**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, for a Permit to Construct the Vierra Reinforcement Project Pursuant to General Order 131-D (U 39 E)	Application No. 18-06-____

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) FOR A PERMIT TO CONSTRUCT THE VIERRA REINFORCEMENT PROJECT

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June 6, 2018

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FOR A PERMIT TO CONSTRUCT THE
VIERRA REINFORCEMENT PROJECT

Pursuant to Section IX(B) of General Order ("GO") 131-D and Rules 2.1 through 2.5 and 3.1 of the California Public Utilities Commission's ("Commission" or "CPUC") Rules of Practice and Procedure, Pacific Gas and Electric Company ("PG&E") respectfully requests a Permit to Construct ("PTC") the Vierra Reinforcement Project ("project") to expand Vierra Substation and install a new 115 kilovolt ("kV") power line between the substation and the Tesla-Stockton Cogen Junction 115 kV Power Line in the City of Lathrop, San Joaquin County.

I. PROJECT OVERVIEW

The Vierra Reinforcement Project proposes to build a new, double-circuit 115 kV power line west from Vierra Substation approximately one mile to the existing Tesla-Stockton Cogen Junction 115 kV Power Line. The expanded substation and new line will provide more electrical capacity and reliability for households and businesses in Lathrop, Manteca, and surrounding areas of San Joaquin County.

The new line will reinforce the area's 115 kV system as well as the 60 kV systems connected to it at Kasson, Manteca, and Salado substations. The double-circuit line will be made up of the Tesla-Vierra and Vierra-Stockton Cogen Junction 115 kV power lines, located together on approximately 16 tubular steel poles ("TSPs"). It will be integrated into the existing system with new protection equipment at several area substations.

Vierra Substation will be expanