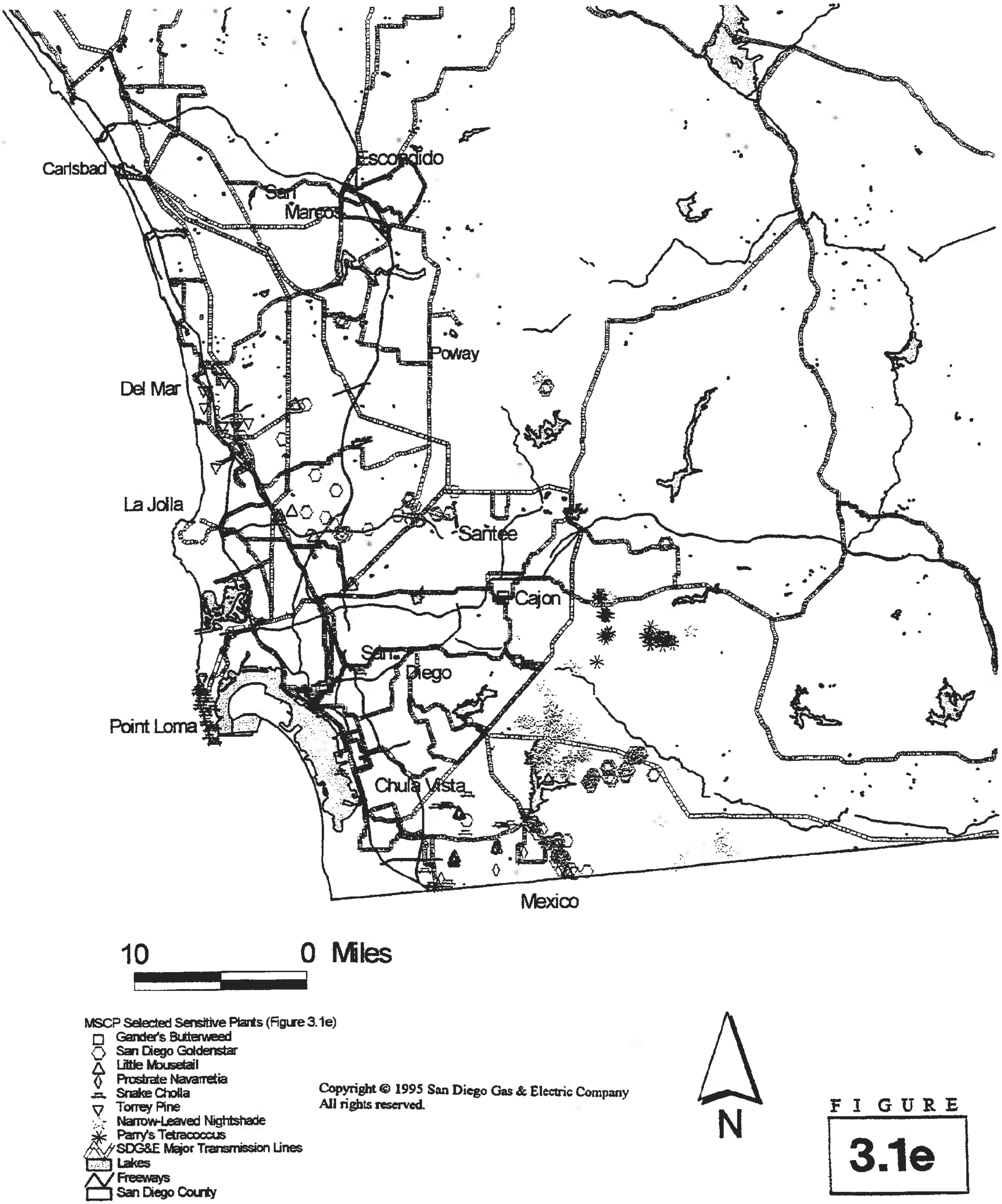
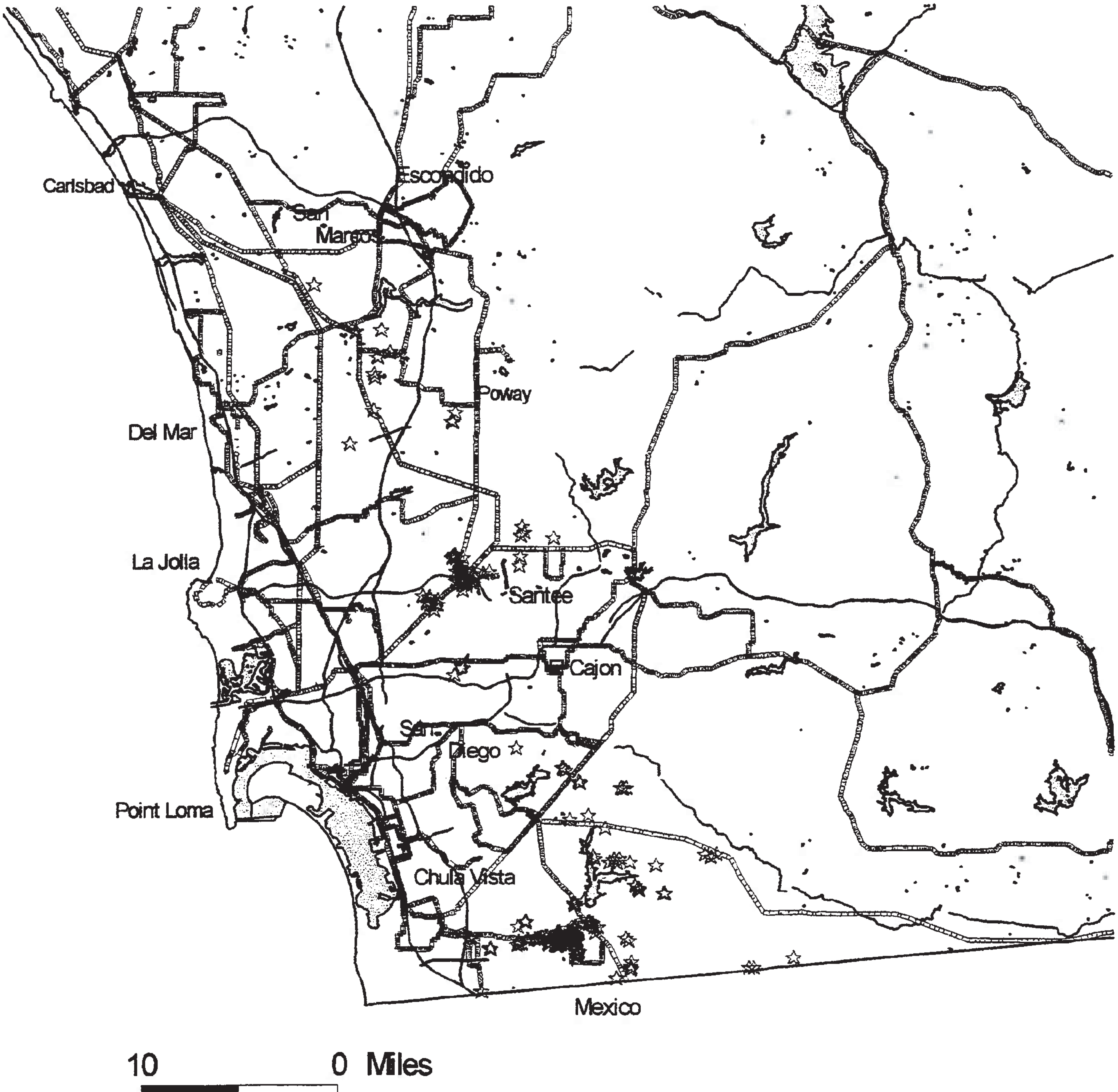


FIGURE
3.1e

SDG&E Subregional NCCP

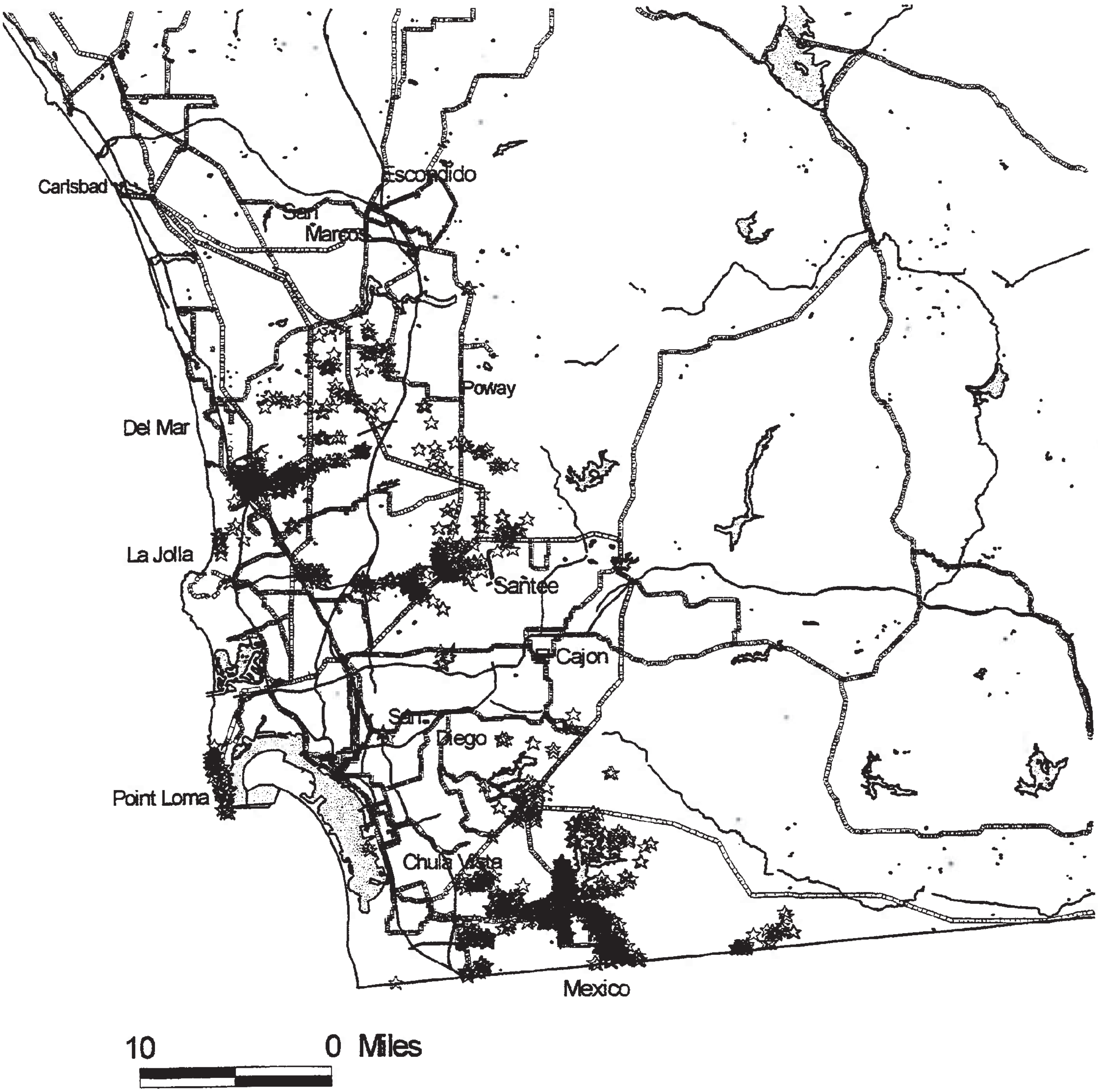


N

MSCP Selected Sensitive Plants (Figure 3.1f)
- Variegated Dudleya
- SDG&E Major Transmission Lines
- Lakes
- Freeways
- San Diego County

FIGURE
3.1f

SDG&E Subregional NCCP



N

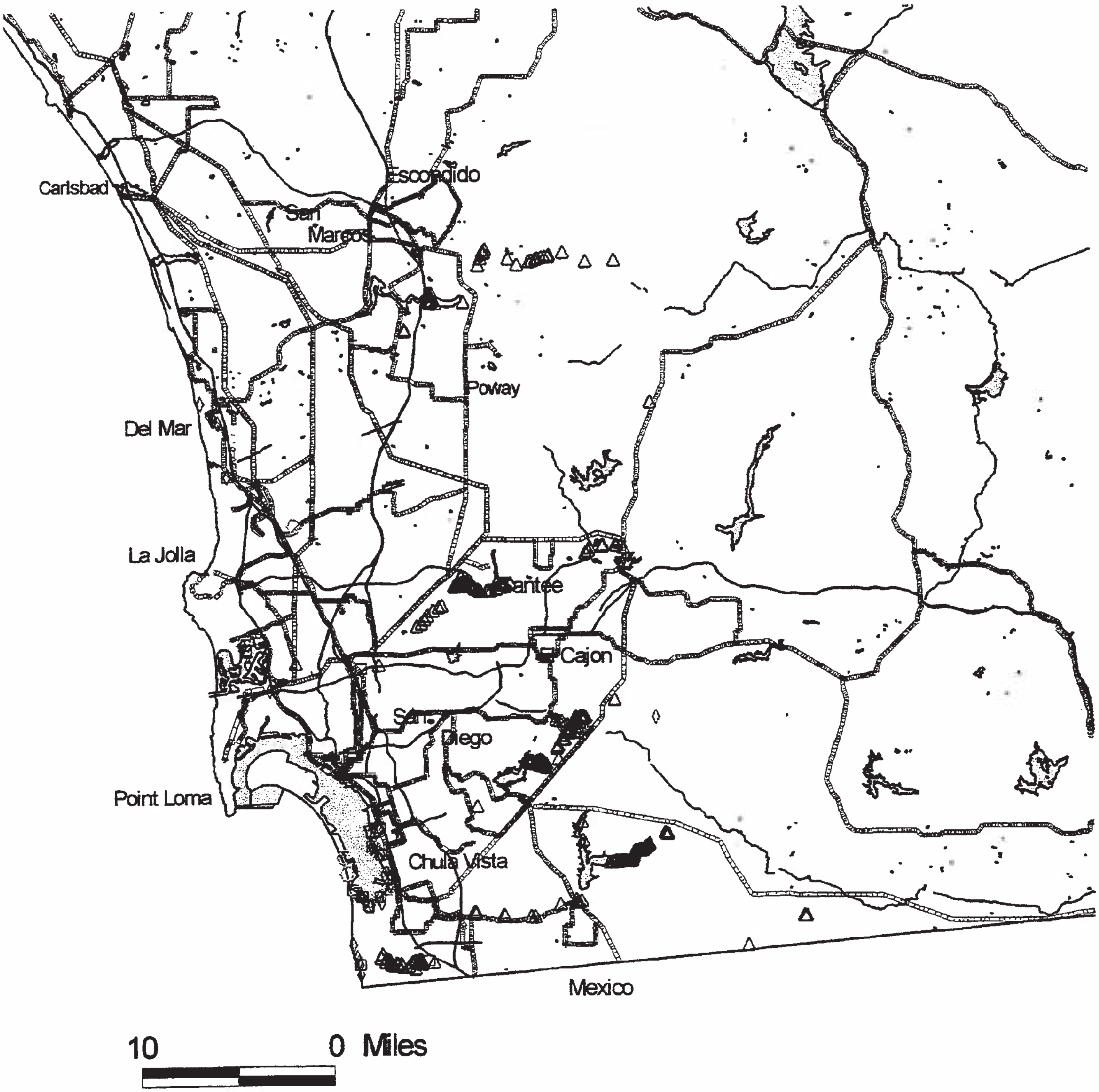
MSCP Selected Sensitive Plants (Figure 3.1g)
San Diego Barrel Cactus
SDG&E Major Transmission Lines
Lakes
Freeways
San Diego County

FIGURE
3.1g

SDGE

Subregional Natural Community Conservation Plan

SDG&E Subregional NCCP



MSCP Selected Sensitive (Figure 3.1h)
- Light-Footed Clapper Rail
- Western Snowy Plover
- Least Bell's Vireo
- Belding's Savannah Sparrow
- SDG&E Major Transmission Lines
- Lakes
- Freeways
- San Diego County

N

FIGURE
3.1h

SDGE

Subregional Natural Community Conservation Plan

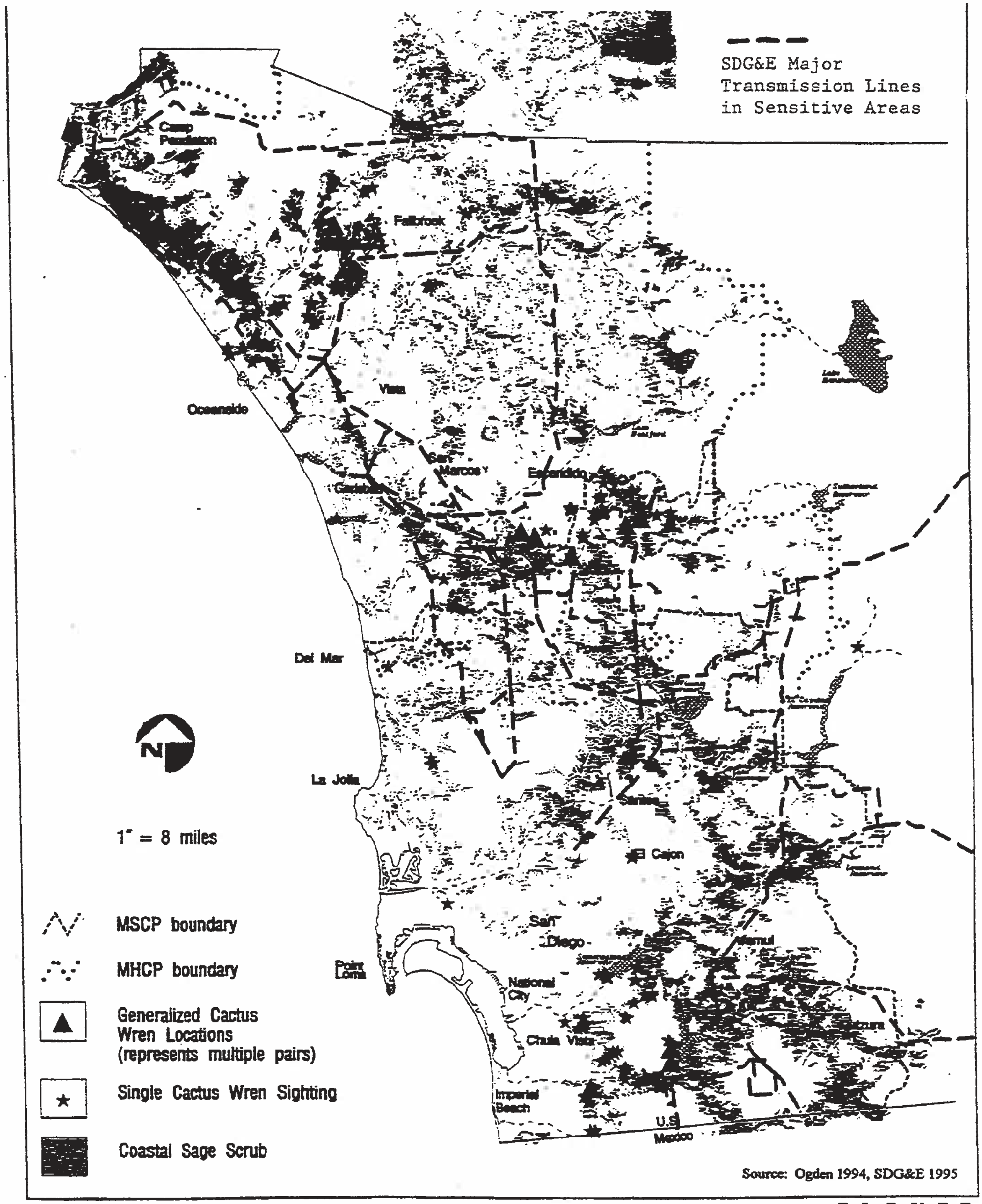


FIGURE 3.1i

Known Distribution of Coastal Cactus Wren in San Diego County

3.2 Impact Assessment

As a regional energy provider SDG&E has several roles. One of the roles is to be a developer. SDG&E must develop and maintain a region-wide network of gas and electric transmission, distribution and resource facilities. From the standpoint of capital investment, SDG&E is probably the largest developer in the SDG&E service territory.

Energy development, like all development, has impacts. However, it is important when reviewing this document that the reader does not confuse the impacts of energy development with typical commercial, industrial, and residential development. Typical development permanently removes large areas of native vegetation, changes the topography, and covers much of the developed area with impervious surfaces. Most of SDG&E's previous and future energy development occurs above or below the earth's surface with very small areas of permanent disturbance. Impacts from energy development include: narrow and unpaved access roads, habitat that continues to exist and grow in rights-of-way, energy facilities (except for generators) that are unoccupied and generate very little traffic, and little or no contribution to edge effects due to predatory pets or extensive human activity. Negative impacts which may occur are habitat fragmentation and provision of human access to remote areas leading to potential exotic species invasion and destruction of habitat.

Construction impacts associated with the development of energy facilities also have less impact than those of typical developments because (1) construction projects associated with development of energy facilities normally are completed over a period of days rather than months or years as with other development projects, and (2) construction activities themselves have less impact, for example, equipment and materials are often delivered by air, thereby minimizing ground disturbances.

Another significant difference between the development of energy facilities and typical development is that there is a greater degree of flexibility in siting and design when developing energy facilities. It is not to SDG&E's benefit to site and develop facilities in an environmentally insensitive manner. Doing so would not result in a measurable increase to company profits. Therefore, it is in the best interest of SDG&E, its rate payers, and shareholders for the company to adopt development and maintenance policies designed toward environmental protection and enhancement. SDG&E is also a resident of the service territory (has been for well over a century) and would like to continue to be a welcome one.

3.2.1 Take of Covered Species

SDG&E's Activities will likely result in the Take of Covered Species and impact their habitat when incidental to otherwise lawful activities and when conducted in full compliance with the terms and conditions of this Subregional Plan.

However, this Subregional Plan is intended to avoid incidents resulting in the Take of Covered Species whenever possible and to implement measures to minimize and mitigate any Take of Covered Species to the maximum extent possible. Events of Take occurring within the terms and conditions of this Subregional Plan will not appreciably reduce the likelihood of the survival and recovery of any Covered Species.

Take of certain Covered Species is to be avoided. (These species are indicated in the Covered Species Table 3.1.) Take authorizations for these so called narrow endemic species will be limited to emergencies and unavoidable impacts from repairs to existing facilities. For new projects, kill or injury of such animal species or destruction of such plants or their supporting habitat would not be covered by the Plan and Implementing Agreement.

3.2.2 Types of Take of Covered Species

3.2.1.1 Impacts to Individual Animals

The Take of protected individuals and impacts to other Covered Species will likely occur as a result of SDG&E's Activities. SDG&E's Activities, including its installation, use, maintenance and repair of its Facilities, are more fully described in Section 2. The Take of these individuals may occur in the form of harassment, death, or displacement.

Of the aforementioned forms of Take of Covered Species and impacts to Covered Species, harassment may be the most common. Harassment of individuals of such species will occur as an unavoidable and unintentional consequence of conducting certain Activities and mitigation measures, such as human activity, the operation of machinery and equipment, and associated noise. Direct killing of or injury to individuals may result from their being struck by vehicles or equipment, or being crushed or trapped in their burrows. Displacement may occur when individual animals move away from long-term maintenance operations to surrounding areas and are forced to compete with animals in these areas for food and living space. Take of Covered Species due to these impacts will be eliminated, minimized or mitigated to the maximum extent possible utilizing the mitigation measures described in Section 7 of the Subregional Plan.

In certain situations, Take of certain species is authorized only under the rubric of operation and maintenance Activities. These situations typically involve potential impacts from Activities on endemic species having narrow ranges in areas *without* an approved regional conservation plan.

For example, Take of the Stephens' Kangaroo Rat (SKR) is only permitted for SDG&E in the Multiple Habitat Conservation Program (MHCP) planning area in northern San Diego County for operation and maintenance activities until the MHCP is approved. After that time, and provided that SKR is conserved within MHCP, Take for new construction Activities will be permitted under the terms of this Plan. This condition only applies to the SKR populations in San Diego County; Riverside County has an approved Take process and mitigation protocol. Furthermore, SDG&E's facilities in Riverside County already exist, and no new impacts are expected.

3.2.1.2 Impacts to Individual Plants

Areas known to contain Covered Species of plants have been delineated in preliminary sruveys for MSCP and MHCP and will be flagged to eliminate or reduce impacts during Activities in these areas. Impacts to individual plants will primarily result from urgent or emergency repair Activities. This Subregional Plan prescribes the implementation of mitigation measures such as specific restoration or reclamation. Unknown populations of Covered Species plants, naturally occurring or intentionally introduced, are expected to exist with the Subregional Plan Area and may also be impacted by SDG&E's Activities. Pre-activity surveys for Covered Species of plants will identify areas of potential impact, and implementation of the provisions for avoidance and/or revegetation as set forth in Section 7 of this Subregional Plan will reduce these impacts.

SDG&E's Geographic Information System (GIS) will contain sensitive species and habitat data to demonstrate sensitive working areas. The Environmental Surveyor will continue to add new data to GIS based on preactivity surveys.

Expansion of Miguel Substation:

SDG&E owns land within the boundaries of its Miguel Substation property adjacent to the Sweetwater Reservoir on which significant populations of Otay Tarplant *"Hemizonia conjugens"* are found. Expansion plans for the substation could threaten about 1,000 - 2,000 of the approximately 12,000 individuals of the Tarplant population on the SDG&E property. Due to the rapidly changing nature of the electric industry, it is impossible to predict with complete certainty how the substation will be expanded, or even if it will become necessary. SDG&E has committed that impacts to sensitive species like the Tarplant, however, will be avoided to the extent possible.

Figure 10a shows the existing footprint of the substation development areas, with the biological resources indicated adjacent to the substation pads. Also outlined is one expansion scenario, the configuration of which is largely determined by the geometry of the existing equipment. Any impacts to the Tarplant populations due to an expansion would be minimized to the extent possible. Should impacts be necessitated, they would be mitigated with the set aside of a nearby area of Tarplant within the Miguel Substation property at a ratio of 2:1. The remaining Tarplant would be retained for mitigation use at a later date.

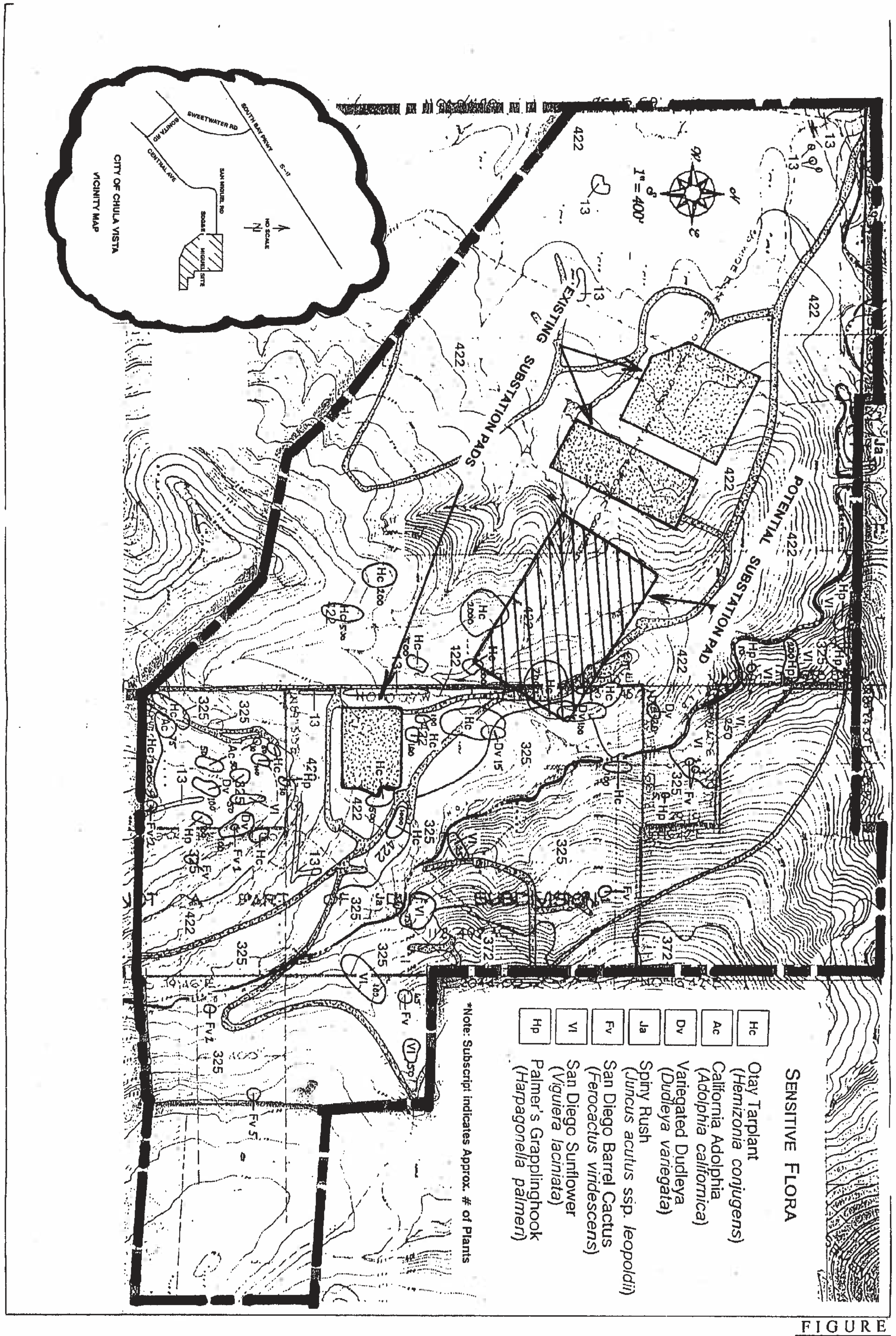


FIGURE **10a**

SDG&E MIGUEL SUBSTATION SITE

3.2.2.2 Impacts to Habitat

SDG&E's Activities will likely result in some impacts to the habitats of Covered Species. Destruction of habitat, including blading or scraping, excavation, and erosion, along with fragmentation and human access to restricted areas, will likely occur in some areas as a result of SDG&E's Activities. Modification of habitat may reduce the prey base or other biological resources for Covered Species and thereby affect an individual's ability to survive. Implementation of the mitigation measures in Section 7.1 will avoid or reduce these impacts to the maximum extent possible.

3.2.2.3 Duration and Intensity of Impacts

The duration and intensity of impacts to Covered Species will vary depending on the location and type of Activity being conducted. Some Activities will result in occasional harassment to individuals while others may result in greater impacts such as the killing of individuals or permanent habitat loss within the Subregional Plan Area. These impacts may be expected to occur throughout the year and may occur within any or all of the Subregional Plan Area.

For example, Activities such as the installation, use, maintenance or repair of Facilities may cause temporary harassment of individuals, while grading and clearing of electric substation pads, gas facilities, or access roads may result in permanent disturbance. Most Activities will allow a majority of Covered Species to re-occupy habitat after the completion of installation, maintenance and repair of a Facility and during its use (e.g. transmission line).

4 Land Use

This section of the Subregional Plan discusses existing and proposed land use activities and policies guiding SDG&E Activities within the Subregional Plan Area.

4.1 Existing Land Use Activities

Existing Land Uses
Existing land use activities on SDG&E owned property, easements, and rights-of-way include installation, operation, maintenance and repair of SDG&E Facilities.

Although a good portion of SDG&E's easements are located within urbanized areas, many large easement corridors cross through and connect biologically sensitive and diverse areas. In addition, a number of substation and gas regulator sites adjoin or contain valuable native habitats. This Subregional Plan addresses only property owned by SDG&E, SDG&E easements and rights-of-way, and Activities within biologically sensitive areas.

4.1.1 Electric Distribution Easement Corridors

These easements are typically 12' in width or narrower. Facilities consists of power poles located in the center of the easement with attachments such as guy anchors, circuit switches, stub and anchors, wires and communication cables. The total percentage of the above ground improvements in the easement area is less than 1% over an easement 200' in length. Access routes to these Facilities are not usually maintained, enabling the habitat to recover.

4.1.2 Electric Transmission Easement Corridors

These easements are typically 20' in width or greater. Facilities may consist of power poles, two-pole structures, steel poles or lattice steel towers. 20'-wide corridors contain a single pole line, while corridors greater than 100' in width could contain as many as five individual transmission lines. Due to the greater span distance between structures, above ground improvements are approximately less than 5% of the easement area. Access to these improvements is normally provided via access roads.

4.1.3 Gas Transmission Easement Corridors

These easements are normally 40' in width or narrower. Above ground improvements are minor and consist of valve boxes, cathodic stations, pipeline identification markers and leak detection devices. Above ground improvements are approximately less than 1% of the easement area. Access to these improvements is provided via access roads.

4.1.4 Electric Substations and Gas Regulator Stations.

These Facilities are located along or at the terminus of transmission easement corridors and are usually surrounded by landscaped areas or as open space areas. It is essential for safe and reliable service that access roads be maintained in a condition which assures that these Facilities can be operated, as necessary, on a 24-hour basis.

4.2 Proposed Land Uses

Forecasting the need, location and exact nature of future energy projects is accomplished by interpreting the projected growth plans from the various local and regional agencies. SDG&E identifies future "load centers" based on the locations, densities, and types of growth indicated in general plans and population forecasts. The current system design of SDG&E's energy network is a response to those plans and forecasts. Many rights-of-way and substations were purchased with space for expansion in the interest of serving future "load centers" that could be predicted from agency plans.

Major preservation plans, currently being prepared under NCCP legislation, will affect the existing growth forecasts to the extent that significant shifts in load center size and location are expected. The results will dictate a reevaluation of the system design needed to serve this region. Some rights-of-way and substations that were intended for expansion may be fully utilized. Existing urban areas may now need to be served with additional utility improvements to accommodate development intensification.

Therefore, SDG&E will not be able to accurately predict the extent of these "load center" shifts until the various preservation plans are completed and agencies modify their growth plans to reflect new patterns of growth and preservation. This Subregional Plan assumes that San Diego will continue to grow, but does not assume where the growth will occur. However, the plan does assume that growth will mean expansion of the energy system. The predictions pertaining to miles of gas and electric transmission lines, number of substations, and amounts of other energy facilities have been based on historical data.

Each new SDG&E project will be subject to CEQA and, if there is federal involvement, NEPA. Exact impacts and mitigation will be determined at that time. At this time, the plan only estimates disturbances to habitat based on past experiences. However, those preparing this plan have estimated that more mitigation than is necessary is being provided to prevent a shortfall as projects are needed.

This Subregional Plan may be amended by SDG&E when General Plans in the region are updated. At that time, the company can better predict what kinds of facilities will be needed and where to serve future growth areas.

In a limited number of cases, there are existing transmission corridors capable of accommodating additional electric and gas transmission facilities. These transmission corridors are shown in fluorescent green on Figure 11a. The vacant positions in Orange County are attached as Figure 11b.

4.3 Projected Grading Disturbances

SDG&E has estimated a total of 124 acres of both temporary and permanent grading disturbances over the next 25 years. Section 4.4 discusses how this calculation was made. It is important to note that not all of this acreage disturbance would occur within habitats considered native, sensitive, or slated for protection. Nevertheless, this estimate should be considered valid because it covers both native and disturbed areas, and as a result reflects the worst case scenario. Specific estimates of native habitat disturbances can only be quantified through individual review of each SDG&E Activity just prior to its occurrence.

4.4 Methodology for Estimating Grading Disturbance

The estimate for total grading disturbances was based on projecting 7 typical SDG&E activities over the course of 25 years. Estimates of individual grading disturbances were based on previous experiences by SDG&E.

4.4.1 New Substations

Approximately 8 acres of permanent grading disturbances may result from the construction of four new electric distribution substations. Of the estimates provided, this is the only one in which grading disturbance over native habitat is probable. Individually, each substation could impact 2 acres of habitat.

The typical substation site is 4.5 acres in size. Of this amount, up to 2 acres accommodate improvements for substation transformers, control house racks, fencing, roads, and transmission feed structures. The remaining land is devoted to setbacks, landscaping, open space access, and fire breaks where required. Figure 12 depicts the typical layout for each substation.

4.4.2 New Electric Transmission Lines Requiring New Rights-of-Way

Approximately 35 acres of grading disturbances may result from the construction of 7 new transmission lines. This acreage amount is the result of each new line requiring an entirely new right-of-way corridor and associated access road system. The above figure represents the aggregate of two different types of new transmission lines. Each type is described as follows:

- New electric transmission, steel: 3 new transmission lines would be supported by either steel lattice towers or steel poles. Each new line would typically require a new right-of-way 100' in width and 4 miles in length. Each would begin and terminate at different substations or at existing transmission lines. Typical ground disturbances for each line would include grading 18 structure sites (25' x 100' each), 2.4 miles of 12' wide access road and 2 temporary wire pulling pads (50'x 200' each). Figure 13 depicts this configuration.

- New electric transmission, wood: 4 new transmission lines would be supported by wood poles. Each new line would typically require a new right-of-way 100' in width and 4 miles in length. Each would begin and terminate at different substations or at existing transmission lines. Typical ground disturbances for each line would include grading 60 structure sites (20' x 20'), 2.4 miles of 12' wide access roads and 4 temporary wire pulling pads (50' x 200' each). Figure 14 depicts this configuration.

  Note: New access roads do not typically traverse the entire right-of-way because of impassable terrain and the use of existing access roads.

4.4.3 New Electric Transmission Lines Within Existing Rights-of-Way

Approximately 23 acres of grading disturbances may result from the construction of 10 new transmission lines placed within existing rights-of-way. This acreage amount is the result of each new line be able to utilize existing access road infrastructure. The above figure represents the aggregate of two different types of new transmission lines placed within existing rights-of-way. Each type is described as follows:

- New electric transmission, steel: 4 new transmission lines would be supported by either steel lattice towers or steel poles. Each new line would typically utilize an existing right of way that is 100' in width and 4 miles in length. Each would begin and terminate at different substations or at existing transmission lines. Typical ground disturbances for each line would require the grading of 18 structure sites (25' x 100' each), .57 miles of 12' access roads and 2 temporary wire pulling pads (50' x 200' each). Figure 15 depicts this configuration.

- New electric transmission, wood: 6 new transmission lines would be supported by wood poles. Each new line would utilize an existing right-of-way that is 100' in width and 4 miles in length. Each would begin and terminate at different substations or at existing transmission lines. Typical ground disturbances for each line would include grading 60 poles sites (20' x 20' each), .57 miles of 12' wide access roads and 4 temporary wire pulling pads (50' x 200'). Figure 16 depicts this configuration.

  Note: New access roads do not typically traverse the entire right-of-way because of impassable terrain and the use of existing access roads.

4.4.4 Transmission Line Reconductoring

Approximately 11 acres of grading disturbances may result from the reconductoring (replacement of wire) of 16 existing transmission lines. Most of this disturbance is the result of creating pulling pads for wire spool trucks. The above figure represents the aggregate of two different types of transmission lines. Each type is described as follows:

- Transmission Line Reconductoring, steel: 8 transmission lines supported by steel lattice towers or steel poles may be reconductored. Each line would typically be within an existing right-of-way 100' in width and 4 miles in length. Each would begin and terminate at different substations or existing transmission lines. No new access roads or tower sites would be required. Typical ground disturbances for each line would be limited to temporary establishment of 2 wire pulling sites (50' x 200' each). Figure 17 depicts this configuration.

- Transmission Line Reconductoring, wood: 8 transmission lines supported by wood poles may be reconductored. Each line would be within an existing rights-of-way 100' in width and 4 miles in length.

Each would begin and terminate at different substations or at existing transmission lines. No new access roads or poles sites would be required. Typical ground disturbances for each line would include establishment of 4 wire pulling (50' x 200' each). Figure 18 depicts this configuration.

4.4.5 Individual Minor Repairs, Overhead Electric Transmission or Distribution

Approximately 20 acres of grading disturbances may result from 240 various minor operational construction and maintenance repairs. Generally, these activities will occur within existing rights-of-way that contain both electric distribution and transmission facilities.

A typical example of an incident might be the replacement of a wooden power pole knocked over by high winds. Repair requirements would require grading to accommodate a new access road (150' x 12') to the site and temporary construction pad (40' x 40') for repair and installation of the replacement pole. Figure 19 depicts the typical configuration of an individual repair incident.

4.4.6 Gas Line Repairs

Approximately 19 acres of grading disturbances may result from 3 types of gas line repairs involving leaks, erosion and relocations. The above acreage is an aggregate of 3 types of repairs described as follows:

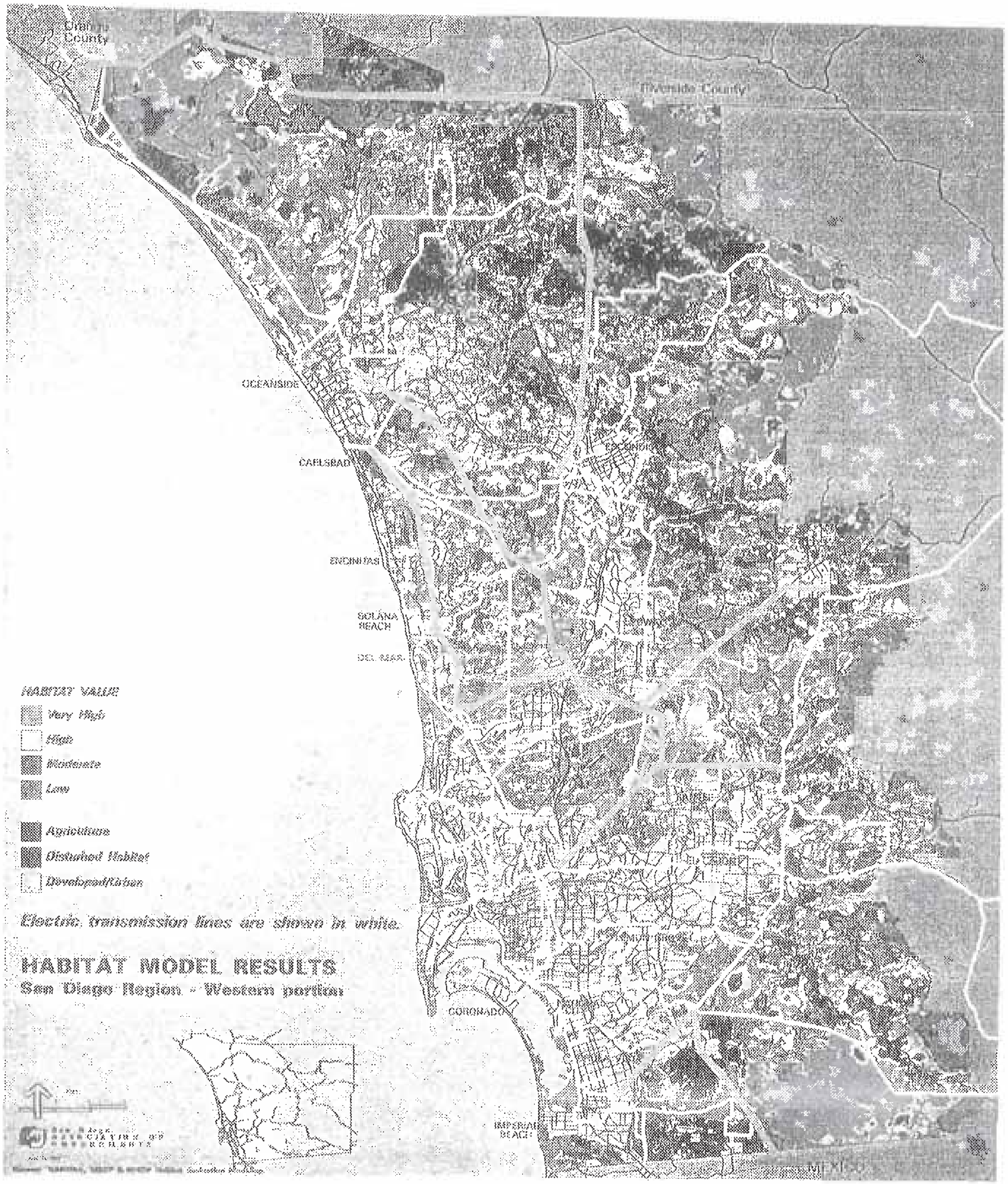
- Gas Line Leak Repair: 5 leak repair incidents are projected. Construction crews would excavate an area around the pipe so that a sleeve could be placed over the leak. The typical trench would be 10' x 100' and would be surrounded by a temporary construction area of 50' x 200'. Figure 20 depicts the typical configuration of an individual leak repair incident.

- Pipeline Relocation: 2 relocations are projected. Relocations due to pipeline failure are rare. A new pipeline alignment and necessary construction equipment would require a temporary construction area of 50' x 300'. Figure 21 depicts the typical configuration of an individual pipeline relocation.

- Gas Line Erosion Repair: 25 repair incidents are projected. These repairs are usually the result of streams eroding the earth from around pipelines and leaving them dangerously exposed. Typical improvements require an area of 50' x 100' so that unwanted fill material can be removed and replaced with recompacted material, erosion control blankets and or protective rip rap rock. An additional temporary construction area of 150' x 200' would surround the improvement area and would be used for grading equipment, trenching machines, cranes, crew trucks and storage. Figure 22 depicts the typical configuration of an individual gas line erosion repair.

4.4.7 New Gas Transmission

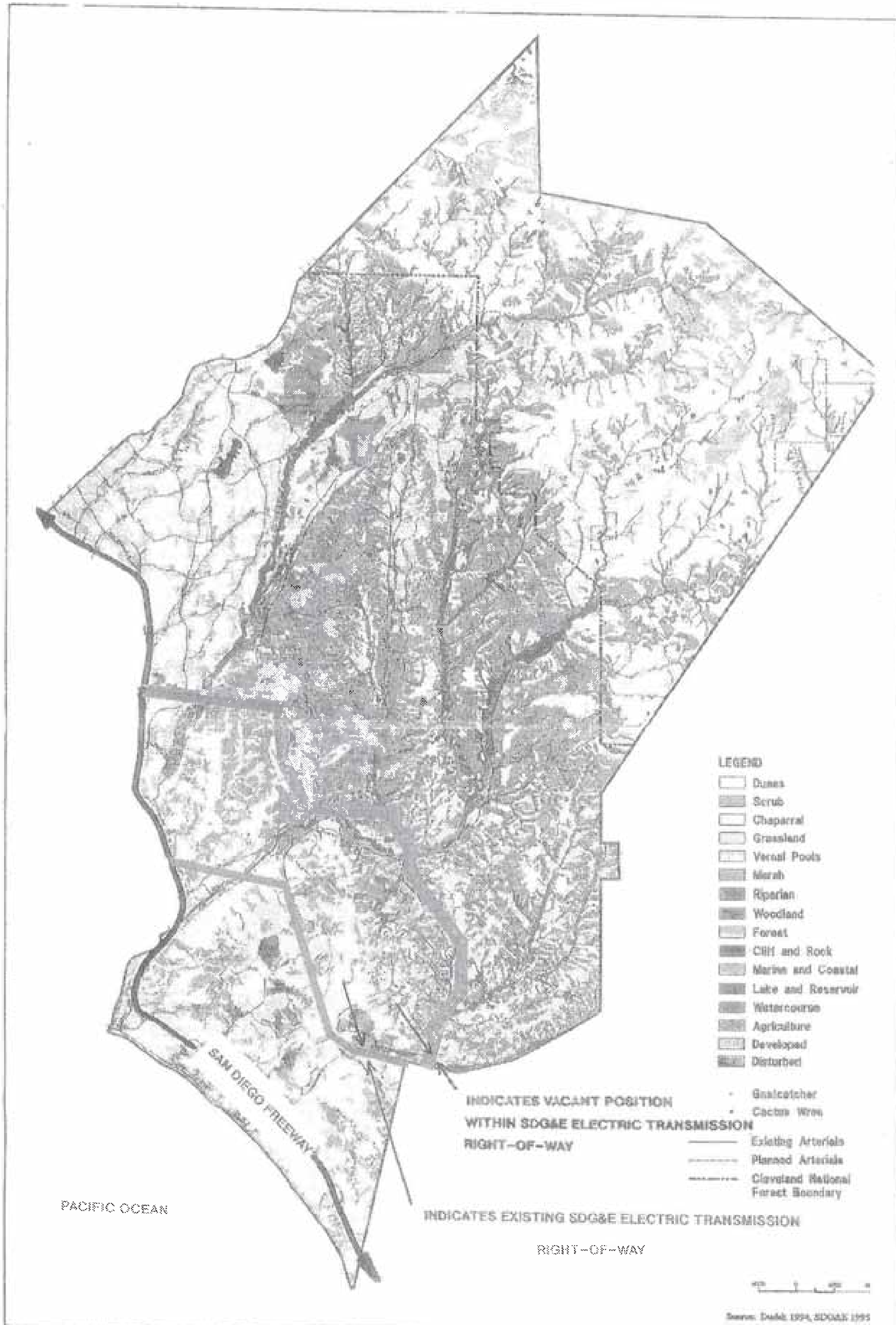
Approximately 8 acres of grading disturbances may result from the construction of one or more new gas transmission lines. This acreage amount is the result of the need for entirely new right-of-way corridor and associated road system.



SDG&E Electric Transmssion System Vacant Positions in Transmission Corridors

Green Lines Are Vacant Positions

FIGURE **11a**



SDG&E Electric Transmission System Vacant Positions in Transmission Corridors (Orange County)

FIGURE 11b

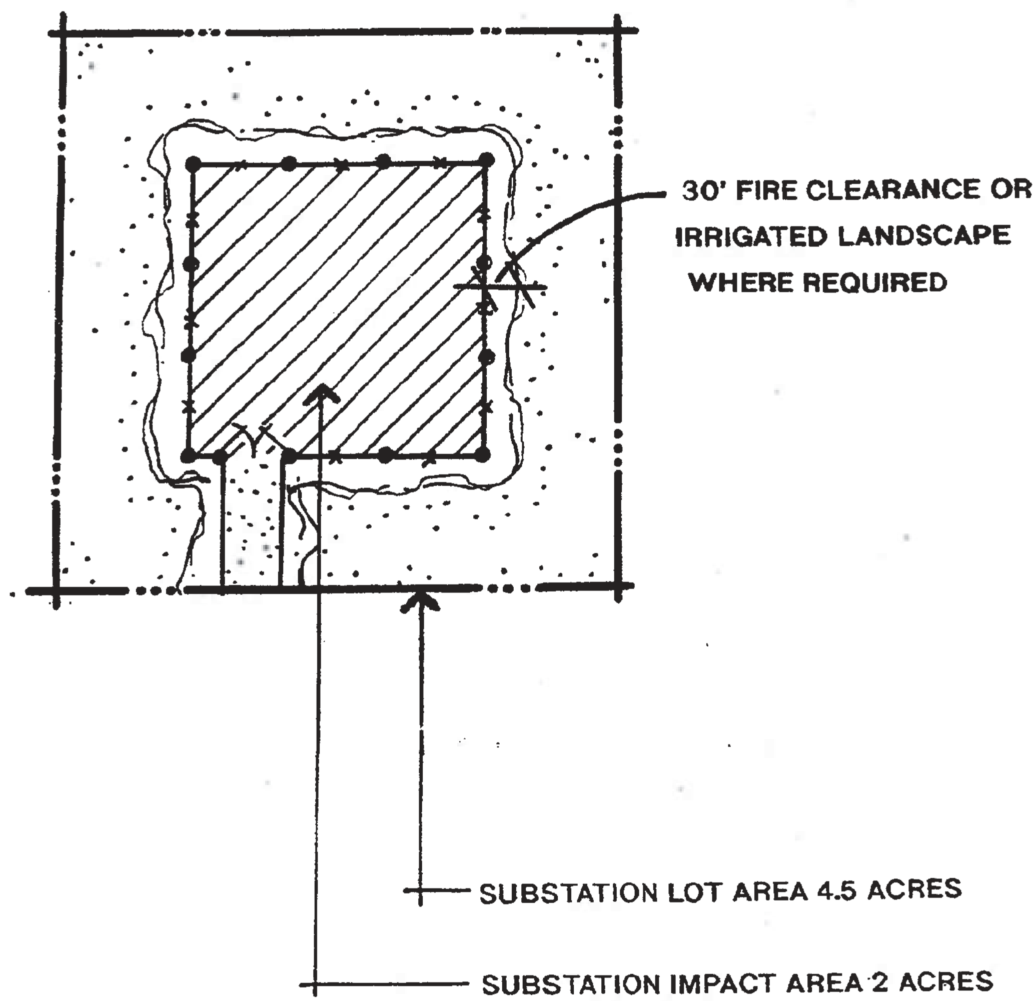
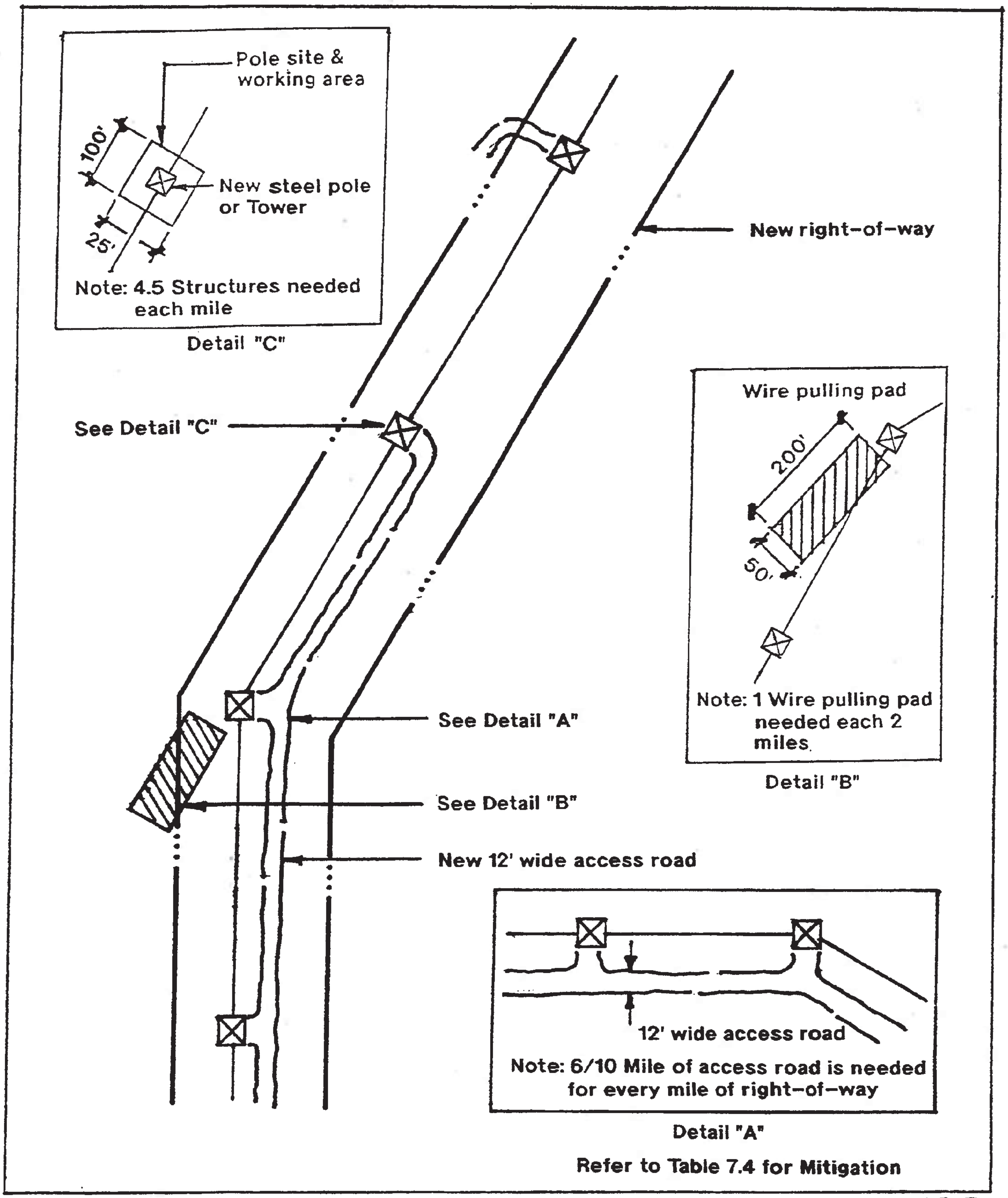


FIGURE 12

Typical Substation Impact Diagram



Typical New Electric Transmission Line Requiring New R/W (Steel) Impact Diagram

FIGURE

13

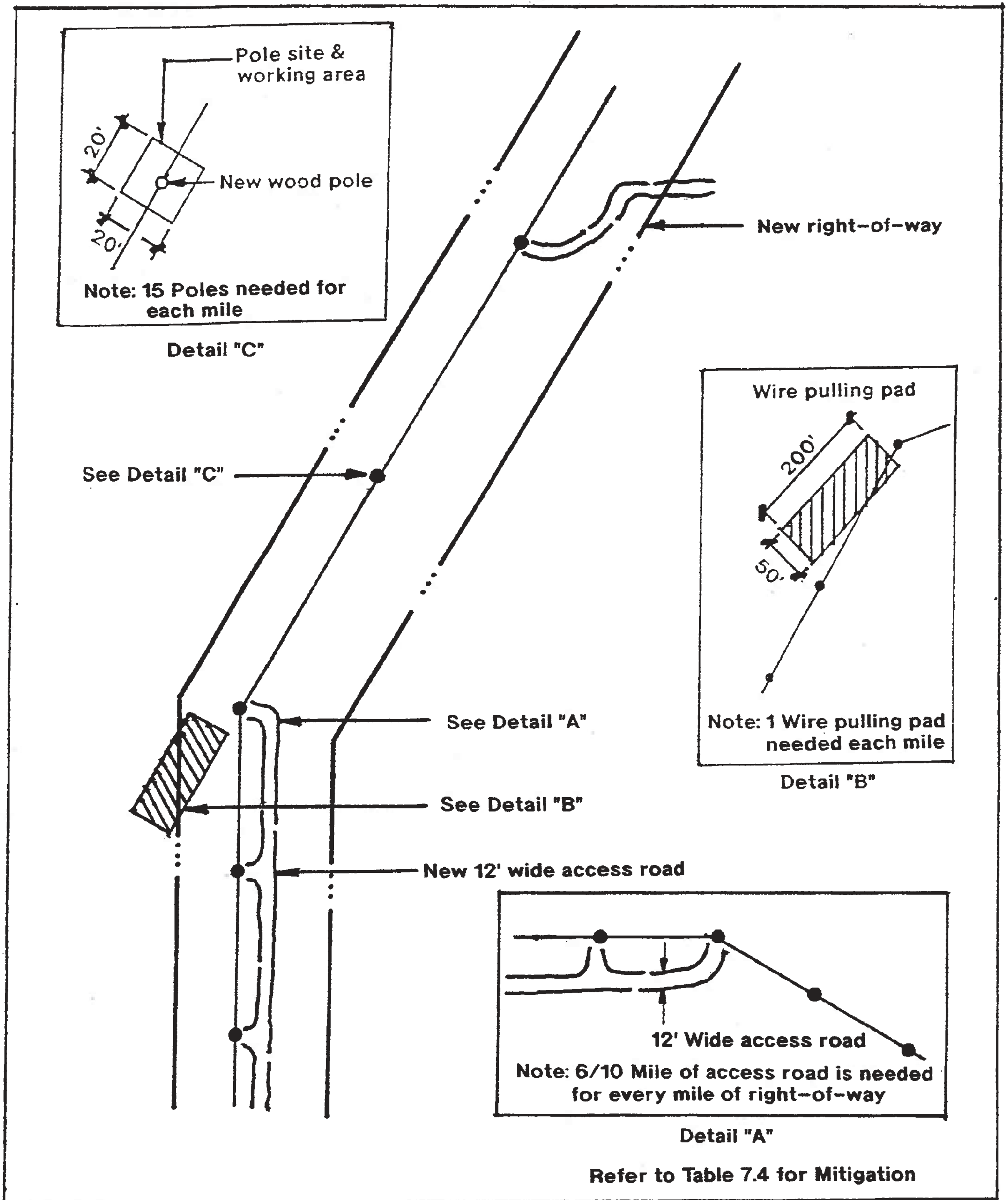


FIGURE 14

Typical New Electric Transmission Line
Requiring New R/W (Wood)
Impact Diagram

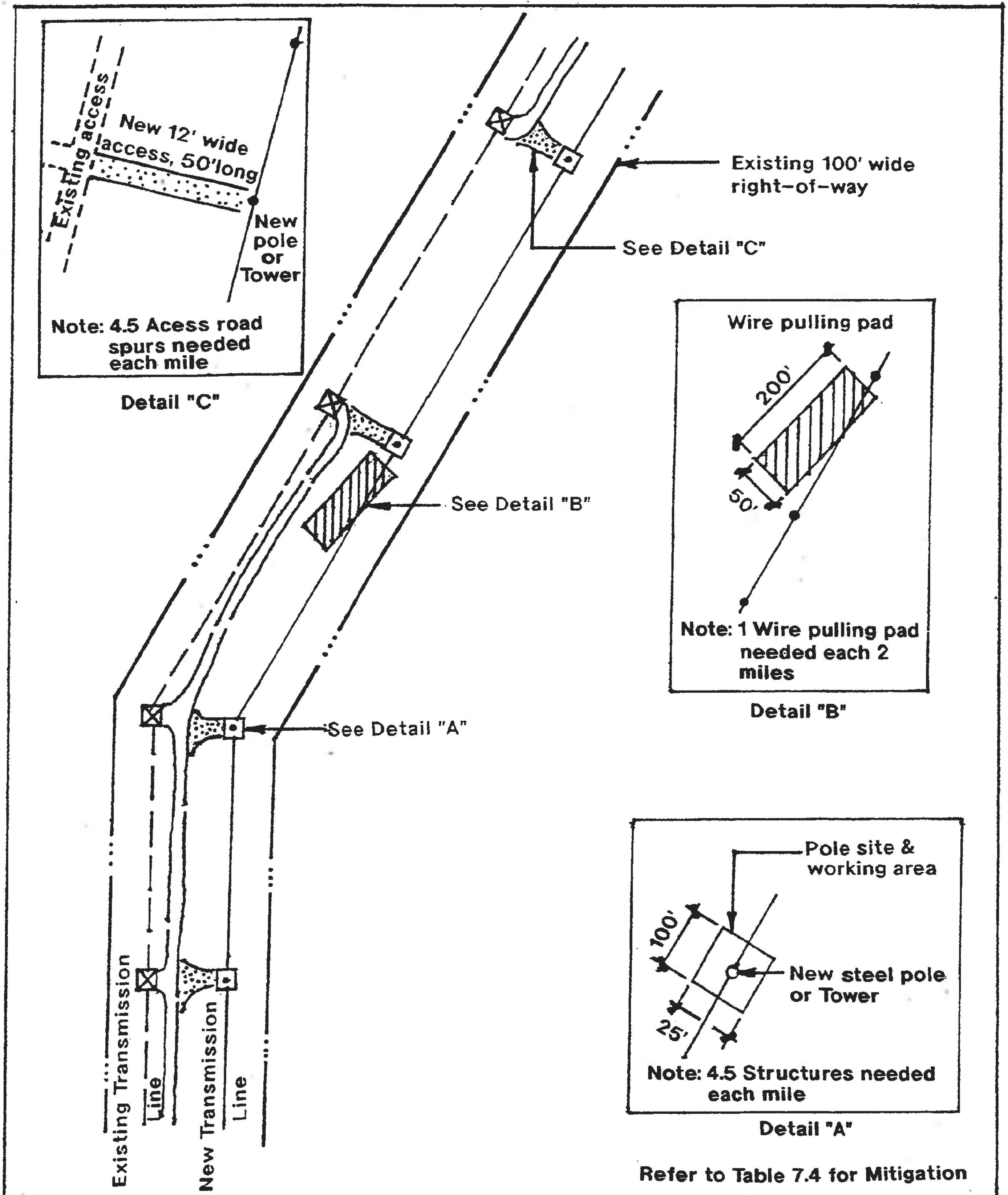
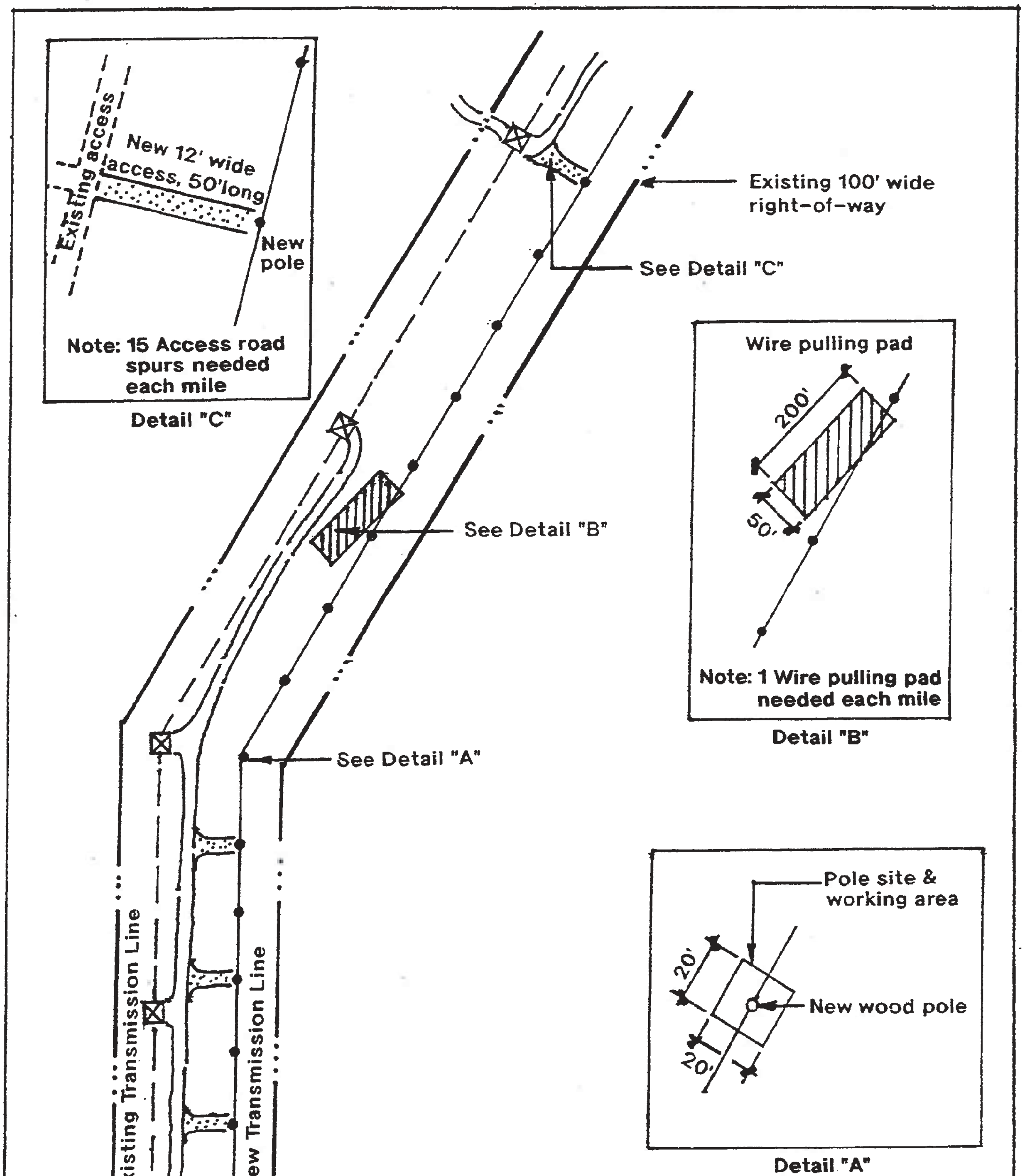


FIGURE
15

Typical New Electric Transmission Line in Existing R/W (Steel) Impact Diagram

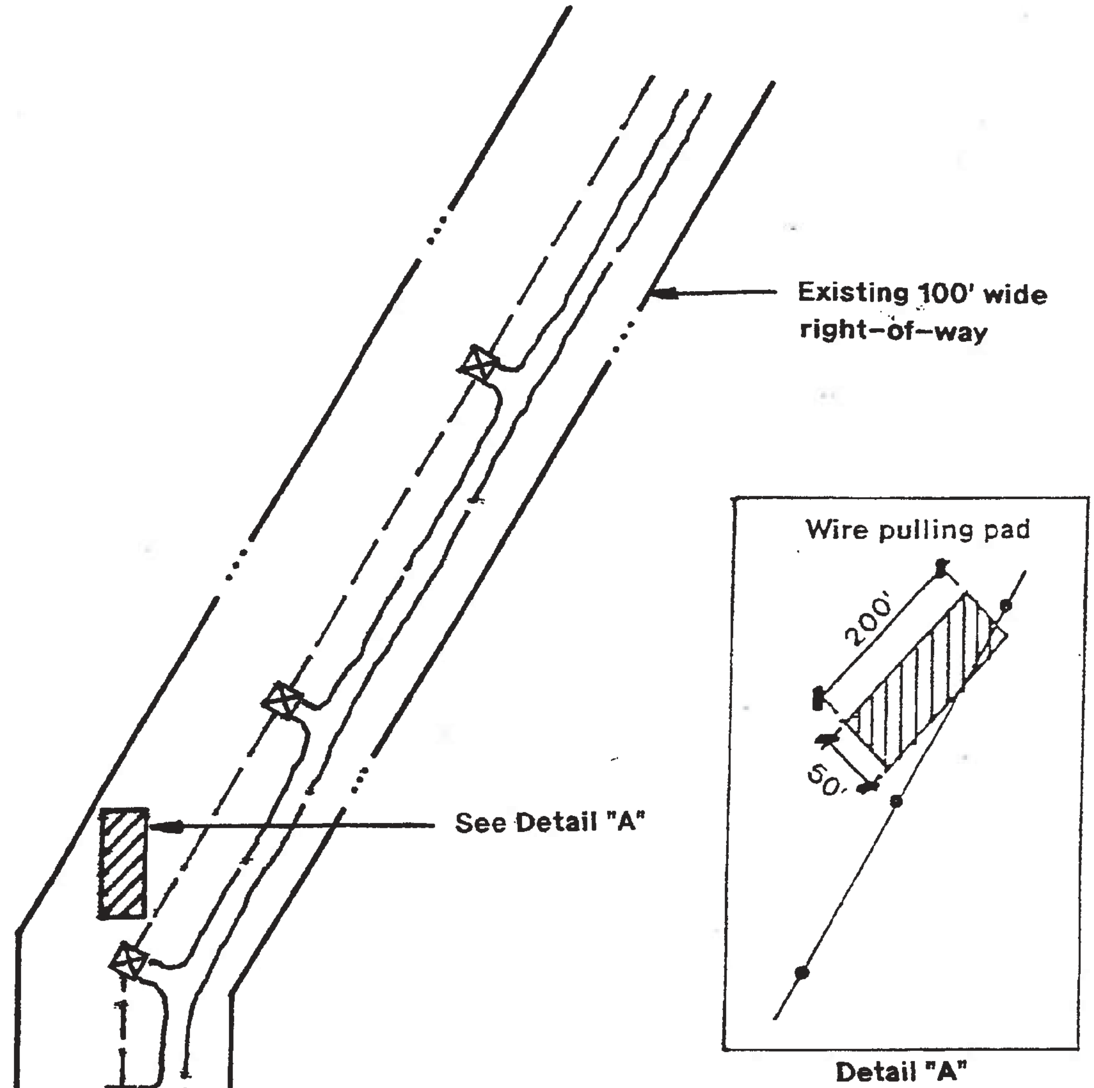


Refer to Table 7.4 for Mitigation

FIGURE

16

Typical New Electric Transmission Line in Existing R/W (Wood) Impact Diagram



- Typical steel reconductor (4 mile length)
- One temporary wire pulling site per each 2 miles
- Disturbances limited to temporary impacts in wire pulling sites
- Refer to Table 7.4 for Mitigation

Typical Electric Transmission Reconductor in Existing R/W (Steel) Impact Diagram

FIGURE **17**

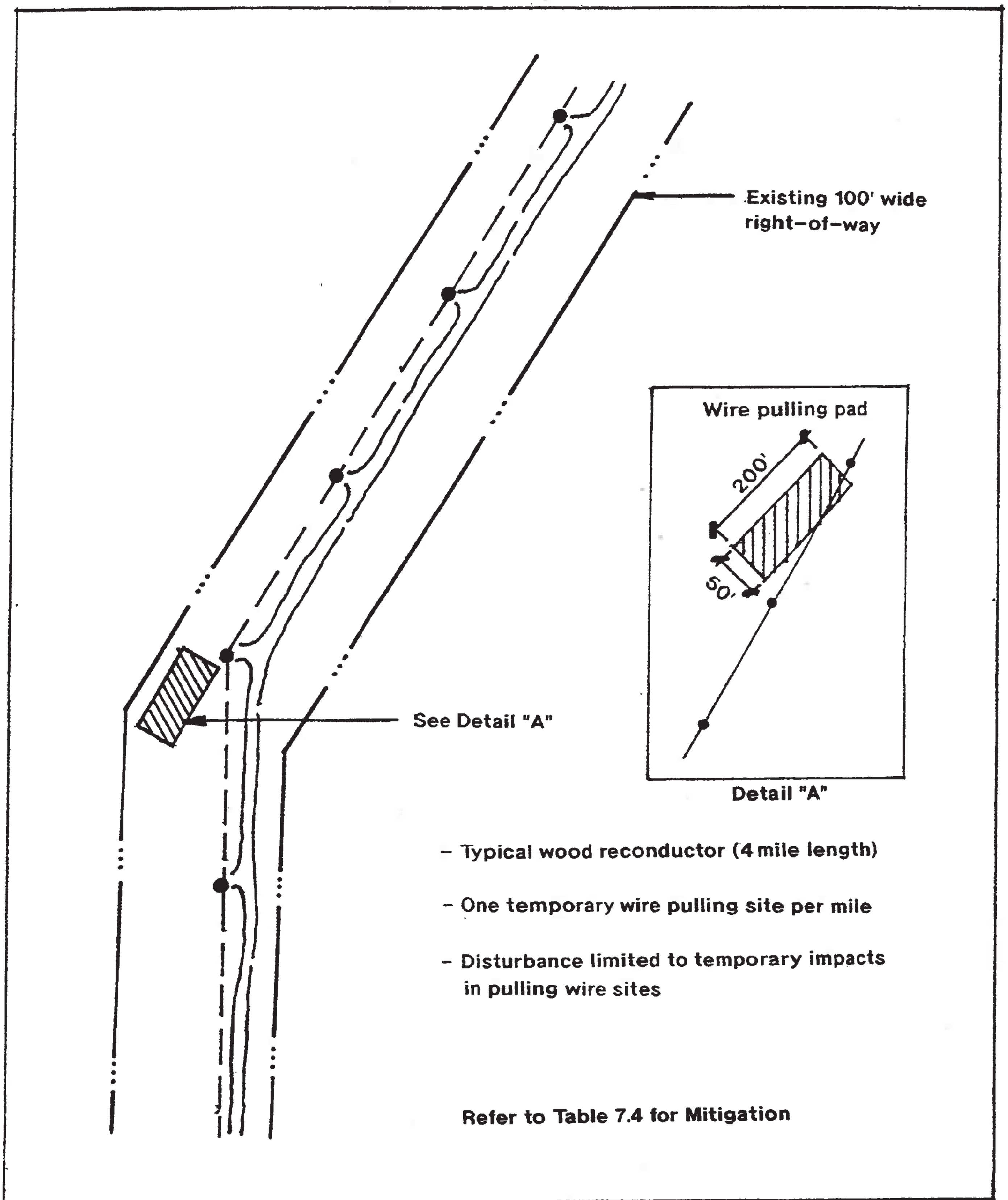


FIGURE 18

Typical Electric Transmission Reconductor in Existing R/W (Wood) Impact Diagram

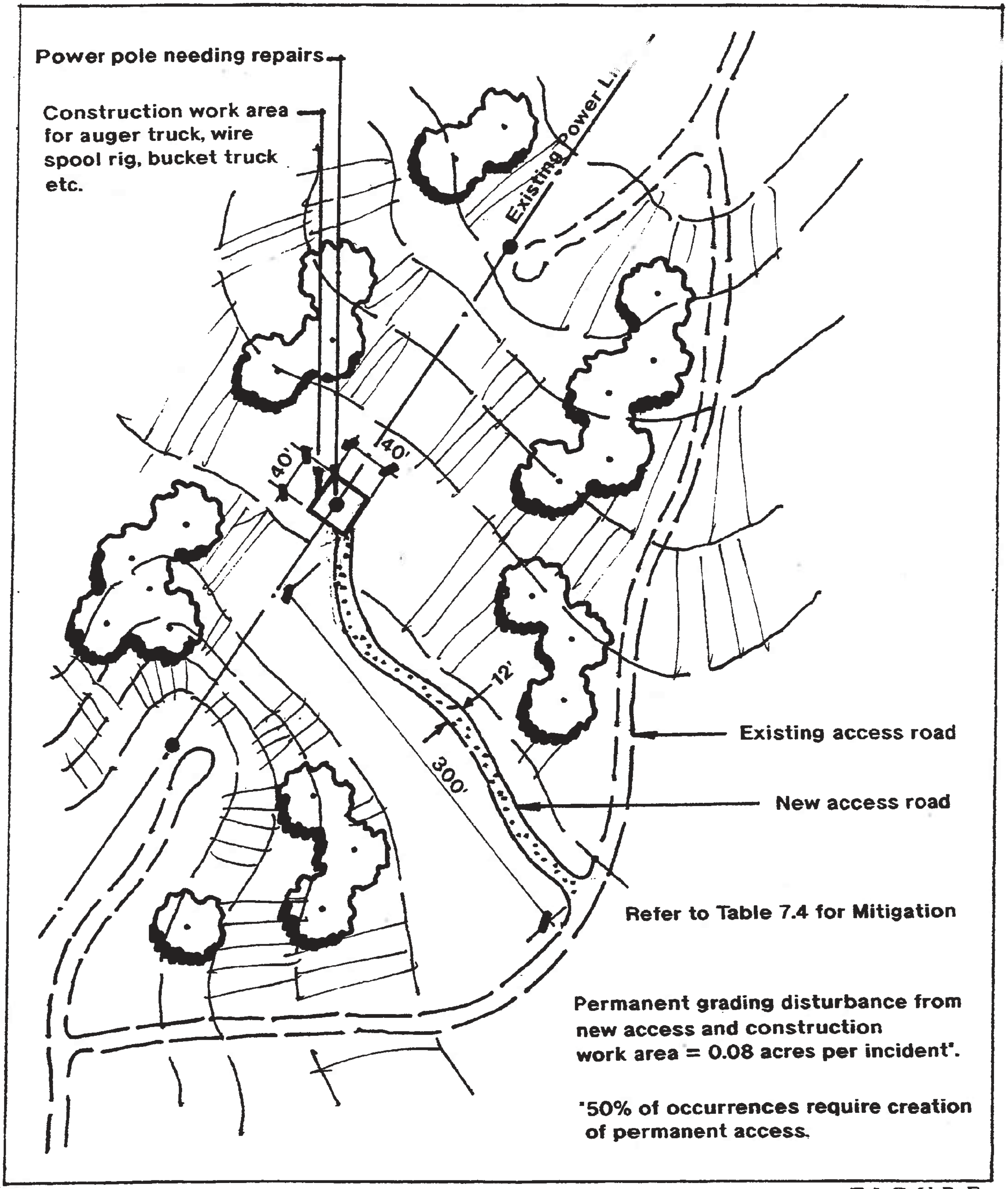


FIGURE 19

Typical Electrical Transmission or Distribution Repairs Impact Diagram

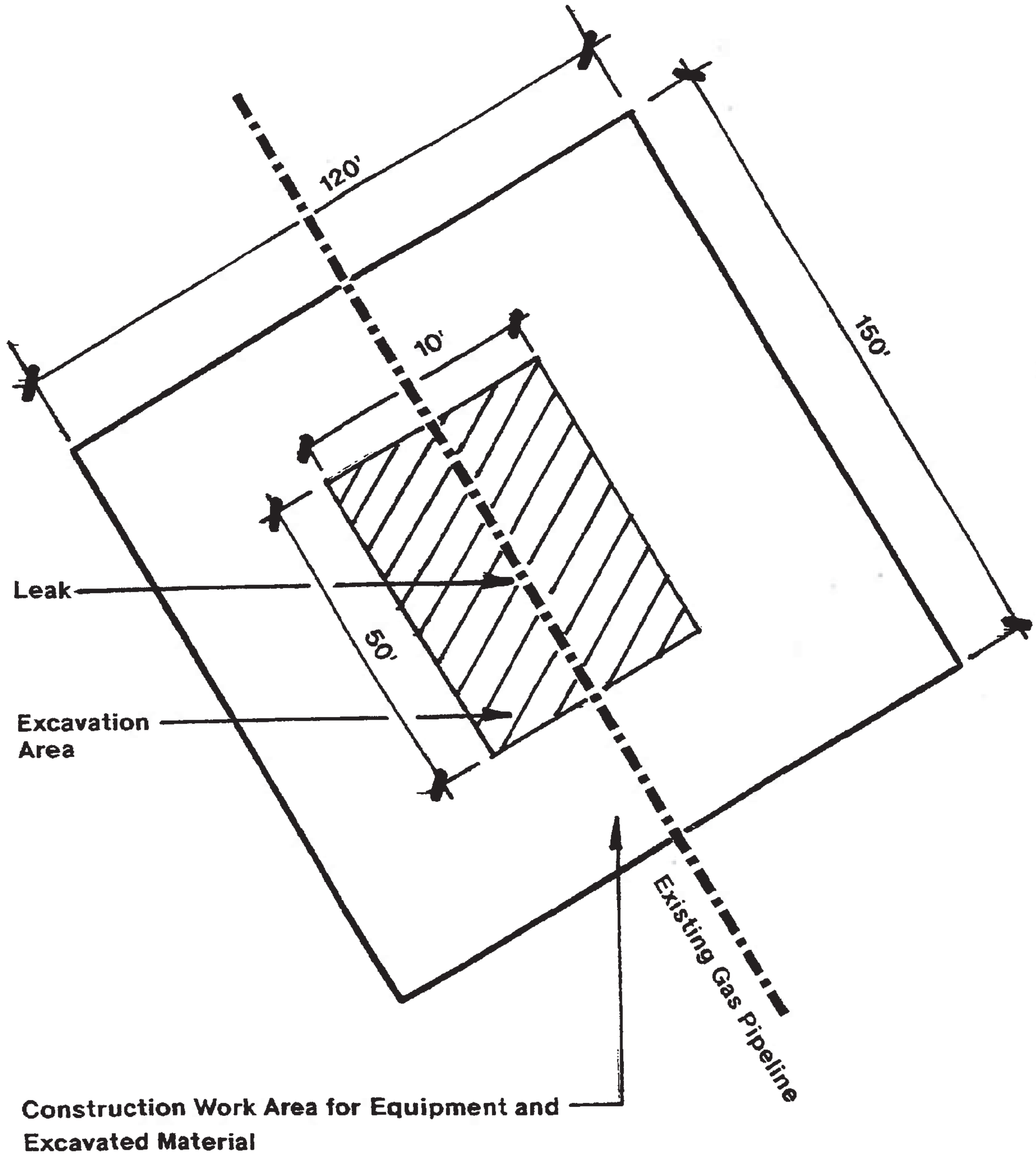
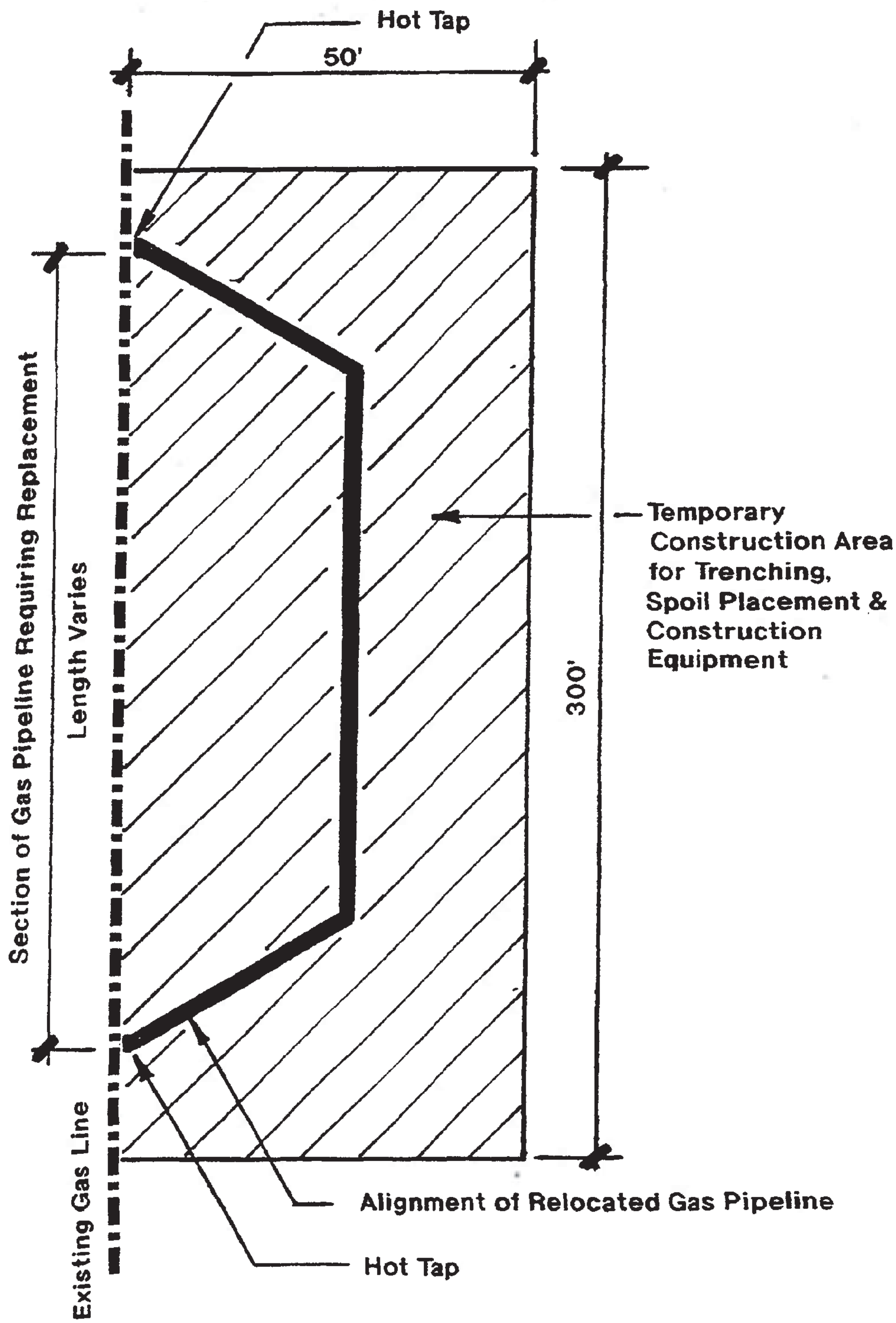


FIGURE 20

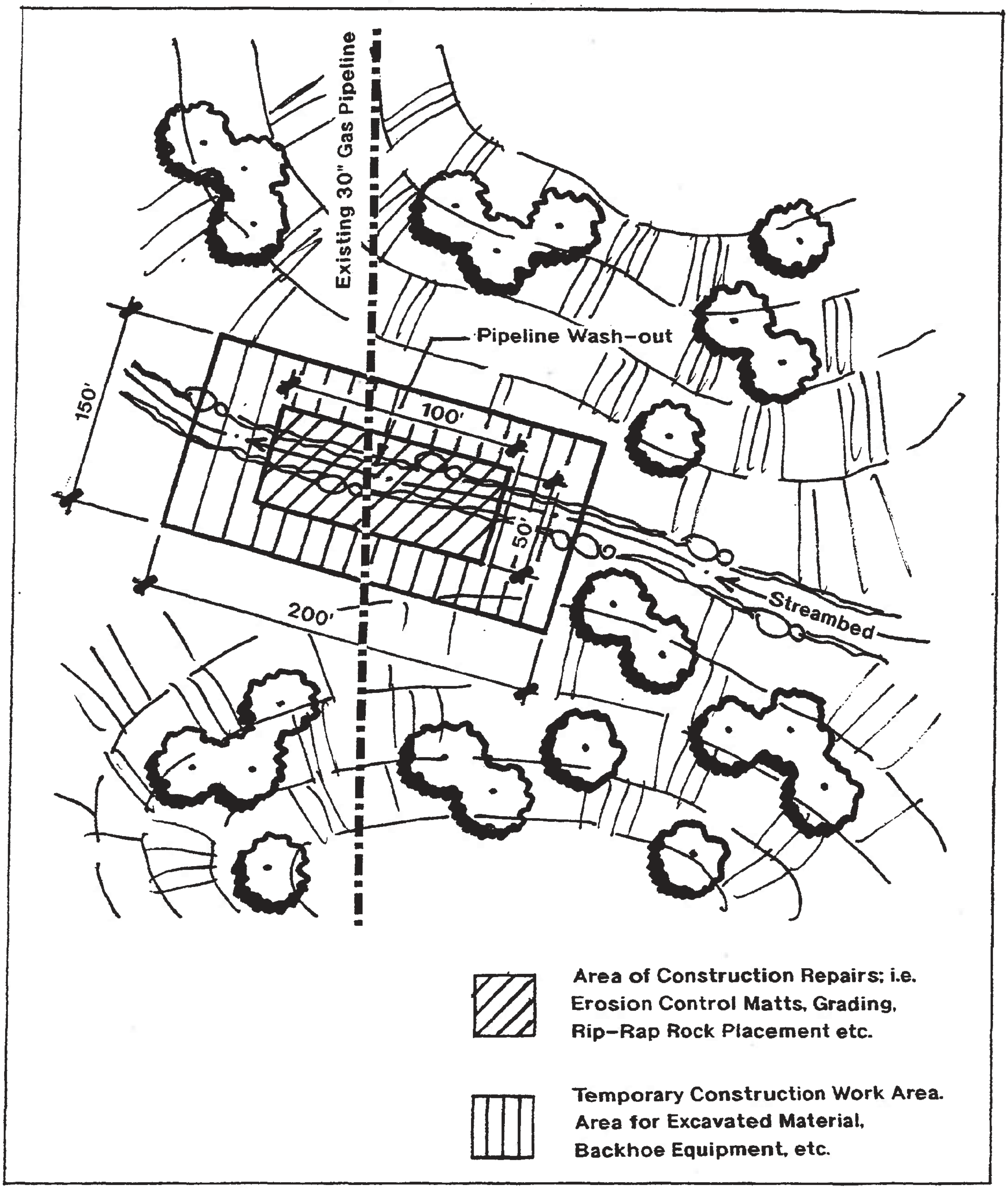
Typical Corrective Action to Repair Gas Pipeline Leak Impact Diagram



Refer to Table 7.4 for Mitigation

FIGURE 21

Typical Gas Pipeline Relocation Impact Diagram



Typical Corrective Streambed Repair to Protect Gas Pipeline Impact Diagram

FIGURE 22

5 Relation to Other Regional Habitat Conservation Plans

As of early 1995, a number of subregional and subarea comprehensive habitat and multiple species conservation plans proposed in southern California by various local governments, local bodies, and private entities are nearing the implementation phase of their plans. Included among these plans are the Multiple Species Conservation Plan generated as a part of San Diego's Clean Water Program, San Diego Association of Governments (SANDAG's) Multiple Habitat Conservation Program, the South Orange County NCCP Subregional Plan, the Riverside County Habitat Conservation Plan, and the County of San Diego's Multiple-Habitat Conservation and Open Space Plan. With limited exceptions relating to Preserve Areas in such plans, as described in Section 6, and certain threatened or endangered species with highly restricted habitat as described in Section 3, this Subregional Plan will be fully implemented independent of such other plans.

6 SDG&E Activities Within Habitat Conservation Plan Preserves

Activities Within Preserve Areas

As generally described in Section 2 of this Subregional Plan, SDG&E Activities will include the maintenance, repair, and replacement of existing Facilities as well as the installation, maintenance, repair, and replacement of new Facilities. Existing Facilities are and new Facilities may be expected to be, in part, located within established Preserve Areas of Habitat Conservation Plans (HCPs), state, federal, or local preserve areas including public and private lands or other areas set aside for the protection of plants and animals. SDG&E's Activities, particularly those related to new Facilities, are responsive to the growth and service needs of SDG&E customers within the Subregional Plan Area. However, SDG&E is not able to predict with any reasonable degree of certainty what the growth and service needs of its customers will be during the term of this Subregional Plan or what Facilities will be needed to meet those needs.

As a part of its efforts to coordinate the implementation of this Subregional Plan with any effective HCP which may be affected by SDG&E Activities, the following agreements will be adhered to for Activities occurring or proposed to occur in preserve areas.

6.1 Maintenance, Repair, and Replacement of Existing Facilities

Without her authoriz ion from USFWS or CDFG, SDG&E may conduct all necessary maintenance, repair, and replacement Activities with respect to all existing Facilities which are now or may hereafter be located within a Preserve Area of an HCP, if conducted in accordance with the provisions of this Subregional Plan.

6.2 Installation, Maintenance, Repair, and Replacement of New Facilities

6.2.1 New Gas and Electric Transmission Facilities

As a result of the extensive, rapid, and continuing development within the Subregional Plan Area, existing and proposed Preserve Areas are or will be dispersed among and in some cases surrounded by developed areas. USFWS and CDFG recognize that as a public utility SDG&E is obligated to provide safe, reliable, efficient, and cost-effective electric and gas service throughout the developed area of its service territory in compliance with the Public Utilities Code and subject to the jurisdiction of the California Public Utilities Commission. Unavoidably, therefore, the construction of new electric and gas transmission Facilities through or within Preserve Areas will be necessary in certain circumstances to meet the service requirements of developing areas. Where SDG&E determines that new electric or gas transmission Facilities are necessary within part of a Preserve Area, it will coordinate with USFWS and CDFG in accordance with the procedure set forth below to plan and construct such new Facilities in a manner which avoids or minimizes any impacts to Covered Species and their habitat, to the extent possible, while not impairing SDG&E's ability to meet the service demands of its customers in accordance with its responsibilities as a public utility.

Whenever SDG&E determines that it is necessary to install a new electric transmission line, or electric substation, or to install a new gas transmission line, or gas regulator station in any part of a Preserve Area, SDG&E shall provide USFWS and CDFG with written notice of its intent to install such Facilities which shall contain a detailed description of such Facilities and of their location, along with a map of the area. At a minimum, the information contained on the pre-activity survey form is required. USFWS and CDFG may request a tour of the proposed site and a staff meeting to discuss it. Within twenty (20) working days of its receipt of SDG&E's notice, USFWS and CDFG shall provide SDG&E with their written response setting forth any objections to and alternatives to the location of the Facilities within the Preserve

Area. Within ten (10) working days of receiving the objections of USFWS of CDFG, or both, SDG&E shall provide USFWS and CDFG with its written reply to their response. Within ten (10) working days of receiving the SDG&E reply, USFWS and CDFG shall approve or deny SDG&E's proposed location for the Facilities within the Preserve Area. If no objections are received by SDG&E from USFWS or CDFG within twenty (20) working days of SDG&E's notice, USFWS and/or CDFG shall be deemed to have concurred with the Activity described in SDG&E's original notice. If USFWS and CDFG denies the location, SDG&E may, within ten (10) working days of receiving such denial appeal to a review panel consisting of Regional Director, USFWS, Director, CDFG, and SDG&E, whose decision shall be final for purposes of this Subregional Plan. The appeal conference must be held within twenty (20) working days.

6.2.2 New Gas and Electric Distribution Facilities

The project proponent, other than SDG&E, that is requesting the extension of distribution facilities to serve his/her project shall obtain approval of said extension of facilities as part of their overall project approval.

7 Mitigation

The basic formula for addressing the impacts of SDG&E Activities in sensitive resource areas is first to attempt to avoid impacts to Covered Species and their habitats, second to minimize necessary impacts to Covered Species to the extent feasible, and third to mitigate for those unavoidable impacts. The biological mitigation for anticipated impacts of SDG&E Activities takes three forms:

- SDG&E agrees to conduct Activities in an environmentally sensitive manner in accordance with adopted Operational Protocols.

  SDG&E's Operational Protocols are behavioral and construction techniques which, when employed in the field, represent an environmentally sensitive approach to construction and maintenance. The protocols are primarily based upon impact avoidance and minimization and recognize that often minor adjustments during planning, construction, or maintenance activities can yield major benefits to the environment. Operational Protocols are discussed in detail in Section 7.1.

- SDG&E agrees to allow certain fee-owned rights-of-way to be used for wildlife and habitat preservation.

  SDG&E will restrict the use and development of certain land owned by SDG&E underlying specific electric transmission facilities and otherwise comprising a part of SDG&E electric transmission rights-of-way, which contain habitat, connect fragmented habitat areas, or which may contribute to the habitat carrying capacity of Preserve Areas managed as a part of other conservation plans. SDG&E will restrict the use and development of such land to SDG&E's utility activities as described in this Subregional Plan through a prohibitory easement granted in favor of USFWS and

CDFG, as more fully described in Section 7.3 of this Subregional Plan and subject to the terms and conditions of the Implementing Agreement.

- SDG&E agrees to cause the conveyance of certain high quality habitat land to USFWS, CDFG, or their designee, as further mitigation measure for unavoidable impacts to Covered Species or their habitat as a result of Activities covered by the Subregional Plan. These lands will comprise the SDG&E Mitigation Credits. Mitigation Credits will be reduced as they are used for mitigation in accordance with the ratios set forth in Section 7.4. The amount of Mitigation Credit to be conveyed has been predicted for the initial term of this Subregional Plan (25 years) based upon the expected impacts to habitat which will result from the Activities covered by the Subregional Plan, as more fully described in Section 4. The use of Mitigation Credits will not be necessary where habitat enhancement measures have been successful as a mitigation measure.

  Mitigation Credits which are unused at the expiration or termination of the Subregional Plan shall remain available for utilization, as appropriate, as mitigation for any project or action which may be required under CEQA, NEPA, or other environmental or natural resource law, as more fully described in the Implementing Agreement.

As more fully described in the Implementing Agreement, USFWS, CDFG, and SDG&E agree that, absent Unforeseen Circumstances, the mitigation measures provided in this Subregional Plan constitute the only mitigation measures that shall be required for any activity covered by the Subregional Plan where it results in an impact to a Covered Species or its habitat.

7.1 Operational Protocols

Operational protocols represent an environmentally sensitive approach to traditional utility construction, maintenance and repair Activities recognizing that slight adjustments in construction techniques can yield major benefits for the environment. The appropriate Operational Protocols for each individual project will be determined and documented by the Environmental Surveyor. The information regarding the qualifications and responsibilities of the environmental surveyor is contained in Appendix B. The following mitigation measures shall be adhered to by SDG&E.

7.1.1 General Behavior for All Field Personnel

1. Vehicles must be kept on access roads. A 15 mile-per-hour speed limit shall be observed on dirt access roads to allow reptile species to disperse. Vehicles must be turned around in established or designated areas only.

2. No wildlife, including rattlesnakes, may be harmed, except to protect life and limb.

3. Firearms shall be prohibited on the rights-of-way except for those used by security personnel.

4. Feeding of wildlife is not allowed.

5. SDG&E personnel are not allowed to bring pets on the rights-of-way in order to minimize harassment or killing of wildlife and to prevent the introduction of destructive domestic animal diseases to native wildlife populations.

6. Parking or driving underneath oak trees is not allowed in order to protect root structures except in established traffic areas.

7. Plant or wildlife species may not be collected for pets or any other reason.

8. Littering is not allowed. SDG&E shall not deposit or leave any food or waste on the rights-of-way or adjacent property.

9. Wild Fires shall be prevented or minimized by exercising care when driving and by not parking vehicles where catalytic converters can ignite dry vegetation. In times of high fire hazard, it may be necessary for trucks to carry water and shovels, or fire extinguishers in the field. The use of shields, protective mats, or other fire prevention methods shall be used during grinding and welding to prevent or minimize the potential for fire. Care should be exhibited when smoking in natural habitats.

10. Field crews shall refer environmental issues including wildlife relocation, dead or sick wildlife, hazardous waste, or questions about avoiding environmental impacts to the Environmental Surveyor. Biologists or experts in wildlife handling may need to be brought in by Environmental Surveyor for assistance with wildlife relocations.

7.1.2 Training

11. All SDG&E personnel working within the project area shall participate in an employee training program conducted by SDG&E, with annual updates. The program will consist of a brief discussion of endangered species biology and the legal protections afforded to Covered Species; a discussion of the biology of the Covered Species protected under this Subregional Plan; the habitat requirements of these Covered Species; their status under the Endangered Species Acts; measures being taken for the protection of Covered Species and their habitats under this Subregional Plan; and a review of the Operational Protocols. A fact sheet conveying this information will also be distributed to all employees working in the project area.

12. Designated SDG&E staff will conduct selected reviews of SDG&E operations. Any proposed modifications to Operational Protocols, procedures or conditions will be promptly provided to CDFG and USFWS for their review and input for required permit or Subregional Plan amendments.

7.1.3 Preactivity Studies

13. The Environmental Surveyor shall conduct preactivity studies for all activities occurring off of access roads in natural areas. The scope of these studies is included in Appendix A. The Environmental Surveyor will complete a preactivity study form contained in Appendix A, including recommendations for review by a biologist and construction monitoring as appropriate. Biologists should be called in when there is the potential for unavoidable impacts to Covered Species. The forms are for information only, and will not require CDFG or USFWS approval. These forms shall be faxed to CDFG and USFWS, along with phone notification, who will reply within 5 working days, indicating if they would like to review the project and/or suggest recommendations for post project monitoring. If a biologist is required, he/she will be contacted concurrent to notification to CDFG and USFWS. SDG&E's project may proceed during this time if necessary, in compliance with the recommendations of the biologist (For narrow endemic species see mitigation IV following Table 3.1). USFWS survey protocols performed by qualified biologists will be required for new projects which are defined as projects requiring CEQA review.

In those situations where the Environmental Surveyor cannot make a definitive species identification, an on-call biologist will be brought in. When the biologist is called, he or she will be contacted concurrently with CDFG and USFWS. The biologist will make the determination of the species in question and recommend avoidance or mitigation approaches to the Environmental Surveyor and a decision will be made. In those situations where more than one visit may be necessary to identify a given species, such as certain birds, no more than three site visits shall be required. It is expected that the typical USFWS search protocols will not be utilized in most situations due to the Plan's avoidance priority. Background information necessary to complete the annual report shall be collected on the preactivity study form and used by SDG&E to prepare the annual report.

14. In order to ensure that habitats are not inadvertently impacted, the Environmental Surveyor shall determine the extent of habitat and flag boundaries of habitats which must be avoided. When necessary, the Environmental Surveyor should also demark appropriate equipment laydown areas, vehicle turn around areas, and pads for placement of large construction equipment such as cranes, bucket trucks, augers, etc. When appropriate, the Environmental Surveyor shall make office and/or field presentations to field staff to review and become familiar with natural resources to be protected on a project specific basis.

15. SDG&E will maintain a library of rare plant locations known to SDG&E occurring within easements and fee owned properties. "Known" means a verified population, either extant or documented using record data. Information on known sites may come from a variety of record data sources including local agency Habitat Conservation Plans, pre-activity surveys, or biological surveys conducted for environmental compliance on a project site (e.g. initial study), but there is no requirement for development of original biological data. Plant inventories shall be consulted as part of pre-activity survey procedures.

7.1.4 Maintenance, Repair and Construction of Facilities

16. Maintenance, repair and construction Activities shall be designed and implemented to minimize new disturbance, erosion on manufactured and other slopes, and off-site degradation from accelerated sedimentation, and to reduce maintenance and repair costs.

17. Routine maintenance of all Facilities includes visual inspections on a regular basis, conducted from vehicles driven on the access roads where possible. If it is necessary to inspect areas which cannot be seen from the roads, the inspection shall be done on foot, or from the air.

18. When the view of a gas transmission line marker becomes obscured by vegetation on a regular basis requiring repeated habitat removal, consideration shall be given to the replacement of markers with taller versions.

19. Erosion will be minimized on access roads and other locations primarily with water bars. The water bars are mounds of soil shaped to direct flow and prevent erosion.

20. Hydrologic impacts will be minimized through the use of state-of-the-art technical design and construction techniques to minimize ponding, eliminate flood hazards, and avoid erosion and siltation into any creeks, streams, rivers, or bodies of water by use of Best Management Practices.

21. When siting new facilities, every effort will be made to cross the wetland habitat perpendicular to the watercourse, spanning the watercourse to minimize the amount of disturbance to riparian areas (See Figure 4).

22. Gas and other facilities cross streambeds and require maintenance and repair. During such times water may be temporarily diverted as long as after disturbance natural drainage patterns are restored to minimize the impact of the disturbance and help to reestablish or enhance the native habitat. Erosion control during construction in the form of intermittent check dams and culverts should also be considered to prevent alteration to natural drainage patterns and prevent siltation.

23. Impacts to wetlands shall be minimized by avoiding pushing soil or brush into washes or ravines.

24. During work on facilities, all trucks, tools, and equipment should be kept on existing access roads or cleared areas, to the extent possible.

25. Environmental Surveyor must approve of activity prior to working in sensitive areas where disturbance to habitat may be unavoidable.

26. Insulator washing is allowed from access roads if other applicable protocols are followed.

27. Brush clearing around facilities for fire protection shall not be conducted from March through August without prior approval by the Environmental Surveyor. The Environmental Surveyor will make sure that the habitat contains no active nests, burrows, or dens prior to clearing.

28. In the event SDG&E identifies a covered species of plant within a 10' radius around power poles, which is the area required to be cleared for fire protection purposes, SDG&E shall notify USFWS (for ESA listed plants), and CDFG (for CESA listed plants), in writing, of the plant's identity and location and of the proposed Activity, which will result in a Take of such plant. Notification will occur ten (10) working days prior to such Activity, during which time USFWS or CDFG may remove such plant(s). If neither USFWS or CDFG have removed such plant(s) within the ten (10) working days following the notice, SDG&E may proceed to complete its fire clearing and cause a Take of such plant(s).

    When fire clearing is necessary in instances other than around power poles, and the potential for impacts to Covered Species exists, SDG&E will follow the preactivity study and notification procedures in Operational Protocol number 13.

29. Wire stringing is allowed year round in sensitive habitats if conductor is not allowed to drag on ground or in brush and vehicles remain on access roads.

30. Maintenance of cut and fill slopes shall consist primarily of erosion repair. In situations where revegetation would improve the success of erosion control, planting or seeding with native hydroseed mix may be done on slopes.

31. Spoils created during maintenance operations shall be disposed of only on previously disturbed areas designated by the Environmental Surveyor or used immediately to fill eroded areas. Cleared vegetation shall be hauled off the rights-of-way to a permitted disposal location.

32. Within 6 months of Plan approval, environmentally sensitive tree trimming locations will be identified in the tree trim computer data base system utilized by tree trim contractors. (This data base also tracks the date of each tree trim, type of tree, where threatening dogs reside, etc.). The Environmental Surveyor should be contacted to perform a preactivity survey when trimming is planned in environmentally sensitive areas. Whenever possible, trees in environmentally sensitive areas (determined by CDFG and SDG&E) will be scheduled for trimming in the non-sensitive times.

33. No new Facilities and Activities shall be planned which disturb vernal pools, their watersheds, or impact their natural regeneration. Continued historic maintenance of existing infrastructure utilizing existing access roads is allowed to continue in areas containing vernal pool habitat. New construction of overhead infrastructure which spans vernal pool habitats is allowed as long as the placement of facilities or the associated construction activities in no way impact the vernal pools.

34. If any previously unidentified dens, burrows, or plants are located on any project site after the preactivity survey, the Environmental Surveyor shall be contacted. Environmental Surveyor will determine how to best avoid or minimize impacting the resource by considering such methods as project or work plan redevelopment, equipment placement or construction method modification, seasonal/time of day limitations, etc...

35. The Environmental Surveyor shall conduct monitoring as recommended in the preactivity survey report. At completion of work, the Environmental Surveyor shall check to verify compliance, including observing that flagged areas have been avoided and that reclamation has been properly implemented. Also at completion of work, the Environmental Surveyor is responsible for removing all habitat flagging from the construction site.

36. The Environmental Surveyor shall conduct checks on mowing procedures, to ensure that mowing is limited to a 12-foot wide area on straight portions of the road (slightly wider on radius turns), and that the mowing height is no less than 4 inches.

37. Supplies or equipment where wildlife could hide (e.g., pipes, culverts, pole holes) shall be inspected prior to moving or working on them to reduce the potential for injury to wildlife. Supplies or equipment that cannot be inspected or from which animals could not be removed shall be capped or otherwise covered at the end of each work day. Old piping or other supplies that have been left open, shall not be capped until inspected and any species found in it allowed to escape. Ramping shall be provided in open trenches when necessary. If an animal is found entrapped in supplies or equipment, such as a pipe section, the supplies or equipment shall be avoided and the animal(s) left to leave on its own accord, except as otherwise authorized by CDFG.

38. All steep-walled trenches or excavations used during construction shall be inspected twice daily (early morning and evening) to protect against wildlife entrapment. If wildlife are located in the trench or excavation, the Environmental Surveyor shall be called immediately to remove them if they cannot escape unimpeded.

39. Large amounts of fugitive dust could interfere with photosynthesis. Fugitive dust created during clearing, grading, earth-moving, excavation or other construction activities will be controlled by regular watering. At all times, fugitive dust emissions will be controlled by limiting on-site vehicle speed to 15 miles per hour.

40. Before using pesticides in areas where burrowing owls may be found, a pre-activity survey will be conducted.

7.1.5 Maintenance of access roads shall consist of:

41. Repair of erosion by grading, addition of fill, and compacting. In each case of repair, the total area of disturbance shall be minimized by careful access and use of appropriately sized equipment. Repairs shall be done after preactivity surveys conducted by the Environmental Surveyor and in accordance with the recommendations regarding construction monitoring and relevant protocols. Consideration should be given to source of erosion problem, when source is within control of SDG&E.

42. Vegetation control through grading should be used only where the vegetation obscures the inspection of facilities, access may be entirely lost, or the threat of Facility failure or fire hazard exists. The graded access road area should not exceed 12'-wide on straight portions (radius turns may be slightly wider) (See Figure 23).

43. Mowing habitat can be an effective method for protecting the vegetative understory while at the same time creating access to a work area. Mowing should be used when permanent access is not required since, with time, total revegetation is expected. If mowing is in response to a permanent access need, but the alternative of grading is undesirable because of downstream siltation potential, it should be recognized that periodic mowing will be necessary to maintain permanent access.

44. Maintenance work on access roads should not expand the existing road bed (See Figure 23).

45. Material for filling in road ruts should never be obtained from the sides of the road which contain habitat without approval from Environmental Surveyor..

7.1.6 Construction of new access roads shall comply with the following:

46. SDG&E access roads will be designed and constructed according to the SDG&E *Guide for Encroachment on Transmission Rights-of-Way (4/91).*

47. Access roads will be made available to managers of the regional preserve system subject to coordination with SDG&E.

48. New access roads shall be designed to be placed in previously disturbed areas and areas which require the least amount of grading in sensitive areas during construction whenever possible (See Figure 5). Preference shall be given to the use of stub roads rather than linking facilities tangentially.

49. SDG&E will consider providing access control on access roads leading into the regional preserve system where such control provides benefit to sensitive resources.

50. New access road construction is allowed year round. Every effort shall be made to avoid constructing roads during the nesting season. During the nesting season, the presence or absence of nesting species shall be determined by a biologist and appropriate avoidance and minimization recommendations followed.

7.1.7 Construction and Maintenance of Access Roads Through Streambeds

51. Construction of new access roads through streambeds requires a Streambed Alteration Agreement from CDFG and/or consultation with the Army Corps of Engineers.

52. Maintenance or construction vehicle access through shallow creeks or streams is allowed. However, no filling for access purposes in waterways is allowed without the installation of appropriately sized culverts. The use of geotextile matting should be considered when it would protect wetland species.

53. Staging/storage areas for equipment and materials shall be located outside of riparian areas. (See Figure 23).

7.1.8 Survey Work

54. Brush clearing for foot paths or line-of-sight cutting is not allowed from March through August in sensitive habitats without prior approval from the Environmental Surveyor, who will ensure that activity does not adversely affect a sensitive species.

55. SDG&E survey personnel must keep vehicles on existing access roads. No clearing of brush for panel point placement is allowed from March through August without prior approval from the Environmental Surveyor.

56. Hiking off roads or paths for survey data collection is allowed year round so long as other protocols are met.

7.1.9 Emergency Repairs

57. During a system emergency, unnecessary carelessness which results in environmental damage is prohibited.

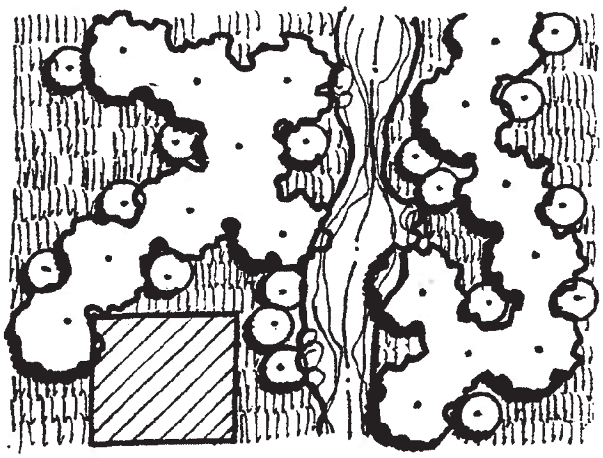
58. Emergency repair of facilities is required in situations which potentially or immediately threaten the integrity of the SDG&E system, such as pipe leaks, or downed lines, slumps, slides, major subsidence, etc. During emergency repairs the Operational Protocols contained in this Subregional Plan shall continued to be followed to fullest extent possible.

59. Once the emergency has stabilized, any unavoidable environmental damage will be reported to the Environmental Surveyor by the foreman. The Environmental Surveyor will develop a mitigation plan and ensure its implementation is consistent with this Subregional Plan.

7.1.10 Activities of Underlying Fee Owners

60. Most SDG&E rights-of-way are held in easement only. The activities of underlying fee owners cannot be controlled by SDG&E and are not covered by this Subregional Plan.

61. When sensitive habitat exists on either side of a utility right-of-way, SDG&E will not oppose underlying fee owners dedicating said property to conservation purposes. Underlying fee owners are expected to comply with applicable federal, state, and local regulations.



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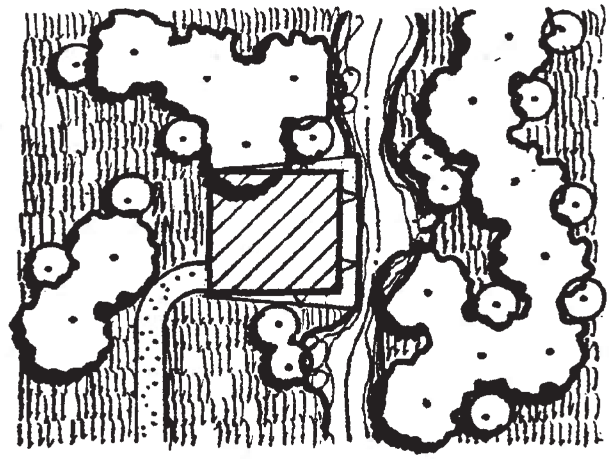

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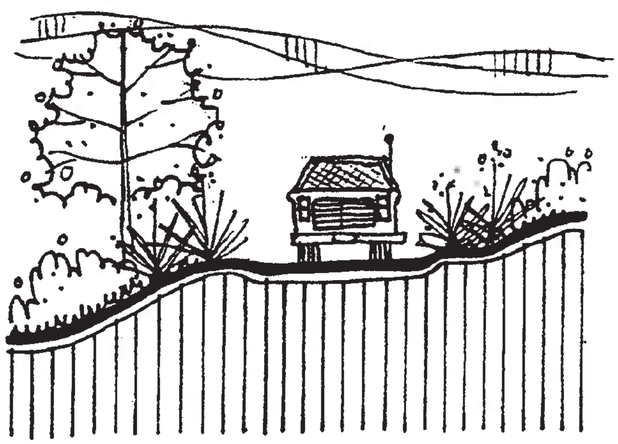
CONSTRUCTION STAGING/STORAGE AREAS SHOULD BE LOCATED OUTSIDE OF STREAMS



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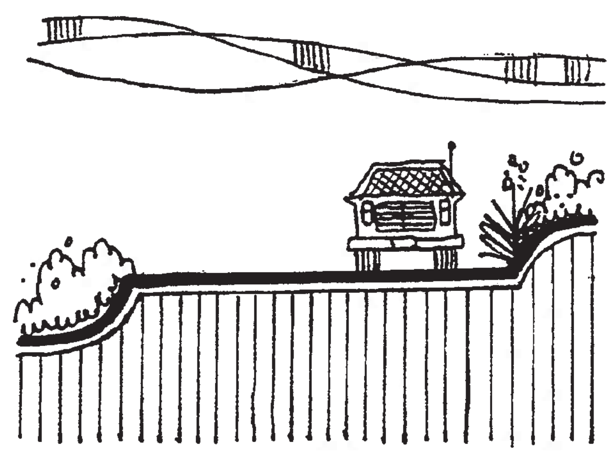

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ACCESS ROAD MAINTENANCE SHOULD NOT EXPAND THE EXISTING ROAD BED

FIGURE

Operational Protocol Diagrams

23

7.2 Habitat Enhancement Measures

The purpose of this section is to describe the techniques and permit the substitution of habitat enhancement measures when it is more beneficial than the use of mitigation credits. Habitat enhancement increases the value of biological resources in an impacted area, thereby improving the value of that habitat for Covered Species. Habitat enhancement activities shall occur under the direction of a Habitat Restoration Specialist. All disturbed areas, whether inside or outside of preserves, and which do not need to be maintained in a cleared state, shall be enhanced, either through vegetation restoration, habitat reclamation, or a combination of the two. Vegetation restoration entails a range of techniques.

For SDG&E Activities occurring within the Preserve, and for SDG&E Activities affecting riparian/wetland areas, the particular enhancement methodology will be proposed by SDG&E, with USFWS and CDFG concurring prior to implementation. For all other areas outside of the Preserve, SDG&E has discretion over the enhancement method selected, although it is expected that a standard coastal sage scrub seed mix will be used for reseeding many disturbed areas. For impacts both within and outside Preserve, if habitat enhancement is not selected, or is not successful according to the criteria specified in the mitigation flow chart (Figure 24), then a deduction from the SDG&E Mitigation Credits shall be made in accordance with ratios contained in Section 7.4. For all temporary impacts greater than 500 square feet, acreage not meeting success criteria shall be deducted from SDG&E mitigation credits at a 1:1 ratio. For areas of less than 500 square feet, success criteria will not be required to be met. In such areas, refer to erosion control measures contained in Section 7.1.

7.2.1 Vegetation Restoration

The Habitat Restoration Specialist has a range of vegetation restoration techniques from which to choose:

Hydroseeding

Vegetation restoration will typically be done using a native seed mix obtained from a commercial seed provider and shall be applied by hydroseeding. For hydroseeding inside the Preserve areas, seed will be obtained from the local gene-pool and similar composition to the reference site.

Vegetation restoration shall be conducted from mid-November through mid-January to take advantage of rainy season precipitation, and should not be artificially irrigated.

Seed mix specifications and application techniques shall be provided by the Habitat Restoration Specialist, who will be an acknowledged specialist in native habitat restoration or a plant ecologist with experience developing native restoration plans in Southern California. The Habitat Restoration Specialist will be responsible for restoration plans within the Preserve.

If restoration lands contain areas used for temporary roads, staging areas, or other intensive activities, the soil may become so compacted that revegetation is difficult. In cases such as this, disking and plowing the compacted soil will loosen it and improve the success of hydroseed revegetation. Disking may also foster weed growth and should only be used where an influx of weeds would not adversely affect adjacent native plant communities.

Consideration shall be given to supplemental planting of species of concern in areas where it is desirable to expand existing colonies. For example, supplemental planting may be highly desirable in areas containing chollas or prickly pear cactus. Supplemental planting and plant relocation should only be done in disturbed areas that are thought to be suitable. Habitat conversion and impacts to extant native vegetation should be avoided.

Hand-Seeding

Seed may be applied by hand and raked into the top inch of soil. This method is best suited for small areas and areas that are inaccessible to a hydroseed truck.

Imprinting

Imprinting is the mechanical formation of smooth-walled V-shaped furrows in the soil surface, application of seed and injection of beneficial mycorrhizal fungi into the soil surface. This method is best suited for areas that are accessible by bulldozer and where there is a potential problem with weeds.

Soil and Plant Salvage

Native vegetation from the area to be impacted should be removed, mulched and stockpiled separately. Top soil should also be removed and stockpiled separately. Following construction activities, the top soil should be replaced and covered with the mulch. The top soil and mulch both have native propagules and the mulch reduces the erosion potential. This method is well suited for temporary roads, staging areas, or other intensive activities.

Quality Assurance

Monitoring, involving visual inspection, shall be conducted on restoration sites after one year. A second application may be made. If, after one more year, restoration is deemed unsuccessful, the wildlife agencies, in cooperation with SDG&E, will determine whether the remaining loss shall be mitigated through a deduction from the SDG&E Mitigation Credits, or a third application would better achieve the intended purpose.

Coverage standards will be based on comparisons with established stands of the target vegetation, or another reference area. The means of determining success should be based on estimates of cover by native species, cover of exotic species, and diversity of native species. The cover of native species should increase and the cover of weed species should decrease, eventually approximating the reference area. The reference areas should be a nearby stand of vegetation that the restoration is attempting to emulate. It should have a similar aspect, slope, and soil type.

Cover for the restoration and references areas should be estimated using repeatable cover classes. One tested system is as follows:

Cover Class	1	2	3	4	5	6
% Cover	0-5	5-25	25-50	50-75	75-95	95-100
Mean Cover	2.5	15	37.5	62.5	85	97.5

SUCCESS CRITERIA MILESTONES

Criteria*	Year 1	Year 2
Cover by Exotic Species**	140%	130%
Cover by Native Species (trees shrubs and herbaceous species)	60%	70%

*Values are relative to reference area
**Percent total cover

7.2.2 Habitat Reclamation

Habitat reclamation techniques should be considered when re-seeding would be an ineffective habitat enhancement due to the presence of stronger and more prolific exotic vegetation in the proximity.

Habitat reclamation involves the elimination of existing exotic vegetation (weed abatement) to facilitate the natural re-colonization of a native habitat. An example of where habitat reclamation would be appropriate is in wetland areas containing tamarisk or giant reed.

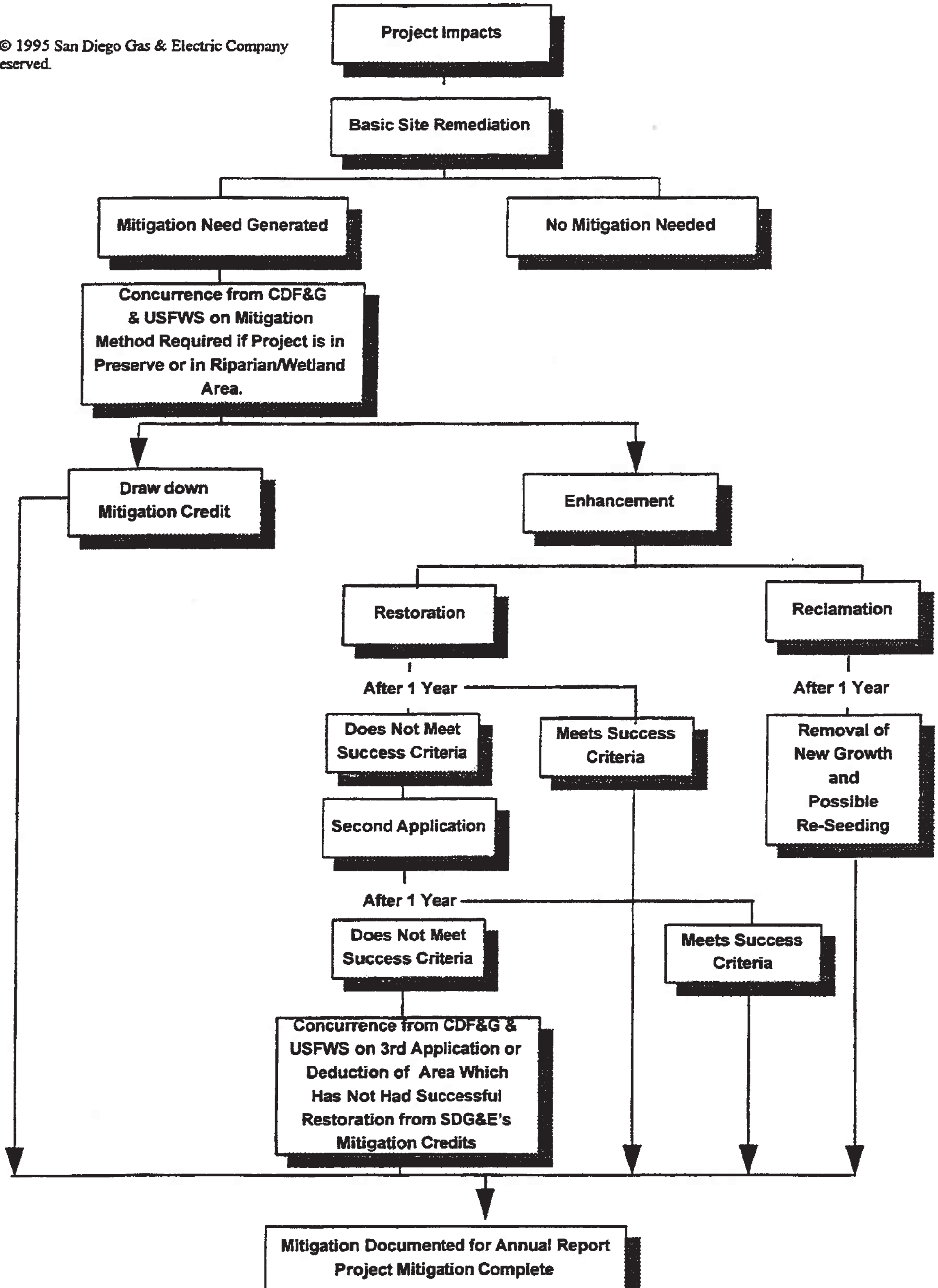
In order to avoid net loss of wetland and riparian habitat, exotic species should be removed at a 2:1 ratio. Exotics should be removed from the site and disposed of off-site. Soil should be prepared for new native growth to occur. In areas larger than 500 square feet, reseeding will supplement the recovery of native vegetation

Reclamation shall be limited to initial removal and one-time removal of new growth within one year if necessary. In certain cases, such as with Arundo removal, it may be necessary to clear invasive vegetation a third time. Once weeds are controlled, if extensive reclamation is undertaken, supplemental planting may be necessary to keep weeds out.

The habitat reclamation shall be done under the direction of the Habitat Restoration Specialist who will determine the abatement technique to be used and the area in the vicinity of the project site on which abatement would be most effective in facilitating reclamation on the project site.

7.2.3 Procedure

(Refer to Figure 24).Figure 24 -- Mitigation Flow Diagram



SDG&E Mitigation Flow Diagram
(For Temporary Disturbances)

FIGURE
24

7.3 Fee-Owned Rights-of-Way

Certain of SDG&E's electric transmission rights-of-way consist of real property owned in fee by SDG&E. Such fee owned rights-of-way are of various widths and cover a variety of habitat types. Some of the fee-owned rights-of-way may serve as the foundation for the creation by USFWS and CDFG of valuable wildlife corridors between Preserve Areas. The fee-owned rights-of-way subject to this subsection are identified on Figure 25a and 25b.

As a further mitigation measure, SDG&E will restrict the use and development of such lands to those SDG&E activities covered by this Subregional Plan. Subject to the terms and conditions of the Implementing Agreement, SDG&E shall effect such use and development restriction by granting a prohibitory easement in favor of USFWS and CDFG, or their designee, to be recorded in County Recorder's Office for the County in which such land is located.

To assist in the creation of these corridors, SDG&E agrees that it will not, and that it will not allow any other person, to use such rights-of-way for any purpose other than for SDG&E Activities conducted in accordance with this Agreement, the Permits and the Subregional Plan. SDG&E's agreement to limit its use of such rights-of-way shall remain effective for so long as USFWS and CDFG continuously uses such rights-of-way in combination with other real property rights acquired by USFWS and CDFG in adjoining property, the use of which is subject to similar limited or restricted uses, to establish functional and effective corridors for Covered Species between separated Habitat and Preserve Areas, and, for so long as such corridors are properly functioning and necessary for the conservation of Covered Species. SDG&E's agreement to limit the use of such rights-of-way will be memorialized in a negative or open space easement in favor of USFWS and CDFG, or their designee, and recorded in the County Recorder's Office for the county in which such rights-of-way are located. Such easement shall be substantially in the form of the easement attached hereto. However, in the event that any of such rights-of-way shall cease to be an essential element of a properly functioning, effective and necessary corridor, all easement rights conveyed by SDG&E affecting any such right-of-way shall terminate and revert back to SDG&E without limitation or reservation.

To the extent SDG&E rights-of-way extend over land in which it does not hold an undivided fee ownership interest, SDG&E agrees to approve of and when appropriate, encourage the conveyance, grant or dedication of such land by the fee owner to any relevant Habitat Conservation Planning Management entity for wildlife conservation purposes; provided, however, any such conveyance, grant or dedication shall be subject to the authorizations and Permitted Activities granted by USFWS and CDFG to SDG&E herein and to the rights of SDG&E to use such property for public utility purposes to the extent SDG&E held such rights, in law or in equity, at the time of such conveyance, grant or dedication. SDG&E further agrees, where the company's land rights allow, to prevent the underlying land owner from removing habitat within rights-of-way of significant habitat value to the extent feasible.

Fee Owned Rights-of-Way are Designated with Pink Lines Within Black Circles - Typical

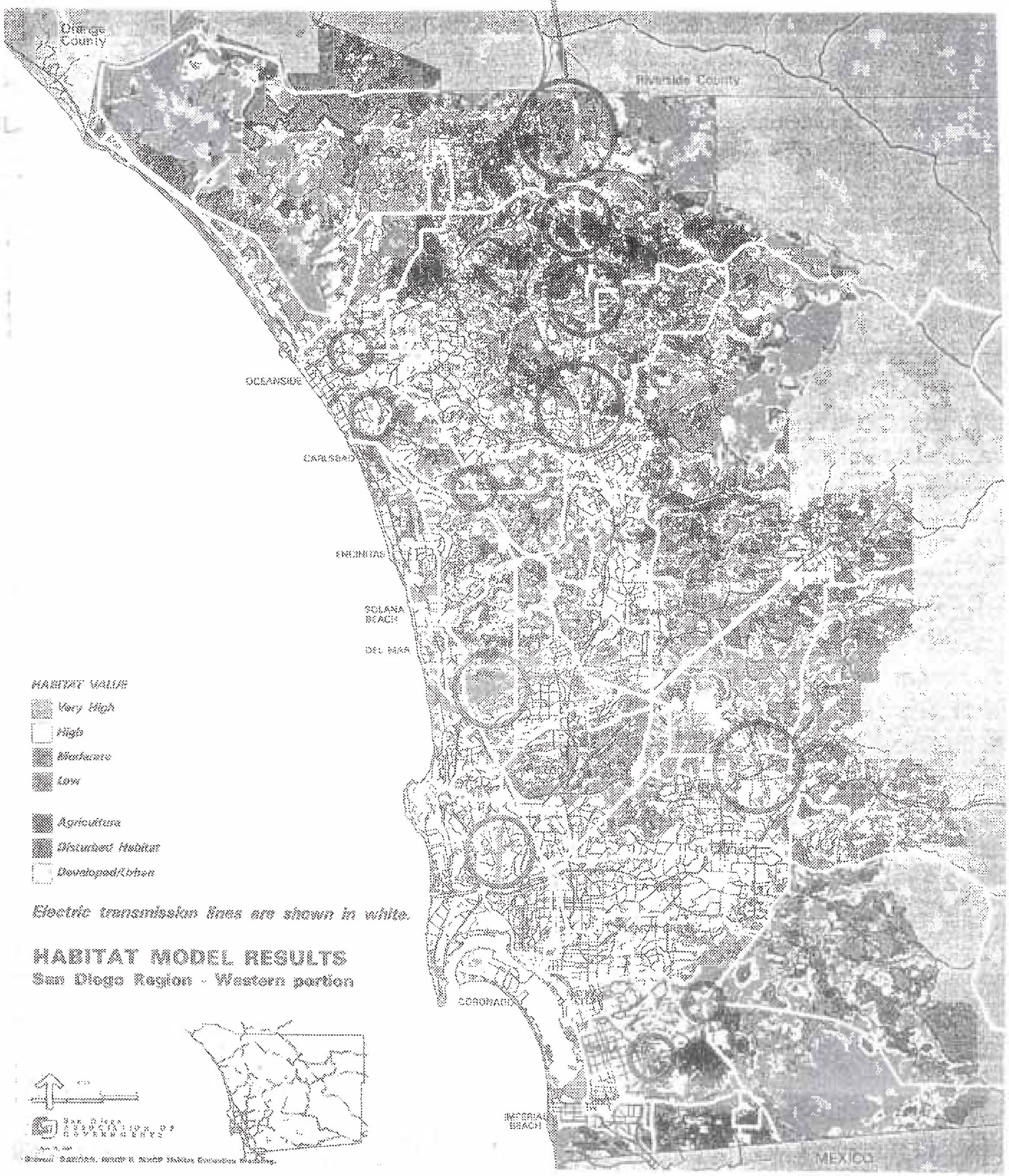
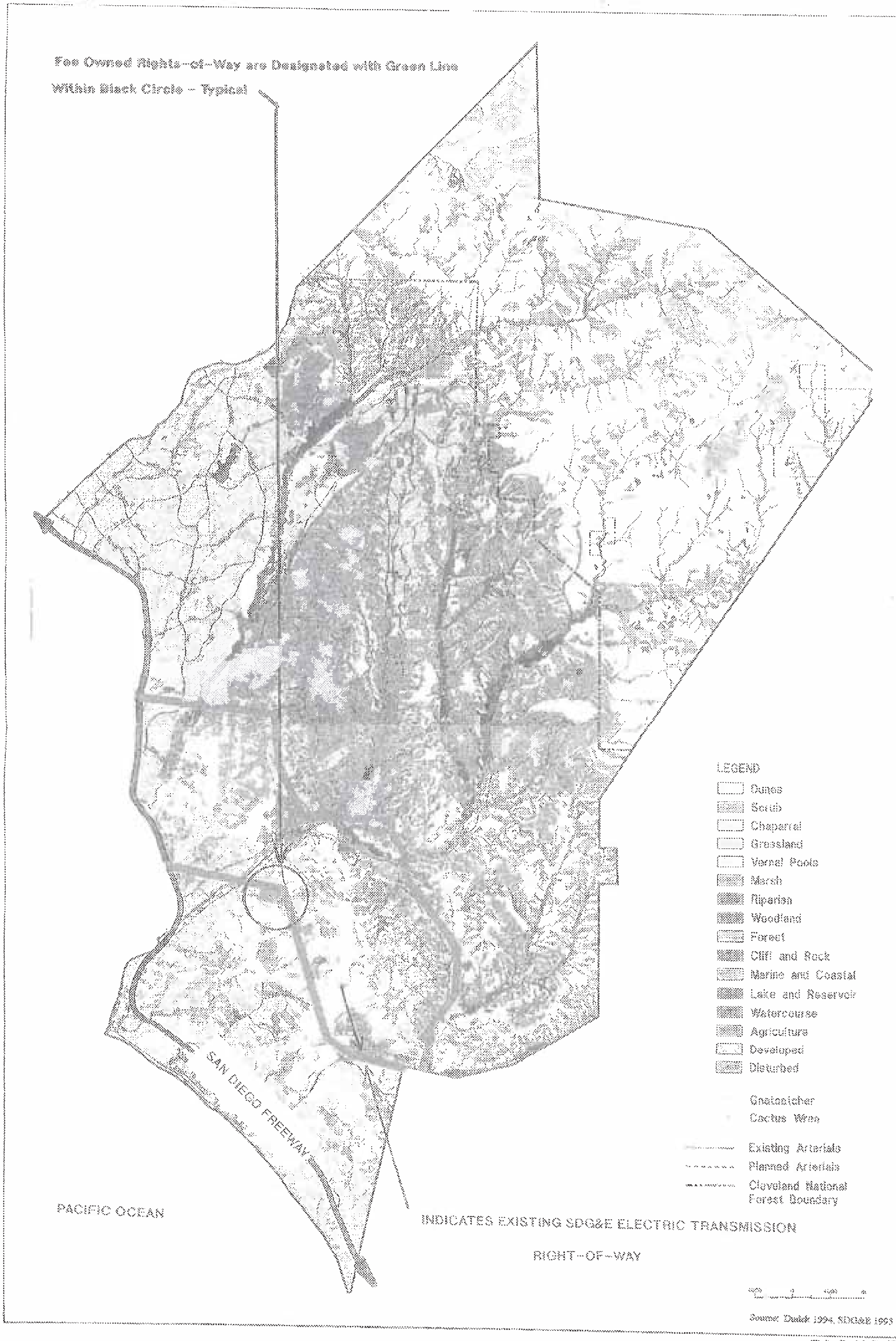


FIGURE **25a**

SDG&E Electric Transmission System Fee Owned Rights-of-Way



SDG&E Electric Transmission System Fee Owned Rights-of-Way

FIGURE 25b

7.4 Mitigation Credits

SDG&E will provide the USFWS and the CDFG with funds to enable the procurement of approximately 240 acres of high quality habitat land. The provision of such funds will create a conservation bank in favor of SDG&E in which SDG&E will hold approximately 240 acres of Mitigation Credits for impacts to covered species or their habitats which result from SDG&E Activities. Mitigation Credits associated with the SDG&E Subregional Plan will be drawn upon and deducted from available Mitigation Credits to mitigate for unavoidable impacts associated with SDG&E Activities. Habitat enhancement opportunities may be available and pursued prior to such deductions being taken from the SDG&E Mitigation Credits as discussed in Section 7.2.

The habitat associated with the SDG&E Mitigation Credits is of very high value. The location and configuration of the land will play a critical role in meeting region-wide conservation goals. As such, the Mitigation Credits serve as mitigation for both in-kind and out-of-kind covered species and habitat impacts, without regard to the type of habitat and the biological value of the habitat impacted, except with regard to wetlands falling within the jurisdiction of the Army Corps of Engineers pursuant to Section 10 of the Rivers and Harbors Act and Sections 403 and 404 of the Clean Water Act.

In the Annual Report which will be prepared as a condition of this Plan, the general condition of the habitat assoicated with the Mitigation Credits will be discussed, with special attention paid to changes in the habitat such as from stochastic events like fires and drought. The Report will also include a table showing how many credits were used from the Mitigation Credits (expressed in acres) and how many are left.

Also in the Annual Report will be an analysis jointly prepared by SDG&E, CDFG and USFWS on the performance of the management entity who are overseeing the day-to-day operations of the habitat associated with the Mitigation Credits. It may be necessary based on the outcome of that reporting to transfer control to CDFG or USFWS, if all of the parties agree.

The ratio between impacts from Activities and corresponding deductions from the Mitigation Credits are as follows:

Table 7.4

ACTIVITY	LOCATION	DURATION	RATIO
New Facilities	Inside Preserve*	Permanent	2:1
	Inside Preserve	Temporary	(a)(c)
	Outside Preserve	Permanent	1:1
	Outside Preserve	Temporary	(a)
Maintenance of Existing Facilities	Inside Preserve	Permanent	2:1
		Temporary	(a) (b)
	Outside Preserve	N/A	(b)

(a) Temporary impacts are mitigated through basic site remediation which, includes native hydroseed for erosion control. However, if roots are not grubbed during temporary impacts, the hydroseeding may not be necessary. This applies to areas greater than 500 square feet, and only where grubbing occurred. For all temporary impacts greater than 500 square feet, acreage not meeting success criteria shall be deducted from SDG&E mitigatión credits at a 1:1 ratio.

(b) Impacts associated with maintenance of existing facilities are mitigated for the term of the permit by SDG&E's agreement to restrict development other than SDG&E activities on fee-owned rights-of-way which contain habitat, connect fragmented habitat areas, or contribute to the habitat carrying capacity of the Preserve Areas in the region. SDG&E agrees to limit its use of such rights-of-way to utility activities.

(c) Same as (a), except that any portion of the temporarily impacted area which does not revegetate in accordance with Section 7.2 and the Mitigation Flow Chart attached as Figure 24, then acreage not meeting success criteria shall be deducted from the SDG&E Mitigation Credits.

*The term "Preserve" in Table 7.4 means the area encompassed by the MSCP's Multi-Habitat Planning Area (MHPA) map (as currently defined or ultimately adopted), the equivalent maps for the MHCP and MHCOS programs in San Diego County, the South Orange County NCCP Subregional Plan reserve area, and the Riverside County Conservation Agency Core reserve areas. If no preserve areas are formally delineated, those areas which are designated moderate, high, and very high quality habitat on habitat on evaluation maps prepared for the respective planning areas are considered the "Preserve."

8 Alternatives

Within its service territory, the demands of customers for electric power and natural gas are met by SDG&E. As a public utility, SDG&E is required by Public Utilities Code Section 451 to provide these utility services in a safe and reliable manner. The CPUC has the authority under Public Utilities Code Sections 701, 761 and 762 to require public utilities to establish and maintain the facilities and property rights which are necessary to provide safe and reliable service. In addition, SDG&E sets corporate goals in an effort to attain the highest quality and dependability of service at the lowest rates it can achieve.

These customer demands, legislative mandates, regulatory controls and corporate goals require that SDG&E install new facilities necessary to meet the growing demands of its customers, and that such new facilities and all existing facilities be adequately maintained and repaired to ensure safety and reliability. This Subregional Plan addresses such installation, operation, maintenance, and repair Activities and their potential to impact Covered species or their habitat.

The curtailment of any aspect of the SDG&E Activities would render SDG&E's public utility services, to a greater or lesser extent, inadequate to meet demand, inefficient, unsafe, and unreliable.

An alternative to this Subregional Plan is to do no conservation plan at all. The no plan alternative would mean that the SDG&E Activities described in the Subregional Plan would remain subject to "take" prohibitions of ESA and CESA. Incidental Take permits would be required for such Activities on a project by project and species by species basis. The case by case process of permitting is cumbersome. It has the potential to miss or to inadequately examine protective and conservation issues and measures, which may be too ill defined, unrecognized or vague to enable a clean and meaningful impact analysis or to articulate needed mitigation measures. This Subregional Plan addresses such issues from an ecosystem or habitat basis, wherein such protections or conservation measures are affected, whether or not defined, as a functioning aspect or part of the protected and covered ecosystem or habitat. Because this Subregional Plan provides comprehensive multiple species and habitat conservation, and is not limited to listed species, it provides a net benefit to the environment in that it protects and conserves species in a manner which may prevent any future listing of such species. In addition, the Subregional Plan provides SDG&E with long term predictability concerning the nature of its operations for which in takings are permitted, avoiding cumbersome procedures and potential facility compromising delays.

9 Funding

Funding requirements must be guaranteed in order for this Plan to be implemented. Therefore, SDG&E must be solvent enough to provide the financial confidence that will constitute such a guarantee. SDG&E has served the San Diego area for over 114 years. The Company's evident stability is reflected in an A+ Standard & Poor's bond rating, an A1 bond rating by Moody's, and by the historical fact that SDG&E has not missed a dividend in 84 years. In 1994, SDG&E's operating revenues exceeded operating expenses by $321,916,000.00. The fiscal health is such that SDG&E was able to declare a dividend of $1.52 for each of its 116,484,000 shares of common stock for a 9.1% return on common equity. These figures, along with the Company's financial history should provide adequate assurance that SDG&E has the fiscal soundness to fulfill its financial commitments with regard to the implementation of this Plan.

10 Acknowledgments

This plan was prepared over a two-year period by San Diego Gas & Electric staff and consultants, with support from several outside entities. Any omission of names is not intentional.

SAN DIEGO GAS & ELECTRIC PROJECT TEAM

Don L. Rose, Project Manager
Thomas G. Acuña, Land Planner
Stella A. Holland, Land Planner
Mark S. Chomyn, Land Planner
James R. Dodson, Environmental Attorney
Carole L. Major, Document Preparation

OUTSIDE CONSULTANTS

James E. Whalen, J. Whalen Associates
David Levine, Natural Resource Consultants
Sweetwater Environmental Biologists, Inc.

INTERN

Kimberly F. Seibly

DATA BASE SUPPORT

Timothy J. Hurley, GIS Project Manager, SDG&E
Ogden Environmental & Energy Services Company (MSCP & MHCP biological data)
Dudek & Associates (MHCP & South Orange County biological data)
RECON (Riverside County biological data)
County of San Diego (MHCOS biological data)
San Diego Association of Governments (GIS support)

WILDLIFE AGENCIES

Ron Rempel, California Department of Fish & Game
Theresa Stewart, California Department of Fish & Game
Sherry Barrett, United States Fish & Wildlife Service
Jacalyn Fleming, United States Fish & Wildlife Service

Appendix A
Scope of Preactivity Study

The purpose of the preactivity study is to determine the presence or absence of sensitive resources on or in the vicinity of a project area. Preactivity studies may be appropriate for any type of SDG&E field operation in a natural area. Prior to activities off of access roads in natural areas , the Environmental Surveyor conducts a preactivity study and records the findings of the study on the Preactivity Study Form (See Figure 26, pages 1 and 2). The preactivity study documents information such as:

- Type, location, and size of project
- Date, time, weather, and surrounding land uses
- Evaluation of type and quality of habitat
- Work description and methods which will be used to avoid or minimize ground disturbance, including biological monitoring during construction
- Anticipated impacts (if any) and proposed mitigation, i.e., enhancement or deduction from mitigation credits
- Map of location of work area

This Environmental Surveyor's recommendations regarding how to complete the project while avoiding or minimizing disturbance to environmental resources is detailed verbally to field personnel and followed by written documentation. The preactivity study will be conducted no earlier than 30 days before the surface disturbing activity. If surface disturbance has not commenced within 30 days, the Environmental Surveyor will conduct a verification study. The Environmental Surveyor's verbal and written recommendations will be submitted to the field crew within 1 week of conducting the study and prior to the activity.

The Preactivity Study Form is also faxed to CDFG and USFWS, along with telephone notification who will reply within 5 working days, indicating if they would like to review the project. When a project can be completed avoiding impacts to natural resources, notification of CDFG and USFWS is for information only, and will not require approval, SDG&E's project may proceed during this time if necessary.

However, when the project cannot be completed without impacts, thus necessitating mitigation, CDFG and USFWS concurrence is required on the need for post-project site enhancement and on the enhancement method. For all new Facilities and related Activities, if Habitat cannot be avoided, a qualified biologist shall be called in to perform surveys following methodologies accepted by the Service. Upon receipt of the Preactivity Study Form, CDFG and USFWS has 15 working days to concur with the enhancement method. If CDFG and USFWS concurrence is not conveyed within 15 working days, the need for post-project enhancement and the enhancement method will be conducted in accordance with the enhancement method specified in the notice.

In both cases, the data recorded on the Preactivity Study Form is then entered into a SDG&E computer data base which is used to develop SDG&E's annual report to the CDFG and USFWS.

Preactivity Survey Form

LPPM Field ID #: ______

Date Request Rcvd: ______

Project Name: ______

Address/Location: ______

Project Type: ______

Originating Dept: ______

Requestor: ______

Requestor Phone #: ______

LPPM Field Rvwr: ______

LPPM Fld Rvwr Phone #: ______

Project Budget #: ______

Const #/Work Order: ______

Account #: ______

Function Code: ______

Date of Field Survey: ______

Weather Conditions: ______

Site Elevation: ______

Thomas Bros Ref #: ______

APN: ______

Field Survey Start Time: ______

Field Survey Stop Time: ______

Hours Spent in Field: ______

Linear Feet: ______

Square Feet: ______

Biologist Required?: ______

Total Hours Spent on This Request: ______

Preactivity Survey Form (sheet 2 of 2)

Project Name ______________________________

Field ID# ______________

Surrounding Land Use/Habitat

North ______________________________

South ______________________________

East ______________________________

West ______________________________

Proposed Work Description

____
____
____
____
____
____

Habitat Evaluation

____
____
____
____
____
____
____

Reviewer Recommendation

____
____
____
____
____
____

Appendix B
SDG&E Environmental Surveyor Program Certification

GOAL

SDG&E shall implement and comply with the terms of the NCCP Subregional Plan (Plan) by utilizing a professional staff familiar with land use planning and environmental protection techniques.

DEFINITION OF STAFF

SDG&E staff is defined as employees of SDG&E or its independent agents, contractors, consultants practicing land use planning, biology, or similar profession and capable of implementing the terms and goals of the Plan.

BIOLOGICAL RESOURCES TRAINING PROGRAM

To ensure adequate training, staff shall be trained and tested by a recognized independent environmental consultant with experience in environmental biology. Specific focus shall be to ensure that all of the species of plants and animals covered by the Plan can be identified and protected during operation, maintenance, and new construction activities. The consultant shall provide a certification for "Environmental Surveyor" to staff members successfully fulfilling the requirements of the training program.

Specifically, training for SDG&E staff shall consist of a 10-week, 40-hour course called the "Comprehensive Biological Resource Training Program." The Program's curriculum, goals, and objectives are attached as "Exhibit A." From time to time in consultation with the wildlife agencies, the program curriculum will be revised and updated.

TESTING

SDG&E shall test and will continue to test its staff periodically for competency in relevant environmental science and field work expertise.

STAFF SKILLS REQUIREMENTS

SDG&E staff shall be capable of implementing the following:

A) <u>Prior to maintenance activity, SDG&E operations, or project construction:</u>

- Conducting preliminary site visits to determine the extent and location of native vegetation communities and native wildlife within each project area.
- Assess the potential for the presence of sensitive habitats, plants or wildlife species on the site; especially species listed as threatened or endangered at the state or federal level.
- Review existing databases and general references to compile known records of sensitive species in the vicinity of the site.
- Determine the need for further biological assessment by expert biologists.

B) <u>In cases where no further analysis (by expert biologists) is required:</u>

- Document the existing vegetation communities and representative wildlife species.
- Determine the extent and location of project impacts.
- Advise field crews on methods for proceeding, which avoid impacts to sensitive areas, and implement other Operational Protocols as appropriate.
- Recommend specific mitigation measures to offset unavoidable impacts.
- Monitor construction or maintenance activities to avoid impacts to sensitive areas.
- Prepare follow-up reports describing the work completed and effect of project on biological resources.

C) <u>In cases where further analysis is required by biological experts:</u>

- Work with expert biologist to ensure comprehensive analysis is completed.

STAFF CERTIFICATION

SDG&E shall provide an updated list of qualified staff and copies of the Environmental Certification during the month of January each year to CDF&G and USFWS for review and record keeping. Copies of classroom work and testing shall only be submitted at the first certification of each qualified staff member. Thereafter, only copies of their Environmental Surveyor certification shall be provided on a yearly basis. Additional qualified staff members may be added to the list during the year by submitting copies of their class work, testing results and Environmental Certification.

EXHIBIT "A"

**SAN DIEGO GAS & ELECTRIC COMPANY
ENVIRONMENTAL TRAINING PROGRAM
CURRICULUM /
GOALS AND OBJECTIVES**

1) *Establish a broad overview of ecology, ecosystems, and the science of conservation biology.*

   a) Describe the flow of energy, nutrients, and water through an ecosystem including role of autotrophs, heterotrophs, nitrogen fixation, photosynthesis, and energy break down. Identify examples of these basic processes in southern California ecosystems.

   b) Describe the basic components of an ecosystem (primary producer, consumer, tertiary consumers, etc.) Identify examples of these trophic levels in southern California's ecosystems.

   c) Describe the general effects of development on natural ecosystems including removal of native diversity, disruption of natural systems (eutrophication), and the benefits of habitat restoration.

   d) Define the physical and biological factors that make southern California an unusual region.

2) *Use standard biological references and field guides to identify vegetation communities, and plant and wildlife species common to southern California ecosystems.*

   a) Identify the dominant indicator plant species for common vegetation communities with southern California.

   b) Identify the common reptile, bird, and mammal species in southern California's ecosystems.

   c) Be able to prepare detailed vegetation map of a particular area and identify dominant plants in each community,

   d) Understand how to use dichotomous keys for identifying common plants of coastal sage scrub, chaparral, and riparian habitats.

   e) Create a library of natural history field guides including standards guides for plants, reptiles, birds, and mammals.

f) Create a matrices of habitats and key indicator species.

3) *Use range maps, species accounts, existing biological resources assessments, and data bases to determine the general biological setting and determine the potential for a particular area to support sensitive habitat, plants, or wildlife.*

a) Define what habitats and sensitive species may occur in a particular area of interest before initiating a field survey.

b) Determine the appropriate references for acquiring additional information on specific biological resources.

4) *Identify typical habitat types for federally listed and State listed wildlife species throughout southern California with a focus on the coastal California gnatcatcher, lease Bell's vireo, southern willow flycatcher, southwestern arroyo toad, and Pacific pocket mouse.*

a) Understand basic biology of the coastal California gnatcatcher, lease Bell's vireo, southern willow flycatcher, arroyo toad, and Pacific Pocket mouse, including biology, habitat requirements, and potential impacts to these species associated with SDG&E's activities.

b) Be familiar with the diversity of sensitive species throughout the region (Species of Concern) with emphasis on those plants and wildlife species typically encountered in coastal sage scrub habitats.

c) Determine the appropriate season for sensitive species surveys.

d) Determine the need for professional biologists to conduct focused surveys.

5) *Understand basic principles of conservation biology focusing on the viability of populations and the process of local extinction.*

a) Compare and contrast the genetic, stochastic, demographic, and environmental factors affecting the stability of a population.

b) Define the effects of habitat fragmentation and the importance of wildlife movement corridors to maintaining stable populations.

c) Describe Soule's "extinction vortex" and how it may apply to small and fragmented populations in southern California.

d) Identify wildlife movement corridors by topography, vegetation, and surrounding urbanization.

6) *Understand the history of state and federal laws affecting wildlife management with a focus on Sections 4, 7, 9, and 10 of the federal Endangered Species Act and the Natural Community Conservation Plan. Understand how the Endangered Species Act works in conjunction with CEQA, NEPA, and the Fish and Game Code (including CESA).*

   a) Describe the evolution of and need for wildlife management laws from the Lacey Act, Migratory Bird Treaty Act, and Endangered Species Act.

   b) Describe basic components of the federal Endangered Species Act.

   c) Describe "take" as it pertains to southern California with reference to harassment, removal of potentially occupied habitats, and direct removal of occupied habitats.

   d) Describe the listing process and Candidate system and why this system is currently under review.

   e) Compare and contrast the Section 7 and Section 10 processes.

   f) Describe the components of a Biological Assessment and Habitat Conservation Plan.

   g) Describe the NCCP and how habitat-based conservation plans differ from the single species conservation.

   h) Describe pertinent projects, decisions, and controversies surrounding the federal Endangered Species Act.

7) *Understand the basic component of Section 404 of the Clean Water Act and Section 1600 of the Fish and Game Code with emphasis on determining the need for professional delineation of wetlands and stream courses through an area. Identify wetland versus upland vegetation, hydric soil types, and "unusual" wetlands such as vernal pools and ephemeral streams.*

   a) Define the basic component of Section 404 and Section 1600.

   b) Create a checklist for wetlands, including soils, hydrology, and vegetation.

   c) Identify common wetland indicator species.

   d) Use the basic methods and reference material pertaining to official wetland delineations.

e) Understand need for professional advice on determining full extent of "wetlands" in xeric habitats.

8) *Incorporate the various methods of habitat restoration and revegetation in coastal sage scrub and wetland habitats into biological mitigation programs.*

a) Compare and contrast the basic methods of coastal sage scrub revegetation, including hydroseeding, native regrowth, and container planting.

b) Compare the contrast the basic methods of wetland restoration for southern California's riparian ecosystems with emphasis on mulefat scrub and willow scrub habitats.

c) Determine the projects requiring irrigation and those that may function well without irrigation.

d) Understand ecological benefits of erosion, control measures, removal of weeds (especially giant reed grass), cowbird trapping, controlled human access, fencing, interpretive signs, and other mitigation measures.

e) Describe mitigation banking and site-specific measures and how these methods can work together.

9) *Establish the forms, methods, and review system for Preactivity Survey and conduct a Preactivity Survey.*

a) Create a field survey form identifying all pertinent aspects of the biological setting requiring review during a Preactivity Survey.

b) Conduct a Preactivity Survey to determine the extent and location of native vegetation communities and the potential for the area to support sensitive biological resources, including sensitive habitats, corridors, plants, and wildlife.

c) Determine the need for further biological assessments by a professional biologist.

d) Incorporate photodocumentation into report preparation.

e) Prepare an annual report pertaining to all areas surveyed under the program.

Attachment 45

Joint Comment Letter Provided by USFWS and CDFW

U.S. Fish and Wildlife Service
Carlsbad Fish and Wildlife Office
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Carlsbad, California 92011
760-431-9440
FAX 760-431-9618

California Department of Fish and Wildlife
South Coast Region
3883 Ruffin Road
San Diego, California 92123
858-467-4201
FAX 858-467-4239

In Reply Refer To:
FWS/CDFW-13B0124-15CPA0217

APR 24 2015

Mr. Andrew Barnsdale
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102-3298

Subject: Comments on the Draft Environmental Impact Report for the South Orange County Reliability Enhancement Project, Orange County, California (SCH#2013011011)

Dear Mr. Barnsdale:

The U.S. Fish and Wildlife Service (Service) and the California Department of Fish and Wildlife (Department), hereafter collectively referred to as the Wildlife Agencies, have reviewed the Draft Environmental Impact Report (DEIR) for the South Orange County Reliability Enhancement Project (SOCRE) dated February 23, 2015. The comments and recommendations provided herein are based on the information provided in the DEIR, our knowledge of sensitive and declining vegetation communities in the region, and our participation in San Diego Gas and Electric's (SDG&E) Subregional Natural Community Conservation Plan/Habitat Conservation Plan (Subregional NCCP/HCP).

The primary concern and mandate of the Service is the protection of public fish and wildlife resources and their habitats. The Service has legal responsibility for the welfare of migratory birds, anadromous fish, and endangered animals and plants occurring in the United States. The Service is also responsible for administering the Federal Endangered Species Act (Act) of 1973, as amended (16 U.S.C. 1531 *et seq*.). The Department is a Trustee Agency and a Responsible Agency pursuant to the California Environmental Quality Act (CEQA; §§ 15386 and 15381, respectively) and is responsible for ensuring appropriate conservation of the state's biological resources, including rare, threatened, and endangered plant and animal species, pursuant to the California Endangered Species Act (CESA; Fish and Game Code § 2050 *et seq*.) and Fish and Game Code section 1600 *et seq*. The Department also administers the Natural Community Conservation Planning (NCCP) program, a California regional habitat conservation planning program. SDG&E currently participates in the NCCP program by implementing its approved SDG&E Subregional NCCP/HCP.

The purpose of the proposed SOCRE project is to increase the reliability and operational flexibility of the SDG&E South Orange County 138-kilovolt (kV) system to reduce the risk of electrical outages. The project includes upgrading SDG&E's San Juan Capistrano and Talega substations; the construction of a new double-circuit 230-kV transmission line (approximately 7.8 miles long) from the San Juan Capistrano Substation to the Talega Substation, within an existing transmission line corridor; the relocation of several transmission line segments (approximately 1.8 miles, total) adjacent to Talega and San Juan Capistrano substations, to accommodate the proposed expansion of the San Juan Capistrano Substation and new 230-kV line; and the relocation of several 12-kV distribution line segments (approximately 6 miles) into underground conduit and overhead on existing and new structures located between the San Juan Capistrano Substation and Prima Deschecha Landfill. In addition SDG&E will acquire approximately 9.97 acres of new right-of-way along 0.3 mile of new transmission line corridor within the Talega Hub/Corridor area west of the Talega Substation. SDG&E estimates that construction will take approximately 64 months.

The proposed project is anticipated to permanently impact 1.59 acres and temporarily impact 2.01 acres of coastal sage scrub, and permanently impact 2.42 acres and temporarily impact 8.42 acres of non-native grassland. Species found within the survey area include the State and federally endangered southwestern willow flycatcher (*Empidonax traillii extimus*) and least Bell's vireo (*Vireo bellii pusillus*) and the federally threatened coastal California gnatcatcher (*Polioptila californica californica;* gnatcatcher). The federally endangered arroyo toad (*Anaxyrus californicus*) was not documented during project-specific surveys, but has been documented within the survey area in the past (Cadre 2013). In addition, the proposed project is anticipated to permanently impact 0.25 acre and temporarily impact 1.01 acres of arroyo toad designated critical habitat, and permanently impact 2.28 acres and temporarily impact 3.94 acres of gnatcatcher designated critical habitat.

The Wildlife Agencies offer the following comments and recommendations (enclosure) to assist the California Public Utilities Commission (CPUC) in avoiding or minimizing potential project impacts on biological resources. We appreciate the opportunity to comment on the DEIR. If you have questions regarding this letter, please contact Patrick Gower (Service) at (760) 431-9440 extension 352 or Eric Hollenbeck (Department) at (858) 467-2720.

Sincerely,

for Karen A. Goebel
Assistant Field Supervisor
U.S. Fish and Wildlife Service

Gail K. Sevrens
Environmental Program Manager
California Department of Fish and Wildlife

Enclosure

Literature Cited

Cadre. 2013. 2012 Status Report-Five Year Arroyo Toad Radio Telemetry/Pitfall Trapping Upland Habitat Characterization Pattern Study Adjacent to Planning Area 8 within Rancho Mission Viejo, Orange County, California. Rancho Mission Viejo, January 8, 2013.

Enclosure
Comments on the Draft Environmental Impact Report for the South Orange County Reliability Enhancement Project, Orange County, CA

1. The Final EIR (FEIR) should include a figure that shows the location of the proposed 9.97 acres of new rights-of-way detailed in Section 2.3.5.1.

2. Table 4.4-1 in the DEIR indicates that surveys for sensitive species have not been completed for the 12-kV Distribution line. The FEIR should require completion of these surveys before the onset of project impacts to identify sensitive species present; SDG&E should then coordinate with the Wildlife Agencies to ensure that potential impacts to sensitive species are avoided and minimized to the maximum extent practicable consistent with the SDG&E NCCP/HCP.

3. The DEIR outlines the use of helicopters in section 2.4.6, page 2-61. Because helicopters produce an effect commonly referred to as “rotor wash,” which emulates extreme wind conditions that vary based on the size of the helicopter and the proximity to the receptor, the Department recommends the CPUC identify sensitive biological receptors (e.g., avian nesting) within the FEIR. The FEIR should include a mitigation measure that establishes a three-dimensional biological buffer between helicopter activities and all sensitive biological receptors as determined by a qualified biologist. A system should be developed for the biological monitors to effectively convey the buffers to the CPUC, the Wildlife Agencies, and helicopter pilots. The helicopters should be equipped with global positioning sensors that will be used by SDG&E to ensure compliance with established buffers. Any incursions should be reported to the CPUC and the Department. The DEIR specifies the use of three classes of helicopters, totaling approximately 168 hours of rotor time. The DEIR does not specify how many hours of rotor time are anticipated for each class of helicopter. Because each size or class of helicopter has a different level of disturbance associated with it that can be used as a rough-step scale in determining future biological buffers (e.g. nests), the Department recommends that the FEIR provide preliminary estimates of the rotor hours for each type of helicopter. Actual hours should be reported to the CPUC. Given the potential biological impacts associated with helicopter use, including nest failures due to rotor wash, the Wildlife Agencies recommend that helicopter use be limited to operations where a clear net benefit to sensitive biological resources is proposed. As an example, in remote areas where current access routes are not available, helicopters have been used to deliver materials without requiring additional habitat disturbance associated with new access roads. This in turn limits future access and disturbance associated with recreation.

4. The DEIR states that special status plant species were considered unlikely to occur based on three main criteria which rely heavily on the California Natural Diversity Database (CNDDB). While the Department recognizes the CNDDB as a very powerful and useful tool, it is a positive occurrence database. Because a positive occurrence database only reports current survey information, there may be gaps in cumulative survey effort relevant to the current project. The DEIR states that some species were excluded due to a lack of CNDDB records, old CNDDB records, or habitat patches being small, degraded, or isolated. Although it may potentially be valid to exclude degraded habitat, this document does not define degraded habitat, and some special status species such as southwestern willow flycatcher and

arroyo toad may still occur in degraded habitat. For these reasons, the Department does not recommend reliance on these factors for determining species presence or habitat suitability.

5. Many of the focal surveys identified in the DEIR were completed in 2010. Southwestern willow flycatcher has been in decline in southern California in recent years[1], so we recommend completing updated surveys for this species to inform efforts to avoid and minimize potential impacts to breeding territories for this species consistent with the SDG&E NCCP/HCP. In addition, the Wildlife Agencies recommend completing updated surveys for all State and federally listed species within areas not covered under the NCCP/HCP (i.e., U.S. Army Corps of Engineers [Corps] jurisdictional areas). Avoidance and minimization of impacts to sensitive habitats, sensitive species, and isolated populations should be given careful consideration because the severity of an impact may be exacerbated by the current climate.

6. Figure 4.4.3 should include all preserves (e.g., Forester Ranch, Talega, Reserve at Rancho Mission Viejo), conserved areas, and open space areas. The DEIR (page 4.4-45) states that discrepancies among publicly available data prevent an accurate estimate of the impacts within existing conserved areas or visually depicting the impacts to conserved areas. The Wildlife Agencies recommend that the FEIR contain an analysis based on any available or additional information in order to fully enumerate the referenced impacts. We will work with you to ensure that you have the approximate boundaries for the areas in question to include figures and estimated impacts to preserves, conserved areas, and open space areas in the FEIR; the Service will provide you with Graphic Information System files and other supporting documentation.

7. Based on our review of the DEIR, the Wildlife Agencies request additional coordination with SDG&E to determine if the project will result in impacts that are in conflict with existing conservation easements. If such impacts are anticipated, we request additional coordination among SDG&E, the Wildlife Agencies, the easement holder(s), and CPUC with the goal of modifying the project to avoid potential impacts to areas anticipated to be permanently protected. If such impacts cannot be avoided, additional coordination with the easement holders will be necessary to discuss a process for addressing the anticipated impacts in a manner that does not compromise existing conservation plans.

8. The DEIR states that Preserve areas, "...include existing reserve or conservation areas established by regional planning documents..." (page 4.4-48). The Wildlife Agencies recommend the FEIR clearly state that all areas denoted as moderate, high, and very high quality habitat will be subject to mitigation as if they are part of an existing reserve or conservation area, consistent with the SDG&E Subregional NCCP/HCP (Section 6, SDG&E Activities within Habitat Conservation Plan Preserves).

9. Section 4.4.3.3 of the FEIR should include a figure that shows the portions of the project that occur within designated arroyo toad and gnatcatcher critical habitat overlain on an aerial

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[1] U.S. Fish and Wildlife Service. 2014. Southwestern willow flycatcher (*Empidonax traillii extimus*) 5-year review: Summary and evaluation. Arizona Ecological Services. Phoenix, Arizona. August 15, 2014.

photograph with vegetation communities, locations of sensitive species, and proposed permanent and temporary impacts.

10. Mitigation Measure MM BR-6 of the DEIR indicates that active bird nests will not be removed, “unless the project is expressly permitted to do so by the USFWS or CDFW.” Migratory nongame native bird species are protected under the Federal Migratory Bird Treaty Act (MBTA) of 1918 (Title 50, § 10.13, Code of Federal Regulations) and sections 3503, 3503.5, and 3513 of the California Fish and Game Code which prohibit take of all migratory birds, including raptors and other nongame birds and their nests. There is no authority for the Department to permit such an activity, and the Service only authorizes take under MBTA in emergency situations involving imminent loss of life or property. The Wildlife Agencies recommend buffer reductions for special status species be implemented as appropriate in accordance with the approved plan as noted in MM BR-6 in coordination with the Wildlife Agencies.

11. Mitigation Measure MM BR-1 of the DEIR restricts vehicular traffic in project locations to established construction areas. The Wildlife Agencies recommend that the FEIR specify that use of disturbed or low habitat value areas be given priority over undisturbed or higher habitat value areas that are otherwise permitted for impacts. MM BR-1 also specifies that if the applicant is unable to maintain a 50-foot exclusionary buffer from jurisdictional wetland features, the applicant will submit best management practices to the CPUC for review and approval. Currently, impacts to Corps jurisdictional wetlands are not covered under the SDG&E Subregional NCCP/HCP. As a Responsible Agency under CEQA Guidelines section 15381, the Department has authority over activities in streams or lakes that will divert or obstruct the natural flow, or change the bed, channel, or bank (including vegetation associated with the stream or lake) of a river or stream, or use or deposit material from a streambed. The Wildlife Agencies recommend SDG&E notify the Corps and the Department regarding potential impacts to streams or wetlands.

12. The Wildlife Agencies recommend MM BR-2 be revised in the FEIR to require monthly monitoring reports for review to be submitted to the CPUC and the Wildlife Agencies. Unauthorized or unexpected impacts to listed species that occur as a result of this project should be reported to the Wildlife Agencies and the CPUC within 48 hours.

Attachment 46

SDG&E’s Easements

2 of (3)

EASEMENT OF RIGHT OF WAY

CROCKER-CITIZENS NATIONAL BANK, a national banking association, as Trustee under the will of Jerome O'Neill, deceased, as Grantor, for and in consideration of the sum of Ten Dollars and other valuable consideration paid by San Diego Gas & Electric Company, a corporation, as Grantee, receipt whereof is hereby acknowledged, does hereby grant to said San Diego Gas & Electric Company, a corporation, its successors and assigns, an easement of right of way in, upon, over, under and across the lands hereinafter described to erect, construct, change the size of, improve, reconstruct, relocate, replace, repair, maintain and use a line or numerous lines of poles and/or steel towers and wires and/or cables suspended thereon and supported thereby, and underground conduits, cables, vaults and manholes, for the transmission and distribution of electricity and for all other purposes connected therewith, and for telephone, signal and communication purposes, including guys, anchorage, crossarms, braces and all other appliances and fixtures for use in connection therewith and also for pipelines for any and all purposes, together with their necessary fixtures and appurtenances, at such locations and elevations upon, along, over and under the hereinafter described right of way as Grantee may now or hereafter deem convenient and necessary at any time and from time to time, together with the right of ingress thereto and egress therefrom, to and along said right of way by a practical route or routes in, upon, over and across the hereinafter described lands, together with the right to clear and keep clear said right of way from explosives, structures and materials.

The lands in which said easement of right of way is hereby granted are situated in the County of Orange, State of California, and are particularly described as follows, to-wit:

That portion of Rancho Mission Viejo or La Paz, as shown on a map thereof recorded Decmeber 19, 1867, in Book 1, pages 63 and 64 of Patents, Records of Los Angeles County, California, described as follows:

Fractional Sections 4 and 9 in Township 8 South, Range 7 West, San Bernardino Base and Meridian, in said Rancho Mission Viejo or La Paz, as said Sections are shown on

Record of Survey sectionizing said Rancho, recorded in Book 9, pages 15 to 22 inclusive, in the office of the County Recorder of said Orange County.

The easement of right of way in the aforesaid lands is particularly described as follows:

Commencing at Corner No. 3 of said Rancho Mission Viejo or La Paz; thence South 19° 17' 37" East (Record South 20° 00' 38.3" East per Record of Survey Map, Book 9, pages 15 to 22 inclusive) along the Westerly boundary line of said Rancho Mission Viejo or La Paz, a distance of 5926.28 feet to a point in said Westerly boundary line, said point being designated as Point "A" in that certain grant of right of way 150.00 feet in width recorded November 19, 1964, in Book 7308 at pages 374 to 377 inclusive of Official Records of said Orange County, California, said Point "A" also bears South 19° 17' 37" East (Record South 20° 00' 38.3" East per Record of Survey Map, Book 9, pages 15 to 22 inclusive), a distance of 41.86 feet from the point of intersection of the North line of said Section 9, Township 8 South, Range 7 West, San Bernardino Base and Meridian, with the said Westerly boundary line of said Rancho Mission Viejo or La Paz; thence from said Point "A" South 67° 43' 40" East along the line described in said right of way, a distance of 334.14 feet to a point of intersection with a line that is parallel with and 250.00 feet Easterly, measured at right angles, from said Westerly boundary line of said Rancho Mission Viejo or La Paz; thence North 19° 17' 37" West (Record North 20° 00' 38.3" West per Record of Survey Map, Book 9, pages 15 to 22 inclusive) along said parallel line, a distance of 133.66 feet to a point of intersection with the Northeasterly line of said 150.00 foot-wide right of way, last said point of intersection being the TRUE POINT OF BEGINNING of the right of way herein described; thence from said TRUE POINT OF BEGINNING South 67° 43' 40" East along said Northeasterly line of said 150.00 foot-wide right of way, a distance of 132.21 feet to the most Northerly terminus of the Easterly line of said 150.00 foot-wide right of way; thence North 19° 17' 37" West (Record North 20° 00' 38.3" West per Record of Survey Map, Book 9, pages 15 to 22 inclusive) along the Northerly prolongation of the said Easterly line of said 150.00 foot-wide right of way, a distance of 120.09 feet; thence North 81° 11' 04" West, a distance of 386.11 feet to another point of intersection with the Northeasterly line of said 150.00 foot-wide right of way, last said point of intersection bears North 67° 43' 40" West, a distance of 322.98 feet from the TRUE POINT OF BEGINNING; thence from last said point of intersection South 67° 43' 40" East, a distance of 322.98 feet to said TRUE POINT OF BEGINNING.

Grantor covenants for itself and its successors and assigns, not to erect or construct, or permit to be erected or constructed, any building or other structure, plant any tree or trees, impound water, or drill or dig any well or wells on said easement of right of way.

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CHECKED BY ELB
SKETCH NO. 14 1080

Grantee shall have the right to erect, maintain and use gates in all fences which now cross or shall hereafter cross said route or routes, and to trim and/or remove any trees and/or brush whenever in its judgment the same shall be necessary for the convenient and safe exercise of the rights hereby granted over the above described easement of right of way; the right to transfer and assign this easement in whole or in part being hereby granted to the Grantee.

The Grantor grants to the Grantee, its successors and assigns, the right to trim or top, and to keep trimmed or topped, any and all trees on the lands of the Grantor adjacent to said right of way for a distance of 20.00 feet from the exterior lines of the right of way strip, to such heights as in the judgment of the Grantee, its successors or assigns, shall be reasonably necessary for the proper construction, operation and maintenance of said electric transmission line or lines, but at no point outside the right of way to a height of less than 30.00 feet.

Grantor, its heirs, successors and assigns, shall not increase or decrease the ground surface elevations nor allow the ground surface elevations to be increased or decreased within the boundaries of the above described easement of right of way existing at the date of the execution of this document, nor shall the said ground surface be penetrated to a depth in excess of 12 inches by any tool or implement without the previous written consent of the Grantee.

Grantor covenants for itself, its heirs and assigns, that any prospecting for or development of oil, gas, petroleum, or other hydrocarbon substances on the Grantor's above described property, shall be done from locations outside the boundaries of the above described easement of right of way, and that said prospecting or development shall be done in such a manner and by methods that will not endanger or interfere with the operation, maintenance or repair of Grantee's facilities, located within the above described easement of right of way; Grantor further covenants that no fluid substances shall be stored or impounded within the boundaries of the easement of right of way granted herein.

Grantor also covenants for itself, its heirs, successors and assigns, that no other easement or easements shall be granted on, under or over the above described easement of right of way without the previous written consent of said Grantee.

IN WITNESS WHEREOF, the Grantor______ executed these presents this 18 day of March, 1965.

Executed in the Presence of:

Thelma A. Ledau
Witness.

CROCKER-CITIZENS NATIONAL BANK,
a national banking association

By O.F. Horstmann

By W.W. Wilson

STATE OF California)
COUNTY OF Orange) ss.

ON THIS 18 day of March, 1965, before me, the undersigned, a Notary Public in and for said County and State, residing therein, duly commissioned and sworn, personally appeared O.F. Horstmann, known to me to be the Vice President and W.W. Wilson, known to me to be the Trust Officer of CROCKER-CITIZENS NATIONAL BANK, a national banking association, the national banking association that executed the within Instrument, known to me to be the persons who executed the within Instrument, on behalf of the association, and acknowledged to me that such national banking association executed the within Instrument pursuant to its By-Laws or a Resolution of its Board of Directors.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal the day and year in this certificate first above written.

PATRICIA A. FOSTER
NOTARY PUBLIC-CALIFORNIA
PRINCIPAL OFFICE IN
ORANGE COUNTY

Patricia A. Foster
Notary Public in and for said County and State.

PATRICIA A. FOSTER My Commission Expires April 22, 1968

RECORDED AT REQUEST OF
SECURITY TITLE INS. CO.
IN OFFICIAL RECORDS OF
ORANGE COUNTY, CALIF.
3:14 PM APR 2 1965
J. WYLIE CARLYLE, County Recorder

$4.40
C1

BOOK 7308 PAGE 374

WHEN RECORDED MAIL TO:
San Diego Gas & Electric Co.
P.O. Box 1831
San Diego, Calif.
Attn: Mr. Rauner

15813

150

RECORDED AT REQUEST OF
SECURITY TITLE INS. CO.
IN OFFICIAL RECORDS OF
ORANGE COUNTY, CALIF.
8:00 AM NOV 19 1964
J. WYLIE CARLYLE, County Recorder

EASEMENT OF RIGHT OF WAY

$4.40

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CROCKER-CITIZENS NATIONAL BANK, a national banking association, as Trustee under the will of Jerome O'Neill, deceased, as Grantor, for and in consideration of the sum of Ten Dollars and other valuable consideration paid by San Diego Gas & Electric Company, a corporation, as Grantee, receipt whereof is hereby acknowledged, does hereby grant to said San Diego Gas & Electric Company, a corporation, its successors and assigns, an easement of right of way 150.00 feet in width in, upon, over, under and across the lands hereinafter described to erect, construct, change the size of, improve, reconstruct, relocate, replace, repair, maintain and use a line or numerous lines of poles and/or steel towers and wires and/or cables suspended thereon and supported thereby, and underground conduits, cables, vaults and manholes, for the transmission and distribution of electricity and for all other purposes connected therewith, and for telephone, signal and communication purposes, including guys, anchorage, crossarms, braces and all other appliances and fixtures for use in connection therewith and also for pipelines for any and all purposes, together with their necessary fixtures and appurtenances, at such locations and elevations upon, along, over and under the hereinafter described right of way as Grantee may now or hereafter deem convenient and necessary at any time and from time to time, together with the right of ingress thereto and egress therefrom, to and along said right of way by a practical route or routes in, upon, over and across the hereinafter described lands, together with the right to clear and keep clear said right of way from explosives, structures and materials.

The lands in which said easement of right of way is hereby granted are situated in the County of Orange, State of California, and are particularly described as follows, to-wit:

That portion of Rancho Mission Viejo or La Paz, as shown on a map thereof recorded December 19, 1867, in Book 1, pages 63 and 64 of Patents, Records of Los Angeles County, California, described as follows:

Fractional Sections 4, 9, 15, 16, 22, 23 and 26, and Sections 3, 10, 11 and 14, all in Township 8 South, Range 7 West, San Bernardino Base and Meridian, in said Rancho Mission Viejo or La Paz, as said Sections are shown on

Record of Survey sectionizing, said Rancho recorded in Book 9, pages 15 to 22 inclusive, in the office of the County Recorder of said Orange County.

The easement of right of way in the aforesaid lands is particularly described as follows:

The Easterly, Northerly and Northeasterly line of said right of way shall be parallel with and 100.00 feet Easterly, Northerly and Northeasterly, measured at right angles, and the Westerly, Southerly and Southwesterly line of said right of way shall be parallel with and 50.00 feet Westerly, Southerly and Southwesterly, measured at right angles from the following described line:

Commencing at an angle point in the Southerly boundary line of said Rancho Mission Viejo or La Paz, said angle point being the intersection corner of the common boundary line between the County of San Diego and the County of Orange, with the said Southerly boundary line of said Rancho Mission Viejo or La Paz, said angle point is marked by a 6" x 6" concrete monument and said intersection corner being shown on sheet 2 of 8 sheets of said Record of Survey Map recorded in Book 9 at pages 15 to 22 inclusive, and also shown on sheet 11 of 12 sheets of Record of Survey Map No. 794, filed in the office of the County Recorder of said County of San Diego; thence South 79° 23' 20" East (Record South 80° 05' 43" East per Record of Survey, Book 9, pages 15 to 22 inclusive), along the common boundary line between said Rancho Mission Viejo or La Paz and Rancho Santa Margarita Y Las Flores, a distance of 189.65 feet to a point in said last mentioned common boundary line, which said point is the TRUE POINT OF BEGINNING of the right of way herein described; thence from said TRUE POINT OF BEGINNING North 5° 56' 55" East, a distance of 250.01 feet; thence North 79° 06' 02" West, a distance of 168.07 feet to a point of intersection with a line that is parallel with and 250.00 feet Northerly, measured at right angles from the said Southerly boundary line of said Rancho Mission Viejo or La Paz, said last mentioned point of intersection bears North 10° 53' 58" East, a distance of 250.00 feet from the above described point of commencement; thence continuing North 79° 06' 02" West (Record North 79° 49' 08" West per Record of Survey, Book 9, pages 15 to 22 inclusive), along said parallel line, a distance of 5200.42 feet; thence leaving said parallel line, North 58° 44' 38" West, a distance of 2215.57 feet to a point of intersection with a line that is parallel with and 250.00 feet Easterly, measured at right angles from the Westerly boundary line of said Rancho Mission Viejo or La Paz; thence North 19° 17' 37" West (Record North 20° 00' 38.3" West per Record of Survey Map, Book 9, pages 15 to 22 inclusive), along said last mentioned parallel line, a distance of 14511.96 feet; thence leaving said parallel line, North 67° 43' 40" West (North 68° 26' 18" West, Record per Deed recorded August 28, 1940, in Book 1057, page 248 of Official Records of said Orange County), a distance of 334.14 feet to a point in the Westerly boundary line of said Rancho Mission Viejo or La Paz, said point being designated as Point "A" in that certain Grant Deed recorded March 4, 1964, as Document No. 2699 in Book 6948, page 462 of Official Records of said Orange County, the location of said Point "A" in said Grant Deed is more particularly described as follows:

Commencing at Corner No. 3 of Rancho Mission Viejo or La Paz; thence South 20° 00' 28" East, along the Westerly boundary line of said Rancho Mission Viejo or La Paz, a distance of 5926.28 feet to a point therein, hereinafter known and designated as Point "A"; said Point "A" also bears South 20° 00' 28" East, a distance of 41.86 feet from the point of intersection of the North line of Section 9, Township 8 South, Range 7 West, San Bernardino Base and Meridian, with the said Westerly boundary line of said Rancho Mission Viejo or La Paz.

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CHECKED BY Hust
SKETCH NO. 0-389

The side lines of the hereinbefore described right of way, 150.00 feet in width, shall be lengthened and/or shortened so that said side lines shall be continuous and shall terminate in the boundaries of the above described lands of the Grantor herein.

Grantor covenants for itself and its successors and assigns, not to erect or construct, or permit to be erected or constructed, any building or other structure, plant any tree or trees, impound water, or drill or dig any well or wells on said easement of right of way.

Grantee shall have the right to erect, maintain and use gates in all fences which now cross or shall hereafter cross said route or routes, and to trim and/or remove any trees and/or brush whenever in its judgment the same shall be necessary for the convenient and safe exercise of the rights hereby granted over the above described easement of right of way; the right to transfer and assign this easement in whole or in part being hereby granted to the Grantee.

The Grantor grants to the Grantee, its successors and assigns, the right to trim or top, and to keep trimmed or topped, any and all trees on the lands of the Grantor adjacent to said right of way strip for a distance of 20.00 feet from the exterior lines of the right of way strip, to such heights as in the judgment of the Grantee, its successors or assigns, shall be reasonably necessary for the proper construction, operation and maintenance of said electric transmission line or lines, but at no point outside the right of way strip to a height of less than 30.00 feet.

Grantor, its heirs, successors and assigns, shall not increase or decrease the ground surface elevations nor allow the ground surface elevations to be increased or decreased within the boundaries of the above described easement of right of way existing at the date of the execution of this document, nor shall the said ground surface be penetrated to a depth in excess of 12 inches by any tool or implement without the previous written consent of the Grantee.

Grantor covenants for itself, its heirs and assigns, that any prospecting for or development of oil, gas, petroleum, or other hydrocarbon substances on the Grantor's above described property, shall be done from locations outside the boundaries of the above described easement of right of way, and that said prospecting or development shall be done in such a manner and by methods that will not endanger or interfere with the operation, maintenance or repair of Grantee's facilities located within the above described easement of right of way; Grantor further covenants that no fluid substances shall be stored or impounded within the boundaries of the easement of right of way granted herein.

Grantor also covenants for itself, its heirs, successors and assigns, that no other easement or easements shall be granted on, under or over the above described easement of right of way without the previous written consent of said Grantee.

IN WITNESS WHEREOF, the Grantor______ executed these presents this 17TH day of SEPTEMBER, 1964.

Executed in the Presence of:

Witness.

CROCKER-CITIZENS NATIONAL BANK, a national banking association

By O. E. Horstmann
Vice President

By W. W. Wilson
TRUST OFFICER

STATE OF California) ss.
COUNTY OF Los Angeles)

ON THIS 17 day of Sept., 1964, before me, the undersigned, a Notary Public in and for said County and State, residing therein, duly commissioned and sworn, personally appeared O. E. Horstmann, known to me to be the Vice President and W. W. Wilson, known to me to be the Trust Officer of CROCKER-CITIZENS NATIONAL BANK, a national banking association, the national banking association that executed the within Instrument, known to me to be the persons who executed the within Instrument, on behalf of the association, and acknowledged to me that such national banking association executed the within Instrument pursuant to its By-Laws or a Resolution of its Board of Directors.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal the day and year in this certificate first above written.

Gertrude Struve
Notary Public in and for said County and State.

My Commission Expires May 23, 1968

GERTRUDE STRUVE
NOTARY PUBLIC-CALIFORNIA
PRINCIPAL OFFICE IN
LOS ANGELES COUNTY

BOOK 7308 PAGE 378

WHEN RECORDED MAIL TO:
San Diego Gas & Electric Co.
P.O. Box 1831
San Diego, Calif.
Attn: Mr. Rauner

15814

RECORDED AT REQUEST OF
SECURITY TITLE INS. CO.
IN OFFICIAL RECORDS OF
ORANGE COUNTY, CALIF.
8:00 AM NOV 19 1964
J. WYLIE CARLYLE, County Recorder

EASEMENT OF RIGHT OF WAY
ANCHORAGE

$3.60

25 3376

CROCKER-CITIZENS NATIONAL BANK, a national banking association, as Trustee under the will of Jerome O'Neill, deceased, hereinafter called the "Grantor", for and in consideration of the sum of One Dollar, and other valuable consideration, receipt whereof is hereby acknowledged, does hereby grant to San Diego Gas & Electric Company, a corporation, its successors and assigns, hereinafter called the "Grantee", the right, easement and privilege of placing, constructing, repairing, replacing, maintaining and using, guy poles and/or anchors of such material, size and/or shape, at such locations upon, under, along and over the hereinafter described right of way as Grantee may, at any time and from time to time, deem convenient and necessary for the purpose of supporting that certain electric pole line of Grantee located upon or adjacent to said land, including the right by means of wires, or otherwise, to connect said guy poles and/or anchors with said pole line for the purpose of supporting same, together with the right of ingress thereto and egress therefrom, to and along said right of way over and across the Grantor's land situated in the County of Orange, State of California, and more particularly described as follows:

That portion of Rancho Mission Viejo or La Paz, as shown on a map thereof recorded December 19, 1867, in Book 1, pages 63 and 64 of Patents, Records of Los Angeles County, California, described as follows:

Fractional Sections 22 and 23 in Township 8 South, Range 7 West, San Bernardino Base and Meridian, in said Rancho Mission Viejo or La Paz, as said Sections are shown on Record of Survey sectionizing, said Rancho recorded in Book 9, pages 15 to 22 inclusive in the office of the County Recorder of said Orange County.

Said easement of right of way in the aforesaid lands is particularly described as follows:

Within those certain strips of land, being 10.00 feet in width, lying 5.00 feet on each side, measured at right angles from the following described center lines:

1. Commencing at an angle point in the Southerly boundary line of said Rancho Mission Viejo or La Paz, said angle point being the intersection

corner of the common boundary line between the County of San Diego and the County of Orange, with the said Southerly boundary line of said Rancho Mission Viejo or La Paz, said angle point is marked by a 6" x 6" concrete monument and said intersection corner being shown on sheet 2 of 8 sheets of said Record of Survey Map recorded in Book 9 at pages 15 to 22 inclusive, and also shown on sheet 11 of 12 sheets of Record of Survey Map No. 794, filed in the office of the County Recorder of said County of San Diego; thence South 79° 23' 20" East (Record South 80° 05' 43" East per Record of Survey, Book 9, pages 15 to 22 inclusive), along the common boundary line between said Rancho Mission Viejo or La Paz and Rancho Santa Margarita Y Las Flores, a distance of 189.65 feet to a point in said last mentioned common boundary line; thence leaving said common boundary line North 5° 56' 55" East, a distance of 250.01 feet; thence North 79° 06' 02" West, a distance of 168.07 feet to a point of intersection with a line that is parallel with and 250.00 feet Northerly, measured at right angles from the said Southerly boundary line of said Rancho Mission Viejo or La Paz, said last mentioned point of intersection bears North 10° 53' 58" East, a distance of 250.00 feet from the above described point of commencement; thence continuing North 79° 06' 02" West (Record North 79° 49' 08" West per Record of Survey, Book 9, pages 15 to 22 inclusive), along said parallel line, a distance of 5200.42 feet to a point hereinafter known and designated as Point "A"; thence leaving said parallel line, North 58° 44' 38" West, a distance of 2215.57 feet to a point of intersection with a line that is parallel with and 250.00 feet Easterly, measured at right angles from the Westerly boundary line of said Rancho Mission Viejo or La Paz, said point of intersection being the TRUE POINT OF BEGINNING of the right of way herein described; thence from said TRUE POINT OF BEGINNING South 50° 58' 53" West, a distance of 71.00 feet.

2. Beginning at the point described above as Point "A"; thence South 21° 04' 40" West, a distance of 71.00 feet.

IN WITNESS WHEREOF, the Grantor ______ executed these presents this 17TH day of SEPTEMBER, 1964.

Executed in the Presence of:

[signature]
Witness.

CROCKER-CITIZENS NATIONAL BANK, a national banking association

By [signature]
Vice President

By W. W. Wilson
TRUST OFFICER

DRAWN BY [initials]
CHECKED BY [initials]
SKETCH NO. 0-389

STATE OF California } ss.
COUNTY OF Los Angeles }

ON THIS 17 day of Sept, 1964, before me, the undersigned, a Notary Public in and for said County and State, residing therein, duly commissioned and sworn, personally appeared O. E. Hartmann, known to me to be the Vice President and W. W. Wilson, known to me to be the Trust Officer of CROCKER-CITIZENS NATIONAL BANK, a national banking association, the national banking association that executed the within Instrument, known to me to be the persons who executed the within Instrument, on behalf of the national banking association, and acknowledged to me that such national banking association executed the within Instrument pursuant to its By-Laws or a Resolution of its Board of Directors.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal the day and year in this certificate first above written.

Gertrude Struve
Notary Public in and for said County and State.

My Commission Expires May 23, 1968

GERTRUDE STRUVE
NOTARY PUBLIC-CALIFORNIA
PRINCIPAL OFFICE IN
LOS ANGELES COUNTY

Attachment 47

Prima Deshecha Conservation Easements

This Document was electronically recorded by
Clerk of the Board

Recorded in Official Records, Orange County
Tom Daly, Clerk-Recorder

NO FEE
2012000137245 11:10am 03/09/12
93 401 E01 47
0.00 0.00 0.00 0.00 138.00 0.00 0.00 0.00

RECORDING REQUESTED BY AND:
WHEN RECORDED MAIL TO:

THE RESERVE AT RANCHO
MISSION VIEJO
28811 ORTEGA HIGHWAY
SAN JUAN CAPISTRANO, CA 92675

Space Above for Recorder's Use Only

Exempt from payment of recording fees pursuant to Government Code Sections 6103 and 27383

Portion of APN: 124-140-44, 124-081-24, 124-081-27, 124-081-26, 124-081-22, 124-101-05, 124-101-06, 125-162-06, 125-172-05

Unincorporated Area

Project No: PM 126-47
Location: Prima Deshecha Landfill

CONSERVATION EASEMENT DEED

THIS CONSERVATION EASEMENT DEED ("Conservation Easement") is made this 6th day of March 2012, by the COUNTY OF ORANGE, a political subdivision of the State of California ("Grantor"), in favor of The Reserve at Rancho Mission Viejo, a California non-profit public benefit corporation ("Grantee"), with reference to the following facts.

RECITALS

A. Grantor is the sole owner in fee simple of certain real property located in the County of Orange, State of California, known as the Prima Deshecha Landfill (the "Landfill"). Within the Landfill is an approximately 474.7-acre parcel (the "Property" – Exhibit "C"), which is legally described on Exhibits "A-1" and "A-2" and depicted on Exhibits "B-1" and "B-2" attached hereto and incorporated by this reference; and

B. On January 10, 2007, Rancho Mission Viejo, LLC ("RMV"), the United States Fish and Wildlife Service ("USFWS"), Santa Margarita Water District ("SMWD") and Grantor entered into an Implementation Agreement ("IA") for the Southern Orange County Subregion Natural Community Conservation Plan/Master Streambed Alteration Agreement/Habitat Conservation Plan ("Southern HCP") that, among other things, designates the Property as Supplemental Open Space (SOS) area to mitigate[,in part,] for the impacts of the Landfill and the Avenida La Pata Road improvements. Compliance with the Southern HCP and IA, including permanent conservation of the SOS area is required as a condition of federal Endangered Species Act Incidental Take Permit No. TE144133-0 issued on January 10, 2007 to Grantor ("Take Permit"); and

D. Grantor's participation in the Southern HCP also involves the inclusion of approximately 11,950 acres of regional park land into the 32,818-acre Habitat Reserve in addition to the above-referenced SOS; and

E. The areas within the Landfill designated as SOS represent those portions of the landfill site that the approved General Development Plan (GDP) does not anticipate as landfill disposal operations. These areas would not likely be affected by existing and future landfill operations and are intended to be preserved in a natural condition to the maximum extent possible. However, since this refuse disposal facility is expected to be in operation until 2067, and in landfill post-closure maintenance beyond 2067, it cannot be known with absolute certainty whether some of the areas designated as SOS may be needed for on-going maintenance and post-closure maintenance after landfill closure. Any such maintenance will be performed in accordance with the provisions of the SOS Management Plan included in Appendix M of the Southern HCP; and

F. The Property possesses certain ecological and habitat values that benefit endangered, threatened, and other rare species (collectively, "Conservation Values"). These species and their habitats are of aesthetic, ecological, educational, historical, recreational, and scientific value to the people of California and the people of the United States. These values include plants and habitat such as coyote brush scrub, southern willow scrub, mule fat scrub, alkali marsh, freshwater marsh, ephemeral drainages, coastal sage scrub and avian wildlife, such as the least Bell's Vireo and California Gnatcatcher, and are of great importance to both Grantor and Grantee; and

G. The Property has been identified as being occupied by species of native plants and wildlife which Grantor and Grantee desire to conserve, protect, restore and/or enhance; and

H. Grantee is a non-profit entity formed under the laws of the State of California and is authorized to hold conservation easements under California Civil Code § 815 <u>et seq.</u>; and

I. Grantor intends to convey to Grantee the right to conserve, protect, restore and/or enhance the Conservation Values of the Property in perpetuity; and

J. Grantee agrees by accepting this grant to honor the intentions of Grantor stated herein and to conserve, protect, restore and/or enhance in perpetuity the Conservation Values of the Property in accordance with the terms of this easement; and

K. Grantee acknowledges that Grantor operates the adjacent property as an active sanitary landfill and that accordingly Grantee's rights under this easement to traverse the Property shall be limited as to routes, procedures and times as compatible with landfill operations and safety;

L. USFWS, an agency within the United States Department of Interior, has jurisdiction over the conservation, protection, restoration and management of fish, wildlife, plants, and the habitat necessary for biologically sustainable populations of these species within the Unites States pursuant to the Endangered Species Act, 16 U.S.C. Section 1531, et seq., the Fish and Wildlife Coordination Act, 16 U.S.C. Sections 661 – 666c, the Fish and Wildlife Act of 1956, 16 U.S.C. Section 742(f) *et seq*. and other provisions of federal law; and

M. This instrument, when recorded, will (1) document Grantor's grant to Grantee of the subject Conservation Easement; and (2) set forth the rights and obligations of the parties with respect to the Conservation Easement.

COVENANTS, TERMS, CONDITIONS AND RESTRICTIONS

In consideration of the above recitals and the mutual covenants, terms, conditions, and restrictions contained herein, and pursuant to California law, including Civil Code Section 815, *et seq*. Grantor hereby voluntarily grants and conveys to Grantee a conservation easement in perpetuity over the Property in accordance with the terms and conditions hereinafter set forth. This Conservation Easement shall run with the land and be binding on Grantor's heirs, successors, administrators, assigns, lessees, and other occupiers or users of the Property or any portion of it.

1. Purpose.

(a) The purpose of this Conservation Easement is to ensure the Property will be retained in perpetuity in its natural, restored, or enhanced condition consistent with the Southern HCP and IA and to prevent any use of the Property that will materially impair or interfere with the Conservation Values of the Property, subject to rights reserved to Grantor as provided elsewhere in this document (the "Purpose"). Grantor intends that this Conservation Easement will confine the use of the Property to such activities, including without limitation, those involving the preservation and enhancement of native species and their habitat to those consistent with the habitat conservation purposes of this Conservation Easement.

(b) Future enhancements on the Property will include the following activities:

(1) Permanent maintenance obligations ("Long Term Maintenance"), that occurs on the Property as described in Section 15 herein; or

(2) Activities described in Section 5 herein.

2. Grantee's Rights. To accomplish the purpose of this Conservation Easement, Grantor hereby grants and conveys the following rights to Grantee:

(a) To preserve and protect the Conservation Values of the Property.

(b) To enter upon the Property in order to monitor compliance with and to otherwise enforce the terms of this Conservation Easement. Grantee acknowledges that Grantor's adjacent property is an active landfill with heavy equipment and associated hazards. Prior to each entry upon the Property, Grantee shall provide Grantor at least 24 hours prior notice and shall sign in at the Operations Office at the Landfill; and

(c) To prevent any activity on or use of the Property that is inconsistent with the purpose of this Conservation Easement, except as reserved in Section 5, and to require the restoration of such areas or features of the Property that may be damaged by an inconsistent activity or use.

(d) All mineral, air, and water rights necessary to protect and to sustain the biological resources of the Property, which rights shall remain a part of and be put to beneficial use upon the Property consistent with purposes of this Conservation Easement; and

(e) The right to all present and future development rights, provided any exercise of such rights must preserve the Property in its natural, restored, or enhanced condition. Any exercise of present and future development rights by Grantee shall not be in conflict with the Conservation Values of the Property; and

(f) The right to enforce by means, including, without limitation, injunctive relief, the terms and conditions of this Conservation Easement. Enforcement through injunctive relief shall pertain only to uses within the Property and shall not apply to the continuation of existing and future landfill operations within the adjacent Landfill.

3. Prohibited Uses. Any activity on or use of the Property inconsistent with the Purpose of this Conservation Easement and not included as a Covered Activity in the Southern HCP or reserved herein as a right of Grantor is prohibited.

4. Grantor's Duties. Grantor shall undertake all reasonable actions to prevent the unlawful entry and trespass by persons whose activities may degrade or harm the Conservation Values of the Property. In addition, Grantor shall undertake all necessary actions to protect Grantee's rights under Section 2 of this easement, including, but not limited to, Grantee's water rights.

5. Reserved Rights. Grantor reserves to itself, and to its personal representatives, heirs, successors, and assigns, all rights accruing from its ownership of the Property, including the right to engage in or to permit or invite others to engage in all uses of the Property that are consistent with the Purpose of this Conservation Easement, including the following uses:

(a) All Covered Activities listed in the Southern HCP, Chapter 10, Section 10.1.7A.

(b) Activities on the Property, including constructing and managing improvements (i) required by regulatory mandates of the State of California and/or other regulatory agencies in conjunction with Grantor's operation and oversight of the Prima Deshecha Landfill and/or (ii) required for the extension of Camino De Los Mares and Avenida La Pata, as identified in the 2000 Master Plan of Arterial Highways. Camino De Los Mares is not included as a Covered Activity in the Southern HCP. If activities required for the extension of Camino De Los Mares degrade or harm the Conservation Values of the Property, the USFWS may require suitable replacement habitat in accordance with a plan approved by Grantee and USFWS.

(c) Actions necessary to restore, protect or maintain the Property including (i) repair or reconstruction of existing structures damaged by seasonal rains and other events (ii) installation of structures required to protect the existing improvements and landscape elements; (iii) modification of drainage to direct flows to the Property as needed to provide additional hydrology in support of the riparian vegetation; (iv) dredging of materials from within the easement area in response to erosion and subsequent siltation that fills in and modifies the features of the mitigation program for the Property; and, (v) thinning out of riparian trees and shrubs where necessary to maintain suitability of the Property for use by the least Bell's vireo and other riparian-dependent wildlife species.

(d) Access. Reasonable access through the Property to adjacent land over existing roads, or to perform obligations or other activities permitted by this Conservation Easement. In addition, police and other public safety organizations and their personnel may enter the Property to address any legitimate public health or safety matter.

(e) Habitat Enhancement Activities. Restoration of native plant communities, including the right to plant native trees and shrubs of the same type as currently existing on the Property. For purposes of preventing erosion and reestablishing native vegetation, the Grantor shall have the right to revegetate areas that may be damaged by the permitted activities under this Section 5, naturally occurring events or by the acts of persons damaging the natural, restored, or enhanced condition of the Property.

(f) Repair and Remediation of Damage or Refuse. Removal or trimming of vegetation downed or damaged due to natural disaster, removal of man-made debris, removal of parasitic (as it relates to the health of the host plant) and non-native or exotic plant or animal species.

(g) Erection and Maintenance of Informative Signage. Erection and maintenance of signage and other notification features saying "Natural Area Open Space," "Protected Natural Area," or similar descriptions that inform persons of the nature and restrictions on the Property. Prior to erection of such signage, the Grantor shall submit detailed plans showing the location of such signs to the USFWS and to Grantee for review and approval, which approval shall not be unreasonably withheld, conditioned or delayed, provided, however, that such approval shall be deemed to have been given by Grantee and the USFWS if both USFWS and Grantee fail to respond to a request therefor on or prior to the date that is sixty (60) days after their receipt of request therefor. It shall be reasonable for Grantee and the USFWS to withhold consent of such structures that are in direct or potential conflict with the preservation of the Natural Condition of the Property.

(h) No Interference with Development of Adjacent Property. This Conservation Easement is not intended to in any way limit Grantor or any of Grantor's successors and assigns from (1) constructing, placing, installing, and/or erecting any improvements upon Grantor's adjacent landfill property (2) installing and/or maintaining the subsurface infrastructure improvements, utility lines, landscaping (including irrigation and runoff) landscape mitigation, and/or similar non-structural improvements on the adjacent Property, and/or (3) developing adjacent property for any purposes, except as limited by any local, state or federal permit requirements for such development and provided that neither any such activity nor any effect resulting from such activity amounts to a use of the Property, or has an impact upon the Property, that is prohibited by Section 3 above.

(i) Fire Protection. The right to maintain existing fire roads, trim or remove brush, otherwise perform preventative measures required by the fire department to protect structures and other improvements from potential fires, and perform any other brush management activities in compliance with the applicable brush management programs of the local jurisdictions and consistent with the terms and conditions of the permits, entitlement and approvals issued for development of Grantor's adjacent property.

6. Limitation on Public Use. This Conservation Easement does not convey a general right of access to the public.

7. Enforcement.

(a) Right to Enforce. Grantor and its subsequent transferees and assigns, grant to the Grantee a discretionary right to enforce this Conservation Easement in a judicial action against any person(s) or other entity(ies) violating or attempting to violate this Conservation Easement; provided, however, that no violation of this Conservation Easement shall result in a forfeiture or reversion of title. The rights under this Section are in addition to, and do not limit rights conferred in Section 2 above, or any rights of the various documents created thereunder or referred to therein.

(b) Notice.

(1) If Grantee determines Grantor is in violation of the terms of this Conservation Easement, Grantee shall give written notice to Grantor of such violation and shall demand the cure of such violation by issuing written notice to Grantor (hereinafter "notice of violation") informing Grantor of the violation and demanding cure of such violation.

(2) Grantor shall cure the noticed violation within sixty (60) days of receipt of said written notice from Grantee. If said cure reasonably requires more than sixty (60) days, Grantor shall begin cure within the sixty (60) day period and work diligently to complete such cure. If Grantor disputes the notice of violation, it shall issue a written notice of such dispute (hereinafter "notice of dispute") to the Grantee within thirty (30) days of receipt of written notice of violation.

(3) If Grantor fails to cure the noticed violation(s) within the time period(s) described in Section 7(b)(2) above, Grantee may bring an action at law or in equity in a court of competent jurisdiction to enforce compliance by Grantor with the terms of this Conservation Easement. In such action, the Grantee may (i) recover any damages to which they may be entitled for violation by Grantor of the terms of this Conservation Easement, (ii) enjoin the violation, *ex parte* if necessary, by temporary or permanent injunction without the necessity of proving either actual damages or the inadequacy of otherwise available legal remedies, or (iii) pursue other equitable relief, including, but not limited to, the restoration of the Property to the condition in which it existed prior to any such violation or injury. Grantee may apply any damages recovered to the cost of undertaking any corrective action on the Property.

(4) If Grantor provides Grantee with a notice of dispute, as provided herein, Grantee shall meet and confer with Grantor at a mutually agreeable place and time, not to exceed thirty (30) days from the date that Grantee receives the notice of dispute. Grantee shall consider all relevant information concerning the disputed violation provided by Grantor and shall determine whether a violation has in fact occurred and, if so, whether the notice of violation and demand for cure issued by Grantee is appropriate in light of the violation.

(5) If, after reviewing Grantor's notice of dispute, conferring with Grantor and considering all relevant information related to the violation, Grantee determines that a violation has occurred, Grantee shall give Grantor notice of such determination in writing. Upon receipt of such determination, Grantor as applicable, shall have sixty (60) days to cure the violation. If said cure reasonably requires more than sixty (60) days Grantor shall begin cure within the sixty (60) day period and work diligently to complete such cure.

(c) Cost of Enforcement. Reasonable costs incurred by Grantee or third party beneficiary specified in Section 14(o) in enforcing the terms of this Conservation Easement, including without limitation, costs of suit and attorneys' fees, and any costs of restoration necessitated by violation of the terms of this Conservation Easement shall be borne by Grantor.

(d) Discretion of Grantee, and Third Party Beneficiary. Enforcement of the terms of this Conservation Easement by Grantee and the third party beneficiary specified in Section 14(o) shall be at the discretion of the enforcing party, and any forbearance by Grantee, or the third party beneficiary to exercise its rights under this Conservation Easement in the event of any breach of any term of this Conservation Easement shall not be deemed or construed to be a waiver by Grantee or the third party beneficiary of such term or of any subsequent breach of the same or any other term of this Conservation Easement or of any of Grantee's rights (or third party beneficiary's rights) under this Conservation Easement. No delay or omission by Grantee or the third party beneficiary in the exercise of any right or remedy shall impair such right or remedy or be construed as a waiver.

(e) Acts Beyond Grantor's Control. Nothing contained in this Conservation Easement shall be construed to entitle Grantee or the third party beneficiary to bring any action against Grantor for any injury to or change in the Property resulting from (i) any natural cause beyond Grantor's control, including without limitation, fire, flood, storm, and earth movement, or any prudent action taken by Grantor under emergency conditions to prevent, abate, or mitigate significant injury to persons and or the Property or (ii) acts by Grantee or third parties beyond the control of the Grantor. Notwithstanding the above, Grantor remains obligated to implement the relevant responses to Changed Circumstances identified in Appendix M of the Southern HCP.

Any action undertaken during emergency conditions must receive prior authorization from the Department of Army (through expedited procedures, if appropriate) if the action involves a discharge of dredged or fill material into waters of the United States.

(f) Third Party Beneficiary Right of Enforcement. All rights and remedies conveyed to Grantee under this Conservation Easement Deed shall extend to and are enforceable by the third party beneficiary specified in Section 14(o). These rights are in addition to, and do not limit, the rights of enforcement under the Take Permit.

8. Enforcement by Grantor. Grantor, any "Successor Grantors" (as defined below) and their successors shall have the right to enforce by proceedings at law or in equity, all restrictions, conditions, covenants and restrictions, now or thereafter imposed by the provisions of this Conservation Easement any amendment thereto, including the right to specific enforcement and otherwise to prevent the violation of any such restrictions, conditions,

covenants or conditions, provided, Grantor shall not have the right to terminate this Conservation Easement.

9. Costs of Liabilities. Grantor, its successors and assigns retain all responsibilities and shall bear all costs and liabilities of any kind related to the ownership, operation, upkeep, and maintenance of the Property.

(a) Taxes, No Liens. Grantor, its successors and assigns shall pay before delinquency all taxes, assessments, fees, and charges of whatever description levied on or assessed against the Property by competent authority (collectively "taxes"), including any taxes imposed upon, or incurred as a result of, this Conservation Easement, and shall furnish Grantee with satisfactory evidence of payment upon request. Grantor, its successors and assigns shall keep Grantee's interest in the Property free from any liens, including those arising out of any obligations incurred by Grantor or any labor or materials furnished or alleged to have been furnished to or for Grantor at or for use on the Property.

(b) Hold Harmless. Grantor shall hold harmless, indemnify, and defend USFWS and Grantee and its directors, officers, employees, agents, contractors, and representatives (collectively, "Indemnified Parties") from and against all liabilities, penalties, costs, losses, damages, expenses (without limitation), causes of action, claims, demands, or judgment, including reasonable attorneys' fees, arising from or in any way connected with: (1) injury to or the death of any person, or physical damages to any property, resulting from any acts or omissions, conditions, or other matters related to or occurring on or about the Property, regardless of cause, unless due solely to the negligence of any of the Indemnified Parties under this Conservation Easement; (2) the violation or alleged violation of, or other failure to comply with, any state, federal, or local law, regulation, or requirement, by any person other than any of the Indemnified Parties, in any way affecting, involving, or relating to the Property; and (3) the breach by Grantor of any of its obligations set forth in this Conservation Easement.

(c) Condemnation. Grantor shall immediately notify Grantee and USFWS in writing of any action to condemn this Conservation Easement. The purposes of this Conservation Easement are presumed to be the best and most necessary public use as defined at Code of Civil Procedure Section 1240.680 subject to Code of Civil Procedure Section 1240.690 and 1240.700.

10. Conveyance "As-Is". Notwithstanding anything to the contrary contained herein, it is understood between the parties that the easement rights conveyed by this Conservation Easement are expressly subject to all matters of record as of the date this Conservation Easement is executed and are conveyed in an "AS IS" condition, "with all faults" as of such date. The existing condition of' vegetation on the Property is shown on Exhibit D attached hereto and described in Appendix M of the Southern HCP. The Property is subject to periodic groundwater and air quality monitoring in compliance with State and Federal regulations. There is currently no indication of hazardous materials on the Property.

11. Transfer or Easement. This Conservation Easement may be assigned or transferred by Grantee upon written approval of USFWS, which approval shall not be unreasonably withheld or delayed, but Grantee shall give Grantor and USFWS at least thirty (30)

days prior written notice of the transfer. In particular, approval of any assignment may be withheld in the reasonable discretion of USFWS if the transfer will result in a single owner holding both the Conservation Easement and the fee title to the Property and, upon such transfer, the doctrine of merger would apply to extinguish the Conservation Easement by operation of law, unless prior to the assignment or transfer, an alternative mechanism acceptable to USFWS to achieve the purposes of this Conservation Easement following such merger has been provided for. Grantee may assign this Conservation Easement only to the California Department of Fish & Game ("CDFG") or another entity or organization authorized to acquire and hold conservation easements pursuant to Civil Code Section 815.3 (or any successor provision then applicable) or the laws of the United States and reasonably acceptable to USFWS. Grantee shall require the assignee to record the assignment in the county where the Property is located. The failure of Grantee to perform any act provided in this section shall not impair the validity of this Conservation Easement or limit its enforcement.

12. Transfer of Property. Grantor agrees to incorporate the terms of this Conservation Easement by reference in any deed or other legal instrument by which Grantor divests itself of any interest in all or any portion of the Property, including, without limitation, a leasehold interest. Grantor agrees that the deed or other legal instrument shall also incorporate by reference applicable provisions of the Southern HCP and IA, and any amendments to those documents. Grantor further agrees to give written notice to Grantee, and USFWS of the intent to transfer any interest at least thirty (30) days prior to the date of such transfer. Grantee or USFWS shall have the right to prevent subsequent transfers in which prospective subsequent claimants or transferees are not given notice of the covenants, terms, conditions and restrictions of this Conservation Easement (including the exhibits and documents incorporated by reference in it). If Grantor proposes to transfer fee title to the Property to the then Grantee of this Conservation Easement, and if the doctrine of merger would apply and extinguish the Conservation Easement by operation of law upon such transfer, then the transfer shall be subject to the prior written approval of USFWS, which approval shall not be unreasonably withheld or delayed. Approval of any such transfer to the Grantee may be withheld in the reasonable discretion of USFWS unless, prior to the transfer, an alternative mechanism acceptable to USFWS to achieve the purposes of this Conservation Easement following such merger has been provided for. Upon the recordation of such writing accepting such assignment and assuming such duties, such assignee (the "Successor Grantor"), to the extent of such assignment, shall have the same rights and powers and be subject to the same obligations and duties as are given to and assumed by Grantor herein and Grantor shall be released and relieved of such rights and obligations provided that notwithstanding any such assignment or transfer, Grantor shall remain liable to perform and fund its obligations under the Southern HCP plan and Take Permit until and unless an assignment of the Permit and release of Grantor's obligations thereunder is approved in writing by the USFWS as provided in the IA. The failure of Grantor, Grantee, or USFWS to perform any act provided in this section shall not impair the validity of this Conservation Easement or limit its enforceability in any way.

13. Notices. All notices, demands, requests, consents, approvals, or communications from one party to another shall be personally delivered or sent by facsimile to the persons set forth below or shall be deemed given five (5) days after deposit in the United States mail, certified and postage prepaid, return receipt requested, and addressed as follows, or at such other address as any Party may from time specify to the other parties in writing:

To Grantor:	County of Orange OC Waste & Recycling 300 North Flower Street, Suite 400 Santa Ana, California 92703 Attention: Director
To Grantee:	The Reserve at Rancho Mission Viejo 28811 Ortega Highway San Juan Capistrano, California 92675
To USFWS:	United States Fish and Wildlife Service Carlsbad Fish and Wildlife Office 6010 Hidden Valley Road, Suite 101 Carlsbad, California 92011

or to such other address as Grantor, Grantee or USFWS may designate by written notice to other parties. Notice shall be deemed effective upon delivery in the case of personal delivery or delivery by overnight courier or, in the case of delivery by first class mail, five (5) days after deposit into the United States Mail.

14. General Provisions.

(a) Controlling Law. The laws of the United States and the State of California shall govern the interpretation and performance of this Conservation Easement.

(b) Liberal Construction. Any general rule of construction to the contrary notwithstanding, this Conservation Easement shall be liberally construed in favor of and to effect the purposes of this Conservation Easement and the policy and purpose set forth in California Civil Code Section 815, et seq. If any provision in this instrument is found to be ambiguous, an interpretation consistent with the purposes of this Conservation Easement that would render the provision valid shall be favored over any interpretation that would render it invalid.

(c) Severability. If a court of competent jurisdiction voids or invalidates on its face any provision of this Conservation Easement, such action shall not affect the remainder of this Conservation Easement. If a court of competent jurisdiction voids or invalidates the application of any provision of this Conservation Easement to a person or circumstances, such action shall not affect the application of the provision to other persons or circumstances.

(d) Entire Agreement. This instrument together with the attached exhibits, including the documents referred to in Appendix M of the Southern HCP sets forth the entire agreement of the parties with respect to the Conservation Easement and supersedes all prior discussions, negotiations, understandings, or agreements relating to the Conservation Easement. No alteration or variation of this instrument shall be valid or binding unless contained in an amendment in accordance with Section 14 (n).

(e) No Forfeiture. Nothing contained herein will result in a forfeiture or reversion of Grantor's title in any respect.

(f) Successors. The covenants, terms, conditions, and restrictions of this Conservation Easement shall be binding upon, and inure to the benefit of, the parties hereto and their respective personal representatives, heirs, successors, and assigns and shall constitute a servitude running in perpetuity with the Property.

(g) Covenant Running with the Land. This Conservation Easement and covenants contained herein are (i) imposed upon the property encumbered by or otherwise subject to this Conservation Easement, (ii) shall run with and against the same and shall be a charge and burden thereon for the benefit of Grantee and/or the current holder of this Conservation Easement and (iii) are perpetual and irrevocable.

(h) Termination of Rights and Obligations. A party's rights and obligations under this Conservation Easement shall terminate upon transfer of the party's interest in the Conservation Easement or the Property, except that liability for acts or omissions occurring prior to transfer shall survive transfer.

(i) Captions. The captions in this instrument have been inserted solely for convenience of reference and are not a part of this instrument and shall have no effect upon its construction or interpretation.

(j) No Hazardous Materials Liability.

(1) Grantor's Representations and Warranties. Grantor represents and warrants that it has no knowledge of any release or threatened release of Hazardous Materials (defined below) in, on, under, about or affecting the Property.

(2) Grantee and Third Party Beneficiary not an Owner, Operator or Responsible Party. Despite any contrary provision of this Conservation Easement, the parties do not intend this Conservation Easement to be, and this Conservation Easement shall not be, construed such that it creates in or gives to Grantee or the third party beneficiary any of the following:

(i) The obligations or liabilities of an owner or "operator," as those terms are defined and used in Environmental Laws (defined below), including, without limitation, the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (42 U.S.C. Section 9601 et seq.; hereinafter, "CERCLA"); or

(ii) The obligations or liabilities of a person described in 42 U.S.C. Section 9607(a)(3) or (4); or

(iii) The obligations of a responsible person under any applicable Environmental Laws: or

(iv) The right to investigate and remediate any Hazardous Materials associated with the Property; or

(v) Any control over Grantors' ability to investigate, remove, remediate or otherwise clean up any Hazardous Materials, associated with the Property.

(3) Environmental Indemnification. Grantor and Grantor's successors in interest shall indemnify, protect and defend with counsel acceptable to Grantee, and hold harmless the Indemnified Parties (as defined in Subsection 9(b) above) from and against any claims (including, without limitation, third party claims for personal injury or death, damage to property, or diminution in the value of the property), actions, administrative proceedings (including informal proceedings), judgments, damages, punitive damages, penalties, fines, costs, liabilities (including sums paid in settlements of claims), remedial action, compliance requirements, enforcement and clean-up actions of any kind, interest or losses, attorneys' fees (including any fees and expenses incurred in enforcing this indemnity), consultant fees, and expert fees that arise directly or indirectly from or in connection with: (i) the claimed presence or Release (as defined below) of any Hazardous Materials whether into the air, soil, surface water or groundwater of or at the Property; (ii) any violation or alleged violation of Environmental Law (as defined below) affecting the Property, whether occurring prior to or during Grantor's ownership of the Property and whether caused or permitted by Grantor or any person other than Grantor; or (iii) any claim or defense by Grantor or any third party that any Indemnified Party is liable as an "owner" or "operator" of the Property under any Environmental Law. The foregoing indemnity obligations shall not apply with respect to any Hazardous Materials released or deposited as a result of action by the Indemnified Parties on or about the Easement Area. The indemnity obligations of any successor in interest of Grantor pursuant to this Subsection 14(j)(3) shall be limited to the portion of the Property to which the successor takes title. Notwithstanding any statutory limitation otherwise applicable, the indemnity obligations of Grantor to the Indemnified Parties pursuant to this Subsection 14(j)(3) shall continue after transfer to a successor in interest unless a written request for consent to assignment of such indemnity obligations to a successor in interest is approved by Grantee. In considering any such request, Grantee may take into account the financial capabilities of the successor in interest, without regard to any third party financial assurances. Grantee's consent to such assignment may be denied only if there is a commercially reasonable basis for such denial

(4) Definitions

(i) The term "*Hazardous Materials*" includes, without limitation, (a) material that is flammable, explosive or radioactive; (b) petroleum products, including by-products and fractions thereof; and (c) hazardous materials, hazardous wastes, hazardous or toxic substances or related materials defined in CERCLA; Resource Conservation and Recovery Act (42 U.S.C. 6901 et seq.); the Hazardous Materials Transportation Act (49 U.S.C. Section 5101 et seq.); the Hazardous Waste Control Law (California Health & Safety Code Section 25100 et seq.); the Hazardous Substance Account Act (California Health & Safety Code Section 25300 et seq.), and in the regulations adopted and publications promulgated pursuant to them, or any other applicable federal, state or local laws, ordinances, rules, regulations or orders now in effect or enacted after the date of this Conservation Easement.

(ii) The term "*Environmental Laws*" includes, without limitation, any federal, state, local or administrative agency statute, ordinance, rule, regulation, order or requirement relating to pollution, protection of human health or safety, the environment or Hazardous Materials. Grantor represents, warrants and covenants to Grantee that Grantor's activities upon and use of the Property will comply with all Environmental Laws.

(iii) The term "*Release*" means any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping or disposing of any Hazardous Materials into the environment (including, without limitation, the continuing migration of Hazardous Materials into, onto or through the soil, surface water, or groundwater, and the abandonment or discarding of barrels, containers, and other receptacles containing any Hazardous Materials), whether or not caused by, contributed to, permitted by, acquiesced to or known to Grantor.

(k) Grantor. Grantor represents and warrants that there are no outstanding mortgages or liens in the Property that have not been expressly subordinated to this Conservation Easement, and that the property is not subject to any other conservation easement.

(l) Additional Easements. Except in conjunction with carrying out its Covered Activities, and as provided in Section 5(b)(ii) above, Grantor shall not grant any additional easements, rights of way or other similar interests in the Property (other than a security interest that is subordinate to this Conservation Easement), without first obtaining the written consent of Grantee and USFWS. Grantee or USFWS may withhold such consent if it reasonably determines that the proposed interest or transfer is inconsistent with the purposes of this Conservation Easement or will impair or interfere with the Conservation Values of the Property. This Section 14(l) shall not prohibit transfer of a fee or leasehold interest in the Property that is subject to this Conservation Easement and complies with Section 12.

(m) Recordation. Grantor shall promptly record this instrument in the official records of Orange County, California and immediately notify the Grantee and USFWS through the mailing of a conformed copy of the recorded easement. Grantee may re-record this instrument at any time as may be required to preserve its right in the grant.

(n) Amendment. Grantor and Grantee may amend this Conservation Easement only by mutual written agreement and with the written consent of USFWS. Any such amendment shall be consistent with the Purpose of this Conservation Easement and shall not affect its perpetual duration. Any such amendment shall be recorded in the official records of Orange County, State of California.

(o) Third Party Beneficiary. Grantor and Grantee acknowledge that USFWS shall be deemed, and is hereby a third party beneficiary of this Conservation Easement with a right of access to the Property and a right to enforce the terms and provisions hereof. The conditions for Grantee's access to the Property under paragraph 2(b) shall apply to USFWS except (1) when USFWS has reason to believe a violation of the Take Permit, or laws or regulations applicable to the Permit, has occurred or may be occurring which, in the USFWS's good faith judgment, warrants immediate or noticeless access; or (2) entry, without consent, is otherwise for law enforcement purposes consistent with the Fourth Amendment to the Constitution.

USFWS shall be required to sign in at the Operations Office at the landfill prior to any entry onto the Property when entry is required pursuant to Section 2(b).

In addition, Grantor and Grantee acknowledge that USFWS is expressly granted certain additional rights under this Conservation Easement, including but not limited to a right to prior written notice of certain specified actions and a right of approval of certain specified actions.

(p) Counterparts. The parties may execute this instrument in two or more counterparts, which shall, in the aggregate, be signed by all parties; each counterpart shall be deemed an original instrument as against any party who has signed it. In the event of any disparity between the counterparts produced, the recorded counterpart shall be controlling.

15. Long-Term Maintenance. Grantor, its successors and assigns shall continue to be solely responsible for permanent maintenance of the Property. Such permanent maintenance shall consist of the following activities: (a) annual removal of trash or in-organic debris; (b) repair and remediation of damage or refuse by removing or trimming of vegetation downed or damaged due to natural disaster, removal of man-made debris, removal of parasitic (as it relates to the health of the host plant) and non-native or exotic plant or animal species; and (c) annual maintenance of signage and other notification features saying "Protected Natural Area," or similar descriptions that inform persons of the nature and restrictions on the Property.

16. All documents referenced in this Conservation Easement including, but not limited to, the Southern HCP, IA, and Take Permit are hereby incorporated herein as if set forth in full.

Dated: 3/6/12

COUNTY OF ORANGE

By: ______________________

Chairman, Board of Supervisors
Orange County, California

SIGNED AND CERTIFIED THAT A COPY
OF THIS DOCUMENT HAS BEEN DELIVERED
TO THE CHAIRMAN OF THE BOARD
PER GC § 25103, RESO. 79-1535

ATTEST:

____
Clerk of the Board of Supervisors
of Orange County, California

STATE OF CALIFORNIA)
) ss.
COUNTY OF ORANGE)

ACKNOWLEDGEMENT

On ______________________, before me, ______________________,personally appeared ______________________, personally known to me (or proved to me on the basis of satisfactory evidence) to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

WITNESS my hand and official seal.

____

Approved as to Form
County Counsel

By: ______________________
Deputy

Dated: Jan. 27, 2012

Recommended for Approval
OC Waste & Recycling

____

ACCEPTANCE

The Reserve at Rancho Mission Viejo ("Grantee") hereby accepts the interest in real property conveyed by the above Deed of Conservation Easement dated ________________ from the County of Orange ("Grantor") and consents to the recordation thereof by its duly authorized officer.

Executed at San Juan Capistrano, California, this 9th day of December, 2011.

THE RESERVE AT RANCHO MISSION VIEJO,
a California nonprofit public benefit corporation

By: ____________________________
Title: President

By: ____________________________
Title: Secretary

STATE OF CALIFORNIA)
) ss.
COUNTY OF Orange)

On December 9, 2011, before me, Kristie Vikse, a notary public for the State of California personally appeared Richard Browning who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/~~are~~ subscribed to the within instrument and acknowledged to me that he/~~she/they~~ executed the same in his/~~her/their~~ authorized capacity(ies), and that by his/~~her/their~~ signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

KRISTIE VIKSE
Commission # 1816422
Notary Public - California
Orange County
My Comm. Expires Oct 6, 2012

Signature Kristie Vikse [SEAL]

STATE OF CALIFORNIA)
) ss.
COUNTY OF ORANGE)

On December 9, 2011, before me, CINDY R. LANE, a notary public for the State of California personally appeared DANIEL R. FERONS who proved to me on the basis of satisfactory evidence to be the person(~~s~~) whose name(~~s~~) is/~~are~~ subscribed to the within instrument and acknowledged to me that he/~~she~~/~~they~~ executed the same in his/~~her~~/~~their~~ authorized capacity(~~ies~~), and that by his/~~her~~/~~their~~ signature(~~s~~) on the instrument the person(~~s~~), or the entity upon behalf of which the person(~~s~~) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

CINDY R. LANE
Commission # 1840506
Notary Public - California
Orange County
My Comm. Expires Mar 15, 2013

Signature Cindy R. Lane [SEAL]

CONFORMED COPY

RECORDING REQUESTED BY
AND WHEN RECORDED, RETURN TO:

The Reserve at Rancho Mission Viejo
28811 Ortega Highway
San Juan Capistrano, CA 92675
Attention: Laura Coley Eisenberg

Recorded in Official Records, Orange County
Hugh Nguyen, Clerk-Recorder
NO FEE
* $ R 0 0 0 6 9 7 0 6 3 7 $ *
2014000376468 10:44 am 09/17/14
63 413 A17 10
0.00 0.00 0.00 0.00 27.00 0.00 0.00 0.00

Space Above for Recorder's Use Only

Exempt from payment of recording fees pursuant to Government Code Sections 6103 and 27383

Portion of APN: 124-140-44
124-081-24

Unincorporated Area

Project No: PM 126-50
Location: Prima Deshecha Landfill

AMENDMENT TO AND SPREADER OF CONSERVATION EASEMENT DEED
(Prima Deshecha Supplemental Open Space Area)

THIS AMENDMENT TO AND SPREADER OF CONSERVATION EASEMENT DEED ("**Amendment**") is dated as of September 9, 2014, and entered into by and between COUNTY OF ORANGE, a political subdivision of the State of California ("**Grantor**"), and THE RESERVE AT RANCHO MISSION VIEJO, a California non-profit public benefit corporation ("**Grantee**"). Grantor and Grantee are sometimes individually referred to herein as a "**Party**" and jointly as the "**Parties**."

THE PARTIES ENTER INTO THIS AMENDMENT based upon the following facts, intentions and understandings.

A. Grantor and Grantee are parties to that certain Conservation Easement Deed, dated March 6, 2012, and recorded in the Official Records of the County of Orange on March 9, 2012 as Instrument No. 2012000137245 ("**Conservation Easement**"). The terms, covenants, conditions and restrictions of the Conservation Easement are hereby incorporated by reference; and, unless otherwise defined herein, the capitalized terms used herein shall have the meaning given to them in the Conservation Easement.

B. Section 14(n) of the Conservation Easement provides that the Parties may amend the Conservation Easement by their mutual written agreement and with the written consent of the U.S. Fish and Wildlife Service ("**USFWS**") so long as any amendment is consistent with the Purpose of the Conservation Easement and does not affect its perpetual duration.

C. Grantor desires to amend the Conservation Easement by annexing certain additional open space lands to the Property (i.e., those approximately 474.7 acres of land already covered by the Conservation Easement, also referred to herein as the "**Existing Supplemental Open Space Area**"). The lands to be annexed consist of 12.2 acres and are more particularly described on **Exhibit A**, and depicted on **Exhibit B**, both of which are attached hereto and incorporated herein by this reference (the "**Additional Supplemental Open Space Area**"). After annexation of the Additional Supplemental Open Space Area, the Property covered by the Conservation Easement will total 486.9 acres and will be in the configuration shown on **Exhibit C** attached hereto and incorporated herein by this reference.

D. The annexation of the Additional Supplemental Open Space Area to the Property is consistent with the Purpose of the Conservation Easement in that it will ensure that both the Existing Supplemental Open Space Area and the Additional Supplemental Open Space Area will be retained in perpetuity in their natural, restored, or enhanced condition consistent with the Orange County Southern Subregion Habitat Conservation Plan, thus preserving and enhancing native species and their habitat.

E. Grantee is agreeable to the annexation of the Additional Supplemental Open Space Area to the Property, and to conserve, protect, restore and/or enhance in perpetuity the Conservation Values of this additional land in accordance with the terms of the Conservation Easement.

F. As set forth in its Biological Opinion on the La Pata Avenue Extension Project (FWS-OR-12B0070-13F0310) dated November 7, 2013, the USFWS has indicated its consent to the annexation of the Additional Supplemental Open Space Area to the Conservation Easement by its approval of the Biological Resources Construction Plan, dated November 5, 2013 for the La Pata Avenue Extension Project.

NOW, THEREFORE, in consideration of the above-stated facts, intentions and understandings and mutual covenants contained herein and other good and valuable consideration, the receipt of which is hereby acknowledged, the Parties hereto agree as follows:

1. Annexation of the Additional Supplemental Open Space Area. The "Property" described in the Conservation Easement is hereby amended and expanded to include the Additional Supplemental Open Space Area described in said Exhibit A and depicted in said Exhibit B; and generally configured as shown in said Exhibit C.

2. Miscellaneous.

a. Except as amended hereby, all terms, covenants, restrictions and conditions of the Conservation Easement shall remain unmodified and in full force and effect and is hereby ratified and confirmed by the Parties.

b. The date of this Amendment set forth above is for reference purposes only. The effective date of this Amendment shall be the date this Amendment is recorded in the Official Records of the County of Orange, California.

IN WITNESS WHEREOF, the Parties have caused this Amendment to be duly executed by their respective authorized representatives as of the date first above written.

GRANTOR

COUNTY OF ORANGE,
a political subdivision of the State of California

By: ______________________
Chairman, Board of Supervisors
Orange County, California

Approved as to Form
Office of the County Counsel
Orange County, California

By: ______________________
Deputy

Date: 8-6-14

Signed and certified that a copy of this document has been delivered to the Chairman of the Board per G.C. Sec. 25103, Reso 79-1535

ATTEST:

____
for Susan Novak
Clerk of the Board of Supervisors
Orange County, California

ACKNOWLEDGMENT

STATE OF CALIFORNIA)
)
COUNTY OF ORANGE)

On ______________ before me, ______________________________ a notary public, personally appeared ____,

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Signature ______________________

(Seal)

GRANTEE

THE RESERVE AT RANCHO MISSION VIEJO, a California nonprofit public benefit corporation

By: ______________________________
Richard M. Broming, President

By: ______________________________
Don Bunts, Secretary

ACKNOWLEDGMENT

STATE OF CALIFORNIA)
)
COUNTY OF ORANGE)

On July 9, 2014 before me, Cindy R. Lane a notary public, personally appeared Don Bunts,

who proved to me on the basis of satisfactory evidence to be the person(~~s~~) whose name(~~s~~) is/~~are~~ subscribed to the within instrument and acknowledged to me that he/~~she~~/~~they~~ executed the same in his/~~her~~/~~their~~ authorized capacity(~~ies~~), and that by his/~~her~~/~~their~~ signature(~~s~~) on the instrument the person(~~s~~), or the entity upon behalf of which the person(~~s~~) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Signature Cindy R. Lane

(Seal)

CINDY R. LANE
Commission # 2007760
Notary Public - California
Orange County
My Comm. Expires May 15, 2017

DIRVC.v1rev062314

ACKNOWLEDGMENT

STATE OF CALIFORNIA)
)
COUNTY OF ORANGE)

On ______________ before me, ______________________________ a notary public, personally appeared ____;

who proved to me on the basis of satisfactory evidence to be the person(~~s~~) whose name(~~s~~) is/~~are~~ subscribed to the within instrument and acknowledged to me that he/~~she/they~~ executed the same in his/~~her/their~~ authorized capacity~~(ies)~~, and that by his/~~her/their~~ signature~~(s)~~ on the instrument the person~~(s)~~, or the entity upon behalf of which the person~~(s)~~ acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Signature ______________________

(Seal)

KRISTIE VIKSE
Commission # 1990629
Notary Public - California
Orange County
My Comm. Expires Oct 6, 2016

"EXHIBIT A"
LEGAL DESCRIPTION

THAT PORTION OF LAND IN THE COUNTY OF ORANGE, STATE OF CALIFORNIA DESCRIBED AS FOLLOWS: BEGINNING AT THE SOUTHEASTERLY END OF THAT CERTAIN COURSE SHOWN AS NORTH 03°34'26" WEST 790.91 ON THE RECORD OF SURVEY FILED IN BOOK 92, PAGE 15 OF RECORDS OF SURVEY IN THE OFFICE OF THE COUNTY RECORDER OF SAID COUNTY; THENCE ALONG SAID COURSE, 750.61 FEET; THENCE SOUTH 89°53'02" EAST, 161.19 FEET; THENCE SOUTH 88°03'34" EAST, 230.96 FEET; THENCE SOUTH 01°37'41" EAST, 213.03 FEET; THENCE SOUTH 15°19'11" EAST, 410.64 FEET; THENCE SOUTH 46°55'45" EAST, 349.97 FEET; THENCE SOUTH 25°36'39" EAST, 243.69 FEET; THENCE SOUTH 25°09'08" EAST, 207.97 FEET; THENCE SOUTH 29°40'59" EAST, 63.89 FEET; THENCE SOUTH 48°43'21" EAST, 56.64 FEET; THENCE SOUTH 53°58'21" EAST, 39.34 FEET; THENCE SOUTH 61°39'16" EAST, 47.94 FEET; THENCE SOUTH 61°50'02" EAST, 79.97 FEET; THENCE SOUTH 27°28'58" WEST, 104.34 FEET TO A POINT ON A LINE SHOWN AS NORTH 55°38'50" WEST, 680.48 FEET ON CONSERVATION EASEMENT PM 126-47, RECORDED IN THE COUNTY OF ORANGE, CALIFORNIA ON MARCH 06, 2012; THENCE NORTH 55°38'50" WEST ALONG SAID LINE, 546.34 FEET; THENCE NORTH 35°53'37" WEST ALONG SAID EASEMENT BOUNDARY, 261.00 FEET; THENCE NORTH 50°09'52" WEST ALONG SAID EASEMENT BOUNDARY, 554.20 FEET; THENCE SOUTH 28°54'52" WEST, ALONG SAID EASEMENT BOUNDARY, 103.60 FEET; TO THE POINT OF BEGINNING.

"EXHIBIT A"
LEGAL DESCRIPTION

PREPARED UNDER THE RESPONSIBLE
CHARGE OF:

3/28/14

Bryan A. Stirrat, P.E.
RCE 22631

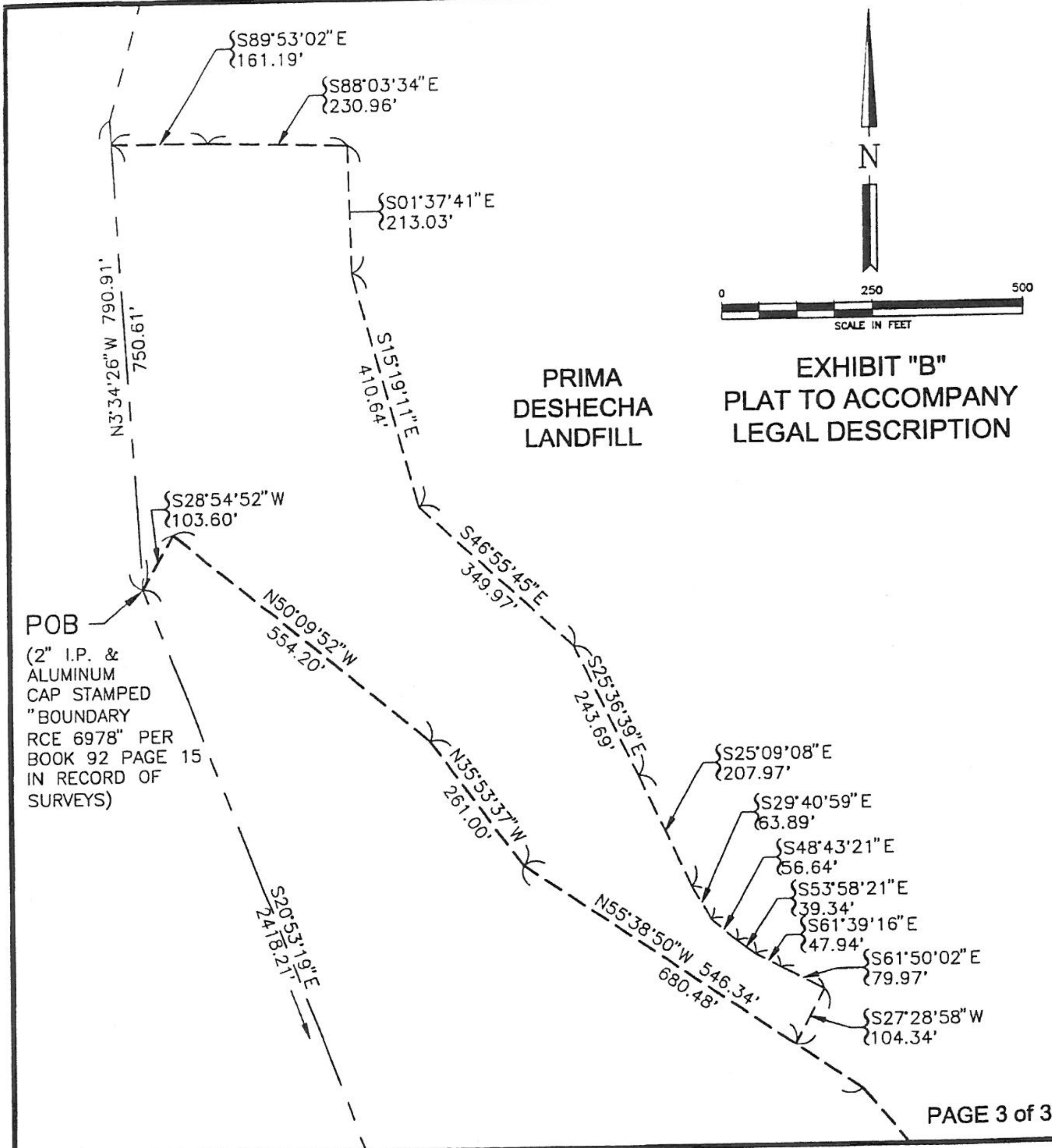


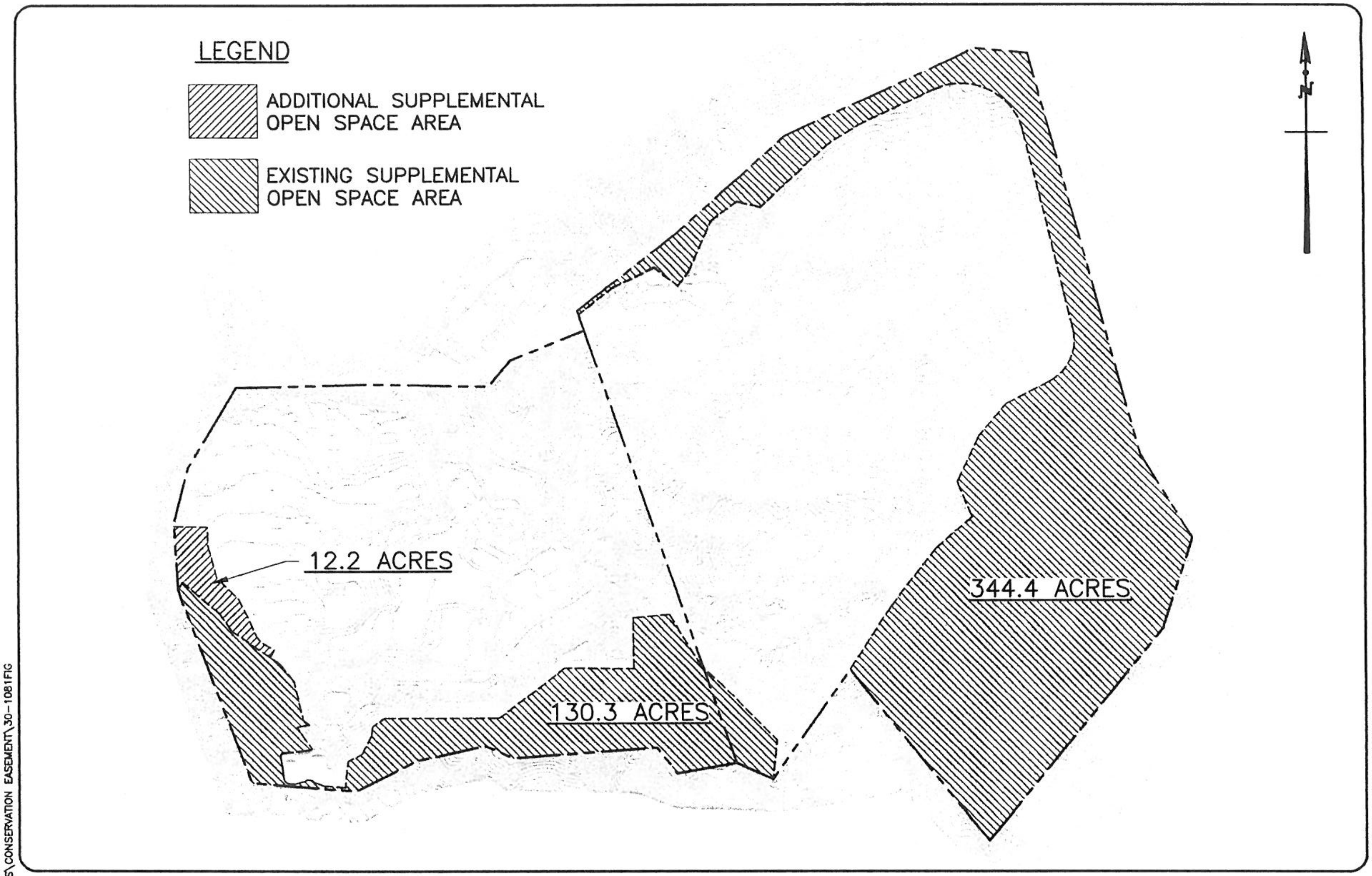
EXHIBIT "B"
PLAT TO ACCOMPANY LEGAL DESCRIPTION

TETRA TECH BAS
1360 Valley Vista Drive, Diamond Bar, CA 91765
TEL 909.860.7777 FAX 909.860.8017

PREPARED UNDER THE RESPONSIBLE CHARGE OF:

3/28/14
DATE

REGISTERED PROFESSIONAL ENGINEER
BRYAN A. STIRRAT
No. 22631
12/31/15
CIVIL
STATE OF CALIFORNIA



BAS 1360 Valley Vista Drive, Diamond Bar, CA 91765 TEL 909.860.7777 FAX 909.860.8017	PRIMA DESHECHA LANDFILL 486.9 ACRE SUPPLEMENTAL OPEN SPACE AREA	SCALE 1"=1600' DATE 04/2014 DRAWN BY D.L.L. FILE NAME: 30-1081FIG

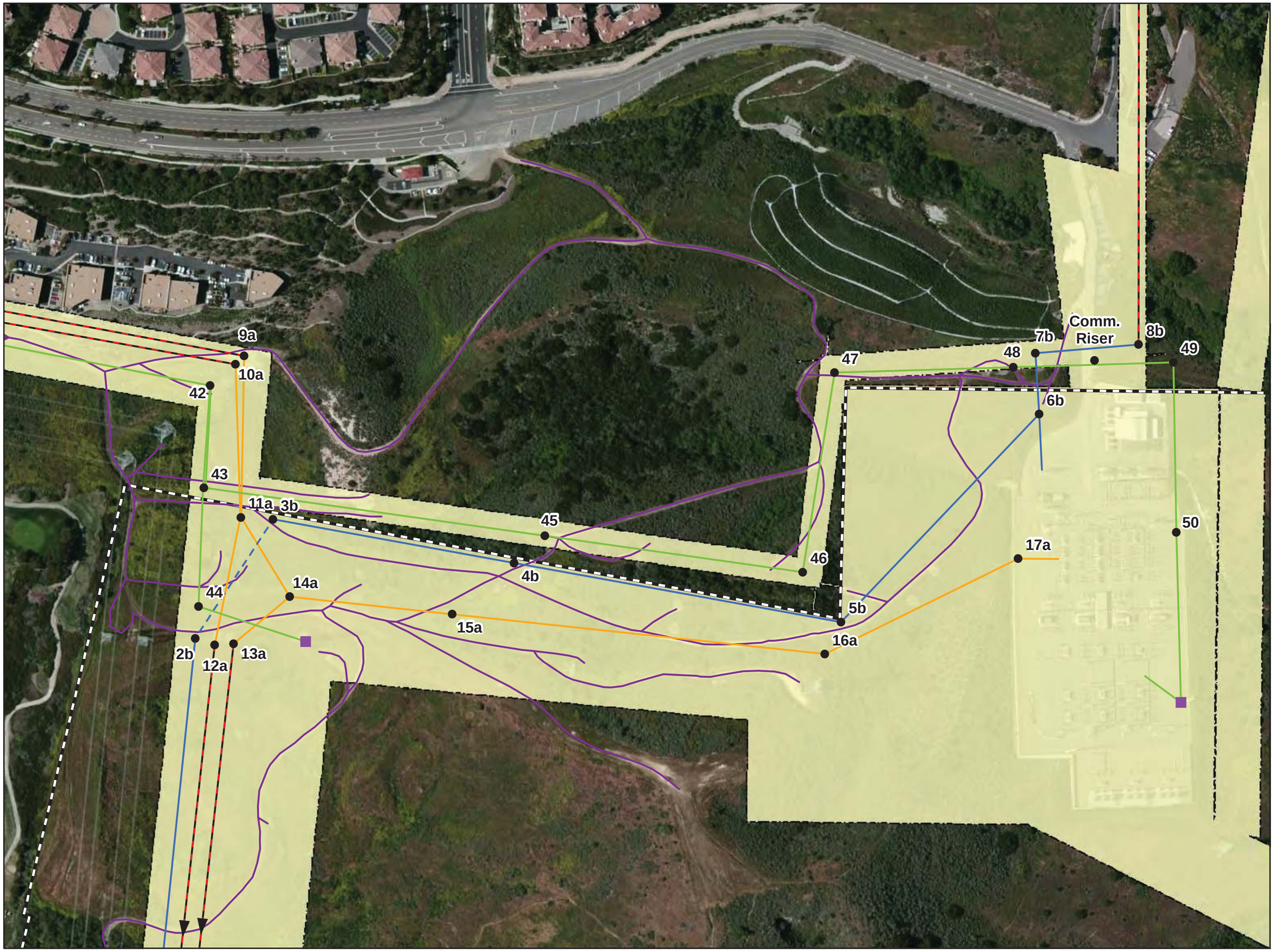
G:\DWG\PRIMA\EASEMENTS\CONSERVATION EASEMENT\30-1081FIG

Exhibit C

Attachment 48

Proposed Project, Segment 4 Refinement

FOR DISCUSSION PURPOSES ONLY - BASED ON PRELIMINARY ENGINEERING



SOCRE Project Rights-of-Way Map

Proposed Project Segment 4 Design Revision

(Design Date September 2015)

Facilities

- Existing Structure to be used in place
- Proposed New Structure
- Existing OH
- 69kV-UG
- 69kV-OH
- 138kV-OH
- 230kV-OH
- Existing Access Roads

Easements & Boundaries

- MCB Pendleton Boundary
- Existing SDG&E Easements, ROW, & Fee-Owned Property

SDG&E is providing this map with the understanding that the map is not survey grade. Certain technology used under license from AT&T Intellectual Property I, L.P. Copyright ©1998 – 2007 AT&T Intellectual Property 1, L.P. All Rights Reserved.

0 210 420 Feet

N

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
Content may not reflect National Geographic's current map policy. Sources: National Geographic, Esri, DeLorme, HERE, UNEP-WCMC, USGS, NASA, ESA, METI, NRCAN, GEBCO, NOAA, increment P Corp.; SDG&E, 2015

SDGE
A Sempra Energy utility

G:\SOCRUP\MXD\SOCRE_ROWMapGen3_NoWorkAreas.mxd

Attachment 49

SOCRE Project Rights-of-Way Map, Post RDEIR Design

FOR DISCUSSION PURPOSES ONLY - BASED ON PRELIMINARY ENGINEERING

SOCRE Project Rights-of-Way Map

Post R-DEIR Design

(Design Date September 2015)

Sheet 1 of 7

Facilities

- Existing Structure to be used in place
- Proposed New Structure
- Existing OH
- 69kV-UG
- 69kV-OH
- 138kV-OH
- 230kV-OH
- Existing Access Roads
- LaPata Road Grading

Work Areas (Impacts)

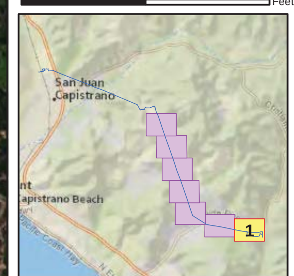
- Permanent Impact
- Temporary Work Area

Easements & Boundaries

- Prima Deschecha Landfill Conservation Easement
- MCB Pendleton Boundary
- Existing SDG&E Easements, ROW, & Fee-Owned Property

0 300 600 Feet

N



Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
Content may not reflect National Geographic's current map policy. Sources: National Geographic, Esri, DeLorme, HERE, UNEP-WCMC, USGS, NASA, ESA, METI, NRCAN, GEBCO, NOAA, increment P Corp.; SDG&E, 2015

G:\SOCRUP\MXD\SOCRE_ROWMapGen3.mxd

FOR DISCUSSION PURPOSES ONLY - BASED ON PRELIMINARY ENGINEERING

SOCRE Project Rights-of-Way Map

Post R-DEIR Design

(Design Date September 2015)

Facilities

- Existing Structure to be used in place
- Proposed New Structure
- Existing OH
- 69kV-UG
- 69kV-OH
- 138kV-OH
- 230kV-OH
- Existing Access Roads
- LaPata Road Grading

Work Areas (Impacts)

- Permanent Impact
- Temporary Work Area

Easements & Boundaries

- Prima Deschecha Landfill Conservation Easement
- MCB Pendleton Boundary
- Existing SDG&E Easements, ROW, & Fee-Owned Property

0 300 600 Feet

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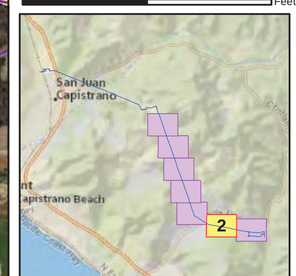

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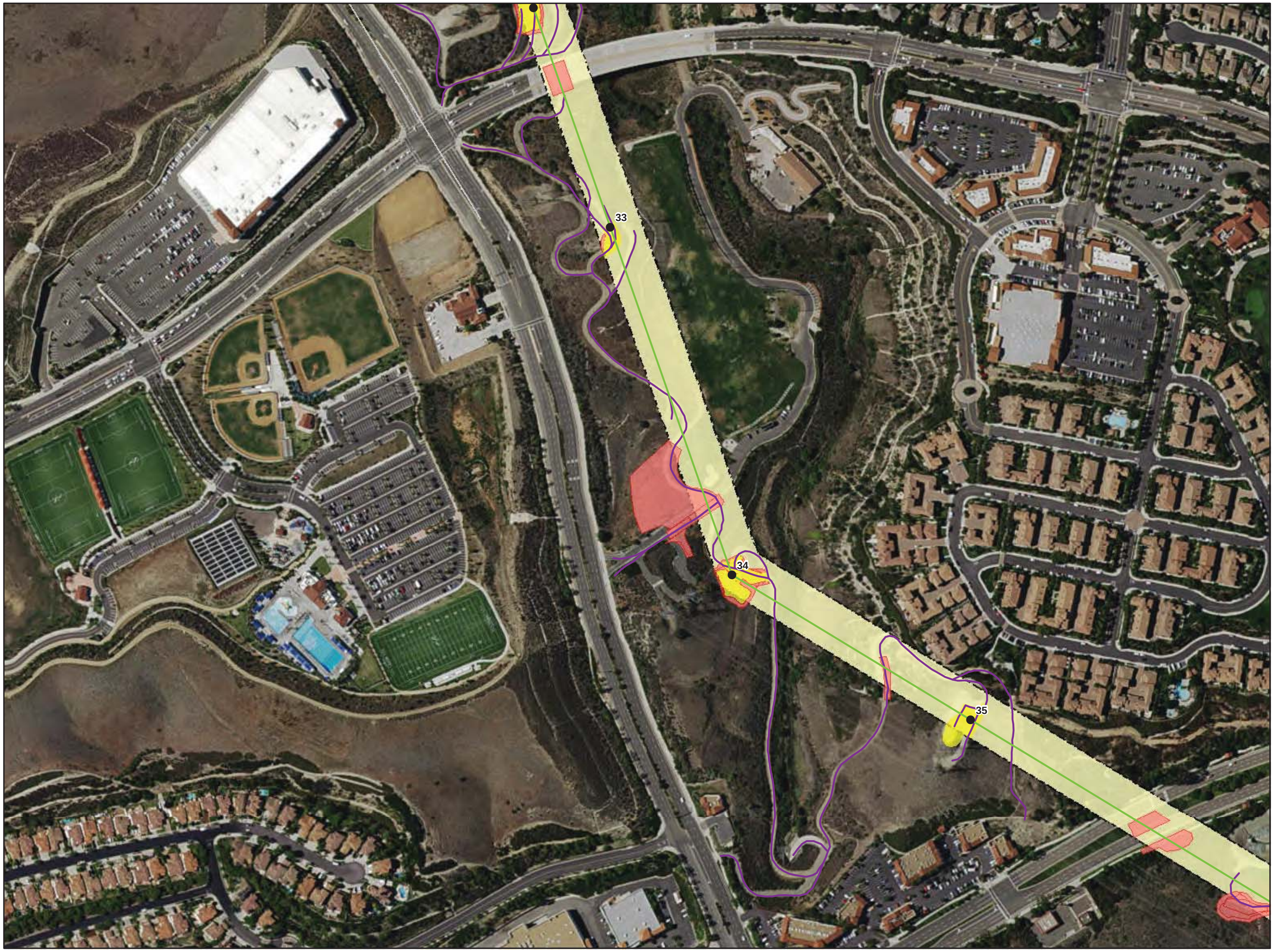

SOCRE Project Rights-of-Way Map

Post R-DEIR Design

(Design Date September 2015)

Facilities

- Existing Structure to be used in place
- Proposed New Structure
- Existing OH
- 69kV-UG
- 69kV-OH
- 138kV-OH
- 230kV-OH
- Existing Access Roads
- LaPata Road Grading

Work Areas (Impacts)

- Permanent Impact
- Temporary Work Area

Easements & Boundaries

- Prima Deschecha Landfill Conservation Easement
- MCB Pendleton Boundary
- Existing SDG&E Easements, ROW, & Fee-Owned Property

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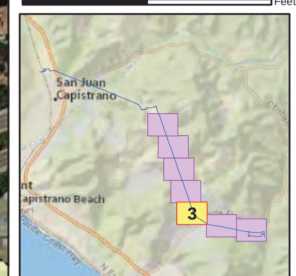

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SDGE A Sempra Energy utility

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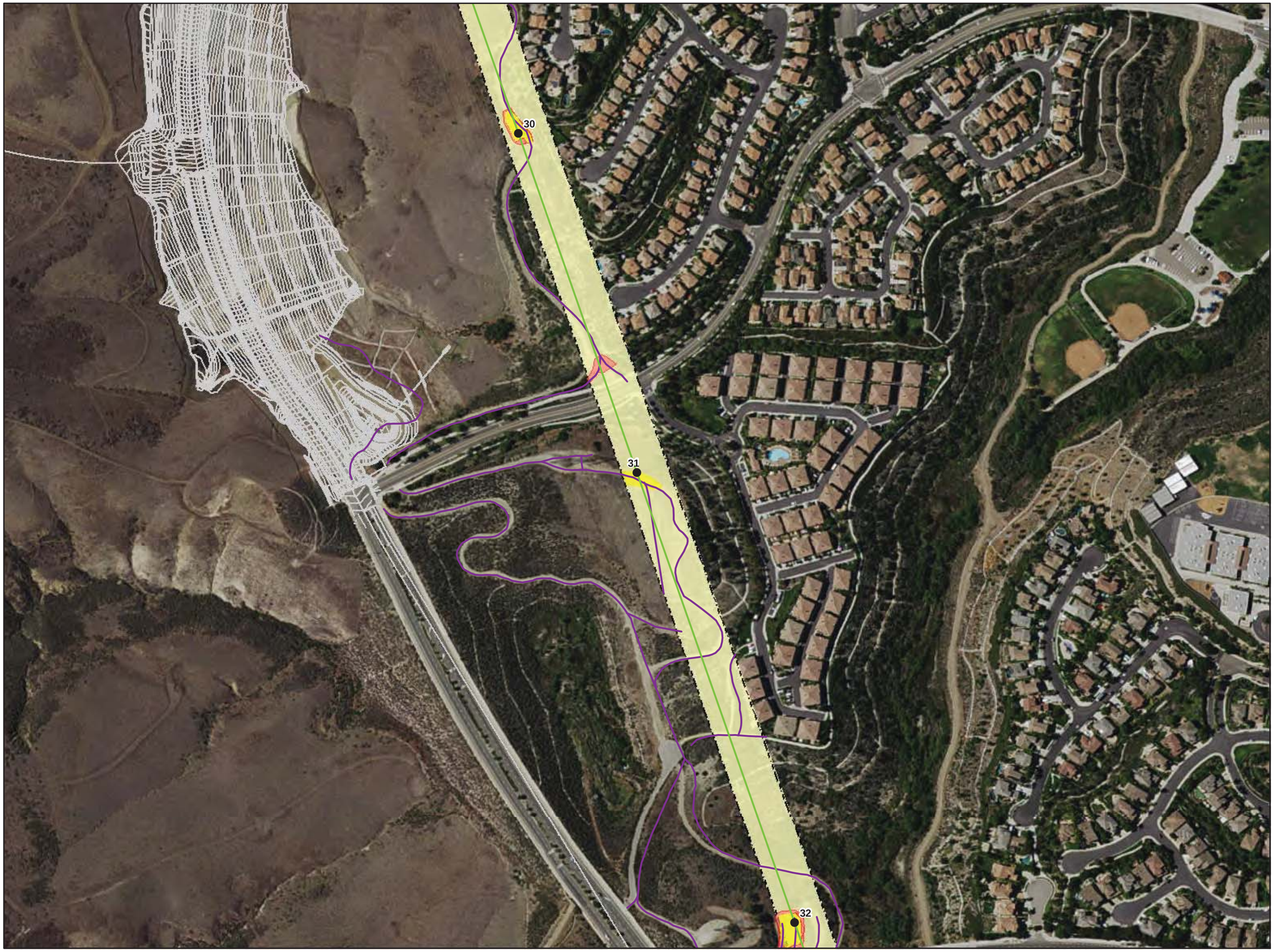

SOCRE Project Rights-of-Way Map

Post R-DEIR Design

(Design Date September 2015)

Sheet 4 of 7

Facilities

- Existing Structure to be used in place
- Proposed New Structure
- Existing OH
- 69kV-UG
- 69kV-OH
- 138kV-OH
- 230kV-OH
- Existing Access Roads
- LaPata Road Grading

Work Areas (Impacts)

- Permanent Impact
- Temporary Work Area

Easements & Boundaries

- Prima Deschecha Landfill Conservation Easement
- MCB Pendleton Boundary
- Existing SDG&E Easements, ROW, & Fee-Owned Property

0 300 600 Feet

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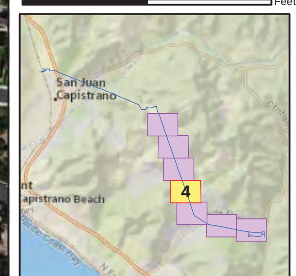

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FOR DISCUSSION PURPOSES ONLY - BASED ON PRELIMINARY ENGINEERING

SOCRE Project Rights-of-Way Map

Post R-DEIR Design

(Design Date September 2015)

Facilities

- Existing Structure to be used in place
- Proposed New Structure
- Existing OH
- 69kV-UG
- 69kV-OH
- 138kV-OH
- 230kV-OH
- Existing Access Roads
- LaPata Road Grading

Work Areas (Impacts)

- Permanent Impact
- Temporary Work Area

Easements & Boundaries

- Prima Deschecha Landfill Conservation Easement
- MCB Pendleton Boundary
- Existing SDG&E Easements, ROW, & Fee-Owned Property

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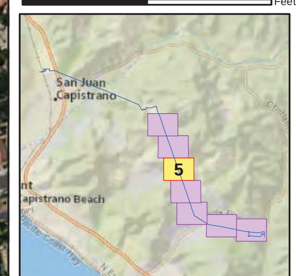

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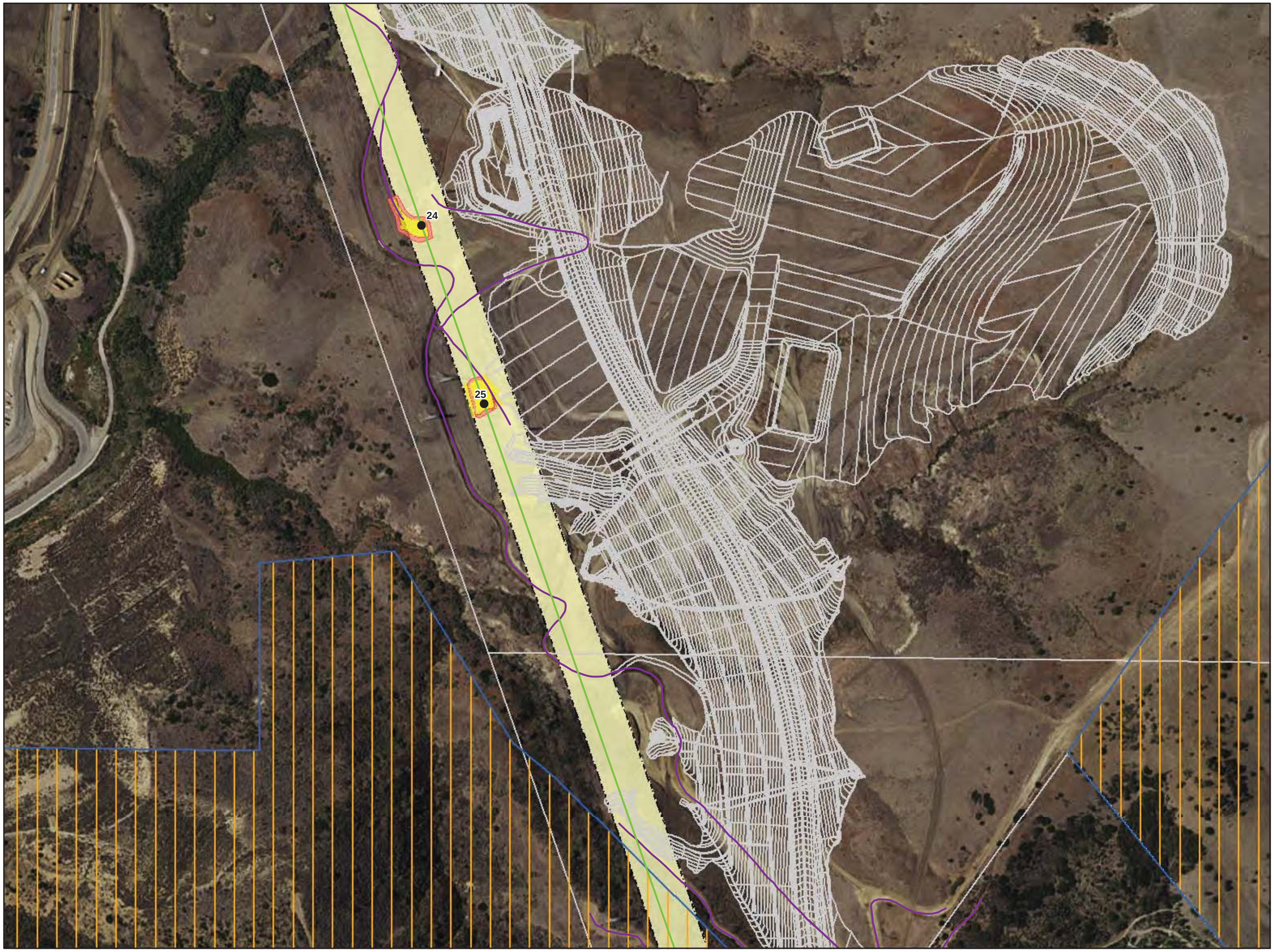

SOCRE Project Rights-of-Way Map

Post R-DEIR Design

(Design Date September 2015)

Sheet 6 of 7

Facilities

- Existing Structure to be used in place
- Proposed New Structure
- Existing OH
- 69kV-UG
- 69kV-OH
- 138kV-OH
- 230kV-OH
- Existing Access Roads
- LaPata Road Grading

Work Areas (Impacts)

- Permanent Impact
- Temporary Work Area

Easements & Boundaries

- Prima Deschecha Landfill Conservation Easement
- MCB Pendleton Boundary
- Existing SDG&E Easements, ROW, & Fee-Owned Property

0 300 600 Feet

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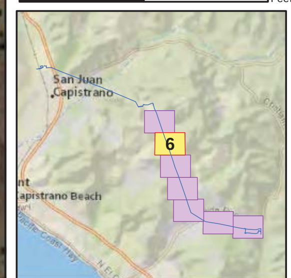

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
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FOR DISCUSSION PURPOSES ONLY - BASED ON PRELIMINARY ENGINEERING

SOCRE Project Rights-of-Way Map

Post R-DEIR Design

(Design Date September 2015)

Sheet 7 of 7

Facilities

- Existing Structure to be used in place
- Proposed New Structure
- Existing OH
- 69kV-UG
- 69kV-OH
- 138kV-OH
- 230kV-OH
- Existing Access Roads
- LaPata Road Grading

Work Areas (Impacts)

- Permanent Impact
- Temporary Work Area

Easements & Boundaries

- Prima Deschecha Landfill Conservation Easement
- MCB Pendleton Boundary
- Existing SDG&E Easements, ROW, & Fee-Owned Property

0 300 600 Feet

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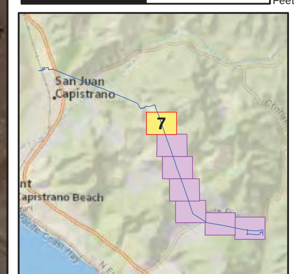

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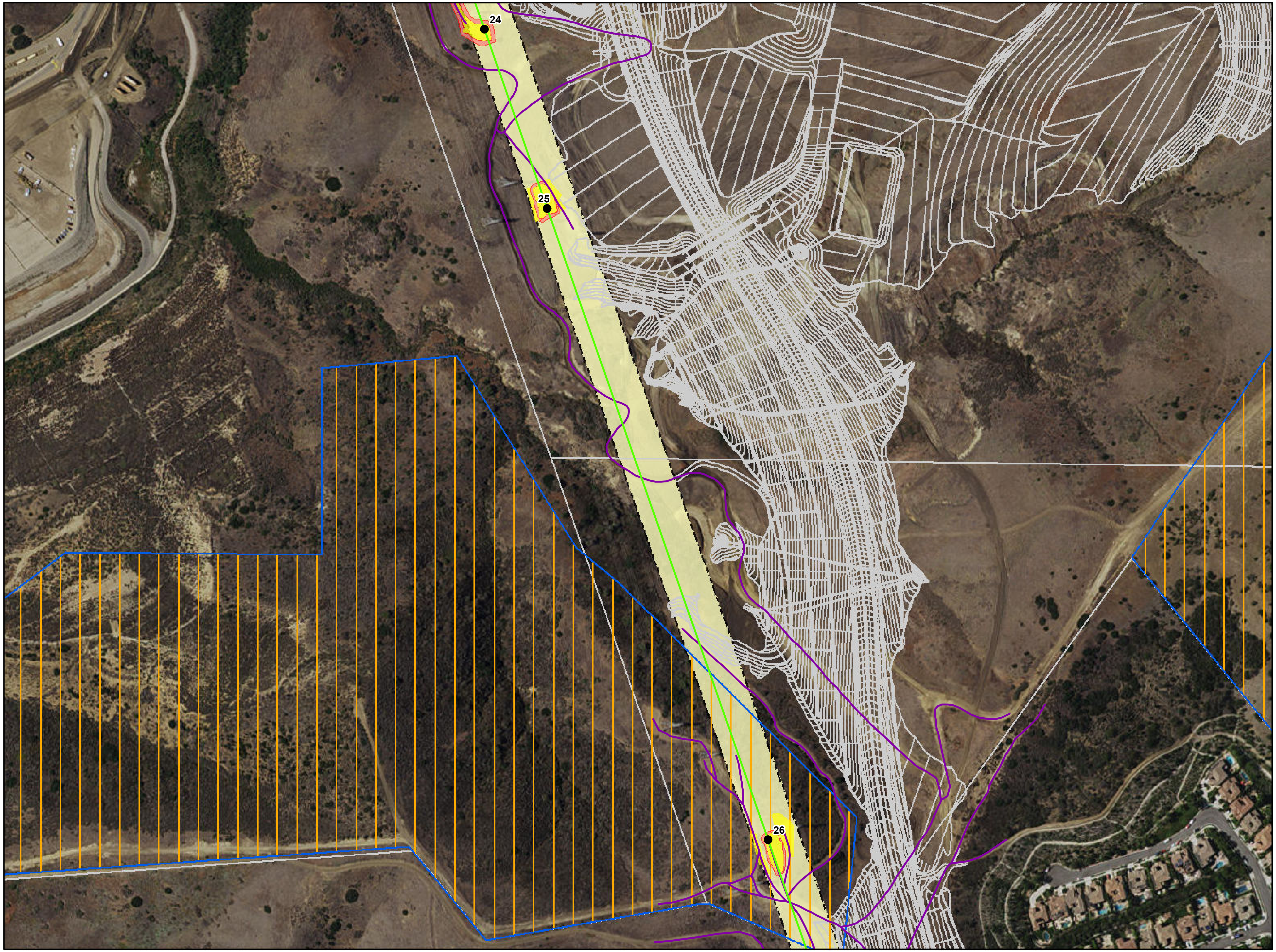
Attachment 50

SOCRE Project Rights-of-Way Map,
Prima Deshecha Landfill Conservation Easement

SOCRE Project Rights-of-Way Map

Rev. September 2015



Facilities

- Proposed New Structure
- 230kV-OH
- Existing Access Roads
- LaPata Road Grading

Work Areas (Impacts)

- Permanent Impact
- Temporary Work Area

Easements & Boundaries

- Prima Deschecha Landfill Conservation Easement
- Existing SDG&E Easements, ROW, & Fee-Owned Property

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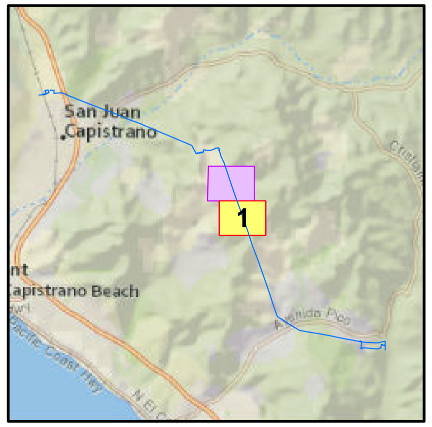

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
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SOCRE Project Rights-of-Way Map

Rev. September 2015

Sheet 2 of 2

Facilities

- Proposed New Structure
- 230kV-OH
- Existing Access Roads
- LaPata Road Grading

Work Areas (Impacts)

- Permanent Impact
- Temporary Work Area

Easements & Boundaries

- Prima Deschecha Landfill Conservation Easement
- Existing SDG&E Easements, ROW, & Fee-Owned Property

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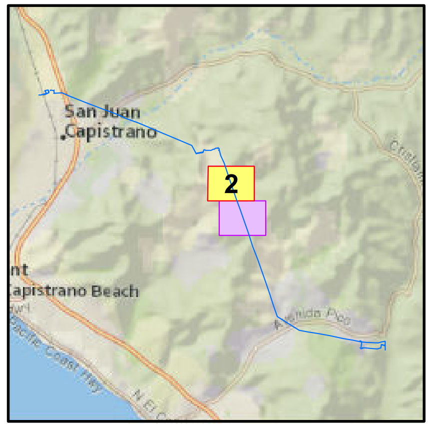

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
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Attachment 51

SOCRE Project Structure 26 Detail Map

SOCRE Project
Structure 26
Proposed New Structure
230kV - Overhead
Existing Access Road
Permanent Impact
Temporary Work Space
Prima Deschecha Landfill Conservation Easement
Existing SDG&E Easements, Rights of Way, & Fee-Owned Property
Permanent Impact Area Outside of SDG&E ROW
26
Permanent Iimpact Outside of ROW 210 sq. ft.
Permanent Impact
Temporary Work Area
SDG&E is providing this map with the understanding that the map is not survey grade. Certain technology used under license from AT&T Intellectual Property I, L.P. Copyright ©1998 – 2007 AT&T Intellectual Property 1, L.P. All Rights Reserved.
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San Juan Capistrano
Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
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Attachment 52

SOCRE Project Structure 26 Aerial Photo


approximate western edge of SDG&E ROW 45587
Z120062
Structure 26
Z23161
Impact area identified for potential parking/ use of a crane, bucked truck, or similar piece of equipment during construction and/ or maintenance
125 ft
© 2015 Google
Google earth
33°28'47.89" N 117°36'36.89" W elev 751 ft eye alt 1267 ft

Attachment 53

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Attachment 56

SOCRE ED-10 SDG&E Partial Response 2
dated July 14, 2015

Rebecca Giles
Regulatory Case Manager
San Diego Gas and Electric Company
8330 Century Park Court
San Diego, CA 92123-1530

July 14, 2015

Reg.12-10/A.12-05-020
SOCRE CPCN

Sent Via Electronic Mail

Mr. Andrew Barnsdale CPUC - Energy Division 505 Van Ness Avenue San Francisco, CA 94102	Rob Peterson CPUC - Energy Division 505 Van Ness Avenue San Francisco, CA 94102

Re: ED10-SDG&E Partial Response 2– PN14.2

Dear Mr. Barnsdale and Mr. Peterson:

Attached is ED10-SDG&E Partial Response 2. This submittal provides responses to Question PN14.2 as clarified in a teleconference with Energy Division on July 10, 2015 and completes the utility's response to this request.

If you have any questions or require additional information, please feel free to contact me by phone at (858) 636-6876 or e-mail: **RGiles@semprautilities.com.**

Sincerely,

Signed

Rebecca Giles
Regulatory Case Manager

Enclosures:

cc: Allen Trial – SDG&E
Richard Raushenbush - SDG&E
Mary Turley – SDG&E
Central Files - SDG&E
Elizabeth Cason – SDG&E
Charles Mee – ORA
Edward Moldavsky – ORA
Andrew Barnsdale – ED
William Stephenson – ED Consultant
Nicholas Sher – CPUC
Jacki Ayer – Frontlines
Jordan Pinjuv – CAISO

Question: PN14.2

Table 14.2 was not completed as requested in Data Gap PD-14.1. Complete Table 14.2. The values inserted into this table should represent a standard GIS substation site and should not be specific to the Trabuco Substation or the South Orange County service area. Be sure to provide values that are detailed enough to differentiate between the different sized substations, as well as, provide values for each substation scenario listed. Schedule a conference call with the CPUC the week of July 6 to discuss typical acreage requirements for GIS substations. Provide meeting notes from call.

SDGE Response: PN14.2

During a July 10, 2015 conference call regarding Energy Division's Data Gap 14.2, Energy Division clarified that the Data Gap and associated Table 14.2 is seeking information specifically about potential construction of a 230/138/12 kV Gas Insulated Substation (GIS) at or adjacent to SDG&E's existing Trabuco Substation, which would be interconnected to an existing Southern California Edison (SCE) 220 kV transmission line. Energy Division also clarified that it was not asking for SDG&E's approved standard design, or a design that SDG&E considered prudent. Energy Division also stated that meeting notes were not to be provided.

SDG&E has provided Energy Division with its June 24, 2015 Rebuttal Testimony, which responds to the Office of Ratepayer Advocates' suggestion of such an alternative to the Proposed Project. In Chapters 8 and 9, SDG&E explains that ORA's Trabuco Substation Alternative is infeasible, ineffective, and would cost more than the Proposed Project. As an initial matter, an SCE interconnection would delay fixing South Orange County's reliability issues for years, have negative impacts on both SDG&E's and SCE's systems, and require Reliability Upgrades that will add time and costs to mitigating the risks addressed by SDG&E's Proposed Project. Moreover, ORA's proposal requires additional work to provide the same redundancy benefit as the Proposed Project. Further, Trabuco Substations cannot accommodate a 230 kV substation without acquiring more property (displacing existing businesses), a cost not required to rebuild Capistrano Substation on existing SDG&E-owned property.

Among the points made by SDG&E with respect to a Trabuco Substation Alternative:

- **The Trabuco Substation Alternative Does Not Add a 230 kV Source at the Load Center for South Orange County**

Adding a 230 kV source at Capistrano Substation is more effective and efficient because of the close proximity to the center of load in South Orange County to Capistrano Substation. Trabuco Substation is not at the load center for South Orange County. Rather, it is located several miles north of the load center, with Capistrano Substation located between Trabuco and the calculated load center. Generally speaking, energy injected from the 230 kV system into the 138 kV system will then flow towards the load center, across the 138 kV network, before it can then flow out to serve customer load. Capistrano is the best of all existing locations given the load center.

Also, Trabuco Substation is located adjacent to three 138 kV transmission lines, unlike the six lines that will terminate at Capistrano Substation upon completion of the SOCRE Project, and the four lines that currently terminate at Talega Substation. In order for a second 230/138 kV source located at Trabuco Substation to be fully redundant to the existing source at Talega, and given that two of the lines are located on common structures south of Trabuco Substation, it would be necessary to add at least one additional 138 kV line from Trabuco Substation to Capistrano Substation. As discussed above, energy will tend to flow south from Trabuco towards the load center at Capistrano Substation. Following loss of Talega Substation, with Trabuco Substation acting as the sole source to South Orange County, this would result in several hundred megawatts of energy flowing south from Trabuco. As both lines south of Trabuco (TL13834 and TL13833) share a common tower line, it is possible for a single N-2 contingency to remove both lines from service. This would effectively cut off Trabuco from the bulk of the South Orange County load. As a second source at a rebuilt 230/138/12 kV Capistrano substation would enjoy connectivity from six 138 kV lines, loss of any two lines will still allow Capistrano to supply the bulk of South Orange County load. As a result, substantial work is required on the 138 kV system to allow a 230 kV source at Trabuco Substation to serve South Orange County in the event of a service outage at Talega Substation.

- **An Interconnection with SCE at Trabuco Substation Would Take Years to Accomplish**

SDG&E's Supplemental Testimony, Chapter 5, Section 2 explained the required process for SDG&E to seek interconnection with SCE's system. "SDG&E would need to comply with SCE's Transmission Owner Tariff, the Transmission Control Agreement among transmission owners and the California Independent System Operator ("CAISO"), and the CAISO Tariff." As described in more detail in SDG&E's Supplemental Testimony: "SDG&E estimates that it would take a minimum of twelve months and could take as long as twenty-four months to complete an interconnection application, System Impact Study, and a Facilities Study for an interconnection with SCE as described in the SCE Alternative." SDG&E also would need to obtain CAISO approval. "SDG&E believes that such an application would go through the normal annual transmission planning process. Depending when the CPUC provided such direction, and SCE completed its studies, it could be up to a year before CAISO would decide whether to approve the Commission's preferred solution (and any "Reliability Upgrades" to SCE's or other systems determined to be necessary to permit the interconnection)." The same process would apply if SDG&E were to seek an interconnection to SCE's system as part of the Trabuco Substation Alternative.

These steps are time-consuming, not within SDG&E's control, likely to result in significant additional costs to SDG&E ratepayers (and other CAISO ratepayers), and may not result in approval of an SCE interconnection.

- **An SCE Interconnection at Trabuco Substation Would Have Impacts to Both the SCE and SDG&E Transmission Systems That Would Need to be Mitigated.**

As discussed in SDG&E's Supplemental Testimony, Chapter 5, Section 3, an interconnection with SCE would parallel a robust 230 kV path with a relatively weak 138 kV network. This would have the dual negative impacts of restricting the allowable flow on the 230 kV path while subjecting the 138 kV system to network flows for which it was not designed. Restricting allowable flow on the SCE lines in South Orange County could result in limiting the transfer capability between the SDG&E and SCE systems, resulting in reduced import capability for both utilities. In fact, such an interconnection may have a significant impact on Southern California's import capability.

Any interconnection with SCE's 230 kV transmission lines in South Orange County would result in the same negative impacts – including an interconnection at Trabuco Substation. SDG&E has provided Energy Division with the results of power flow analyses demonstrating such effects.

The California ISO identified the same concerns with any alternative that would include a similar connection to SCE's 230 kV system, as expressed by CAISO witness Robert Sparks:

> The Group 3 DEIR alternatives [alternatives that incorporate elements that parallel the South Orange County 138 kV system with the SCE 230 kV system] provide a new independent transmission source to serve the SDG&E's South Orange County service area from the SCE system. […] The SCE 230 kV line is a critical facility associated with the transmission corridor between the Los Angeles area and the San Diego area. As a consequence, the Group 3 DEIR alternatives result in the 138 kV network being paralleled to the existing 230 kV corridor linking the Los Angeles basin and San Diego.

> This paralleling of lower capacity networks with higher capacity networks lowers the overall capability of the 230 kV corridor.
>
> The CAISO conducted additional analysis to test the impact of the Group 3 DEIR alternatives on the capability of the 230 kV corridor. Based on this analysis, the CAISO found numerous overloading concerns under Category B and Category C contingencies in the South Orange County and SCE systems. The CAISO identified four thermal overloads for Category B contingencies and 52 thermal overloads for Category C contingencies in the 2024 Summer Off-Peak case. Even for the 2024 Summer Peak case with only about 200 MW flowing northbound between the two areas, there were 3 thermal overloads identified for Category C contingencies. This indicates that the Alternatives have significant adverse impacts on the Transfer Capability between the two areas and system operation without further improvement in the south Orange County system.

SCE's System Impact Study is similarly likely to identify significant impacts to a number of important import paths and therefore require Reliability Upgrades to SCE's and SDG&E's systems at SDG&E's expense (which would be passed on to CAISO ratepayers). To properly assess the risk to the import limit, a WECC PRG (Path Rating Group) would be formed to determine any additional projects that would be needed to mitigate the impact to the import limit. These costs also would be attributed to SDG&E and then to CAISO ratepayers.

Because none of the Reliability Upgrades or WECC projects have been identified at this time (and would not be for at least several years), their environmental impacts have not been assessed.

- **The Trabuco Substation Alternative Has Not Been Assessed to Determine Its Effectiveness and Impacts.**

ORA did not present a coherent plan of service to address the reliability issues in SDG&E's South Orange County system. ORA describes its Trabuco Substation Alternative as an interconnection of Trabuco Substation and an SCE transmission line, but does not describe any other work it recommends to address the South Orange County reliability issues (other than its infeasible and ineffective suggestions regarding Talega Substation, addressed in Chapter 3 of SDG&E's Rebuttal Testimony). ORA's cost estimate for its Trabuco Substation Alternative expressly excludes "the costs of rebuilding Capistrano Substation as a 138/12 kV substation, or the cost of reconfiguring the Talega Substation," and ORA nowhere identifies any upgrades to SDG&E's 138 kV system. ORA does not discuss how the SCE interconnection may affect the flow of power over the 138 kV and 230 kV transmission systems in South Orange County specifically, and the bulk power system in Southern California generally.

SDG&E, which has an obligation to provide reliable electric service to its South Orange County customers, must address the reliability issues in its system with a coherent and comprehensive plan of service. Assuming for the moment that all of the required work is feasible to construct and can be completed in a reasonable period of time, and based upon its preliminary analyses of the Trabuco Substation alternative, SDG&E sets forth below the necessary elements of a plan of service that includes an SCE 230 kV interconnection at an expanded and rebuilt Trabuco Substation. It does not include upgrades to neighboring systems which will only be known after a comprehensive analysis.

Lacking a plan from ORA or Frontlines, SDG&E made the following assumptions to create a high-level power flow assessment to determine the effectiveness of the Trabuco Substation Alternative. The following changes were made to the model:

- The existing Trabuco 138 kV straight bus was re-configured into a breaker and a half bus.
- A new breaker and a half 230 kV bus was created for the new Trabuco Substation 230 kV connection.
- 60 MVar capacitor banks were added to the end buses of the new Trabuco 230 kV breaker and a half bus.
- One of the two SCE 220 kV transmission lines which connect San Onofre to Santiago was opened and the ends connected to the new 230 kV bus at Trabuco Substation.
- Two 230/138 kV transformers were added to connect the Trabuco 230 kV bus to the Trabuco 138 kV bus.
- Talega Banks 60 and 62 were removed.
- WECC Path 43 was increased to 1161 MW.

SDG&E's power flow assessment found the following:

- Transmission line TL695, which is connected to the Talega 138 kV bus will need to be replaced, and 69 kV capacitors will need to be added at Oceanside and Basilone Road substations. Further analysis is needed to specify equipment size and location.
- When either Talega Bank 61 or 63 is out of service, flow on Path 43 will be constrained. Additional analysis is needed to determine the new path flow limit.

Table 9-1 lists transmission elements which will load above the Applicable Rating in violation of NERC standards. Table 9-2 lists contingencies which will require load to be shed.

Table 9-1: Contingencies Leading to Violation of Applicable Ratings with Trabuco Substation Alternative

	Near Term Transmission Planning Horizon	Long Term Transmission Planning Horizon	
Year =	2020	2025	2030
Contingency	Overloaded Element	Overloaded Element	Overloaded Element
C3:TA BK61 + TB to SO230	TA BK63	TA BK63	TA BK63
C3:13846 + TB to SO230	-	13836	13836
C3:TB to SO230 + TB to Santiago230	-	13816	13816

Table 9-2: Contingencies Requiring Load to be Shed with Trabuco Substation Alternative

	Near Term Transmission Planning Horizon	Long Term Transmission Planning Horizon	
Year =	2020	2025	2030
Contingency	Overloaded Element	Overloaded Element	Overloaded Element
C3:13831 + TB to SO230	-	-	13816
C3:13835 + 13836	-	-	13846C
C3:13835 + TB to SO230	-	13816	13816
C3:13836 + TB to SO230	13846A, 13846C	13846A, 13846C	13846A, 13846C
C3:13846 + TB to SO230	13836	13836	13836
C3:TA BK61 + TB to SO230	TA BK63	TA BK63	TA BK63
C3:TA BK61 + TB to Santiago230	TA BK63	TA BK63	TA BK63
C3:TA BK63 + TB to SO230	TA BK61	TA BK61, TA 5E CB	TA BK61, TA 5E CB
C3:TA BK63 + TB to Sangiago230	-	TA BK61	TA BK61

C3:TB to SO230 + TB to Santiago230	-	13816, TA BK61, TA BK63	13816, TA BK61, TA BK63

SDG&E has not thoroughly evaluated the SCE-Trabuco Alternative. Generally, it would likely be necessary to upgrade the two existing lines from Trabuco to Capistrano and Laguna Niguel, and add a third Trabuco-Capistrano 138 kV line in order to make a 230/138 kV source at Trabuco fully redundant to Talega. This would also include rebuilding and expanding the 138 kV yard at Capistrano to accommodate the additional line termination. SDG&E has not had sufficient time to estimate the cost of upgrading/adding these lines. This would also include rebuilding and expanding the 138 kV yard at Capistrano to accommodate the additional line termination. SDG&E may also need to construct a new dynamic voltage control device (SVC, STATCOM or Synchronous Condenser) at the new Trabuco Substation at an estimated cost of $80 million to $100 million (without AFUDC, permitting or mitigation). Additional analysis is needed to determine the size of equipment.

A single 230/138 kV transformer at a rebuilt Trabuco substation is not a feasible alternative. Good utility practice requires a certain level of redundancy in substation design. SDG&E generally designs major bulk power substations to have multiple, redundant sources (i.e., two transmission sources, multiple transformers, double buses, etc.) so that planned or forced outages do not result in a complete loss of capacity. A single 230/138 kV transformer would be removed from service for any single planned or forced outage involving the bank, and thereby remove a rebuilt Trabuco Substation as a source for the 138 kV network. A 230/138 kV Trabuco substation fed from two 230 kV lines, through a conventional breaker & half bus arrangement, feeding two or more parallel 230/138 kV transformers could not be removed as a source for the 138 kV system for any single contingency. The single-transformer arrangement would not meet one of SDG&E's objectives for this project, which is to provide a fully redundant source to South Orange County in the event of the catastrophic loss of Talega Substation, and thus would not achieve the same level of reliability as SDG&E's Proposed Project.

The aggregate South Orange County peak load is forecast to exceed the capacity of SDG&E's standard 230/138 kV transformer (392 MVA), or even a non-standard 450 MVA transformer. Therefore, SDG&E would install at a minimum two 392 MVA 230/138 kV transformers at Trabuco and reserve space for a future third transformer to enable enough capacity to feed the South Orange County load center at the system peak demand. The site for the transformers must be large enough to accommodate them, and will increase grading and below grade impact.

- SDG&E's current load forecast for South Orange County predicts load will exceed 450 MW in 2017. As a result, a rebuilt Trabuco Substation with a single 392 MVA or 450 MVA transformer would not be able to provide redundancy for South Orange County in the event of a Talega Substation outage even before construction of the proposed Trabuco

230/138/12 kV Substation would be complete. Even if load growth is a bit slower, designing the system only to a near-term planning horizon is short sighted. The expected service life of a transformer is over 60 years. If a rebuilt Trabuco Substation has only a single 450 MVA transformer, then additional infrastructure will likely be required if there is unexpected load growth within the transformer's service life. This event would require installation of another transformer and the infrastructure required to connect it to the grid, which would require further expansion of the substation, and result in greater future costs.

- Moreover, SDG&E must look at the practice of custom equipment from a global system perspective. Increasing the rating of a transformer also increases the rating of the equipment around it. The bus, circuit breakers, etc. must be analyzed to ensure they meet the larger MVA rating of the larger capacity transformer. Moreover, to ensure reliability in the event the 450 MVA transformer were to fail, SDG&E would need to acquire a spare 450 MVA transformer as this is a non-standard size for which SDG&E has no spare. It may also cause reliability issues for shortage of spares on any larger sized equipment that is also customized due to the higher MVA rating of the transformer. To mitigate this issue, any spare equipment deemed "unique" must also be ordered and incorporated into SDG&E's spare policy. Warehousing and ongoing upkeep of these devices add "hidden" costs that need to be accounted for in analyzing the financial impact of this decision. Additionally, impedance values must be analyzed and size/spacing must be custom designed to meet any increases in equipment size caused by additional cooling design changes in the equipment, which are necessary to meet the higher rating.

SDG&E notes that this alternative effectively adds an interconnection between SDG&E's 138 kV system and SCE's 230 kV system, where none exist today, and would subject the 138 kV system in SOC to significant and likely unpredictable loop flows. This alternative presents some significant operational challenges that would need to be thoroughly studied. Moreover, connecting to a major 230 kV transmission path may reduce the maximum amount of power which can be transferred into Southern California from Nevada, Arizona or Mexico. This can only be determined after a thorough study of the interconnection.

- **Trabuco Substation Does Not Have Space to Add a 230 kV Switchyard, and Expansion Would be Difficult and Costly**.

    - <u>Trabuco Substation Does Not Have Space to Add a 230 kV Switchyard</u>

There is no room at the Trabuco Substation property for expansion to a 230/138/12 kV substation. Trabuco Substation is bounded by the I-5 freeway to the east and Camino Capistrano to the west. There are businesses immediately north and south of the substation. See

Attachment 41 to SDG&E's Rebuttal Testimony (Google Earth aerial photo of Trabuco Substation).

SDG&E's existing Trabuco Substation is built on a pad approximately 290 ft x 323 ft. The substation was built as a single bus- single breaker 138/12 kV distribution substation, with a planned ultimate configuration of four 138/12 kV transformers and four 138 kV transmission lines. Trabuco Substation currently has three 138 kV transmission lines and four 138/12 kV transformers. Trabuco Substation was built with an older, less compact design, and thus is somewhat larger than Pico Substation. However, due to its layout of the 138 kV on the west side of the substation, along Camino Capistrano, and the 12 kV distribution coming from the east side out to Camino Capistrano, there is no room for expansion inside the Trabuco Substation site.

ORA's Trabuco Substation Alternative proposes to convert Trabuco Substation into a 230/138/12 kV substation. Such a substation is considerably larger than a distribution substation.

SDG&E's requirement for a 230/138 kV transmission bus serving bulk power transformers is a breaker and half arrangement. (See Attachment 30 to SDG&E's Rebuttal Testimony). This is required for a cost effective, reliable bus configuration that allows for breaker and/or bus maintenance without line/bank interruption and minimal disruption in a breaker failure situation. It is also SDG&E's standard to build at least one spare position when constructing a new substation to allow for future growth and/or maintenance activities. Doing so is prudent and cost-effective, while failing to do so could result in significant additional costs if rebuilding the substation is later necessary to address such issues.

If Trabuco Substation were rebuilt as a 230/138/12 kV substation, the minimum requirement for the substation would be:

- A 6 element 230 kV 3000A (possibly 4000A due to the SCE connection) breaker and half bus arrangement, with two 230 kV TL positions, two high side connections to the 230/138 kV transformer positions spare positions (TL and bank spare position), and a voltage regulating device.

- A new expanded control shelter to accommodate the additional control & protection necessary for the added transmission elements

- A minimum 12 element 138 kV 3000 amp breaker and half bus arrangement, with four 138/12 kV transformers, two low side connections for the 230/138 kV transformers, four 138 kV TLs, and spare positions.

To allow for property line setback requirements and required landscaping required by local or state jurisdiction and/or noise requirements, fire safety requirements, and standard drive aisle access, a minimum size yard for a 230/138/12 kV substation yard would be approximately 6-7 acres using GIS technology or approximately 12 acres using AIS technology – depending on the topography and arrangement of the land. This acreage accounts for the space requirements for water quality and hydromodification management criteria, as required by the Regional Water

Quality Control Board, which is usually met through the combined use of underground infiltration tanks, and above ground detention basins. This acreage also accounts for required drive aisles between equipment for proper maintenance access and equipment transport, placement of equipment for optimum EMF and noise requirements, installation of required underground termination connections, cable pulling space requirements, and any required pole placements.

Even using GIS technology, an expanded 230/138/12 kV Trabuco Substation will not fit on the existing substation property. Using GIS technology, an expanded 230/138/12 kV Trabuco Substation would require purchasing of the adjoining properties to the north and south of the existing substation site. This acreage is necessary to allow for construction of the new and required 230/138 kV breaker and half bus arrangement, and a complete rebuild in the northern property of the existing distribution station.

- <u>Expanding and Rebuilding Trabuco Substation Would be Difficult and Costly</u>

As noted above, Trabuco Substation is bounded by the I-5 freeway to the east and Camino Capistrano to the west. There are businesses immediately north and south of the substation, both of which would need to be acquired in order to build a 230/138/12 kV substation. The parking lot to the north is part of an AT&T Operations District facility. To expand Trabuco Substation would require negotiating acquisition of one or more business properties, or pursuing condemnation if possible. Either would incur considerable additional cost, to be imposed on ratepayers, that does not exist at Capistrano Substation, where SDG&E already owns sufficient property to construct a 230/138/12 kV substation—and can do so efficiently while undertaking the required rebuild of the aging existing substation. While a cost of the property acquisition cannot be obtained on such a short time frame, the cost would be substantial due to the cost of property acquisition, and the cost of relocating the existing businesses that would have to be acquired.

The Trabuco Substation would have to be completely rebuilt to align the 230/138/12 kV within the narrow strip of land, while the existing Trabuco Substation remains in operation to serve customers. The new 138/12 kV substation would be moved to the property north of the existing substation property in order to accommodate the new 230 kV GIS and bank additions in both the existing property and the property to the South. Trabuco Substation has not been identified at this point as an aging substation required to be rebuilt, and an early rebuild would impose unnecessary costs on ratepayers.

Although no preliminary engineering has been performed, the non- budgetary estimated cost to build a 230/138/12 kV substation at Trabuco would be higher than the proposed 230/138/12 kV rebuilt Capistrano Substation because Trabuco has more existing equipment than Capistrano that would need to be replaced in the rebuilt substation. The estimated cost of constructing a 230/138/12 kV substation at Trabuco and the relocation of the existing distribution circuits is approximately $173 - $211 million. This cost does not include relocating the existing 138 kV transmission, adding new 138 kV and 230 kV transmission lines, permitting, mitigation, property acquisition costs, ROW, or AFUDC.

Attached as Attachment 39 to SDG&E's Rebuttal Testimony is a simple block diagram of what a 230/138/12 kV layout at a rebuilt Trabuco Substation would look like at a minimum. This block diagram is based on equipment sizes from the Proposed Project's Capistrano layout. However, without a complete engineering study and detailed design work, this diagram cannot account for hydro modification, setback and noise requirements, distribution and transmission lines routes entering/exiting the substation, or actual number and size of required underground termination stands and/or poles. Also, without a complete Planning study done on the SCE interconnection, the final actual ratings of the equipment cannot be determined--this may affect the final size of the equipment which may affect the layout. Additional property may need to be acquired to account for all the final engineered requirements.

The layout and visual aesthetics of a rebuilt 230/138/12 kV Trabuco Substation would be very similar to the proposed rebuilt 230/138/12 kV Capistrano Substation, with two 40-50 ft GIS buildings required for the 138 kV and the 230 kV GIS, and a voltage control device.

A 230/138/12 kV Trabuco Substation would have to be built in two phases. Phase 1 would include moving the entire existing substation to the north and rebuilding it to include 138 kV GIS and equivalent distribution equipment to the existing site (four 138/12 kV transformers, four sections of 12 kV switchgear, and four 12 kV capacitors). Phase 2 would include removing existing equipment, grading, and installing the 230 kV equipment, including the two 230/138 kV transformers, 230 kV GIS and the required voltage control device. This 230 kV equipment would be placed on the existing yard and the property acquired immediately to the south of the existing site. The length of the construction would also be similar to Capistrano and would depend upon system outage requirements. The estimated construction length could be between 2-3 years.

The impact to the area would involve site work noise and dust suppression, and construction in the street of Camino Capistrano for almost the entire construction length. Street construction would be lengthy due to the relocation of the existing 16 distribution circuits and three 138 kV transmission lines and then the installation of the 230 kV transmission lines and new 138 kV lines to Capistrano Substation. Traffic would also be impaired by the haul trucks required for the site development work.

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Notwithstanding SDG&E's concerns regarding the feasibility, prudence and cost of a Trabuco Substation Alternative, and the reduced reliability and increased cost of considering a rebuilt Trabuco Substation with a single, non-standard transformer, Energy Division has requested that SDG&E provide estimates of required acreage for rebuilding Trabuco Substation to meet the equipment options presented in Energy Division's Table 14.2. Energy Division also instructed SDG&E not to provide a range of acreage estimates, but rather to provide a single number. Energy Division's Table 14.2 only provides for fewer 138/12 kV transformers than currently exist at Trabuco Substation, and thus necessitates construction of a new distribution substation. If the Commission were to order SDG&E to construct a 230/138/12 kV substation at and adjacent to the existing Trabuco Substation, SDG&E would seek to construct the substation with the minimum requirements described above, which would require approximately 6-7 acres using GIS technology. Subject to its expressed concerns and the caveats noted in footnotes to its responses to Table 14.2, SDG&E provides its responses to Table 14.2 below.

Attachment to PD14.2

Table PD-14.2 – Original Data Request: Estimated acreage required for various sized standard GIS substations
Table PD-14.2 – Revised Data Request: Estimated acreage required for various sized GIS substations located at SDG&E's existing Trabuco Substation or adjacent to it. All estimates are subject to SDG&E's concerns set forth above.

	One 230/138-KV Transformer	One 230/138-kV Transformer with room for one spare	Two 230/138-kV Transformers	Two 230/138-kV Transformer with room for one spare
One 138/12-kV Transformer	5 acres (1) (2)(5)(6)(7)(8)	5.5 acres (1)(2)(5)(6)(7)(8)	5.5 acres (1)(2)(5)(7)(8)	6.4 acres (1)(2)(5)(7)
One 138/12-kV Transformer with room for one spare	5 acres (1)(2)(5)(6)(7)(8)	5.5 acres (1)(2)(5)(6)(7)(8)	5.5 acres (1)(2)(5)(7)(8)	6.4 acres(1)(2)(5)(7)
Two 138/12-kV Transformers	5 acres (1)(3)(6)(7)(8)	5.5 acres (1)(3)(6)(7)(8)	5.5 acres (1)(3)(7)(8)	6.4 acres (1)(3)(7)
Two 138/12-kV Transformers with room for one spare	5.4 acres (1)(3)(6)(8)	5.8 acres (1)(3)(6)(8)	5.8 acres (1)(3)(8)	6.8 acres (1)(3)
Three 138/12-kV Transformers	5.4 acres (1)(4)(6)(8)	5.8 acres (1)(4)(6)(8)	5.8 acres (1)(4)(8)	6.8 acres (1)(4)
Three 138/12-kV Transformers with room for one spare	5.4 acres (1)(4)(6)(8)	5.8 acres (1)(4)(6)(8)	5.8 acres (1)(4)(8)	6.8 acres (1)(4)

(1) Site Caveats

- This acreage could decrease or increase depending upon final equipment required with SCE interconnection.
- This is based on using current SDG&E equipment including SDG&E's standard 230/138 kV 392MVA transformer.
- This acreage allows room for a dynamic voltage control device, which may be reduced to a static device upon further engineering of the Trabuco Substation Alternative.
- This layout is not based on a detailed and engineered design. It is simply a high level conceptual layout.
- This assumes a 20 foot setback along the western length of the properties which is the same setback that currently exists at Trabuco. It does not account for any required setbacks on the north, south, or east side of the property or additional setbacks along Camino Capistrano.
- This does not account for any geotechnical site specific requirements which may affect site grading.
- This assumes we can install driveways along Camino Capistrano.
- This assumes we can acquire (at the minimum), the property immediately north and south of Trabuco Substation. The cost of doing so is unknown. Additional property may be required to meet hydromodification and setback requirements as acquisition of the north and south parcels combined with the existing Trabuco substation property will only amount to a total of 5.7 acres.
- This acreage assumes 25% for hydromodification/water quality but may more or less space could be required once detailed design and study has taken place.
- This acreage may not meet noise requirements without additional barriers although some acreage has been included to minimize noise at property line.
- This may not meet spacing required for transmission and distribution getaways or any required pole placements inside the substation as further study would be required to determine spacing required for this infrastructure.

(2) Trabuco Substation currently has four distribution 138/12 kV transformers and 16 distribution circuits. To only install one distribution transformer will mean relocating approximately 90MVA of substation capacity to adjacent substations near Trabuco. The two adjacent substations (Capistrano and Margarita) are both already heavily loaded, serving almost 160 MVA of load between them. Moving 90 MVA of capacity to these two substations is not possible and would trigger construction of a new 138/12 kV distribution substation to meet these needs. If this occurs, it would move at least 12 distribution circuits to the new substation site (approximately 2.5 to 3 acres) and a minimum of two 138 kV transmission lines to serve the new substation site. Depending on the location of the new substation site to the existing Trabuco load, the new substation would meet SDG&E's standards for a distribution substation ultimate configuration of four 138/12 kV transformers and 16 circuits at the new substation site.

(3) Trabuco Substation currently has four distribution 138/12 kV transformers and 16 distribution circuits. To only install two distribution transformers will mean relocating approximately 60MVA of substation capacity to adjacent substations located near Trabuco. The two adjacent substations

(Capistrano and Margarita) are both already heavily loaded, serving almost 160 MVA of load between them. Moving 60 MVA of capacity to these two substations is not possible and would trigger construction of a new 138/12 kV distribution substation (approximately 2.5 to 3 acres) to meet these needs. If this occurs, it would move at least 8 distribution circuits to the new substation site and a minimum of two 138 kV transmission lines to serve the new substation site. Depending on the location of the new substation site to the existing Trabuco load, the new substation would meet SDG&E's standards for a distribution substation ultimate configuration of four 138/12 kV transformers and 16 circuits at the new substation site.

(4) Trabuco Substation currently has four distribution 138/12 kV transformers and 16 distribution circuits. To only install three distribution transformers will mean relocating approximately 30MVA of substation capacity to adjacent substations located near Trabuco. This impact would need to be studied, but it could trigger construction of a new 138/12 kV distribution substation (approximately 2.5 to 3 acres) to meet these needs. If this occurs, it would move at least 4 distribution circuits to the new substation site and a minimum of two 138 kV transmission lines to serve the new substation site. Depending on the location of the new substation site to the existing Trabuco load, the new substation would meet SDG&E's standards for a distribution substation ultimate configuration of two 138/12 kV transformers and 8 circuits at the new substation site.

(5) SDG&E does not consider it prudent to install space for only one 138/12 kV distribution transformer –at least one spare position is required for a portable transformer connection to mitigate the loss of service if the single transformer were to fail. Moreover, SDG&E's standard practice is to install two distribution transformers to reduce the risk of load dropping in the event of a single transformer outage; without two distribution transformers, SDG&E would seek other means of providing reliable service to its customers through cross-ties to other distribution substations, which has not been studied here.

(6) SDG&E does not consider it prudent to install space for only one 230/138 kV transformer–at least one spare position is required for a spare transformer. As set forth above, installing a single 392 MVA 230/138 kV transformer, or even a non-standard 450 MVA 230/138 kV transformer (with its attendant costs for spares and potential changes to other equipment specifications), would be insufficient to allow a rebuilt 230/138/12 kV Trabuco Substation to serve South Orange County load in the event of a Talega Substation outage, which SDG&E's Proposed Project is able to do.

(7) Space savings at the rebuilt Trabuco Substation acquired through installation of only one or two 138/12 kV transformers is assumed to be gained through lining transformers/switchgear in a row from the West to East direction, thus gaining property back on the North End by eliminating a row of equipment. Further studies would have to be performed to ensure that there is enough space to perform this alignment, and firewalls may be required to protect switchgear from damage caused by catastrophic failure of the oil containing transformers. However, as noted above, a new distribution substation will be required.

(8) 230/138 kV transformer reduction would not necessarily reduce substation footprint as the additional property that could be gained on the East and West sides of the substation would likely still be consumed by setback requirements caused by noise, EMF, and fire safety distances. Additionally, access roads inside the perimeter of the substation would not be re-routed to accommodate this reduction in space.

EXHIBIT 7

SDG&E December 19, 2014 Comments on the Alternatives Screening Report

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December 19, 2014

Andrew Barnsdale, Project Manager
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Re: CEQA Alternatives Screening Report for San Diego Gas & Electric Company's South Orange County Reliability Enhancement Project, Application No. A.12-05-020

Dear Mr. Barnsdale:

San Diego Gas & Electric Company ("SDG&E") provides the following additional comments on the CPUC's "CEQA Alternatives Screening Report for San Diego Gas & Electric Company's South Orange County Reliability Enhancement Project" ("SOCRE Alternatives Report"). These comments supplement the comments provided on November 21, 2014. SDG&E is continuing to complete its comments on the SOCRE Alternatives Report, but provides this second set of comments now to expedite your review.

I. **NERC Reliability Standards for Transmission Planning**

SDG&E has an obligation to provide reliable electric service to South Orange County. *See, e.g.,* D. 14-03-004 at 13 (listing numerous statutory requirements to provide reliable electric service). At the minimum, SDG&E is obligated to comply with all NERC reliability standards by, among other things, the Federal Power Act § 215 and its Transmission Control Agreement with CAISO. In turn, under Public Utilities Code § 345: "The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council." SDG&E identified compliance with the NERC reliability standards to be an objective of the proposed Project.

The SOCRE Alternatives Report discusses the NERC transmission planning standards, which establish minimum reliability criteria, and some of CAISO's more stringent planning criteria. Based upon a consultant's review of certain scenarios over a 10 year planning horizon, the CPUC concludes that SDG&E's current system is not forecast to violate the NERC transmission planning ("TPL") standards because SDG&E is permitted under those reliability standards to drop service to its South Orange County customers under a host of outage events. Therefore, the CPUC concludes that the project is not "necessary" to comply with the NERC standards and that projects that would provide a lower level of reliability to SDG&E's South Orange County customers are proper "alternatives" to the Project.

The Report's discussion, however, is incomplete and therefore fails to recognize the NERC standard's importance in evaluating feasible alternatives.

A. TPL-003-0b (Category C)

NERC Reliability Standard TPL-003-0b addresses "System Performance Following Loss of Two or More Bulk Electric System Elements." TPL-003-0b requires SDG&E to "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." TPL-003-0b at 2. Unlike TPL-002-0b, TPL-003-0b provides: "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." *Id.*

In its 2010-11 Transmission Plan at 207, CAISO found:

> The southern Orange County area in SDG&E's service territory demonstrates multiple Category C-driven issues by 2020. More than 40 combinations of contingencies can result in load shed in the southern Orange County area. Some of these problems are existing ones and there are SPSs to address these issues. Detailed contingency analysis results are presented in Appendix A. There are more than 40 contingencies that result in overloads in 2020 and the number is more than 70 beyond 2025. The ISO standards do not recommend using SPS that looks at more than six contingencies causing more than four elements to get overloaded.

CAISO found that these Category C issues should be mitigated through the Project. See CAISO 2010-11 Transmission Plan, Appendix A at 196-199.

Notwithstanding the CAISO's determination, the SOCRE Alternatives Report at 1-20 asserts:

> Although some transmission planning components of these standards are mandatory (see TPL-003-0b and TPL-004-0a), the applicant is <u>not required</u> by NERC, WECC, or CAISO to design its transmission system <u>to avoid load shedding</u> during the types of outages addressed by NERC standards TPL-003-0 and TPL-004-0 (CAISO 2011a, NERC 2013c). Category C and D events identified by the applicant and during CAISO's review of the proposed project are important considerations (SDG&E 2012, 2014a, CAISO 2011a); however, construction of the proposed project is not necessary to ensure that the applicant's South Orange County 138-kV system remains in compliance with NERC standards TPL-003-0 and TPL-004-0. For this reason, compliance with NERC standards TPL-003-0 and TPL-004-0 does not serve as a useful criterion for the screening of alternatives presented in this report.

(Emphasis added). In other words, the Report concludes that SDG&E can simply discontinue electric service to some or all of its South Orange County customers if any of the Category C outages occur.

The Report's statement is neither complete nor accurate.

First, the statement fails to recognize that the applicant, SDG&E, is "required by … CAISO" to mitigate the South Orange County Category C issues by construction of the Project. The CAISO 2010-11 Transmission Plan states that the Category C issues should be addressed through construction of "SOCRUP Alt. 3," which is the Project. SDG&E is required to do so pursuant to its agreement with CAISO. *See* Transmission Control Agreement § 4.3 ("Participating TOs shall be responsible for operating and maintaining those lines and facilities in accordance with this Agreement, the Applicable Reliability Criteria, the Operating Procedures, and other criteria, CAISO Protocols, procedures, and directions of the CAISO issued or given in accordance with this Agreement.") This statement should be corrected.

Second, the Commission recently expressed its disapproval of long term system planning that relies upon load shedding. Decision 14-03-004 ("We agree with SDG&E and IEP that that it is not prudent to take a long-term system planning approach that assumes reliance on load shedding in a densely-populated urban area as mitigation for contingency events.") The Report should explain why the CPUC is considering alternatives that rely on load shedding for long term solutions in light of the Commission's agreement that it is not prudent to do so. If the CPUC relying on the U.S. Census definition of "urban area" as more than one million people (Report at 1-20) to distinguish when long term load shedding is prudent, the CPUC should clearly state that the roughly 300,000 people in South Orange County served by SDG&E may be subjected to long-term load shedding while the population of San Diego is not.[1]

Third, the Report's conclusion that TPL-003-0b does not require SDG&E to mitigate Category C issues in South Orange County is inaccurate. The Report's conclusion is based on the assumption that SDG&E may simply shed load if Category C events occur. Based on this understanding, the Report concludes that compliance with TPL-003-0b is not a useful screening criteria and that alternatives that do not mitigate the Category C issues are feasible.

The Report's conclusion fails to recognize that TPL-003-0b requires that before, during and after the failure of two or more transmission elements (a Category C event), the electric system must remain "System Stable and both Thermal and Voltage Limits within Applicable Rating." TPL-003-0b at 4, Table I (Column 1 under System Limits or Impacts).[2] Footnote a explains: "Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control."

The impact of this Category C requirement can be summarized as follows:

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[1] SDG&E fully serves Dana Point, San Clemente and San Juan Capistrano, and shares service with SCE in Aliso Viejo, Laguna Beach, Laguna Hills, Laguna Niguel and Mission Viejo. In local unincorporated communities, SDG&E fully serves Ladera Ranch and Las Flores and partially serves Coto de Caza. SDG&E also serves other unincorporated areas that are not included in the US Census such as Wagon Wheel.

[2] The NERC Glossary of Terms defines a System Operating Limit ("SOL") as the most limiting value that ensures operation within acceptable reliability criteria. A facility thermal rating is a SOL. SDG&E is required by NERC Transmission Operating Standards to operate within SOLs. TOP-004-2_R1 ("Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).")

(1) To avoid the System Operator shedding South Orange County load (*i.e.,* taking lines out of service, which stops electric service to customers served off such lines) in such an event, SDG&E must design its system to: (1) avoid an N-1-1 situation where a single outage of a transmission element would leave the system vulnerable, in the event of a second outage, to any line exceeding its Applicable Rating, as CAISO's Operating Procedure 3100 would require preparing for such a second outage by shedding load after the first outage alone; and (2) avoid a situation where any Category C outage would result in any line exceeding its Applicable Rating. Where a line has both a normal and emergency rating, and the thermal loading of the line can be brought back to its normal rating within the time limit allowed by the emergency rating, then a line will not exceed its Applicable Rating. However, in South Orange County, many lines have no emergency rating or very short-term emergency ratings (15 minutes to 30 minutes), and therefore load shedding must occur immediately upon the thermal loading of the line exceeding its normal rating.

(2) In South Orange County, because many lines have no emergency rating or very short-term emergency ratings (15 minutes to 30 minutes), SDG&E's system must be designed for immediate load shedding under the circumstances described above to remain within Applicable Ratings. Because there is insufficient time for manual load shedding, the only method for such immediate load shedding is a Special Protection System (SPS). However, while CAISO considers SPS an appropriate mitigation tool in certain circumstances, its planning standards state: "There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS. B) The SPS should not be monitoring more than 4 system elements or variables." There are too many Category C contingencies in South Orange County where the Applicable Ratings would not allow time for manual adjustment of the system for SDG&E to utilize SPSs in compliance with CAISO planning standards. As SDG&E is bound to follow CAISO planning standards, SDG&E cannot employ SPS to mitigate all of the Category C contingency events in SOC.

SDG&E explains the application of TPL-003-0b's requirement to keep "Thermal and Voltage Limits within Applicable Rating" in more detail below.

The attached CAISO Procedure 3100, "System Operating Limit Establishment Procedure for the Operations Horizon," explains pre-and post-contingency requirements to stay within facility ratings. Attached Procedure 3100A, Examples on Acceptable Thermal Performance, provides a particularly clear explanation. As explained in CAISO Procedure 3100 at 15-17:

> 3.6.2 Mitigating SOLs in Post-contingency State
>
> After a contingency occurs, the system may be in the following states:
>
> (1) Post-contingency Acceptable System Performance is not met. The System Operators shall take immediate actions to adjust the system to meet the Post-contingency Acceptable System Performance.
>
> (2) All Post-contingency Acceptable System Performance is met. However, Pre-contingency Acceptable System Performance is not met. The System Operators shall take immediate actions

to adjust system to meet the Pre-contingency Acceptable System Performance within applicable time duration.

(3) All Post-contingency Acceptable System Performance and Pre-contingency Acceptable System Performance are met. However, studies indicate that the system will experience unacceptable post-contingency performance if another contingency is to occur. The system needs to be adjusted as soon as practicable to prepare for the next contingency.

3.6.3 Mitigating Thermal Limited SOLs

While there are stability or voltage limited SOLs within the ISO system, the majority of the SOLs are established based on thermal limitations. Since no facility should be operated above its applicable thermal limits, an SOL may be established as a pre-contingency flow limit to ensure that following a contingency, all facilities remain within their applicable Facility Ratings. For these flow limits, System Operators must be aware what facilities are being protected under their applicable facility ratings, so that if the contingency occurs, they can take appropriate actions.

Facility ratings are generally defined as normal or short-term with the distinction being that normal ratings may be used continuously whereas use of short-term ratings is time limited. In addition, there may be multiple short-term ratings with different time limits applicable for their use. In all cases, ratings must have a time duration (whether continuous or other) specified for that rating.

When a pre-contingency flow limit is established, it is important to understand that if the actual pre-contingency flow is at or near the flow limit, three scenarios exist for post-contingency flow (as illustrated in 3100A, WECC Examples on Acceptable Thermal Performance):

1. Post-contingency facility loading may be within normal ratings1 in which case no further action is necessary.

2. Post-contingency facility loading may be above normal ratings, but within a defined short-term rating. In that case the System Operator must take whatever action is necessary to return facility loading to an applicable continuous rating within the time frame allowed by the short-term rating. For example, consider a line with the following ratings:

Description	Limit	Duration
Normal	800 MVA	Continuous
Short-term 4-hour	900 MVA	4 hour
Short-term 15-min	950 MVA	15 min

And assume that the post-contingency loading of the line is 910 MVA. In this case the line loading is within its 15 minute short-term rating and the System Operator has 15 minutes to return line loading to an appropriate lower level. In most cases this will be to the 800 MVA normal rating; however, each Participating Transmission Owner defines short-term ratings based on its facility rating methodology and the conditions under which they may be applied. It is possible, for example, for the 15 minute rating to be based on returning the line loading to be within the 4 hour rating in 15 minutes and to be within the normal rating in an additional 4 hours.

> …
>
> However, for facilities in SCE, SDG&E, and VEA, the facility rating methodology is to return the facility loading below the next available lower short-term rating within the associated time duration, then to return the facility loading below the normal rating within additional time duration associated with the lower short-term rating. In the absence of specific instructions to the contrary as provided by SCE, SDG&E, or VEA, it is assumed that following a contingency which loads some facility above its normal rating, but within a defined short-term rating, the facility loading can be returned below the next available lower short-term rating within the associated time duration and then be returned below the normal rating within the additional time duration as specified for the lower short-term rating in use2.
>
> 3. Post-contingency facility loading may be above all defined ratings. If pre-contingency loading was within the defined pre-contingency SOL, this should not be the case; however, if at any time any facility is loaded above its highest defined short-term rating, the System Operator shall take immediate actions to get the facility loading within its defined rating.
>
> A clear distinction needs to be made between exceeding a pre-contingency flow limit and exceeding all defined Facility Ratings. If a pre-contingency flow limit is being exceeded, actions must be taken to either reduce loading or mitigate the concern, (such as checking with the facility owner to determine if higher short-term ratings can be applied based on current conditions). If some facility is loaded above all defined ratings for that facility,

(Footnote omitted). Again, attached CAISO Procedure 3100A provides a clear depiction of the different scenarios.

Under TPL-003-0b, Category C3 provides that the assessed contingency is as follows: "Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency." This "N-1-1" scenario means that, after a single outage, SDG&E must be able to make manual system adjustments that will allow the system to perform within applicable ratings (the SOL) in the event of another outage.

During normal operations, SDG&E operators monitor system conditions and make adjustments as necessary to maintain reliability. Following a single element outage (N-1), the Transmission Security Management (TSM) software will assess the system to determine if a second element outage, referred to as (N-1)-1, will create a system condition which will results in an overload. If the TSM finds a potential overload exists, then operators must take action to prevent the overload prior to the second outage. In laymen's term, "operators are securing the system for the next outage."

In South Orange County, because there is no significant generation to turn on to reduce overloads, the only option is to shed load (*i.e.*, stop serving customers). This will result in lowering the flow of power through the overloaded element and removing the overload. Therefore, in South Orange County, <u>following the loss of a single element system</u>, operators must make adjustments to prepare for the loss of the next element (Category C) and the only option is to shed load.

The time within which SDG&E must make such adjustments, *i.e.*, shed load, is determined by the line ratings. When a transmission line has a thermal overload, the temperature of the metal conductor increases. For overhead lines, as the conductor heats up, the transmission line will sag. Under CPUC General Order 95, SDG&E's transmission lines must maintain certain clearances from the ground and structures. Whether there is tolerance for sag depends on the circumstances of each transmission line. If the temperature continues to increase, at some point the conductor will be damaged, requiring replacement of the line and a long duration outage.

In setting Normal and Emergency Ratings, a utility must take into account the physical limitations of the conductor itself, the construction of the line and tolerance for any sag, the normal demand on the line and, if any emergency rating is set, how long the line can be above the normal rating before the physical limits are exceeded.

In South Orange County, SDG&E's transmission lines were designed for maximum loading without margin for emergency ratings. This was an acceptable practice when these transmission lines were constructed. The Normal Rating of the South Orange County transmission lines have been set at the maximum load that SDG&E believes can be safely accommodated by these lines. There is no tolerance for sag on many of these transmission lines. Although some lines have short emergency ratings (15 to 30 minutes), other lines have no Emergency Ratings.

Because there are no Emergency Ratings some lines in South Orange County, and because TPL-003-0b requires that all other lines in SDG&E's South Orange County system remain within Applicable Ratings even after specified outages of two other transmission elements, SDG&E's measures to reduce overloads on other lines must be essentially instantaneous or SDG&E will be in violation of TPL-003-0b.

To keep the system within Applicable Ratings during a Category C contingency, on lines with no emergency rating (or a short emergency rating), there is no time for operators to manually determine which load to shed. Instead, an automatic protection system must be utilized to disconnect customers within seconds after the other elements fail. These automatic protection systems are known as Special Protection Schemes ("SPS").

SDG&E employs SPS in accordance with CAISO planning standards. Under its Transmission Control Agreement with CAISO, Section 6.1.3: "In operating and maintaining its transmission facilities, each Participating TO shall take proper care to ensure the safety of personnel and the general public. It shall act in accordance with Good Utility Practice, applicable law, the CAISO Tariff, CAISO Protocols, the Operating Procedures, and the Applicable Reliability Criteria." CAISO has adopted Planning Standards as authorized by the CAISO Tariff. The CAISO Planning Standards currently in effect are effective from September 18, 2014 to March 30, 2015.

CAISO has considered the advantages and disadvantages of SPS, and provided guidance on the use of SPS to mitigate Category C and D contingencies:

> As stated in the NERC glossary, a Special Protection System (SPS) is "an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition of faulted components to maintain system reliability." In the context of new projects, the possible action of an SPS would be to detect a transmission outage

> (either a single contingency or credible multiple contingencies) or an overloaded transmission facility and then curtail generation output and/or load in order to avoid potentially overloading facilities or prevent the situation of not meeting other system performance criteria. …
>
> The primary reasons why SPS might be selected over building new transmission facilities are that SPS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, SPS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, SPS is a commonly considered alternative to building new infrastructure in an effort to keep costs down when integrating new generation into the grid and/or addressing reliability concerns under multiple contingency conditions. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability. These reliability concerns necessarily dictate that guidelines be established to ensure that performance of all SPSs are consistent across the ISO controlled grid.

CAISO Sept. 2014 Planning Standards at 9.

Given these concerns, CAISO set specific guidelines for the use of SPS that are binding on SDG&E. SPS6 provides: "A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS. B) The SPS should not be monitoring more than 4 system elements or variables." *Id.* at 10.

The SOCRE Alternatives Report at 1-16 recognizes that CAISO found that too many SPS would be required in South Orange County to mitigate the many Category C issues, noting: "CAISO described the need for the project based on CAISO guidelines that recommend Special Protection Systems not be used to address more than six contingencies that could cause more than four elements to overload and because the large number of potential Category C events identified exceeds this amount." But the Report then fails to recognize that, because the Category C overloads cannot be mitigated by SPS, other SDG&E transmission lines will exceed their Applicable Ratings. SDG&E more recent analysis, using 2014 load forecasts, still finds too many Category C contingencies requiring instantaneous load shedding to be addressed with SPSs within CAISO guidelines. As a result, SDG&E will be in violation of TPL-003-0b. Any alternative to the proposed Project must mitigate these violations.

II. <u>Talega Substation Maintenance Outages</u>

Under NERC TPL-004-0b, SDG&E considers "System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)." Such events may include "Loss of a substation (one voltage level plus transformers)." Utilities study such events to determine whether the outage risk makes it prudent to mitigate such risk.

Because Talega Substation is the source of all power to South Orange County, Category D events at Talega Substation (loss of the 230 kV service or the loss of 138 kV service) would drop service to all SDG&E customers in South Orange County—roughly around 300,000 people.

However, because Talega Substation is the sole source, a single forced outage (such as Category B events) that occur during a planned maintenance outage at Talega will drop service to all or some SDG&E customers in South Orange County. *See* CAISO 2010-2011 Transmission Plan at 207 ("Failure of certain components in this area under maintenance conditions can result in loss of entire South Orange County load which is expected to be about 523 MW by 2020. There are 16 combinations of credible contingencies just at Talega substation which result in loss of partial or complete Orange County load under maintenance condition.")

South Orange County peak load exceeds 300 MW and loss of all load is a "NERC reportable event" requiring an investigation into the event. SDG&E must perform maintenance at its Talega Substation. SDG&E can only perform maintenance without a risk of losing some or all South Orange County load if there is a second source of power into the South Orange County system.

Any alternative to the Project should only be considered feasible if it provides such a second source.

III. No Project Alternative

Under CEQA Guideline § 15126.6, Energy Division must consider a "no project" alternative. Section 15126.6(e) provides: "The "no project" analysis shall discuss the existing conditions at the time the notice of preparation is published, or if no notice of preparation is published, at the time environmental analysis is commenced, <u>as well as what would be reasonably expected to occur in the foreseeable future if the project were not approved</u>, based on current plans and consistent with available infrastructure and community services." (Emphasis added).

As discussed above, SDG&E has an obligation to meet NERC reliability standards and CAISO planning standards. If the Commission were to select the "no project" alternative, SDG&E would have an obligation to implement, or where necessary seek authorization to implement, other projects in an attempt to ensure compliance with NERC reliability standards as well as more stringent CAISO standards.

SDG&E's Proponent's Environmental Assessment ("PEA") identified the projects that SDG&E would implement, or where necessary seek authorization to implement, if the Commission were to select the "no project" alternative. *See* PEA at 5-3 to 5-7 ("SDG&E would be required to undertake other construction activities in order to continue providing electric service within South Orange County. These construction activities would likely result in their own significant short-term environmental impacts similar to the Proposed Project and could also result in potential long-term impacts not attributable to the Proposed Project due to requirements for additional easements and ROW. For additional description of theses potential effects, see the Rebuild South Orange County 138kV System Alternative.") In response to ORA's Data Request 6, Question 6, of which Energy Division received a copy. SDG&E stated: "These projects would be the same as those identified under the 'Rebuild the SDG&E Northern 138kV System Alternative.'"

> The Rebuild the SDG&E Northern 138kV System Alternative consists of adding a dynamic voltage control device and replacing two 230/138kV transformers at the Talega Substation, rebuilding the existing Capistrano Substation, upgrading several 138kV transmission lines, modifying three 230kV transmission lines and adding a new 138kV transmission line from San Luis Rey Substation to San Mateo Substation. This additional 138kV transmission line at San Luis Rey Substation, located in the city of Oceanside, County of San Diego would also require the addition of two new 230/138kV transformers. The addition of new transformers would require an expansion of the existing San Luis Rey Substation. The addition of the dynamic voltage control device at Talega Substation would require an expansion of the existing facility. The CAISO, when presented with this project, rejected the Rebuild the SDG&E Northern 138kV System Alternative due to the costs, which are significantly greater than the Proposed Project.

PEA at 5-20 to 5-21.

Contrary to SDG&E's identification of "what would be reasonably expected to occur in the foreseeable future if the project were not approved," CEQA Guideline § 15126.6(e), the SOCRE Alternatives Report says only:

> The components of the No Project Alternative described in this report were defined by the CPUC with input from the applicant. Regardless of whether the proposed project is constructed, it is reasonably foreseeable that the following would occur prior to 2018 (SDG&E 2012, CAISO 2014d):
>
> - o Talega Substation's STATCOM would be replaced; and
> - o Between 2015 and the end of 2017, two new, dynamic synchronous condensers (approximately 700 MVARs at 230 kV)14 would be installed in locations within the South Orange County service area as approved by the CAISO to provide additional reactive power support in the proposed project area.
>
> <u>No other improvements to the applicant's 138-kV and 230-kV transmission systems in addition to the STATCOM and dynamic synchronous condenser installations are included as part of the No Project Alternative</u>. It is assumed, however, that energy efficiency improvements and energy generation installations that would incrementally reduce load on SDG&E's South Orange County 138-kV system will continue to be implemented throughout the 10-year planning horizon.

SOCRE Alternatives Report at 3-3 (emphasis added).

SDG&E notes that replacement of two transformers at Talega Substation is estimated to cost between $15-20 million dollars and replacement of the STATCOM at Talega Substation to maintain voltage support is estimated to cost $80-100 million dollars. This cost estimate does not include the potential purchase of additional property to accommodate the replacement equipment. Neither of these replacements at Talega Substation is needed if the Proposed Project is constructed.

The No Project Alternative described in the SOCRE Alternatives Report does not accurately reflect "what would be reasonably expected to occur in the foreseeable future if the project were not approved," as required by CEQA Guideline § 15126.6(e). As stated in the SOCRE Alternatives Report, the No

Project Alternative “would not substantially reduce the risk of instances that could result in the loss of power to customers served by the South Orange County 138-kV system through the 10-year planning horizon.” As a result, SDG&E would be obliged by its obligation to provide its customers with reliable electric service to implement, and where necessary to seek authorization to implement, the projects identified above.

Consideration of the No Project Alternative must consider the environmental impacts of the work that SDG&E reasonably expects to perform (or seek permission to perform) if the No Project Alternative is selected.

****

SDG&E appreciates Energy Division’s consideration of these comments and will continue to work diligently to provide complete comments on the SOCRE Alternatives Report.

Sincerely,

Mary I. Turley

SDG&E Project Manager

EXHIBIT 8

CAISO Corrected May 26, 2015 Testimony of Robert Sparks

Application No.: 12-05-020

Exhibit No.: __________

Witness: Robert Sparks

In the Matter of the Application of San Diego Gas & Electric Company (U902E) for a Certificate of Public Convenience and Necessity for the South Orange County Reliability Enhancement Project.	Application 12-05-020

CORRECTED TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902E) for a Certificate of Public Convenience and Necessity for the South Orange County Reliability Enhancement Project.	Application 12-05-020

CORRECTED TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Robert Sparks. I am employed by the California Independent System Operator Corporation (CAISO), 250 Outcropping Way, Folsom, California as Manager, Regional Transmission.

Q. Please describe your educational and professional background.

A. I am a licensed Professional Electrical Engineer in the State of California. I hold a Master of Science degree in Electrical Engineering from Purdue University, and a Bachelor of Science degree in Electrical Engineering from California State University, Sacramento.

Q. What are your job responsibilities?

A. I manage a group of engineers responsible for planning the CAISO controlled transmission system in southern California to ensure compliance with NERC, WECC, and CAISO Transmission Planning Standards in the most cost effective manner.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the technical analysis underlying the CAISO's recommendation that the Commission approve San Diego Gas & Electric

Company's (SDG&E) Application for a certificate of public convenience and necessity for the South Orange County Reliability Enhancement (SOCRE) project. This testimony presents an updated analysis of reliability needs in the South Orange County area and a comparative analysis of the SOCRE project versus the alternatives studied in the Energy Division's Draft Environmental Impact Report (DEIR). Based on this updated analysis, the CAISO continues to see reliability needs for the SOCRE project and found that the SOCRE project is superior to the other DEIR alternatives because it is more effective at resolving the identified reliability needs without having negative system impacts on other reliability requirements. The CAISO's recommendations are discussed in more detail in the testimony of Mr. Neil Millar on behalf of the CAISO.

I. CAISO RELIABILITY OBJECTIVES FOR THE SOCRE PROJECT

Q. What is the primary driver for the need for the SOCRE project in the South Orange County area?

A. The SOCRE project is necessary to meet reliability requirements specified by the North American Electric Reliability Corporation (NERC) and the CAISO Planning Standards. As noted in the 2010-2011 transmission plan, the primary driver for the SOCRE project was the exceedance of applicable ratings during multiple Category C contingencies under Planning Standard TPL-003. In addition, the CAISO has identified numerous potential NERC violations of TPL-002 and TPL-003 during planned maintenance outages at the Talega Substation. These reliability concerns cannot be met by existing or expanded remedial action schemes in the study area.

The timing of the SOCRE project was driven by the need for capital maintenance to be conducted by SDG&E. The capital maintenance needs provided the opportunity more efficiently to leverage other construction work to address the excessively complex remedial action schemes in the area and further demonstrated the inadequacy of the existing system to adequately accommodate maintenance or construction-related outages.

Q. When is the SOCRE project needed to comply with the NERC Standards?

A. Notwithstanding a significant reduction in long-term load forecast for the South Orange County area, the SOCRE project is needed immediately, and the reliability concerns worsen over time.[1] The CAISO conducted an updated analysis for this proceeding and found that the reliability concerns are comparable with those initially identified in the CAISO's 2010-2011 transmission plan.

Q. Please explain the CAISO's analysis conducted for this proceeding.

A. The CAISO conducted power flow studies on the 2024 summer peak case for all Category A, B, C and D contingencies in the South Orange County 230/138 kV system without the SOCRE project.[2]

Table 1 presents a summary comparison of the reliability concerns identified in the CAISO's updated analysis and the reliability concerns identified based on the underlying assumptions used in the 2010-2011 transmission plan.[3] Table 1 also shows the impact of the SOCRE project on the 2024 case, which indicates that all reliability concerns are resolved. A detailed comparison of thermal overloads for the most severe contingencies is provided in Table A-2 of Appendix A. All thermal overload results under all contingencies for both cases are provided in Tables A-3A and A-3B of Appendix A, respectively.

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[1] The forecasted 2024 1-in-10 coincident peak load in South Orange County is 489.5 MW. In addition, the CEC's 2024 1-in-10 coincident peak load includes a 43 MW load reduction which results in a net peak load in the summer 2024 of 446 MW, or about 13% lower than net peak load forecast used in the 2010-2011 transmission plan.

[2] The CAISO also notes that the 2013-2014 transmission plan identified sixteen Category C contingency overloads in the South Orange County area with forecasted loads for the year 2015.

[3] The CAISO's updated analysis used the 2024 Summer Peak Case to determine reliability concerns. The 2010-2011 transmission plan analysis used the 2020 Summer Peak Case.

Table 1 Summary Comparison of Reliability Concerns

Pre-Contingency System Condition	NERC Standard	Total number of reliability concerns			
		Power Flow Concerns	Without the SOCRE project		With the SOCRE project
			Updated Analysis	2010-2011 Transmission Plan Analysis	Updated Analysis
all transmission facilities in service	TPL-002 (Category B)	thermal overloads	0	1	0
	TPL-003 (Category C)	thermal overloads	26	44	0
		overloaded branches	8	6	0
		unique contingencies	13	19	0
	TPL-004 (Category D)	area blackout events	2	2	0

As indicated in Table 1, with all facilities in-service pre-contingency, the CAISO's updated analysis shows that there are no Category B contingencies in the South Orange County 138 kV system that would result in violation of NERC mandatory reliability criteria TPL-002 or the CAISO transmission planning standards. However, as described below, there are Category B contingency violations during planned outage conditions required for maintenance of electrical facilities at the Talega substation.

With respect to NERC planning criterion TPL-003, the CAISO identified various South Orange County transmission facilities with thermal overloads in the event of Category C contingencies, despite the lower load demand forecast in the updated analysis. Based on the CAISO's updated analysis for this proceeding, the CAISO identified 26 thermal overloads on 8 distinct facilities. The number of the unique contingencies identified was 13 in the updated analysis, compared to 19 based on the 2010-2011 transmission plan assumptions.[4] The updated results indicate that significant reliability concerns under Category C contingencies are comparable to those initially identified in the CAISO's 2010-2011 transmission plan.

In addition to the contingencies studied above, the CAISO identified two Category D events under TPL-004 that would result in loss of the entire load in the South Orange County service area in both the updated and original analyses. Without the SOCRE project, this potential for an area blackout exists whenever the Talega West/East 230 kV buses or Talega West/East138 kV buses are out of service.

Q. Please explain the CAISO-identified reliability concerns during maintenance outages.

A. Substations are points in the power network where transmission branches and distribution feeders are connected together through circuit breakers or switches via buses and transformers. This allows for the switching operations of transmission equipment for operation and maintenance purposes. Regular maintenance and service on substations without load interruptions is necessary for reliable system operation.

To comply with NERC TPL-002 and TPL-003 R1.3.12, the CAISO, as a Planning Authority, assessed the system reliability performance by including the planned (including maintenance and construction) outage of any bulk electric system element at demand levels for which planned outages are performed. The CAISO identified inadequate system performance during maintenance periods at the Talega 230/138 kV Substation. Table 2 presents reliability concerns with a single facility out of service for maintenance at the Talega 230/138 kV Substation and without the SOCRE project.

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[4] The primary driver for the differences between the 2024 and the 2020 case are the recent system improvements at the Talega and Pico 138 kV substations and the lower load forecast.

Table 2: Reliability Concerns with Facility Out of Service for Maintenance in Talega 230/138 kV Substation

Type ID	Facility Out of Service for Maintenance	Contingency Followed by	Category	Category Description	load serving capability to the South Orange County Area (MW)
Type1-B1	230 East Bus	Bank #63	B	Transformer (B3)	0
Type1-B2	230 West Bus	Bank #60	B	Transformer (B3)	0
Type2-B1		Bank #61	B	Transformer (B3)	195
Type2-B2	CB #4E	Bank #63	B	Transformer (B3)	195
Type1-C01	138 East Bus	CB BK #50	C	Breaker Failure (C2)	0
Type1-C02		CB BK #63	C	Breaker Failure (C2)	0
Type1-C03		138 West Bus	C	Bus Section (C1)	0
Type1-C04		CB #11W	C	Breaker Failure (C2)	0
Type1-C05		CB #5W	C	Breaker Failure (C2)	0
Type1-C06		CB #6W	C	Breaker Failure (C2)	0
Type1-C07		CB #7W	C	Breaker Failure (C2)	0
Type1-C08		CB #8W	C	Breaker Failure (C2)	0
Type1-C09	138 West Bus	138 East Bus	C	Bus Section (C1)	0
Type1-C10		CB #11E	C	Breaker Failure (C2)	0
Type1-C11		CB #5E	C	Breaker Failure (C2)	0
Type1-C12		CB #BK60	C	Breaker Failure (C2)	0
Type1-C13		CB #6T	C	Breaker Failure (C2)	0
Type1-C14		CB #7T	C	Breaker Failure (C2)	0
Type1-C15		CB #8E	C	Breaker Failure (C2)	0
Type1-C16	230 East Bus	230 West Bus	C	Bus Section (C1)	0
Type1-C17		CB #1W	C	Breaker Failure (C2)	0
Type1-C18		CB #2W	C	Breaker Failure (C2)	0
Type1-C19		CB #3W	C	Breaker Failure (C2)	0
Type1-C20		CB #4W	C	Breaker Failure (C2)	0
Type1-C21		CB #BK63	C	Breaker Failure (C2)	0
Type1-C22	230 West Bus	230 East Bus	C	Bus Section (C1)	0
Type1-C23		CB #1E	C	Breaker Failure (C2)	0
Type1-C24		CB #2E	C	Breaker Failure (C2)	0

Type1-C25		CB #3E	C	Breaker Failure (C2)	0
Type1-C26		CB #4E	C	Breaker Failure (C2)	0
Type1-C27		CB #BK60	C	Breaker Failure (C2)	0
Type2-C01	138 West Bus	CB # BK61	C	Breaker Failure (C2)	195
Type2-C02		CB #4T	C	Breaker Failure (C2)	195
Type2-C03		CB #5T	C	Breaker Failure (C2)	195
Type2-C04	230 West Bus	CB # BK61	C	Breaker Failure (C2)	195
Type2-C05		CB #4T	C	Breaker Failure (C2)	195
Type2-C06		CB #5E	C	Breaker Failure (C2)	195
Type2-C07		CB #5T	C	Breaker Failure (C2)	195
Type2-C08	Bank #61	CB #4W	C	Breaker Failure (C2)	195
Type2-C09		CB #5W	C	Breaker Failure (C2)	195
Type2-C10	Bank #63	CB #4E	C	Breaker Failure (C2)	195
Type2-C11		CB #4T	C	Breaker Failure (C2)	195
Type2-C12		CB #5T	C	Breaker Failure (C2)	195
Type2-C13	CB #4E	230 West Bus	C	Bus Section (C1)	195
Type2-C14		CB # BK63	C	Breaker Failure (C2)	195
Type2-C15		CB #1W	C	Breaker Failure (C2)	195
Type2-C16		CB #4W	C	Breaker Failure (C2)	195
Type2-C17		CB #2W	C	Breaker Failure (C2)	195
Type2-C18		CB #3W	C	Breaker Failure (C2)	195
Type2-C19	CB #5E	138 West Bus	C	Bus Section (C1)	195
Type2-C20		CB # BK50	C	Breaker Failure (C2)	195
Type2-C21		CB # BK63	C	Breaker Failure (C2)	195
Type2-C22		CB #11W	C	Breaker Failure (C2)	195
Type2-C23		CB #5W	C	Breaker Failure (C2)	195
Type2-C24		CB #6W	C	Breaker Failure (C2)	195
Type2-C25		CB #7W	C	Breaker Failure (C2)	195
Type2-C26		CB #8W	C	Breaker Failure (C2)	195

The CAISO identified a total of 57 reliability events that would result in an uncontrolled interruption of service when a maintenance outage at the Talega Substation is followed by a contingency event. These events can be broken down into two types: Type 1 events that result in the loss of all load in the South Orange

County area; and Type 2 events that result in the loss of significant, but not all load. The CAISO identified 29 Type 1 events in which the combination of planned maintenance followed by a contingency resulted in uncontrolled interruption of service to the entire South Orange County. Two of these Type 1 events were the result of Category B contingencies, meaning the failure of just a single transformer element could potentially disrupt service to all South Orange County customers during a planned maintenance at the Talega Substation. The remaining 27 Type 1 events were a result of Category C contingencies.

Paraphrasing the operational concern differently, there are no windows for performing necessary maintenance or construction activities without facing unacceptable risk of the loss of all load in South Orange County. This is primarily due to the South Orange County system relying on a single power source from the Talega Substation to serve approximately 460 MW of load. This represents 29 single points of failure as demonstrated by these 29 Type 1 planned maintenance outage/contingency events.

In addition to the 29 Type 1 events, there were also 28 Type 2 events under which planned maintenance followed by a contingency results in an uncontrolled interruption of service to a significant number of customers. Two of the Type 2 events were a result of Category B contingencies. The remaining 26 Type 2 events were a result of Category C contingencies resulting in the loss of substantial South Orange County area load. During these events, the remaining system can only provide load serving capability up to 195 MW, about 40% of the area peak load, to keep facilities within emergency ratings[5]. In other words, there is a very limited time frame when maintenance can be performed on this additional set of facilities without creating unacceptable risk of the loss of load in South Orange County.

[5] Within 30 minutes after the contingency, the equipment loading would need to be reduced to its Normal Rating of approximately 168 MW.

Based on the SDG&E 8760-hour load duration curve[6] there are only about 260 hours a year, or about 3% of all hours, during which the loads in the South Orange County area would be lower than 195 MW. In other words, the 195 MW of load serving capability means that, without the SOCRE project in-service, the CAISO and SDG&E operations would not be able to find adequate maintenance windows without a significant risk of load service interruption.

The existing system does not provide adequate windows for maintenance or planned construction activities without risking area blackout or non-consequential loss of load under four Category B contingencies. This is a violation of the NERC TPL-002 planning standard that does not allow non-consequential load service interruption under Category B contingencies. In addition, during maintenance or planned construction, 53 Category C contingency events result in area blackout or load shedding in South Orange County, which results in an unacceptable reliability risk. There is no acceptable method of implementing the necessary load shedding for these overlapping Category C contingencies. Shedding load after the first contingency to prepare for the second contingency is not allowed by the CAISO Planning Standards for long-term planning purposes. Shedding load after the second contingency would require an exceedingly complex Special Protection System (SPS) that would not meet the CAISO Planning Standards.

Q. Can the reliability concerns identified by the CAISO be resolved through an SPS?

No. The CAISO Planning Standards include guidelines that specifically address the complexity that can reliably be managed in relying on an SPS. As stated in the CAISO Planning Standards, "SPSs have substantial advantages, [but] they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system

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[6] See Figure 5.

performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability." In order to mitigate concerns regarding the complexity of an SPS, the CAISO Planning Standards specify that any one SPS (1) should not be monitoring more than six local contingencies and (2) should not be monitoring more than four transmission system elements.

The CAISO's updated analysis identified 13 unique local contingencies that would need to be monitored by an SPS if the SOCRE project is not built. This is well in excess of the six allowable local contingences that may be addressed by an SPS pursuant to CAISO Planning Standards. In addition, the CAISO's updated analysis identified 8 transmission elements on which power flow would need to be monitored, without the SOCRE Project. This is double the allowed limit of monitored elements for an SPS under the CAISO Planning Standards.[7] In real time system operations, the SPS design would likely need to monitor even more elements because of operational complexities such as load levels, planned maintenance and configuration variation.

Implementation of the SOCRE project eliminates all local contingencies that would otherwise need to be monitored by an SPS.

[7] Please see Tables A-4 and A-5 in Appendix A for the list of 13 unique local contingencies and 8 transmission elements on which power flow would need to be monitored.

II. DEIR ALTERNATIVES TO THE SOCRE PROJECT

Q. Please provide an overview of the alternatives to the SOCRE project identified in the DEIR.

A. The DEIR identified 11 alternatives to the SOCRE project. For this analysis, the CAISO has classified the 11 alternatives into 4 groups based on common mitigation characteristics and system performance.

The No Project alternative is designated as the sole alternative in Group 1. This alternative is unique because it does not address any of the system performance issues identified by the CAISO and therefore does not propose any mitigation strategies. Alternatives B1, B2, B3, B4, and E are designated as Group 2 alternatives, all of which focus on South Orange County 138 kV System improvements.[8] Alternatives C1, C2, and D are designated as Group 3 alternatives, because each one incorporates an element that parallels the South Orange County 138 kV system with the Southern California Electric Company (SCE) 230 kV system. Alternatives F, G, and H are designated as Group 4 alternatives, all of which provide a second new 230 kV or 138 kV transmission source into the South Orange County service area from a substation other than the Talega Substation.

Q. Do the DEIR alternatives to the SOCRE project address the reliability concerns identified by the CAISO?

A. No, all of the DEIR alternatives fail to meet the reliability concerns identified by the CAISO. The CAISO identified ongoing reliability concerns for each Group of DEIR alternatives. Table 3 lists the reliability concerns for each DEIR alternative group.[9]

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[8] The CAISO notes that the Group 2 alternatives are similar to "SOCRUP Alternative 2" as evaluated in the 2010-2011 CAISO transmission plan.
[9] More detailed load flow results are shown in Tables B-1, B-2A, B-2B, B-3A, and B-3B in Appendix A.

Table 3. Summary of Reliability Concerns

<table>
<tr><th colspan="3">Alternatives</th><th colspan="3">Pre-contingency of all facilities in-service</th><th colspan="2">One Element out of service for maintenance at Talega</th></tr>
<tr><th>Group #</th><th>ID</th><th>Name</th><th>Cat. B</th><th>Cat. C</th><th>Cat. D</th><th>Cat. B</th><th>Cat. C</th></tr>
<tr><td>1</td><td>A</td><td>No Project</td><td>0</td><td>26</td><td>2</td><td>4</td><td>53</td></tr>
<tr><td rowspan="5">2</td><td>B1</td><td>Reconductor Laguna Niguel–Talega 138-kV Line</td><td rowspan="5">0</td><td rowspan="5">2</td><td rowspan="5">2</td><td rowspan="5">4</td><td rowspan="5">53</td></tr>
<tr><td>B2</td><td>Use of Existing Transmission Lines</td></tr>
<tr><td>B3</td><td>Phased Construction of Alternatives B1 and B2</td></tr>
<tr><td>B4</td><td>Rebuild South Orange County 138-kV System</td></tr>
<tr><td>E</td><td>New 230-kV Line Operated at 138 kV</td></tr>
<tr><td rowspan="3">3</td><td>C1</td><td>SCE 230-kV Loop In to Capistrano in GIS</td><td rowspan="3">4</td><td rowspan="3">56</td><td rowspan="3">0</td><td rowspan="3">0</td><td rowspan="3">0</td></tr>
<tr><td>C2</td><td>SCE 230-kV Loop In to Capistrano Alt Route</td></tr>
<tr><td>D</td><td>SCE 230-kV Loop In to Reduced-Footprint Substation at Landfill in GIS</td></tr>
<tr><td rowspan="3">4</td><td>F</td><td>230-kV Rancho Mission Viejo Substation</td><td>0</td><td>2</td><td>1</td><td>0</td><td>2</td></tr>
<tr><td>G</td><td>138-kV San Luis Rey–San Mateo Line & Sub Expansion</td><td>0</td><td>4</td><td>1</td><td>0</td><td>2</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="3">SOCRE Project</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
</table>

Q. Do the DEIR alternatives allow for necessary maintenance in the South Orange County area?

A. Only the DEIR alternatives in Group 3 provide a second independent transmission source that is adequate to maintain reliable network service to all the South Orange County load during maintenance conditions followed by a forced outage at the Talega Substation. DEIR alternatives in Groups 1 and 2 do not provide any load serving capability during such conditions. The alternatives in Group 4 add a second independent transmission source at a suboptimal location, and therefore do not provide adequate load serving capability without additional network upgrades.

Table 4. Load Serving Capabilities under Maintenance Conditions

Alternatives			Under maintenance condition followed by one of the forced Outages at Talega Substation		
Group #	ID	Name	load serving capability MW	limiting facility	typical worst event
1	A	No Project	0	NA	Talega 138 kV West out of service followed by Talega 138 kV East Bus outage
2	B1	Reconductor Laguna Niguel–Talega 138-kV Line	0	NA	
	B2	Use of Existing Transmission Lines			
	B3	Phased Construction of Alternatives B1 and B2			
	B4	Rebuild South Orange County 138-kV System			
	E	New 230-kV Line Operated at 138 kV			
3	C1	SCE 230-kV Loop In to Capistrano in GIS	670*	Talega Tap-L. Niguel 138 kV	Break Failure at Capistrano (CB_CP138BT "CP-TR/LNL/PI")
	C2	SCE 230-kV Loop In to Capistrano Alt Route			
	D	SCE 230-kV Loop In to Reduced-Footprint Substation at Landfill in GIS			
4	F	230-kV Rancho Mission Viejo Substation	350	TL13838 (R. M. Viejo-Margarita)	Talega 138 kV West out of service followed by Talega 138 kV East Bus outage
	G	138-kV San Luis Rey–San Mateo Line & Sub Expansion	180	TL13833/32 (San Mateo-L. Niguel)	
SOCRE Project			850	SONGS-Capistrano 230 kV Line	SONGS-Talega 230 kV Line

* Estimated by assuming that TL13834 (Capistrano-Trabuco) was upgraded along with the three alternatives in Group #3, otherwise load serving capability would be limited to 450 MW due to limitations on TL13834.

Q. Please explain why the Capistrano Substation is the best electrical location to add a second transmission source in the South Orange County area.

A. As can be seen in Table 4 above, the Capistrano Substation is the best location to add a second transmission source into the South Orange County area because it can serve the entire load in the event of a maintenance outage followed by a forced outage at the Talega Substation. Providing a second transmission source at this location provides unique benefits because the Capistrano Substation is:

- Electrically located in the load center of SDG&E's South Orange County service area;
- Within close proximity to a collection of 138 kV substations that serve approximately 375 MW of load, or 82% area peak load;
- Currently accommodating six 138 kV transmission lines; and
- Resistant to cascading outages associated with the loss of the existing 138 kV Talega transmission source.

Q. Will the DEIR's No Project Alternative meet the CAISO identified-reliability objectives?

A. No. As described above, the CAISO's analysis of the existing system has demonstrated numerous reliability concerns in the South Orange County system if no upgrade were made in the planning horizon.

Q. If the Commission approves the No Project Alternative what additional improvements will be necessary to meet NERC or CAISO transmission planning standards?

A. To address the identified reliability needs, additional improvements include:

- Upgrading the existing 138 kV system to re-conductor the Talega-Pico, Pico-Capistrano, Capistrano-Trabuco, Talega Tap-San Mateo-Laguna Niguel, Talega-Pico-San Mateo 138 kV lines; and

- Expansion of the 230/138 kV Talega Substation by sectioning the 230/138 kV buses, adding at least two more bay positions at both 230 kV and 138 kV voltage sides, and upgrading the two 230/138 kV transformers (Banks #60 and #62).

However, as described in SDG&E's Initial Prepared Testimony, SDG&E cannot expand the Talega Substation without shutting down its service depending on the status of the construction and the nature of the forced outage because it is the sole transmission source. For this reason, SDG&E considered building a temporary substation configuration to facilitate the construction, but rejected this alternative due to its high estimated cost and the environmental concerns discussed in SDG&E's Proponent's Environmental Assessment (PEA). This minimal work strategy is not cost effective compared with the SOCRE project. The SOCRE project would not only address the identified reliability needs but also eliminate the sole transmission source issue.

Q. Will the DEIR Group 2 Alternatives (B1, B2, B3, B4 and E) meet the CAISO-identified reliability objectives?

A. No. The Group 2 DEIR alternatives are similar to an alternative configuration investigated in the CAISO 2010-2011 TPP. As indicated in Table 3, if all facilities are in-service as a pre-contingency condition, Alternatives B1, B2, B3, B4, and E would address some of the reliability concerns for the Category C events. However, these alternatives would not address the Talega Bank #60 and #62 overload concerns for the overlapping contingency (Category C) of Talega Bank #63 and #61. In addition, the DEIR Alternatives are not adequate to meet system performance during maintenance outages at the Talega Substation as described above. All or a significant amount of customer load in the area would be interrupted with any one of the 4 Category B or the 53 Category C events listed in Table 2.

Q. If the Commission approves one of the DEIR Group 2 alternatives, what additional improvements will be necessary to meet NERC or CAISO transmission planning standards?

A. The scope of each of these upgrade alternatives would need to be expanded to include upgrades to the Talega Substation in order to eliminate the Bank #60 and #62 overloads for the Category C contingency and meet the NERC TPL-002 and TPL-003 maintenance requirement (R1.3.12). This work would include:

- Upgrading two of the 230/138 kV transformers at Talega Substation, Banks #60 and #62; and
- Rebuilding and extending the existing non-standard substation layout and 230/138 kV buses configurations at the Talega Substation.

As described above, rebuilding and expanding the Talega substation is not feasible without building costly temporary facilities during the construction process in order to ensure service to customers. In addition, as indicated in SDG&E's testimony, the equipment at the Capistrano Substation is inadequate and any alternative without rebuilding the Capistrano Substation is infeasible. Based on these considerations, the Group 2 DEIR alternatives will not be a cost effective means to meet the identified reliability concerns when compared to the SOCRE project.[10]

Q. Will the DEIR Group 3 alternatives (C1, C2, or D) meet the CAISO-identified reliability objectives?

A. While these alternatives meet some of the immediate reliability concerns in the South Orange County area, they are unacceptable because of their negative impact on transfer capability on the major transmission corridor between San Diego and the Los Angeles basin.

[10] The CAISO notes that this is the same reason that "SOCRUP Alternative 2" was not selected in the CAISO's 2010-2011 transmission plan.

As discussed in the testimony of Mr. Millar, in approving the SOCRE project, the CAISO ensured that mitigations for the immediate area reliability issues would not compromise the overall effectiveness or reliability of the bulk electric system in Southern California. The existing 230 kV corridor connecting the LA Basin to the San Diego area previously played a key role in supporting flows southward when the San Onofre Nuclear Generating Station was in service. Now this major transmission link between San Diego and the Los Angeles basin serves as a back up to each area during emergency transmission and resource conditions.

The Group 3 DEIR alternatives provide a new independent transmission source to serve the SDG&E's South Orange County service area from the SCE system. In the Group 3 alternatives, the South Orange County 138 kV system would be interconnected with the SCE 230 kV transmission system at the Prima Deschecha landfill near the existing Capistrano Substation and an existing SCE 230 kV line. The SCE 230 kV line is a critical facility associated with the transmission corridor between the Los Angeles area and the San Diego area. As a consequence, the Group 3 DEIR alternatives result in the 138 kV network being paralleled to the existing 230 kV corridor linking the Los Angeles basin and San Diego. This paralleling of lower capacity networks with higher capacity networks lowers the overall capability of the 230 kV corridor.

The CAISO conducted additional analysis to test the impact of the Group 3 DEIR alternatives on the capability of the 230 kV corridor. Based on this analysis, the CAISO found numerous overloading concerns under Category B and Category C contingencies in the South Orange County and SCE systems.[11] The CAISO identified four thermal overloads for Category B contingencies and 52 thermal overloads for Category C contingencies in the 2024 Summer Off-Peak case.[12] Even

[11] See Table B-2A and Table B-2B of Appendix A for more detailed results.
[12] Table B-2A.

for the 2024 Summer Peak case with only about 200 MW flowing northbound between the two areas, there were 3 thermal overloads identified for Category C contingencies. This indicates that the Alternatives have significant adverse impacts on the Transfer Capability between the two areas and system operation without further improvement in the south Orange County system.

Q. If the Commission approves one of the Group 3 DEIR alternatives, what additional improvements will be necessary to meet NERC or CAISO transmission planning standards?

A. To maintain transfer capability between the Los Angeles and San Diego bulk electric power supply systems, major portions of the existing 138 kV transmission lines between the Talega Substation and the Capistrano Substation would need to be rebuilt or upgraded if the Commission were to approve the Group 3 DEIR alternatives. The CAISO would also need to conduct detailed analysis to identify whether additional upgrades to transmission facilities in the SCE system would be needed. Given the additional costs of including these upgrades in the scope of these alternatives, the CAISO expects that the Group 3 DEIR alternatives would not be cost effective when compared to the SOCRE project.

Q. Would the DEIR's Alternative F, 230-kV Rancho Mission Viejo Substation, meet the CAISO-identified reliability objectives?

A. No. Although the specifications of the DEIR's Alternative F may appear to be similar to those of the SOCRE project, Alternative F does not provide an electrically equivalent new 230 kV transmission source in South Orange County when compared to the SOCRE project. In terms of system power flow performance and reliability, the new Rancho Mission Viejo Substation would be inferior to the new Capistrano Substation proposed in the SOCRE project.

The Rancho Mission Viejo Substation is an electrically inferior 230 kV transmission source because (1) it is not electrically located in the load center of South Orange

County, and (2) there are only two 138 kV lines connected to the existing Rancho Mission Viejo Substation.

In addition, because the Rancho Mission Viejo Substation is only one bus away from the Talega Substation, cascading impacts can occur at Rancho Mission Viejo Substation during contingencies at the Talega Substation. The loss of the Talega 138 kV substation (Category D event) would also trip one of the two 138 kV lines out of the Rancho Mission Viejo Substation. This would result in cascading outages on the remaining 138 kV line and lead to interruption of all load service in the south Orange County area, except the distribution load served by the Rancho Mission Viejo Substation. The remaining 138 kV line at the Rancho Mission Viejo Substation would be not be able to serve the other substation loads in the area. This is due to the poor location of the new second transmission source and its weak link with the rest of main 138 kV system.

More details regarding the CAISO's analysis of Alternative F and the identified reliability concerns associated with this alternative are presented in Table B-3A of Appendix A.

Q. If the Commission approves Alternative F what additional improvements would be necessary to meet NERC or CAISO transmission planning standards?

A. As shown in Table B-3A in Appendix A, the 138 kV line between Talega and Laguna Niguel would need to be upgraded in addition to the Alternative F improvements. Also, to avoid cascading outages, an additional 138 kV line may be needed between the Rancho Mission Viejo, Margarita, and Trabuco Substations because upgrading the existing 138 kV lines out of the Rancho Mission Viejo Substation may not be feasible or adequate to address the identified contingency concerns.[13] More system improvements to address load growth would also likely be necessary in the future because of the inferior locational attributes of the Rancho Mission Viejo Substation.

Q. Would the DEIR's Alternative G, New 138-kV San Luis Rey–San Mateo Line and San Luis Rey Substation Expansion, meet the CAISO-identified reliability objectives?

A. No. In addition to feasibility concerns associated with Alternative G, adding a new long 138-kV San Luis Rey–San Mateo line as the new transmission source into the South Orange County area is a significantly weaker source than any of the 230 kV transmission alternatives. Similar to Alternative F, the new transmission source is not electrically located in the load center. There are only two 138 kV lines out of the existing San Mateo Substation, and it is only one bus away from the Talega Substation, which makes the two transmission sources not fully independent.

The loss of the Talega 138 kV substation (Category D event) would trip one of the two 138 kV lines out of the San Mateo Substation. The remaining 138 kV line at the San Mateo Substation would be inadequate to serve the other substation loads in the area, resulting in interruption of all load service in the South Orange County area, except the distribution load served by the San Mateo Substation. This is similar to the poor location issue for Alternative F discussed above. These findings are supported by the identified reliability concerns listed in Table B-3B of Appendix A.

Q. If the Commission approves Alternative G what additional improvements would be necessary to meet NERC or CAISO transmission planning standards?

A. As shown in Table B-3B in Appendix A, the 138 kV lines between Talega and Laguna Niguel and between Talega and Pico would also need to be upgraded. In

[13] The CAISO notes that the Margarita-Trabuco 138 kV line is mostly underground.

addition, as described above, to avoid cascading outages, additional upgrades may be needed at the 230/138 kV San Luis Rey Substation and between San Mateo, Laguna Niguel, and Capistrano. More system improvements to address load growth would also likely be needed in the future due to the inferior locational attributes of a new source at the San Mateo substation. Given the additional costs of including these upgrades in the scope of this alternative, the CAISO expects it would not be cost effective when compared to the SOCRE project.

III. CONCLUSION

Q. Please summarize your conclusions.

A. The CAISO's updated analysis of reliability needs in the South Orange County area found comparable results to the analysis documented in the CAISO's 2010-2011 Transmission Plan. These results confirm the need for the SOCRE Project to meet NERC and CAISO Planning Standards. Based on the CAISO's updated analysis, none of the alternatives in the DEIR provide a more effective means to meet reliability needs identified. The SOCRE project was found to be superior to the DEIR alternatives because the SOCRE project is more effective without negative system impacts on other requirements.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

The CAISO used assumptions consistent with the 2014-2015 transmission plan in conducting its updated SOCRE project analysis. The assumptions are shown in Table A-1 and can be summarized as follows:

- Latest load forecast by California Energy Commission (CEC);
- San Onofre Nuclear Generating Station (SONGS) retirement announced by Southern California Edison on July 6, 2012;
- Once-Through Cooled (OTC) generation retirement schedule;
- CEC/Commission Long-Term Procurement Process forecasts and authorization, including energy efficiency, behind the meter solar, Energy Storage, Demand Response, and conventional resources;
- The Commission's 33% renewable portfolio standards; and
- Network upgrade projects implemented and approved by CAISO since the CAISO 2010-2011 transmission plan.

For comparison purposes, the assumptions in the 2020 Summer Peak case used in the original CAISO's 2010-2011 transmission plan analysis of the SOCRE project are also provided in Table A-1.

The CAISO investigated the 11 DEIR alternatives based on the CAISO's understanding on the available project descriptions. Comparison of system performance between the SOCRE project and the DEIR Alternatives were based on the same assumptions in Table A-1 for the 2024 Summer Peak case.

Load forecast and generation resources assumptions

Table A-1 summarizes and compares the load and generation resource assumptions for the South Orange County area used in the 2024 and the 2020 Summer Peak cases. The forecasted 1-in-10 coincident peak load in the 2024 Summer Peak case is about 3% lower than the peak load in the 2020 Summer Peak case used in the 2010-2011 transmission plan. In addition, there is 48.6 MW of load reduction built into the 2024 Summer Peak case as a result of the projected energy efficiency, energy storage, demand response, distributed generation and the existing landfill generator. Therefore, the net peak load in the 2024 Summer Peak case is about 446 MW, about 13% lower than the net peak load in the 2020 Summer Peak case.

Table A-1. Load and Generation Resources Assumptions (CAISO 2014-2015 TPP VS. CAISO 2010-2011 TPP)

		Unit	2014-2015 TPP: 2024 Summer	2010-2011 TPP: 2020 Summer
Load Forecast	1-in-10 coincident peak	MW	489.5	503.2
Load Reduction	Energy Efficiency	MW	30.9	0
	Demand Response	MW	2	0
	Preferred Resources (DG)	MW	7.3	0
	Energy Storage	MW	3.1	0
	total of load reduction	MW	43.3	0.0
Net Peak Load in SOC		MW	446.2	503.2
Generation Resource (Landfill)		MW (in NQC)	5.3	3.3

Transmission Upgrades

With regard to transmission improvements in the South Orange County 138 kV system since the CAISO 2011-2011 TPP, a few minor network upgrades have been implemented to eliminate various power flow concerns, such as the Talega-Trabuco 138 kV line loop-in and the new 138 kV tap on the Talega-Pico 138 kV line. The Talega synchronous condensers project was approved by the CAISO after the SONGS retirement, and will be in service by the summer of 2015 based on the latest schedule. Figure 1 and Figure 2 show one-line diagrams of the SDG&E South Orange County 230/138 kV system configurations in the years 2011 and 2015 and represent the base case or “existing system” in the CAISO 2010-2011 and 2014-2015 TPP, respectively.

Figure 1. Southern Orange County 230/138 kV System Configuration in the Year of 2011 (the existing system in the CAISO 2010~2011 TPP)

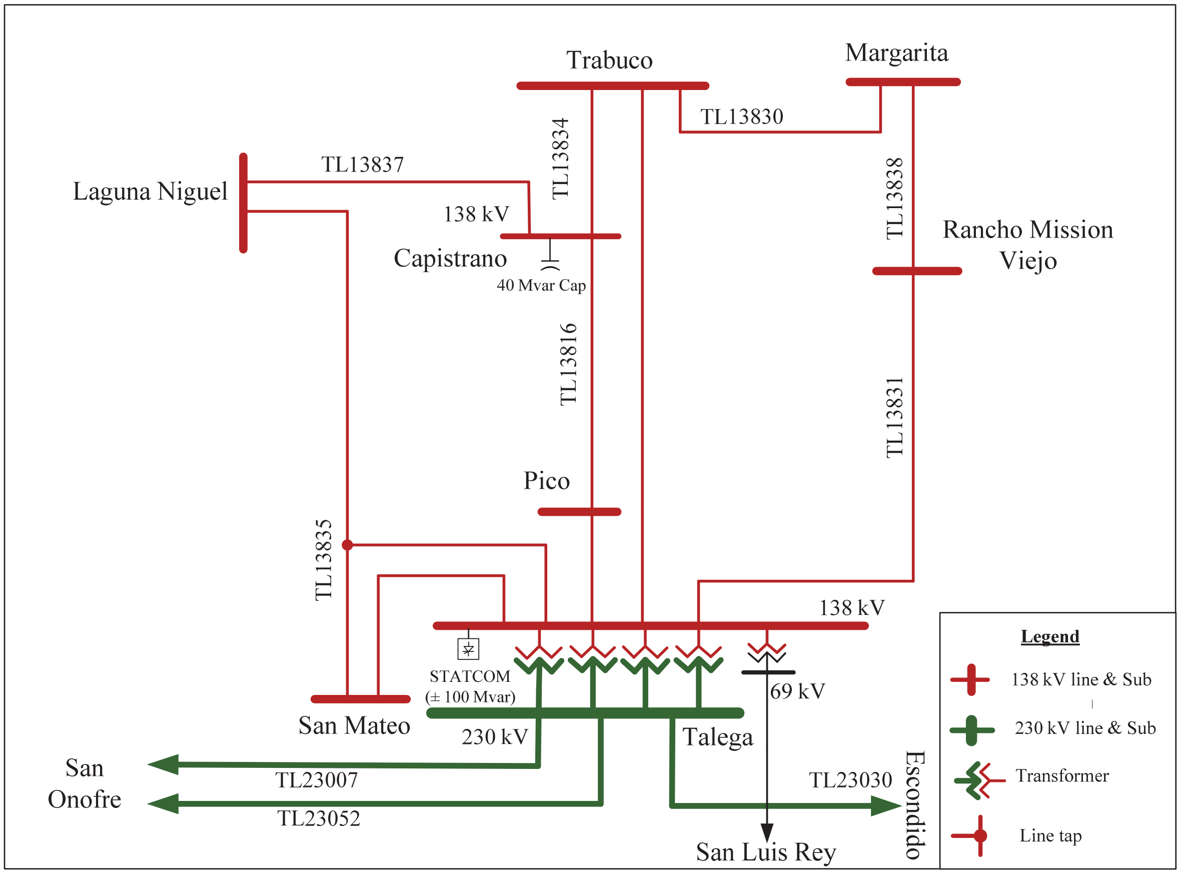

Figure 2. Southern Orange County 230/138 kV System Configuration in the Year of 2015 (the existing system in the CAISO 2014~2015 TPP)

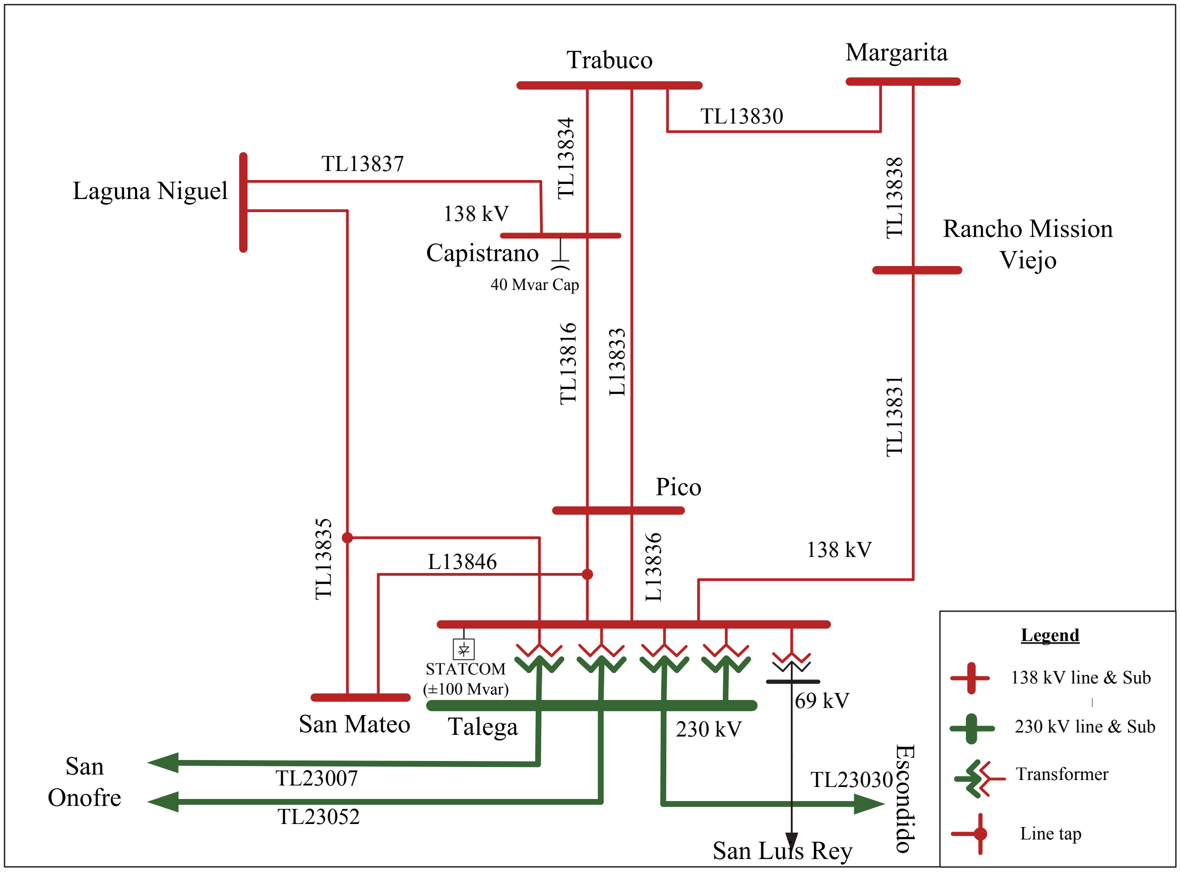

Figure 3 shows the SOCRE project that was approved in the CAISO 2010-2011 Transmission Plan. Figure 4 presents the SOCRE project that was modified by SDG&E and accepted by the CAISO to improve load services at Laguna Niguel and San Mateo without increasing cost after the CAISO 2014-2015 TPP.

Figure 3. Southern Orange County 230/138 kV System Configuration with the proposed SOCRE project modeled in the CAISO 2014~2015 TPP

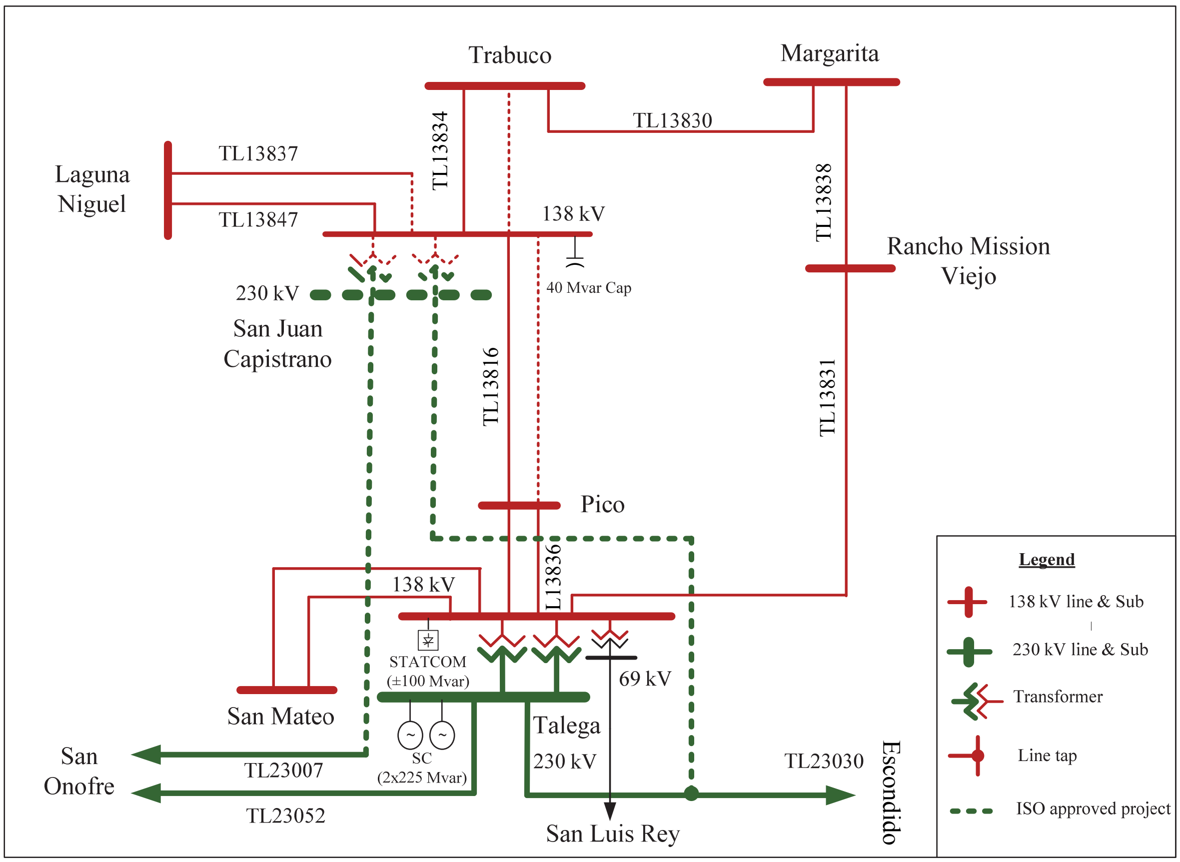

Figure 4. Southern Orange County 230/138 kV System Configuration with the proposed SOCRE project that was refined with minor modifications after the CAISO 2014~2015 TPP (for information purpose only)

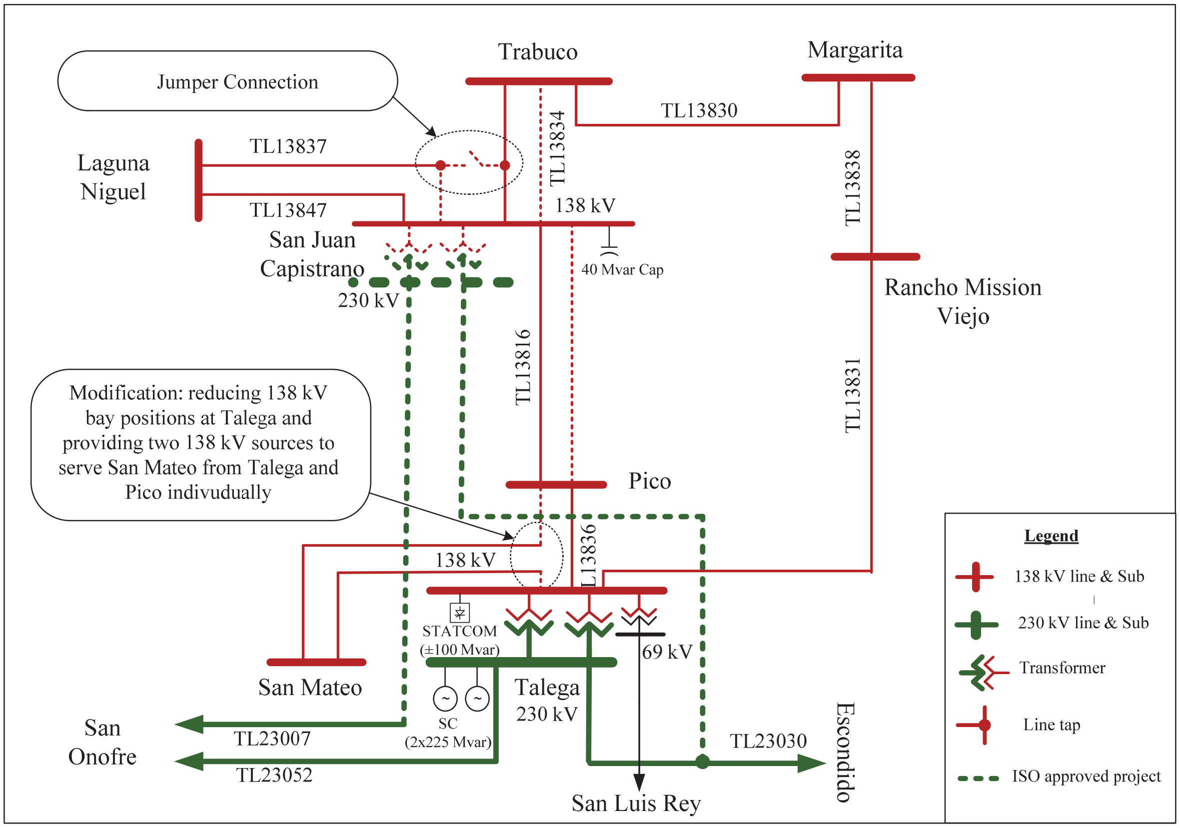

Figure 5. SDG&E's 8760-hour load duration curve used in the CAISO production simulation data base in Gridview

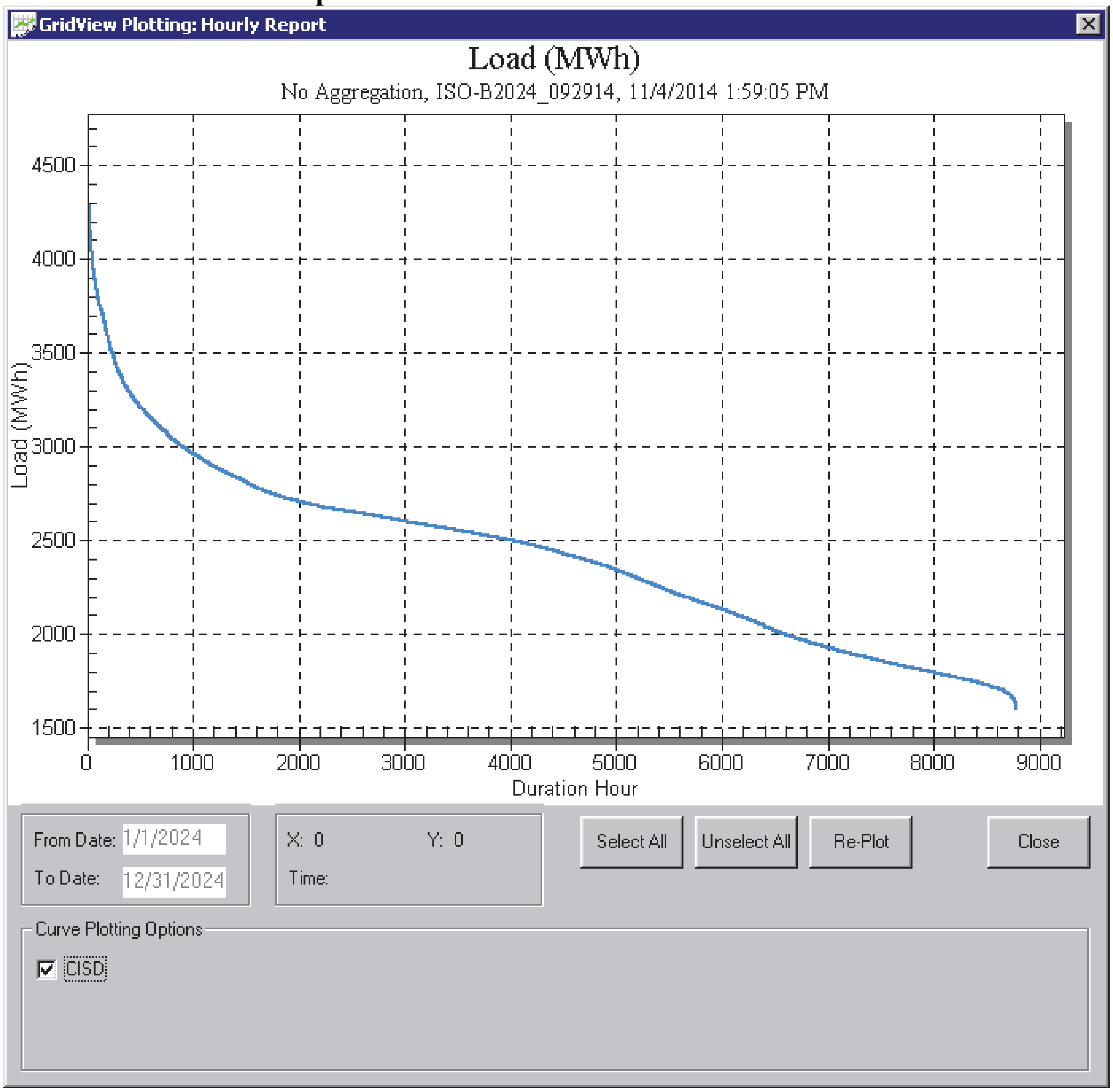

Table A-2 Comparison of Thermal Overloads for Worst Contingency in the SDG&E South Orange County area

CAISO 2014-2015 TPP vs. CAISO 2010-2011 TPP

Overloaded Facility	Worst Contingency	Category	Category Description	Thermal Loading (% over applicable rating)	
				2024 Summer Peak Case	2020 Summer Peak Case
22841 TA TAP 138 22396 LAGNA NL 138 1	SL-10233_ 22840 TALEGA 138 22656 PICO 138 1	B	L-1		101.09
22841 TA TAP 138 22396 LAGNA NL 138 1	TALEGA-TA TAP33-PICO-SANMATEO 138.0 Tap33 -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	127.43	
	TALEGA 138.0 to PICO 138.0 Circuit -- CAPSTRNO 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1		155.88
22112 CAPSTRNO 138 22656 PICO 138 1	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- PICO 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	114.13	
	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1		121.32
22112 CAPSTRNO 138 22860 TRABUCO 138 1	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- PICO 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	144.47	
	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1		156.2
22840 TALEGA 138 22656 PICO 138 1	TALEGA-TA TAP33-PICO-SANMATEO 138.0 Tap33 -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	106.99	

	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1		146.01
22840 TALEGA 138 22842 TA TAP33 138 1	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	113.16	
22841 TA TAP 138 22396 LAGNA NL 138 1	TALEGA-TA TAP33-PICO-SANMATEO 138.0 Tap33 -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	127.43	
	TALEGA 138.0 to PICO 138.0 Circuit -- CAPSTRNO 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1		155.88
22840 TALEGA 138 22842 TA TAP33 138 1	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	113.16	
22842 TA TAP33 138 22656 PICO 138 1	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	109.36	
22844 TALEGA 230 22840 TALEGA 138 1 BK60	Tran TALEGA 230.00 to TALEGA 138.00 BK61 -- Tran TALEGA 230.00 to TALEGA 138.00 BK63	C	T-1/L-1	120.93	131.73
22844 TALEGA 230 22840 TALEGA 138 3 BK62	Tran TALEGA 230.00 to TALEGA 138.00 BK61 -- Tran TALEGA 230.00 to TALEGA 138.00 BK63	C	T-1/L-1	118.68	129.27
SDG&E's South Orange County Service Area	Loss of Talega West/East 230 kV Buses plus BK #60/61/62/63)	D	Loss of substation	load drop for the area (460 MW)	load drop for the area (503 MW)
SDG&E's South Orange County Service Area	Loss of Talega West/East 138 kV Buses plus BK #60/61/62/63)	D	Loss of substation	load drop for the area (460 MW)	load drop for the area (503 MW)

Table A-3A Thermal Overloads in the SDG&E South Orange County area

2024 Summer Peak Case in CAISO 2014-2015 TPP

ID	Overloaded Facility	Contingency	Category	Category Description	Thermal Loading (% over applicable rating)
20SP-1	22112 CAPSTRNO 138 22656 PICO 138 1	SANMATEO-TA TAP-TALEGA-LAGNA NL 138.0 Tap -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	102.85
20SP-2	22112 CAPSTRNO 138 22860 TRABUCO 138 1	PICO 138.0 to TRABUCO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	144.47
20SP-3	22112 CAPSTRNO 138 22860 TRABUCO 138 1	PICO 138.0 to TRABUCO 138.0 Circuit -- R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1/L-1	113.98
20SP-4	22840 TALEGA 138 22656 PICO 138 1	TALEGA-TA TAP33-PICO-SANMATEO 138.0 Tap33 -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	106.99
20SP-5	22112 CAPSTRNO 138 22656 PICO 138 1	PICO 138.0 to TRABUCO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	114.13
20SP-6	22840 TALEGA 138 22842 TA TAP33 138 1	TALEGA 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	113.16
20SP-7	22840 TALEGA 138 22842 TA TAP33 138 1	SANMATEO-TA TAP-TALEGA-LAGNA NL 138.0 Tap -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	108.31
20SP-8	22840 TALEGA 138 22842 TA TAP33 138 1	R.MSNVJO 138.0 to MARGARTA 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	100.26
20SP-9	22842 TA TAP33 138 22656 PICO 138 1	TALEGA 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	109.36
20SP-10	22841 TA TAP 138 22396 LAGNA NL 138 1	TALEGA-TA TAP33-PICO-SANMATEO 138.0 Tap33 -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	127.43

20SP-11	22841 TA TAP 138 22396 LAGNA NL 138 1	CAPSTRNO 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	122.55
20SP-12	22841 TA TAP 138 22396 LAGNA NL 138 1	CAPSTRNO 138.0 to PICO 138.0 Circuit -- PICO 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	111.78
20SP-13	22841 TA TAP 138 22396 LAGNA NL 138 1	PICO 138.0 to TRABUCO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	100.74
20SP-14	22841 TA TAP 138 22396 LAGNA NL 138 1	CAPSTRNO 138.0 to PICO 138.0 Circuit -- R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1/L-1	108.89
20SP-15	22841 TA TAP 138 22396 LAGNA NL 138 1	CAPSTRNO 138.0 to PICO 138.0 Circuit -- CAPSTRNO 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	102.5
20SP-16	22844 TALEGA 230 22840 TALEGA 138 1 BK62	Tran TALEGA 230.00 to TALEGA 138.00 Circu -- Tran TALEGA 230.00 to TALEGA 138.00 Circu	C	T-1/T-1	118.68
20SP-17	22844 TALEGA 230 22840 TALEGA 138 3 BK60	Tran TALEGA 230.00 to TALEGA 138.00 Circu -- Tran TALEGA 230.00 to TALEGA 138.00 Circu	C	T-1/T-1	120.93
20SP-18	22841 TA TAP 138 22396 LAGNA NL 138 1	BA_PI138E_PICO 138KV E	C	Bus Section (C1)	127.43
20SP-19	22844 TALEGA 230 22840 TALEGA 138 1 BK60	CB_TA4W_TA BK 62 + TA BK 63	C	Breaker Failure or internal Fault (C2)	120.93
20SP-20	22844 TALEGA 230 22840 TALEGA 138 1 BK60	CB_TA5W_TA BK 62 + TA BK 63 + TA K 50	C	Breaker Failure or internal Fault (C2)	120.65
20SP-21	22844 TALEGA 230 22840 TALEGA 138 3 BK62	CB_TA4W_TA BK 62 + TA BK 63	C	Breaker Failure or internal Fault (C2)	118.68
20SP-22	22844 TALEGA 230 22840 TALEGA 138 3 BK62	CB_TA5W_TA BK 62 + TA BK 63 + TA K 50	C	Breaker Failure or internal Fault (C2)	118.4
20SP-23	22840 TALEGA 138 22842 TA TAP33 138 1	CA_PI13836B_TL13836 TALEGA-PICO ck 1	C	Commod Structure (C5)	113.16

20SP-24	22841 TA TAP 138 22396 LAGNA NL 138 1	BA_PI138W"PICO_138KV	C	Bus Section (C1)	111.78
20SP-25	22842 TA TAP33 138 22656 PICO 138 1	CA_PI13836B_TL13836 TALEGA-PICO ck 1	C	Commod Structure (C5)	109.36
20SP-26	22840 TALEGA 138 22656 PICO 138 1	CA_TA7T_TA-TB 1 + TA-RMV 1 138 kV	C	Commod Structure (C5)	106.99
20SP-27	SDG&E's South Orange County Service Area	Loss of Talega West/East 230 kV Buses plus BK #60/61/62/63)	D	Loss of substation (D8)	Blackout resulting in load drop for the area (460 MW of customers)
20SP-28	SDG&E's South Orange County Service Area	Loss of Talega West/East 138 kV Buses plus BK #60/61/62/63)	D	Loss of substation (D8)	

Table A-3B Thermal Overloads in the SDG&E South Orange County area

2020 Summer Peak Case in CAISO 2010-2011 TPP

ID	Overloaded Facility	Contingency	Category	Category Description	Thermal Loading (% over applicable rating)
20SP-1	22841 TA TAP 138 22396 LAGNA NL 138 1	SL-10233_ 22840 TALEGA 138 22656 PICO 138 1	B	L-1	101.09
20SP-2	22112 CAPSTRNO 138 22656 PICO 138 1	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	121.32
20SP-3	22112 CAPSTRNO 138 22656 PICO 138 1	R.MSNVJO 138.0 to MARGARTA 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	111.92
20SP-4	22112 CAPSTRNO 138 22656 PICO 138 1	TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	107.34
20SP-5	22112 CAPSTRNO 138 22656 PICO 138 1	TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP -- R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1/L-1	100.48
20SP-6	22112 CAPSTRNO 138 22860 TRABUCO 138 1	CAPSTRNO 138.0 to PICO 138.0 Circuit -- TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP	C	L-1/L-1	101.17
20SP-7	22112 CAPSTRNO 138 22860 TRABUCO 138 1	TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	133.92
20SP-8	22112 CAPSTRNO 138 22860 TRABUCO 138 1	R.MSNVJO 138.0 to MARGARTA 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	137.72
20SP-9	22112 CAPSTRNO 138 22860 TRABUCO 138 1	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	156.2

20SP-10	22840 TALEGA 138 22656 PICO 138 1	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	146.01
20SP-11	22840 TALEGA 138 22656 PICO 138 1	R.MSNVJO 138.0 to MARGARTA 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	136.58
20SP-12	22840 TALEGA 138 22656 PICO 138 1	MARGARTA 138.0 to TRABUCO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	100.09
20SP-13	22840 TALEGA 138 22656 PICO 138 1	CAPSTRNO 138.0 to TRABUCO 138.0 Circuit -- TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP	C	L-1/L-1	101.23
20SP-14	22840 TALEGA 138 22656 PICO 138 1	TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	122.1
20SP-15	22840 TALEGA 138 22656 PICO 138 1	TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP -- R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1/L-1	125.03
20SP-16	22840 TALEGA 138 22656 PICO 138 1	TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	131.94
20SP-17	22841 TA TAP 138 22396 LAGNA NL 138 1	MARGARTA 138.0 to TRABUCO 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	112.57
20SP-18	22841 TA TAP 138 22396 LAGNA NL 138 1	CAPSTRNO 138.0 to PICO 138.0 Circuit -- CAPSTRNO 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	116.81
20SP-19	22841 TA TAP 138 22396 LAGNA NL 138 1	CAPSTRNO 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	121.59
20SP-20	22841 TA TAP 138 22396 LAGNA NL 138 1	CAPSTRNO 138.0 to PICO 138.0 Circuit -- R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1/L-1	124.98

20SP-21	22841 TA TAP 138 22396 LAGNA NL 138 1	CAPSTRNO 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	133.06
20SP-22	22841 TA TAP 138 22396 LAGNA NL 138 1	TALEGA 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	141.01
20SP-23	22841 TA TAP 138 22396 LAGNA NL 138 1	R.MSNVJO 138.0 to MARGARTA 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	144.45
20SP-24	22841 TA TAP 138 22396 LAGNA NL 138 1	TALEGA 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1/L-1	152.72
20SP-25	22841 TA TAP 138 22396 LAGNA NL 138 1	TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	114.14
20SP-26	22841 TA TAP 138 22396 LAGNA NL 138 1	CAPSTRNO 138.0 to TRABUCO 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit	C	L-1/L-1	155.87
20SP-27	22841 TA TAP 138 22396 LAGNA NL 138 1	R.MSNVJO 138.0 to MARGARTA 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit	C	L-1/L-1	106.72
20SP-28	22844 TALEGA 230 22840 TALEGA 138 1 BK#62	Tran TALEGA 230.00 to TALEGA 138.00 BK61 -- Tran TALEGA 230.00 to TALEGA 138.00 BK63	C	T-1/L-1	129.27
20SP-29	22844 TALEGA 230 22840 TALEGA 138 3 BK60	Tran TALEGA 230.00 to TALEGA 138.00 BK61 -- Tran TALEGA 230.00 to TALEGA 138.00 BK63	C	T-1/L-1	131.73
20SP-30	22112 CAPSTRNO 138 22860 TRABUCO 138 1	CB_TA7T_TA-TB 1 + TA-RMV 1 138 kV	C	Breaker Failure or internal Fault (C2)	156.2
20SP-31	22841 TA TAP 138 22396 LAGNA NL 138 1	CA_PI13836B_TL13836 TALEGA-PICO ck 1	C	Commod Structure (C5)	152.16

20SP-32	22840 TALEGA 138 22656 PICO 138 1	CB_TA7T_TA-TB 1 + TA-RMV 1 138 kV	C	Breaker Failure or internal Fault (C2)	146.01
20SP-33	22844 TALEGA 230 22840 TALEGA 138 1	CB_TA5W_TA BK 62 + TA BK 63 + TA K 50	C	Breaker Failure or internal Fault (C2)	132.47
20SP-34	22844 TALEGA 230 22840 TALEGA 138 1	CB_TA4W_TA BK 62 + TA BK 63	C	Breaker Failure or internal Fault (C2)	131.73
20SP-35	22844 TALEGA 230 22840 TALEGA 138 3	CB_TA5W_TA BK 62 + TA BK 63 + TA K 50	C	Breaker Failure or internal Fault (C2)	130
20SP-36	22844 TALEGA 230 22840 TALEGA 138 3	CB_TA4W_TA BK 62 + TA BK 63	C	Breaker Failure or internal Fault (C2)	129.27
20SP-37	22112 CAPSTRNO 138 22656 PICO 138 1	CB_TA7T_TA-TB 1 + TA-RMV 1 138 kV	C	Breaker Failure or internal Fault (C2)	121.32
20SP-38	22841 TA TAP 138 22396 LAGNA NL 138 1	CB_TA7T_TA-TB 1 + TA-RMV 1 138 kV	C	Breaker Failure or internal Fault (C2)	113.72
20SP-39	22841 TA TAP 138 22396 LAGNA NL 138 1	CA_13836_TL13836 TALEGA-PICO ck 1	C	Commod Structure (C5)	101.09
20SP-40	22841 TA TAP 138 22396 LAGNA NL 138 1	B_PI138E_PICO 138KV E	C	Bus Section (C1)	101.09
20SP-41	22841 TA TAP 138 22396 LAGNA NL 138 1	B_TA13836_TALEGA 138KV 13836	C	Bus Section (C1)	101.09
20SP-42	22841 TA TAP 138 22396 LAGNA NL 138 1	BA_PI138E_PICO 138KV E	C	Bus Section (C1)	101.09

20SP-43	22841 TA TAP 138 22396 LAGNA NL 138 1	CB_PI13836_TL13836 TALEGA-PICO ck 1	C	Breaker Failure or internal Fault (C2)	101.09
20SP-44	22841 TA TAP 138 22396 LAGNA NL 138 1	CB_TA8W_TA-PI 1 + TA BK 63 + TA BK 50	C	Breaker Failure or internal Fault (C2)	101.01
20SP-45	22841 TA TAP 138 22396 LAGNA NL 138 1	CB_TA8T_TA-PI 1 138 + TA-SMO 1 138	C	Breaker Failure or internal Fault (C2)	100.91
20SP-46	SDG&E's South Orange County Service Area	Loss of Talega West/East 230 kV Buses plus BK #60/61/62/63)	D	Loss of substation (D8)	Blackout resulting in load drop for the area (460 MW of customers)
20SP-47	SDG&E's South Orange County Service Area	Loss of Talega West/East 138 kV Buses plus BK #60/61/62/63)	D	Loss of substation (D8)	

Table A-4 SPS Design Comparison of Unique Contingencies that would trigger operation of SPS

Unique Contingency #	Unique Contingencies Monitored by SPS	
	Updated SOCRE Analysis (2024 Summer Peak Case)	2010-2011 TPP SOCRE Analysis (2020 Summer Peak Case)
1	CAPSTRNO 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	CAPSTRNO 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit
2	CAPSTRNO 138.0 to PICO 138.0 Circuit -- CAPSTRNO 138.0 to TRABUCO 138.0 Circuit	CAPSTRNO 138.0 to PICO 138.0 Circuit -- CAPSTRNO 138.0 to TRABUCO 138.0 Circuit
3	R.MSNVJO 138.0 to MARGARTA 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit	R.MSNVJO 138.0 to MARGARTA 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit
4	TALEGA 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	TALEGA 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit
5	CAPSTRNO 138.0 to PICO 138.0 Circuit -- PICO 138.0 to TRABUCO 138.0 Circuit	CAPSTRNO 138.0 to PICO 138.0 Circuit -- R.MSNVJO 138.0 to MARGARTA 138.0 Circuit
6	CAPSTRNO 138.0 to PICO 138.0 Circuit -- R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	CAPSTRNO 138.0 to PICO 138.0 Circuit -- TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP

7	PICO 138.0 to TRABUCO 138.0 Circuit -- R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	CAPSTRNO 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit
8	PICO 138.0 to TRABUCO 138.0 Circuit -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	CAPSTRNO 138.0 to TRABUCO 138.0 Circuit -- TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP
9	SANMATEO-TA TAP-TALEGA-LAGNA NL 138.0 Tap -- TALEGA 138.0 to PICO 138.0 Circuit	CAPSTRNO 138.0 to TRABUCO 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit
10	SANMATEO-TA TAP-TALEGA-LAGNA NL 138.0 Tap -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	MARGARTA 138.0 to TRABUCO 138.0 Circuit -- TALEGA 138.0 to PICO 138.0 Circuit
11	TALEGA-TA TAP33-PICO-SANMATEO 138.0 Tap33 -- TALEGA 138.0 to PICO 138.0 Circuit	MARGARTA 138.0 to TRABUCO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit
12	TALEGA-TA TAP33-PICO-SANMATEO 138.0 Tap33 -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit	R.MSNVJO 138.0 to MARGARTA 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit
13	Tran TALEGA 230.00 to TALEGA 138.00 BK#61 -- Tran TALEGA 230.00 to TALEGA 138.00 BK#63	TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP -- R.MSNVJO 138.0 to MARGARTA 138.0 Circuit
14		TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP -- TALEGA 138.0 to PICO 138.0 Circuit
15		TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP -- TALEGA 138.0 to R.MSNVJO 138.0 Circuit
16		TA TAP-LAGNA NL-SANMATEO-TALEGA 138.0 TA TAP -- TALEGA 138.0 to TRABUCO 138.0 Circuit
17		TALEGA 138.0 to PICO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit
18		TALEGA 138.0 to R.MSNVJO 138.0 Circuit -- TALEGA 138.0 to TRABUCO 138.0 Circuit
19		Tran TALEGA 230.00 to TALEGA 138.00 BK61 -- Tran TALEGA 230.00 to TALEGA 138.00 BK63
number of unique contingencies	13	19

Table A-5 Comparison of Monitored System Elements required by an SPS (CAISO 2010-2011 TPP vs CAISO 2014-2015 TPP)

Element or Variables #	Elements Monitored by SPS	
	Updated SOCRE Analysis (2024 Summer Peak Case)	2010-2011 TPP SOCRE Analysis (2020 Summer Peak Case)
1	22112 CAPSTRNO 138 22656 PICO 138 1	22112 CAPSTRNO 138 22656 PICO 138 1
2	22112 CAPSTRNO 138 22860 TRABUCO 138 1	22112 CAPSTRNO 138 22860 TRABUCO 138 1
3	22840 TALEGA 138 22656 PICO 138 1	22840 TALEGA 138 22656 PICO 138 1
4	22841 TA TAP 138 22396 LAGNA NL 138 1	22841 TA TAP 138 22396 LAGNA NL 138 1
5	22844 TALEGA 230 22840 TALEGA 138 1	22844 TALEGA 230 22840 TALEGA 138 1
6	22844 TALEGA 230 22840 TALEGA 138 3	22844 TALEGA 230 22840 TALEGA 138 3
7	22840 TALEGA 138 22842 TA TAP33 138 1	
8	22842 TA TAP33 138 22656 PICO 138 1	
number of elements	8	6

Table B-1 Thermal Overloads in the SDG&E South Orange County area

With Alternative B1/B2/B3/B4/E: Upgrade South Orange County 138 kV System

2024 Summer Peak Case in CAISO 2014-2015 TPP

ID	Overloaded Facility	Contingency	Category	Category Description	Thermal Loading (% over applicable rating)
24SP-1	22844 TALEGA 230 22840 TALEGA 138 1	tran_7019_Tran TALEGA 230.00 to TALEGA 138.00 Circu---tran_7020_Tran TALEGA 230.00 to TALEGA 138.00 Circu	C	T-1-1	120.69
24SP-2	22844 TALEGA 230 22840 TALEGA 138 3	tran_7019_Tran TALEGA 230.00 to TALEGA 138.00 Circu---tran_7020_Tran TALEGA 230.00 to TALEGA 138.00 Circu	C	T-1-1	118.44
24SP-3	SDG&E's South Orange County Service Area	Loss of Talega West/East 230 kV Buses plus BK #60/61/62/63)	D	Loss of substation (D8)	load drop for the area (up to 460 MW of customers)
24SP-4	SDG&E's South Orange County Service Area	Loss of Talega West/East 138 kV Buses plus BK #60/61/62/63)	D	Loss of substation (D8)	

Table B-2A Thermal Overloads in the SDG&E South Orange County area

With Alternative C1/C2/D: SCE 230 kV Loop-in to South Orange County 138 kV System

2024 Summer Peak Case in CAISO 2014-2015 TPP

ID	Overloaded Facility	Contingency	Category	Category Description	Thermal Loading (% over applicable rating) (Summer Peak)
24SP-1	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7000_Line CAPSTRNO 138.0 to LAGNA NL 138.0 Circuit---line_7009_Line TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1-1	105.12
24SP-2	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7009_Line TALEGA 138.0 to R.MSNVJO 138.0 Circuit---tran_7020_Tran TALEGA 230.00 to TALEGA 138.00 Circu	C	T-1/L-1	100.87
24SP-3	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7009_Line TALEGA 138.0 to R.MSNVJO 138.0 Circuit---tran_7019_Tran TALEGA 230.00 to TALEGA 138.00 Circu	C	T-1/L-1	100.8

Table B-2B Thermal Overloads in the SDG&E South Orange County area

With Alternative C1/C2/D: SCE 230 kV Loop-in to South Orange County 138 kV System

2024 Summer Off-Peak Case for the SDGE area with 1600 MW Southbound Flow via Path 44

ID	Overloaded Facility	Contingency	Category	Category Description	Thermal Loading (% over applicable rating) (Summer Off-Peak)
24OP-1	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	B	L-1	103.98
24OP-2	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7000_Line CAPSTRNO 138.0 to LAGNA NL 138.0 Circuit	B	L-1	105.95

24OP-3	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit	B	L-1	112.96
24OP-4	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	B	L-1	142.96
24OP-5	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit---line_7004_Line CAPSTRNO 138.0 to TRABUCO 138.0 Circuit	C	L-1-1	131.84
24OP-6	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	line_7008_Line TALEGA 138.0 to PICO 138.0 Circuit---line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	C	L-1-1	107.19
24OP-7	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit	C	L-1-1	146.16
24OP-8	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7004_Line CAPSTRNO 138.0 to TRABUCO 138.0 Circuit	C	L-1-1	146.36
24OP-9	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7006_Line MARGARTA 138.0 to TRABUCO 138.0 Circuit	C	L-1-1	119.01
24OP-10	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7007_Line R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1-1	112.19
24OP-11	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7008_Line TALEGA 138.0 to PICO 138.0 Circuit	C	L-1-1	107.54
24OP-12	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7009_Line TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1-1	108.69
24OP-13	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---tran_7019_Tran TALEGA 230.00 to TALEGA 138.00 Circu	C	T-1/L-1	101.88

24OP-14	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	SCE-L_0002_Line VIEJOSC 230.0 to S.ONOFRE 230.0 Circu---line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	C	L-1-1	127.4
24OP-15	22112 CAPSTRNO 138 22396 LAGNA NL 138 1	tran_7019_Tran TALEGA 230.00 to TALEGA 138.00 Circu---line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	C	T-1/L-1	101.56
24OP-16	22112 CAPSTRNO 138 22656 PICO 138 1	B_CP138SO_CAPISTRANO 138KV S	C	Bus Section (C1)	111.02
24OP-17	22112 CAPSTRNO 138 22656 PICO 138 1	CB_CP13834_CP-TB 1 + CP-LNL 1 138 kV	C	Breaker Failure or internal Fault (C2)	111.02
24OP-18	22112 CAPSTRNO 138 22656 PICO 138 1	CB_CP13837_CP-TB 1 + CP-LNL 1 138 kV	C	Breaker Failure or internal Fault (C2)	111.02
24OP-19	22112 CAPSTRNO 138 22656 PICO 138 1	line_7000_Line CAPSTRNO 138.0 to LAGNA NL 138.0 Circuit---line_7004_Line CAPSTRNO 138.0 to TRABUCO 138.0 Circuit	C	L-1-1	111.03
24OP-20	22112 CAPSTRNO 138 22656 PICO 138 1	line_7007_Line R.MSNVJO 138.0 to MARGARTA 138.0 Circuit---line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	C	L-1-1	109.35
24OP-21	22112 CAPSTRNO 138 22656 PICO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7000_Line CAPSTRNO 138.0 to LAGNA NL 138.0 Circuit	C	L-1-1	131.48
24OP-22	22112 CAPSTRNO 138 22656 PICO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7004_Line CAPSTRNO 138.0 to TRABUCO 138.0 Circuit	C	L-1-1	160.41
24OP-23	22112 CAPSTRNO 138 22656 PICO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7006_Line MARGARTA 138.0 to TRABUCO 138.0 Circuit	C	L-1-1	117.74
24OP-24	22112 CAPSTRNO 138 22656 PICO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7007_Line R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1-1	109.83

24OP-25	22112 CAPSTRNO 138 22656 PICO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7009_Line TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1-1	105.83
24OP-26	22112 CAPSTRNO 138 22656 PICO 138 1	SCE-L_0002_Line VIEJOSC 230.0 to S.ONOFRE 230.0 Circu---line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	C	L-1-1	130.21
24OP-27	22112 CAPSTRNO 138 22860 TRABUCO 138 1	B_CP138NO_CAPISTRANO 138KV N	C	Bus Section (C1)	112.96
24OP-28	22112 CAPSTRNO 138 22860 TRABUCO 138 1	B_LNL138W_LAGUNA NIGUEL 138KV W	C	Bus Section (C1)	105.95
24OP-29	22112 CAPSTRNO 138 22860 TRABUCO 138 1	B_PI138W_PICO 138KV W	C	Bus Section (C1)	112.96
24OP-30	22112 CAPSTRNO 138 22860 TRABUCO 138 1	BA_PI138W"PICO_138KV	C	Bus Section (C1)	100.11
24OP-31	22112 CAPSTRNO 138 22860 TRABUCO 138 1	CB_CP_CAPBK1_CP-PI 138 + CP CAPBK1	C	Breaker Failure or internal Fault (C2)	112.96
24OP-32	22112 CAPSTRNO 138 22860 TRABUCO 138 1	CB_CP13816_CP-PI 138 + CP CAPBK1	C	Breaker Failure or internal Fault (C2)	112.96
24OP-33	22112 CAPSTRNO 138 22860 TRABUCO 138 1	CB_LNL_BK40	C	Breaker Failure or internal Fault (C2)	105.95
24OP-34	22112 CAPSTRNO 138 22860 TRABUCO 138 1	CB_LNL_BK41	C	Breaker Failure or internal Fault (C2)	105.95
24OP-35	22112 CAPSTRNO 138 22860 TRABUCO 138 1	CB_LNL13837_TL13837 CP-LNL ck 1	C	Breaker Failure or internal Fault (C2)	105.95
24OP-36	22112 CAPSTRNO 138 22860 TRABUCO 138 1	CB_LNL138BT_CP-LNL + TATAP-LNL 1 138	C	Breaker Failure or internal Fault (C2)	101.04

24OP-37	22112 CAPSTRNO 138 22860 TRABUCO 138 1	CB_PI13816_CAPSTRNO - PICO ck 1	C	Breaker Failure or internal Fault (C2)	112.96
24OP-38	22112 CAPSTRNO 138 22860 TRABUCO 138 1	CB_PI138BT_CP-PI 1 + TA-PI 1 138 kV	C	Breaker Failure or internal Fault (C2)	112.88
24OP-39	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7000_Line CAPSTRNO 138.0 to LAGNA NL 138.0 Circuit---line_7016_Line TALEGA 230.0 to S.ONOFRE 230.0 Circuit	C	L-1-1	108.07
24OP-40	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit---line_7000_Line CAPSTRNO 138.0 to LAGNA NL 138.0 Circuit	C	L-1-1	147.94
24OP-41	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit---line_7007_Line R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1-1	100.97
24OP-42	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit---line_7016_Line TALEGA 230.0 to S.ONOFRE 230.0 Circuit	C	L-1-1	115.98
24OP-43	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7000_Line CAPSTRNO 138.0 to LAGNA NL 138.0 Circuit	C	L-1-1	175.32
24OP-44	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit	C	L-1-1	205.57
24OP-45	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7007_Line R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1-1	119.36
24OP-46	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7009_Line TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1-1	130.48
24OP-47	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---tran_7017_Tran CAPSTRNO 230.00 to CAPSTRNO 138.00	C	T-1/L-1	127.02

		Circu			
24OP-48	22112 CAPSTRNO 138 22860 TRABUCO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---tran_7019_Tran TALEGA 230.00 to TALEGA 138.00 Circu	C	T-1/L-1	140.07
24OP-49	22112 CAPSTRNO 138 22860 TRABUCO 138 1	SCE-L_0002_Line VIEJOSC 230.0 to S.ONOFRE 230.0 Circu---line_7000_Line CAPSTRNO 138.0 to LAGNA NL 138.0 Circuit	C	L-1-1	119.06
24OP-50	22112 CAPSTRNO 138 22860 TRABUCO 138 1	SCE-L_0002_Line VIEJOSC 230.0 to S.ONOFRE 230.0 Circu---line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit	C	L-1-1	129.7
24OP-51	22112 CAPSTRNO 138 22860 TRABUCO 138 1	SCE-L_0002_Line VIEJOSC 230.0 to S.ONOFRE 230.0 Circu---line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	C	L-1-1	174.29
24OP-52	22112 CAPSTRNO 138 22860 TRABUCO 138 1	tran_7017_Tran CAPSTRNO 230.00 to CAPSTRNO 138.00 Circu---line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	C	T-1/L-1	126.65
24OP-53	22112 CAPSTRNO 138 22860 TRABUCO 138 1	tran_7019_Tran TALEGA 230.00 to TALEGA 138.00 Circu---line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	C	T-1/L-1	139.64
24OP-54	22113 CAPSTRNO 230 22112 CAPSTRNO 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---tran_7018_Tran CAPSTRNO 230.00 to CAPSTRNO 138.00 Circu	C	T-1/L-1	109.57
24OP-55	22113 CAPSTRNO 230 22112 CAPSTRNO 138 1	tran_7018_Tran CAPSTRNO 230.00 to CAPSTRNO 138.00 Circu---line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit	C	T-1/L-1	109.25
24OP-56	22841 TA TAP 138 22396 LAGNA NL 138 1	line_7015_Line CAPSTRNO 230.0 to S.ONOFRE 230.0 Circuit---line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit	C	L-1-1	111.25

Table B-3A Thermal Overloads in the SDG&E South Orange County area

With Alternative F: 230-kV Rancho Mission Viejo Substation

2024 Summer Peak Case in CAISO 2014-2015 TPP

ID	Overloaded Facility	Contingency	Category	Category Description	Thermal Loading (% over applicable rating)
24SP-1	22841 TA TAP 138 22396 LAGNA NL 138 1	line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit---line_7007_Line R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1-1	108.16
24SP-2	22841 TA TAP 138 22396 LAGNA NL 138 1	line_7004_Line CAPSTRNO 138.0 to TRABUCO 138.0 Circuit---line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit	C	L-1-1	101.64
24SP-3	SDG&E's South Orange County Service Area	Loss of Talega West/East 138 kV Buses plus BK #60/61/62/63)	D	Loss of substation (D8)	Load drop for the area

Table B-3B Thermal Overloads in the SDG&E South Orange County area

With Alternative G: 138-kV San Luis Rey–San Mateo Line & San Luis Rey Sub Expansion

2024 Summer Peak Case in CAISO 2014-2015 TPP

ID	Overloaded Facility	Contingency	Category	Category Description	Thermal Loading (% over applicable rating)
24SP-1	22841 TA TAP 138 22396 LAGNA NL 138 1	line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit---line_7009_Line TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1-1	122.46
24SP-3	22841 TA TAP 138 22396 LAGNA NL 138 1	line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit---line_7007_Line R.MSNVJO 138.0 to MARGARTA 138.0 Circuit	C	L-1-1	108.86
24SP-4	22841 TA TAP 138 22396 LAGNA NL 138 1	line_7004_Line CAPSTRNO 138.0 to TRABUCO 138.0 Circuit---line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit	C	L-1-1	102.26
24SP-2	22842 TA TAP33 138 22656 PICO 138 1	line_7008_Line TALEGA 138.0 to PICO 138.0 Circuit---line_7009_Line TALEGA 138.0 to R.MSNVJO 138.0 Circuit	C	L-1-1	109.09
24SP-5	SDG&E's South Orange County Service Area	Loss of Talega West/East 138 kV Buses plus BK #60/61/62/63)	D	Loss of substation (D8)	load drop for the area

EXHIBIT 9

National Register of Historic Place Evaluation/Return Sheet Ref. No. 15000570

United States Department of the Interior

NATIONAL PARK SERVICE
1849 C Street, N.W.
Washington, DC 20240

The United States Department of the Interior
National Park Service

National Register of Historic Places
Evaluation/Return Sheet

Property Name: San Diego Gas and Electric San Juan Capistrano Substation
Orange County,

Reference Number: 15000570

Reason for Return

The request for Determination of Eligibility is being returned for substantive and technical revision. The submission claims significance under Criterion A in the area of engineering, and the boundary of the property consists of the footprint of the substation building (also referred to as the utility building and hereafter referred to as "the building"). The property owner, which objects to the nomination, petitioned for a substantive review of the nomination which resulted in an extension of the review period. The petitioner presented a number of documents to support its conclusion that the property is not eligible.

It is our opinion that the building is eligible for inclusion in the National Register of Historic Places under Criterion A, but that the documentation submitted is inadequate to fully support this finding and fails to address significant questions brought up by the petitioner.

It is apparent, as noted in the 2008 McKenna report, that the San Juan Capistrano substation likely meets the test of significance under Criterion A. The substation served as a vital and pioneering link between two power distribution systems, allowing for further growth of the overall system and thus spurring growth and development in the region. The building in question, while, as the petitioner points out repeatedly, is only a component of the substation, it is a significant and highly visual component. The location and design of this building, and of similar buildings in other power facilities of the era, is meant to present a face to the community. It is not simply a utilitarian structure meant simply to protect important components from the elements; the decision to utilize a restrained classical vocabulary was a conscious effort to "brand" the facility and present a dignified and substantial air to what is ordinarily a rather mundane component of power infrastructure.

Where the document falls short is in the analysis of integrity of the substation as a whole as it relates to the extant, nominated building. The petitioner rightly points out that a "substation" is more than a building, that it includes many elements that work together to facilitate the flow of power. The nomination as presented gives short shrift to the discussion of what the key components are and of how such a facility works. By limiting the boundaries and description and, for the most part, the focus of the nomination to the footprint of the building, the nomination does not truly provide an analytical discussion of integrity. The substation may have had many of its components moved or demolished, but there are remnants evident on the ground that can help tell the story and illustrate the working of the facility. It might be best, if this property is resubmitted, to revisit the boundaries of the nominated property and to look at the entirety of the facility.

The nomination does not adequately describe the role that equipment in the building played; this is important in helping to support the claim of significance. It is clear that some of the equipment and activities of the substation were sensitive or fragile enough that the construction of a shelter for them was necessary. What were they?

The petitioner's position that the document submitted was substantially revised between its presentation to the State Review Board and its submission to the Keeper is immaterial. The role of the State Review Board is advisory – to advise the State Historic Preservation Officer whether a property meets one of more of the National Register criteria for evaluation and to recommend whether or not it be nominated.

The various reports presented by the petitioner bring up valid points concerning the evaluation of integrity of the property, in particular how the building works in conjunction with the entire substation property and how the loss of certain features of the substation affect the ability of the building to reflect the significant of the substation. In other points of integrity, the reports miss the mark. The analyses of integrity of setting, of design, of materials, and of association are all too narrowly read. The immediate setting of the facility – the building and accompanying structures (both extant and missing) is important; the change from an open agricultural land to residential land is much less so. The alteration of a door or window or two does not constitute a marked change in the integrity of the building; it still represents the functional intent of the designer. So, too, the loss of minor fixtures such as gutters and lights does not constitute a sever loss of integrity of materials. The nomination as presented, does, however, fail to fully account for the effects of the loss of exterior equipment and structure and how this affects the overall integrity of design, feeling, and association.

The comparative analysis provided is a good start, especially in light of the contentious nature of the nomination, but the petitioner does bring up a valid point about the lack of comparable examples of substations (distributive, not generating) in the area. Limiting the comparatives to listed or eligible properties limits the full range of truly comparable resources. This substation was the pioneer in expansion of power distribution in the area. But from reading the nomination, we have no idea what the geographic spread of these facilities was (especially in the historic period), or how many there are or what condition other might be in. Of course, the petitioner misses the mark in the narrow reading of comparables by discounting properties that aren't located in southern California. While nominated for its significance at the local level, the property is still an example of a type common to all developed areas of the state.

To summarize, the substantive aspects of this nomination that need to be addressed are the boundaries, the evaluation of integrity of the building as it relates to the substation as a whole, and a better comparative analysis of similar and relatively contemporaneous facilities in the area.

Technical issues

Please check the appropriate box in Section 3; this is a request for determination of eligibility based on owner objection. Also, if submitting scans of correspondence, please respect the hierarchy of importance of such documents. The official notification of objection from the owner was buried 181 pages into a 400+ page pdf of correspondence. Such a significant part of a nomination package should be up front along with the letter of transmittal.

We appreciate the opportunity to review this DOE and hope that you find these comments useful. Please feel free to contact me if you have any questions. I can be reached at (202) 354-2275 or email at <James_Gabbert@nps.gov>.

Sincerely,

Jim Gabbert, Historian
National Register of Historic Places
9/22/2015

EXHIBIT 10

SDG&E Recirculated DEIR Comment Table

Comment #	Section Name	Page #	Paragraph or Table #	General Comment
				3.0 – Description of Alternatives
1.	3.0	N/A	N/A	Please refer to SDG&E's detailed comment letter for overarching comments on the Description of Alternatives section of the Recirculated DEIR. Specific comments on the content of Section 3.0 are provided below.
2.	3.2.12	2-22	Figure 3-5	Lines 33-34 state that the "Santiago–SONGS 230-kV line would then become two new transmission lines: the Trabuco-SONGS 230 kV transmission line and the Trabuco-Santiago 230-kV transmission line." This is an incorrect statement. The arrangement shown in Figure 3-5 shows a disconnect switch, not a circuit breaker, at Trabuco. The transmission line would be treated as a single 3-terminal transmission line.
3.	3.2.12	2-22 & Fig 3-5	Lines 24-25 Figure 3-5	Text description of the expanded Trabuco 230kV substation states that GIS would be used. However, Figure 3-5 does not appear to show a GIS design.
4.	3.2.12	2-22	Line 24	Text states that the 230/138 kV transformer would be housed in a GIS building. However, within a GIS substation, the switchgear (not the transformers) are typically located in the enclosed gas-insulated buildings. Transformers can be installed within GIS buildings, but such a design would be very costly for the building, would increase the cost of the transformer, and would increase the cost for the ventilation system required to cool the transformers. Additionally, the building size would be very large.
5.	3.2.12	2-23	Lines 17-18	Text states that the Trabuco Substation would have comparable specifications to SDG&E's proposed San Juan Capistrano Substation. This is not true. In order for a Trabuco substation to be equivalent to the proposed San Juan Capistrano, two 392 MVA 230/138kV transformers would be required at the Trabuco site. Only one transformer (even a non-standard 450MVA transformer) would be insufficient in the case Talega is lost. Also, the San Juan Capistrano Substation is being constructed as a very reliable breaker and half configuration whereas the proposed Trabuco design is not even as reliable as a single breaker single bus design.
6.	3.2.12	2-23	Line 22	Text states that "a new 230kV line would not be installed…" This statement is not true. A new 230kV line would need to be constructed to connect the existing SCE 220kV line to the Trabuco substation site. The statement in this line contradicts the description of two new transmission lines that need to be built in order to interconnect with SCE, refer to Alternative J, page 2-22, lines 27-35.
7.	3.2.12	2-23	Lines 20-21	Text states that "Capistrano Substation would not be expanded" This is not true. As SDG&E repeatedly has informed Energy Division and as set forth in attached SDG&E Corrected Opening Testimony, Chapter 5, Corrected Supplemental Testimony, Chapter 3, Section 3, Chapter 4, Section 3, Chapter 5, Section 4, Corrected Rebuttal Testimony, Chapter 5, Section 8, Chapter 8, Section 7, Chapter 9, Section 7, Corrected Second Supplemental Testimony, Chapter 4, Section 6, under all Alternatives to the Proposed Project, the 138/12kV substation at Capistrano would still need to be rebuilt to provide reliable electric service to SDG&E's customers served by that substation, primarily in the City of San Juan Capistrano. SDG&E has a legal obligation to provide reliable electric service, and rebuilding Capistrano, at least as a 138/12 kV substation, is a reasonably anticipated action under all Alternatives as well as the Proposed Project. As set forth in the above testimony, many of the Alternatives would require expansion of the Capistrano 138 kV yard to accommodate a new 138kV line to Capistrano.
8.	3.2.12	2-23	Lines 23-24	The text states that "the SDG&E South Orange County 138kV system would not require any reconductoring under this alternative." This statement is not correct. To avoid violation of NERC TPL-003-0b and its successor TPL-001-4, SDG&E would pursue the following projects to prevent the overloads listed in Table 4-1 of its Second Supplemental Testimony. The list of transmission projects includes: • Upgrade TL13836 to a higher rating: Talega Substation to Pico Substation; • Upgrade TL13816 to a higher rating: Pico Substation to Capistrano Substation; • Upgrade TL13846A to a higher rating: Pico Substation to TL13846 tap point; • Upgrade TL13846C to a higher rating: Talega Substation to TL13846 tap point. In addition, In order for a second 230/138 kV source located at Trabuco Substation to be fully redundant to the existing source at Talega, and given that two of the lines are located are located in a common transmission corridor south of Trabuco Substation and could be subject to a common-mode failure, it would be necessary to add at least one additional 138 kV line from Trabuco Substation to Capistrano Substation.
9.	3.2.12	2-23	Lines 27, 28, 33, & 38	As further explained in comments to Section 5.0 (Comparison of Alternatives), the Trabuco Substation Alternative could have greater impacts to traffic and cumulative impacts when compared to the Proposed Project if full road closures would be required during 230kV underground construction. In addition, there is not sufficient information concerning the design of the Trabuco Substation alternative to accurately compare anticipated impacts to those of the Proposed Project.

Comment #	Section Name	Page #	Paragraph or Table #	General Comment
10.	3.2.12	N/A	Figure 3-5	The Trabuco Substation conceptual Site Plan shows the 230kV connection at the northern portion of the expanded substation site. However, the inset street map (top right corner of the Figure 3-5) shows the 230kV connection at the southern (existing 138kV) portion of the site. In order to connection the 230kV lines at the southern portion of the expanded Trabuco site, the new 230kV yard would need to be constructed at this location, and the 138kV yard would need to be relocated to the northern (expanded) portion of the Trabuco site. This is inconsistent with other descriptions of the Trabuco Substation alternative.
11.	3.2.12	N/A	Figure 3-5	No design or location is provided for 230kV support structures that would be required as part of the Trabuco Substation alternative. Each option would require multiple new 230kV cable pole structures. The western connection option would require two cable poles at the interconnection point (~0.5 mile north of the Trabuco Substation, adjacent to Camino Capistrano). The eastern connection option would require two cable poles at the interconnection point (near the intersection of Los Altos and Plaza Avenue) and two additional cable poles east of the I-5 crossing, immediately west of the intersection of Los Altos and Las Ramblas (33.565298, -117.671742). It's unknown at this time but cable poles could probably fit just east of I5 in the parking lot adjacent to Puerta Real. Parking stalls would be lost and new ROW would be required until we get into franchise position with the cable/trench/conduit. The eastern connection option would also require at least two more cable pole structures to connect to the SCE lines and removal of at least one lattice tower. Further engineering and design with SCE would be required to identify the proper solution. While the underground segments of underground 230kV transmission line would largely be installed in franchise position (city streets) the overhead segment of the eastern connection option would require new ROW.
12.	3.2.12	2-23	Line 13	While the state of existing underground utilities within the segment of Camino Capistrano between the existing SCE transmission lines and the Trabuco Substation site has not been analyzed, it cannot be known at this time if sufficient space exists within this segment of Camino Capistrano to install new 230kV duct bank. Similarly, the proposed alternative underground 230kV alignment, which would connect the existing SCE transmission lines to the Trabuco Substation site partially by new underground transmission lines within Plaza Road, Los Altos Road, and La Alameda Roads, has also not been analyzed. Therefore, the feasibility of connecting the existing SCE transmission lines to the Trabuco Substation site via new underground transmission lines cannot be confirmed.
13.	3.2.12	2-22	Line 46	The text states that "[t] his alternative would not require any work at the existing Capistrano or Talega Substations.." This statement fails to identify the replacement of Talega transformer Banks 60 and 62. These transformer banks are beyond their useful life and will be replaced. As noted previously, this statement also fails to properly account for the need to rebuild Capistrano Substation.
14.	3.2.12	2-22	Lines 27-29	There is no mention of a 230 kV voltage control device, capacitors, or a dynamic voltage control device. These pieces of equipment would likely be needed as part of a Trabuco Substation Alternative. All elements required for the double circuit 230kV transmission line segment must be accounted for.
15.	3.2.12	2-23	Lines 5-7	The RDEIR states that the "CPUC's review of the applicant's power flow data indicates that Alternative J would ensure that each of the potential Category C (N-1-1) contingencies identified by the applicant and CAISO (Section 1.2.1) would be avoided through the 10-year planning period." This statement misstates the relevant inquiry. The proper question is whether Alternative J allows SDG&E to comply with mandatory NERC, WECC and CAISO reliability standards. That must be determined by running power flow analysis of the electric system as modified by Alternative J against NERC contingencies, including Category C (N-1-1) contingencies. SDG&E and CAISO power flow analyses referred to in Section 1.2.1 analyzed the then-current electric system, and as modified by the Proposed Project, against NERC contingencies. Alternative J includes an interconnection with SCE's transmission system, and that change to the electric system was not modeled in any of the power flow analyses referred to in Section 1.2.1. SDG&E provided Energy Division with power flow results showing NERC violations for both ORA's Trabuco Alternative and the RDEIR Alternative J as part of SDG&E's Rebuttal Testimony and Second Supplemental Testimony.
16.	Impact LU-2	2-144	Lines 14-16	The RDEIR states: "However, the proposed project would directly conflict with applicable building height regulations defined within the San Juan Capistrano Municipal Code." The Commission's General Order 131-D, CPUC Decision 94-06-014, and numerous court rulings confirm that the CPUC has exclusive jurisdiction over the construction of electric utility facilities, preempting local ordinances. Therefore the local ordinances cited in the RDEIR are not "applicable" to the Proposed Project.
4.4 – Biological Resources				
17.	4.4	N/A	N/A	Please refer to SDG&E's detailed comment letter for overarching comments on the Biological Resources Section of the Recirculated DEIR. Specific comments on the content of Section 4.4 are provided below.
18.	Impact BR-6	2-77	Line 4	Text states "the proposed project may conflict with two conservation easements established within the Orange County Southern Subregion HCP…" The Talega Conservation Easement has not been recorded, cannot be viewed or reviewed by the public or SDG&E, and therefore should not be described as "established". The Easement has no legal power until it has been recorded. SDG&E has rights that supersede any existing or proposed conservation easements as SDG&E's ROW pre-date all conservation easements in the Project area.

Comment #	Section Name	Page #	Paragraph or Table #	General Comment
19.	Impact BR-6	2-77	Lines 14-16	As an initial matter, any activities conducted by SDG&E within existing SDG&E ROW, Easement, or fee-owned property would not cause a conflict with any subsequently recorded conservation easement or with the provisions of the Orange County Southern Region HCP. The Proposed Project crosses the Prima Deschecha Landfill Conservation Easement at two locations, and contains one proposed new 230kV structure (No. 26), the removal of existing 138kV structures, and the use of existing unpaved access roads. See Exhibit 6 (Second Supplemental Testimony, Attachment 50). The Proposed Project would require temporary work space for the construction of the new 230kV structure and permanent work space for the inspection and maintenance of the 230kV structure (No. 26) for the life of the project (refer to Exhibit 6 (Second Supplemental Testimony, Attachment 51 [Structure 26 Detail Map] and Attachment 52 [Structure 26 Aerial Photograph]). All ground disturbing activities (e.g. grading, grubbing, and vegetation removal) will be contained within the limits of SDG&E's existing ROW. SDG&E would also utilize the existing access road network during construction and operation (refer to Attachment 50). SDG&E's rights to its 150-foot ROW in this area includes the ongoing use of the existing network of unpaved access roads that lead to and connect all existing structures, as well as existing structures owned and operated by SCE within its adjacent ROW. In addition, as shown in Attachments 51and 52, the small portion (approximately 210 square feet) of the Structure 26 work area that could extend outside of SDG&E's existing ROW is limited to the existing roadbed (access road), and no earthwork (grading, grubbing, clearing, etc.) would be required. This area could be used for the placement of construction equipment (such as a crane) or maintenance equipment (such as an aerial bucket truck). As existing road bed, this area is already disturbed. During a meeting with between SDG&E and USFWS on September 11, 2015, the USFWS agreed that this particular scope of work anticipated at this location (Structure 26) would not create a conflict between the Proposed Project and that Prima Deschecha Conservation Easement. USFWS agreed that the Proposed Project would not conflict with the Prima Deschecha Landfill Conservation Easement as work associated with the Proposed Project would be contained within SDG&E existing rights pursuant to SDG&E ROW Easement. Therefore, impacts (if any) of the Proposed Project on the existing Prima Deschecha Landfill Conservation Easement would be less than significant. The Final EIR should incorporate this corrected determination of impacts in the Biological Resources and Land Use and Planning sections.
20.	Impact BR-6	2-75	Line 44	NCCP Implementing Agreement (page16) Section 6.2(a)(3) states the following: (3) *This Agreement provides adequately for the mitigation of potential "significant effects on the environment," as defined in Public Resources Code 66474, that may result from Activities in the Subregional Plan Area.* Therefore, the conclusion for Impact BR-6 should be "Less than Significant With Mitigation" rather than "Significant."
21.	Impact BR-6	2-76	Lines 28-30	This text states that "[t]he SDG&E Subregional NCCP/HCP does not specify a process for coordination with all landowners, conservation easement holders, and regional plans in the proposed project area to determine the locations of preserve areas (SDG&E 1995a,b)." However, NCCP Implementing Agreement (page14) Section 5. 7 states the following: *Whenever any portion of the Subregional Plan Area falls within the boundaries of a Preserve Area, SDG&E will coordinate with USFWS and CDFG in respect of SDG&E Activities within such Preserve Area in accordance with the provisions and procedures of Sections 6 and 7 of the Subregional Plan, and the management entity for any such* *Preserve Area to avoid impacts to Covered Species and biological resources and where impacts are unavoidable to· minimize or mitigate such impacts, as more fully set forth in Section 6 and 7 of the Subregional Plan.* This section of the Implementing Agreement does provide a process for coordination with all landowners, conservation easement holders and regional plans in the proposed project area to determine the locations of preserve areas by coordinating with the USFWS and CDFW (aka CDFG), who would provide approval for the designation of Preserve.
				4.5 – Cultural Resources
22.	4.5	N/A	N/A	Please refer to SDG&E's detailed comment letter for overarching comments on the Cultural Resources Section of the Recirculated DEIR. Specific comments on the content of Section 4.5 are provided below.
				4.10 – Land Use and Planning
23.	4.10	N/A	N/A	Please refer to SDG&E's detailed comment letter for overarching comments on the Land Use and Planning Section of the Recirculated DEIR regarding zoning pre-emption and conservation easements.

Comment #	Section Name	Page #	Paragraph or Table #	General Comment
				5.0 – Comparison of Alternatives
24.	5.0	N/A	N/A	Please refer to SDG&E's detailed comment letter for overarching comments on the Comparison of Alternatives section of the Recirculated DEIR. Specific comments on the content of Section 5.0 are provided below.
25.	5.2	2-148	Lines 38-40	Text refers to the Proposed Project and asserts significant impacts from "(i.e., impacts on air quality, biological resources, cultural resources, land use and planning, transportation and traffic, and cumulative impacts)." This statement is in error. With respect to traffic impacts, as stated in SDG&E's April 10, 2015 Comments on the Draft EIR, Detailed Comments at 3-4: "SDG&E's construction and engineering contractors do not expect a full closure of any of these roads during underground construction and SDG&E did not state there would be any full road closures in the PEA. The Project refinements identified in more detail in Attachment A – Minor Project Design Refinements (Dated April, 2015) will eliminate the temporary and cumulative traffic impacts." With respect to biological and land use impacts, as set forth in SDG&E's September 24, 2015 RDEIR Comments, SDG&E is in full compliance with its Natural Communities Conservation Plan ("NCCP") and, with the Segment 4 Design Revision set forth in Exhibit 2, bringing permanent transmission structures within SDG&E's existing easements, the United States Fish & Wildlife Service ("USFWS") has agreed that no conflict between the Proposed Project and recorded and potential conservation easements is expected. With respect to land use impacts on local height limitations, the Commission's General Order 131-D, CPUC Decision 94-06-014, and numerous court rulings confirm that the CPUC has exclusive jurisdiction over the construction of electric utility facilities, preempting local ordinances. Therefore the local ordinances cited in the RDEIR are not applicable to the Proposed Project. With respect to the potential historical resource, on August 21, 2015, SDG&E submitted to the Keeper its objection to the proposed determination of eligibility of the existing utility structure for the NRHP, opposing the SHRC's recommendation. If the Keeper finds that the existing utility structure is not eligible for listing on the NRHP, then the Proposed Project would not have a significant effect on any historical resource.
26.	5.2.1	2-151	Lines 9-12	Text states that "it is assumed that none of the components of the proposed project would be constructed" and "minor maintenance work would occur as needed to repair or replace failed or inadequate substation equipment." CEQA Guideline § 15126.6(e)(2) requires the EIR to discuss "what would be reasonably expected to occur in the foreseeable future if the project were not approved." This is necessary to "allow meaningful evaluation, analysis, and comparison with the proposed project" and to "foster meaningful public participation and informed decision making." *Id.* § 15126.6(d), (f). This statement does not reflect what is reasonably expected to occur in the foreseeable future. As SDG&E repeatedly has informed Energy Division in response to data requests and as set forth in attached Exhibit 3 (SDG&E Corrected Opening Testimony, Chapter 5), Exhibit 4 (Corrected Supplemental Testimony, Chapter 3, Section 3, Chapter 4, Section 3, Chapter 5, Section 4), Exhibit 5 (Corrected Rebuttal Testimony, Chapter 5, Section 8, Chapter 8, Section 7, Chapter 9, Section 7), and Exhibit 6 (Second Supplemental Testimony, Chapter 4, Section 6) (all of which has been served on Energy Division), under all Alternatives to the Proposed Project, the 138/12kV substation at Capistrano would still need to be rebuilt to provide reliable electric service to SDG&E's customers served by that substation, primarily in the City of San Juan Capistrano. SDG&E has a legal obligation to provide reliable electric service, and rebuilding Capistrano, at least as a 138/12 kV substation, is a reasonably anticipated action under all Alternatives as well as the Proposed Project. As set forth in the above testimony, many of the Alternatives would require expansion of the Capistrano 138 kV yard to accommodate a new 138kV line to Capistrano.
27.	5.2.1	2-151	Lines 16-17	Text states: "It is anticipated that minor maintenance work would occur as needed to repair or replace failed or inadequate substation equipment and transmission line facilities as described in Chapter 3, 'Description of Alternatives.'" At page 2-6, the RDEIR describes two overloads under NERC Category C contingencies and states: "Other Category C (N-1-1) scenarios are also possible by 2020, but these are the two worst-case (highest potential overload) scenarios described by the applicant. In accordance with CPUC General Order 131-D, it is anticipated that the applicant would implement system adjustments (e.g., reconductor 138-kV line segments) prior to this date to ensure that some or all of these overload scenarios do not occur." CEQA Guideline § 15126.6(e)(2) requires the EIR to discuss "what would be reasonably expected to occur in the foreseeable future if the project were not approved." This is necessary to "allow meaningful evaluation, analysis, and comparison with the proposed project" and to "foster meaningful public participation and informed decision making." *Id.* § 15126.6(d), (f). The RDEIR, Section 5.2.1 and Table 5-1 fail to do so.
28.	5.2.2	2-151 2-152 2-153	Lines 38, 44 Line 38 Lines 16-17, 22, 30	Text states that "Alternative B1 does not include the expansion of the existing Capistrano Substation." CEQA Guideline § 15126.6(e)(2) requires the EIR to discuss "what would be reasonably expected to occur in the foreseeable future if the project were not approved." This is necessary to "allow meaningful evaluation, analysis, and comparison with the proposed project" and to "foster meaningful public participation and informed decision making." *Id.* § 15126.6(d), (f). This statement does not reflect what is reasonably expected to occur in the foreseeable future. As SDG&E repeatedly has informed Energy Division in response to data requests and as set forth attached Exhibit 3 (SDG&E Corrected Opening Testimony, Chapter 5), Exhibit 4 (Corrected Supplemental Testimony, Chapter 3, Section 3, Chapter 4, Section 3, Chapter 5, Section 4), Exhibit 5 (Corrected Rebuttal Testimony, Chapter 5, Section 8, Chapter 8, Section 7, Chapter 9, Section 7), and Exhibit 6 (Second Supplemental Testimony, Chapter 4, Section 6) (all of which has been served on Energy Division), under all Alternatives to the Proposed Project, the 138/12kV substation at Capistrano would still need to be rebuilt to provide reliable electric service to SDG&E's customers served by that substation, primarily in the City of San Juan Capistrano. SDG&E has a legal obligation to provide reliable electric service, and rebuilding Capistrano, at least as a 138/12 kV substation, is a reasonably anticipated action under all Alternatives as well as the Proposed Project. As set forth in the above testimony, many of the Alternatives would require expansion of the Capistrano 138 kV yard to accommodate a new 138kV line to Capistrano.

Comment #	Section Name	Page #	Paragraph or Table #	General Comment
29.	5.2.3	2-154 2-155	Line 8, 14, 22, 32, 38 Lines 5, 18-19, 24, 32,	Text states that "Alternative B2 does not include the expansion of the existing Capistrano Substation." CEQA Guideline § 15126.6(e)(2) requires the EIR to discuss "what would be reasonably expected to occur in the foreseeable future if the project were not approved." This is necessary to "allow meaningful evaluation, analysis, and comparison with the proposed project" and to "foster meaningful public participation and informed decision making." *Id.* § 15126.6(d), (f). This statement does not reflect what is reasonably expected to occur in the foreseeable future. As SDG&E repeatedly has informed Energy Division in response to data requests and as set forth attached Exhibit 3 (SDG&E Corrected Opening Testimony, Chapter 5), Exhibit 4 (Corrected Supplemental Testimony, Chapter 3, Section 3, Chapter 4, Section 3, Chapter 5, Section 4), Exhibit 5 (Corrected Rebuttal Testimony, Chapter 5, Section 8, Chapter 8, Section 7, Chapter 9, Section 7), and Exhibit 6 (Second Supplemental Testimony, Chapter 4, Section 6) (all of which has been served on Energy Division), under all Alternatives to the Proposed Project, the 138/12kV substation at Capistrano would still need to be rebuilt to provide reliable electric service to SDG&E's customers served by that substation, primarily in the City of San Juan Capistrano. SDG&E has a legal obligation to provide reliable electric service, and rebuilding Capistrano, at least as a 138/12 kV substation, is a reasonably anticipated action under all Alternatives as well as the Proposed Project. As set forth in the above testimony, many of the Alternatives would require expansion of the Capistrano 138 kV yard to accommodate a new 138kV line to Capistrano.
30.	5.2.4	2-156 2-157	Lines 13, 19 Lines 13, 26-27, 32, 40	Text states that "Alternative B3 does not include the expansion of the existing Capistrano Substation." CEQA Guideline § 15126.6(e)(2) requires the EIR to discuss "what would be reasonably expected to occur in the foreseeable future if the project were not approved." This is necessary to "allow meaningful evaluation, analysis, and comparison with the proposed project" and to "foster meaningful public participation and informed decision making." *Id.* § 15126.6(d), (f). This statement does not reflect what is reasonably expected to occur in the foreseeable future. As SDG&E repeatedly has informed Energy Division in response to data requests and as set forth in attached Exhibit 3 (SDG&E Corrected Opening Testimony, Chapter 5), Exhibit 4 (Corrected Supplemental Testimony, Chapter 3, Section 3, Chapter 4, Section 3, Chapter 5, Section 4), Exhibit 5 (Corrected Rebuttal Testimony, Chapter 5, Section 8, Chapter 8, Section 7, Chapter 9, Section 7), and Exhibit 6 (Second Supplemental Testimony, Chapter 4, Section 6) (all of which has been served on Energy Division), under all Alternatives to the Proposed Project, the 138/12kV substation at Capistrano would still need to be rebuilt to provide reliable electric service to SDG&E's customers served by that substation, primarily in the City of San Juan Capistrano. SDG&E has a legal obligation to provide reliable electric service, and rebuilding Capistrano, at least as a 138/12 kV substation, is a reasonably anticipated action under all Alternatives as well as the Proposed Project. As set forth in the above testimony, many of the Alternatives would require expansion of the Capistrano 138 kV yard to accommodate a new 138kV line to Capistrano.
31.	5.2.8	2-163 2-164	Lines 26, 32 Lines 31, 48	Text states that "Alternative D does not include the expansion of the existing Capistrano Substation." CEQA Guideline § 15126.6(e)(2) requires the EIR to discuss "what would be reasonably expected to occur in the foreseeable future if the project were not approved." This is necessary to "allow meaningful evaluation, analysis, and comparison with the proposed project" and to "foster meaningful public participation and informed decision making." *Id.* § 15126.6(d), (f). This statement does not reflect what is reasonably expected to occur in the foreseeable future. As SDG&E repeatedly has informed Energy Division in response to data requests and as set forth in attached Exhibit 3 (SDG&E Corrected Opening Testimony, Chapter 5), Exhibit 4 (Corrected Supplemental Testimony, Chapter 3, Section 3, Chapter 4, Section 3, Chapter 5, Section 4), Exhibit 5 (Corrected Rebuttal Testimony, Chapter 5, Section 8, Chapter 8, Section 7, Chapter 9, Section 7), and Exhibit 6 (Second Supplemental Testimony, Chapter 4, Section 6) (all of which has been served on Energy Division), under all Alternatives to the Proposed Project, the 138/12kV substation at Capistrano would still need to be rebuilt to provide reliable electric service to SDG&E's customers served by that substation, primarily in the City of San Juan Capistrano. SDG&E has a legal obligation to provide reliable electric service, and rebuilding Capistrano, at least as a 138/12 kV substation, is a reasonably anticipated action under all Alternatives as well as the Proposed Project. As set forth in the above testimony, many of the Alternatives would require expansion of the Capistrano 138 kV yard to accommodate a new 138kV line to Capistrano.
32.	5.2.9	2-165 2-166 2-167	Lines 37, 43 Lines 1, 29, 42, 48 Line 7	Text states that "Alternative E does not include the expansion of the existing Capistrano Substation." CEQA Guideline § 15126.6(e)(2) requires the EIR to discuss "what would be reasonably expected to occur in the foreseeable future if the project were not approved." This is necessary to "allow meaningful evaluation, analysis, and comparison with the proposed project" and to "foster meaningful public participation and informed decision making." *Id.* § 15126.6(d), (f). This statement does not reflect what is reasonably expected to occur in the foreseeable future. As SDG&E repeatedly has informed Energy Division in response to data requests and as set forth in attached Exhibit 3 (SDG&E Corrected Opening Testimony, Chapter 5), Exhibit 4 (Corrected Supplemental Testimony, Chapter 3, Section 3, Chapter 4, Section 3, Chapter 5, Section 4), Exhibit 5 (Corrected Rebuttal Testimony, Chapter 5, Section 8, Chapter 8, Section 7, Chapter 9, Section 7), and Exhibit 6 (Second Supplemental Testimony, Chapter 4, Section 6) (all of which has been served on Energy Division), under all Alternatives to the Proposed Project, the 138/12kV substation at Capistrano would still need to be rebuilt to provide reliable electric service to SDG&E's customers served by that substation, primarily in the City of San Juan Capistrano. SDG&E has a legal obligation to provide reliable electric service, and rebuilding Capistrano, at least as a 138/12 kV substation, is a reasonably anticipated action under all Alternatives as well as the Proposed Project. As set forth in the above testimony, many of the Alternatives would require expansion of the Capistrano 138 kV yard to accommodate a new 138kV line to Capistrano.

Comment #	Section Name	Page #	Paragraph or Table #	General Comment
33.	5.2.10	2-167 2-168	Lines 30, 36 Lines 3, 22, 30,	Text states that "Alternative F does not include the expansion of the existing Capistrano Substation." CEQA Guideline § 15126.6(e)(2) requires the EIR to discuss "what would be reasonably expected to occur in the foreseeable future if the project were not approved." This is necessary to "allow meaningful evaluation, analysis, and comparison with the proposed project" and to "foster meaningful public participation and informed decision making." *Id.* § 15126.6(d), (f). This statement does not reflect what is reasonably expected to occur in the foreseeable future. As SDG&E repeatedly has informed Energy Division in response to data requests and as set forth attached Exhibit 3 (SDG&E Corrected Opening Testimony, Chapter 5), Exhibit 4 (Corrected Supplemental Testimony, Chapter 3, Section 3, Chapter 4, Section 3, Chapter 5, Section 4), Exhibit 5 (Corrected Rebuttal Testimony, Chapter 5, Section 8, Chapter 8, Section 7, Chapter 9, Section 7), and Exhibit 6 (Second Supplemental Testimony, Chapter 4, Section 6) (all of which has been served on Energy Division), under all Alternatives to the Proposed Project, the 138/12kV substation at Capistrano would still need to be rebuilt to provide reliable electric service to SDG&E's customers served by that substation, primarily in the City of San Juan Capistrano. SDG&E has a legal obligation to provide reliable electric service, and rebuilding Capistrano, at least as a 138/12 kV substation, is a reasonably anticipated action under all Alternatives as well as the Proposed Project. As set forth in the above testimony, many of the Alternatives would require expansion of the Capistrano 138 kV yard to accommodate a new 138kV line to Capistrano.
34.	5.2.12	2-171 2-172 2-173	Lines 27, 37 Lines 7, 21, 47-48 Line 5	Text states that "Capistrano Substation would not be expanded, but equipment at Capistrano Substation found to be inadequate would be replaced." CEQA Guideline § 15126.6(e)(2) requires the EIR to discuss "what would be reasonably expected to occur in the foreseeable future if the project were not approved." This is necessary to "allow meaningful evaluation, analysis, and comparison with the proposed project" and to "foster meaningful public participation and informed decision making." *Id.* § 15126.6(d), (f). This statement does not reflect what is reasonably expected to occur in the foreseeable future. As SDG&E repeatedly has informed Energy Division in response to data requests and as set forth in attached Exhibit 3 (SDG&E Corrected Opening Testimony, Chapter 5), Exhibit 4 (Corrected Supplemental Testimony, Chapter 3, Section 3, Chapter 4, Section 3, Chapter 5, Section 4), Exhibit 5 (Corrected Rebuttal Testimony, Chapter 5, Section 8, Chapter 8, Section 7, Chapter 9, Section 7), and Exhibit 6 (Second Supplemental Testimony, Chapter 4, Section 6) (all of which has been served on Energy Division), under all Alternatives to the Proposed Project, the 138/12kV substation at Capistrano would still need to be rebuilt to provide reliable electric service to SDG&E's customers served by that substation, primarily in the City of San Juan Capistrano. SDG&E has a legal obligation to provide reliable electric service, and rebuilding Capistrano, at least as a 138/12 kV substation, is a reasonably anticipated action under all Alternatives as well as the Proposed Project. As set forth in the above testimony, many of the Alternatives would require expansion of the Capistrano 138 kV yard to accommodate a new 138kV line to Capistrano.
35.	5.2.12	2-171	Lines 3-6	Text states that the Trabuco Substation expansions would utilize an approximately 2-acre parcel located north of the existing Trabuco Substation. However, as stated within SDG&E's testimony relating to the Trabuco Alternative, approximately 6 -7 acres of total area would be needed to adequately construct a new 230/138/12kV substation at the Trabuco site. This would require acquisition of not only the 2.7-acre north adjacent parcel, but also the southern adjacent parcel (approximately 1.0 acre).
36.	5.2.8	2-165	Line 20	Text states that "Alternative D would have similar significant impacts on biological resources, cultural resources, and land use." However, this contradicts page 2-163 (lines 26 – 29), which states that Alternative D would avoid significant impacts to cultural resources.
37.	5.2.10	2-167	Lines 36 – 42	Text states that Alternative F (230kV RMV Substation) would "substantially reduce impacts to land use and planning" because the 230kV substation would not be constructed and the Capistrano site, thus eliminating conflicts with local zoning codes governing the maximum height of structures. However, the RMV substation would be constructed to similar specifications as the San Juan Capistrano, and would therefore be anticipated to include GIS buildings approximately 50 feet in height. DEIR section 5.2.10 does not contain a discussion of the consistency of 50-foot buildings with the County of Orange Zoning Ordinance at the RMV site. The Recirculated DEIR (page 2-163, lines 43 – 45) states that 50-foot GIS buildings would create a significant impact at the Prima Deschecha Landfill site, which is also located within unincorporated Orange County. Ultimately, although consistency with local zoning requirements is addressed in an inconsistent manner between alternatives, the Recirculated DEIR fails to acknowledge that local ordinances setting height limitations are preempted by the CPUC's exclusive jurisdiction over substation construction.
38.	5.2.11	2-169	Line 16	Text includes reference "(SCE 2012)". This reference is not included within either the DEIR References (CPUC February 2015) or the Recirculated DEIR References (CPUC August 2015).
39.	5.2.12	2-171	Lines 26 - 28	The text states that the Trabuco Substation alternative would not require reconductoring throughout the 138kV system. This is not necessarily true. As further explained in the comments to Recirculated DEIR Section 3 and SDG&E's testimony, a third (new) 138kV power line would be required between Trabuco and Capistrano. The potential impacts from this 138kV work are not addressed within Section 5.2.12 of the Recirculated DEIR. While the exact impacts associated with this 138kV work cannot be known without at least a preliminary design, impacts would reasonably be anticipated to be greater than those disclosed in the Recirculated DEIR for the Trabuco Substation alternative. Specifically, impacts associated with air quality, biological resources, and cultural resources, would likely increase (compared to the Trabuco Substation alternative as described in the Recirculated DEIR) due to the larger scope of work and impact area alone. Impacts to traffic and transportation would also increase as the existing 138kV alignment between Trabuco and Capistrano is located adjacent to the existing railroad alignment, and also crosses SR-73 and numerous local roadways.

Comment #	Section Name	Page #	Paragraph or Table #	General Comment
40.	5.2.12	2-171	Lines 31-33	The DEIR assumes a reduction in air emission commensurate with the reduction in the area of disturbance. This method does not necessarily provide an accurate comparison of anticipated emissions. The majority of air emissions (for criteria pollutants) are a direct result of the number and duration of use of heavy construction equipment. Disturbance area does not necessarily equate to the amount of heavy construction equipment usage, and thus emissions. Therefore, assuming an 88 percent reduction in emissions is not correct. While assuming a Trabuco Substation alternative could result in overall heavy equipment usage, some reduction of total emissions of criteria pollutants could reasonably be assumed. However, a determination of the exact reduction amount cannot be accurately completed without actually describing a construction scenario and calculating the impacts in a similar method as was completed for the Proposed Project. In addition, the assertion that the Trabuco Substation alternative would reduce emissions below significance thresholds is unsubstantiated and not likely to be correct. While the apparent reduced scope of work the Trabuco Substation Alternative could be assumed to reduce total emissions, the emissions from specific scopes of work or phases of construction could have similar, significant impacts resulting from the emissions of criteria pollutants, including exceedance of localized significance thresholds (LSTs). For example, construction of the 230kV substation at the San Juan Capistrano Substation site would result in exceedance of regional and localized thresholds for NOx, PM_{10}, and $PM_{2.5}$. It is reasonable that construction of the 230kV yard at Trabuco would result in similar emission during substation construction. In addition, as stated in comments to Recirculated DEIR Section 3, SDG&E asserts that the 138/12kV Capistrano Substation would need to be rebuilt and expanded as part of a Trabuco Substation Alternative. Thus, impacts to air quality would still occur at the Capistrano Substation site similar to the Proposed Projects impacts for demolition, site development, and construction of the 138/12kV substation. Impacts from construction of the 230kV yard would be shifted to the Trabuco Substation site. Finally, impacts relating to the emission of criteria pollutants could reasonably be anticipated to be higher for the Trabuco Substation Alternative when compared to the Proposed Project, with respect to substation construction activities. While actual impacts cannot be known due to the lack of detailed design for the Trabuco Alternative, the Trabuco Substation Alternative would include more substation construction activities than the Proposed Project, and thus could ultimately result in higher total emissions and more exceedances of regional and local significance thresholds. The Proposed Project, which would limit major substation construction to the Capistrano site, would include three major phases of construction: 1) demolition (lower and upper yards); 2) site development and grading (lower and upper yards); and 3) substation construction (lower/138kV and upper/230kV). Comparatively, the Trabuco Substation Alternative could require up to six major phases of substation construction spread between two sites (Capistrano and Trabuco). Specifically the Trabuco Substation Alternative would require the following phases at the Trabuco Substation Site: 1) demolition (would occur across the entire expanded site, including both demolition of structures and facilities for the two acquired properties, and demolition of the existing Trabuco 138/12kV substation facilities and getaways); 2) site development and grading (would occur across the entire expanded site); and 3) substation construction, including the rebuilding of the 138/12kV yard and the construction of the new 230/138kV yard. Additionally, the Capistrano Substation would also require major construction, including 1) demolition (lower and upper yards); 2) site development and grading (lower yard only); and 3) substation construction (lower yard, 138/12kV only). Thus, due to the potentially increased substation construction activities, the Trabuco Substation Alternative could require greater amounts of heavy construction equipment, longer cumulative construction duration, and larger disturbance area (6-7 acres at the Trabuco site in addition to the 6.4 acres at the Capistrano Site). Depending upon the actual design and construction scenario for the Trabuco Substation Alternative, impacts to air quality (emissions of criteria pollutants) from substation construction could increase when compared to the Proposed Project.
41.	5.2.11	2-172	Lines 21 – 35	Text states that Alternative J would reduce significant impacts relating to City of San Juan Capistrano zoning height restrictions because Alternative J would not include expansion of the Capistrano Substation. However, as noted above, CPUC’s jurisdiction preempts local land use laws, including height restrictions, and thus a utility project could not conflict with such laws because they are not applicable. Therefore, Alternative J does not reduce significant impacts to land use as compared to the Proposed Project, because such significant impact does not exist.
42.	5.2.12	2-172	Lines 44 – 47	Text states that Alternative J would avoid significant impacts to traffic and transportation, in part by avoiding impacts resulting from underground installation of 138 and 12kV lines west of the Capistrano Substation site (including impacts along Camino Capistrano). However, as previously stated within SDG&E’s comments on Recirculated DEIR Section 3, SDG&E believes that construction and operation of a new 230kV substation at the Trabuco site would still require the reconstruction and expansion of the Capistrano 138/12kV substation. While there would be no 230kV construction at the Capistrano site under the Trabuco Substation Alternative, the potential traffic impacts along Camino Capistrano and Calle San Diego are a result of underground construction of 138kV and 12kV lines, which would still occur as part of the 138/12kV Capistrano Substation rebuild that would still be required under the Trabuco Substation Alternative. Therefore, the impacts to traffic and transportation at Camino Capistrano and Calle San Diego would be similar for the Proposed Project and the Trabuco Substation Alternative.
43.	5.2.12	N/A	N/A	The Recirculated DEIR does not provide sufficient design for the Trabuco Substation Alternative to accurately compare the anticipated impacts to those of the Proposed Project. In addition to the missing scope items (such as the 138kV system upgrades, rebuild of the Capistrano 138/12kV substation, and rebuild of the Trabuco 138/12kV substation) identified within the other comments to Sections 3 and 5 of the Recirculated DEIR, SDG&E believes that other system upgrades are likely in order to complete the interconnection with the SCE system. Because the potential interconnection with SCE at the Trabuco Substation has not been studied by SDG&E, SCE, or the CAISO, the scope of potential system upgrades cannot be known at this time. Therefore, the comparison of the adverse impacts anticipated for the Trabuco Substation Alternative and Proposed Project is flawed, and the potential reduction in impacts that Trabuco Alternative may have is being greatly overstated.

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44.	5.2.12	2-172	Lines 44 – 47	The text states that construction of new 230kV underground "may require partial closures along Camino Capistrano in an industrial area of the City of Laguna Niguel; however, no full road closures are anticipated." This statement is not correct and is misleading. Construction of new 230kV underground, if possible, would require at a minimum partial closure of Camino Capistrano and could require complete closure. Camino Capistrano is a two lane road between the Trabuco Substation and existing SCE transmission lines, and varies in width; however the Oso Creek bridge crossing bottlenecks to approximately 25 feet in width. Assuming that sufficient space exists for installation of new underground 230kV (see comments to Section 3 above), construction would require a minimum of 20 feet, which would result in a minimum closure of one lane of traffic during construction. The OSO Creek crossing may also present many challenges to construction and may require more challenging construction methods due to the age, size and congestion of other utilities on the side of or internal to the bridge. The horizontal drilling method is a method that may work, however, it would require substantial space to accommodate construction on either side of the Oso Creek bridge and may require full road closures during construction and presents risks to the environment such as frac-out. Similarly, if the alternative 230kV connection route is selected (east of I-5, along La Alameda and Los Altos roads), construction of the 230kV underground connection would also require, at a minimum, closure of one lane of traffic, which would equate to half of each of the two-lane roads along the underground alignment. As stated in the DEIR (Section 4.15, Pg. 4.15-19, lines 11-12), complete closure of a roadway during underground construction would be considered a significant impact under CEQA.
45.	5.2.12	2-172	Lines 47 – 50	The text states that the Trabuco Substation Alternative does not include expansion of the Capistrano Substation, and as such would not have cumulative impacts on traffic and transportation associated with the partial closure of Camino Capistrano west of the substation site. However, this statement is not necessarily correct. As described in SDG&E comments to Recirculated DEER Sections 3 and 5, the 138/12kV Capistrano Substation would need to be rebuilt and expanded as part of the Trabuco Substation Alternative. While there would be no 230kV construction at the Capistrano site under the Trabuco Substation Alternative, the potential cumulative traffic impacts along Camino Capistrano are a result of underground construction of 138kV and 12kV lines, which would still occur as part of the 138/12kV Capistrano Substation rebuild that would still be required under the Trabuco Substation Alternative. Therefore, the cumulative impacts to traffic and transportation at Camino Capistrano would be similar for the Proposed Project and the Trabuco Substation Alternative.
46.	5.2.12	2-173	Lines 10 – 15	Text concludes that the Trabuco Substation would reduce impacts to air quality and land use, but these impacts would remain significant (lines 10 & 11). However, lines 12 and 13 contradict this by stating that impacts to air quality would be reduced to less than significant. While a detailed design and construction scenario would be needed to estimate air emissions, SDG&E believes that while the Trabuco Alternative may reduce overall air emissions, it is likely that certain phases of construction (such as site development and substation construction) could continue to result in temporary, significant exceedances of regional and local significance thresholds in a similar manner to the Proposed Project.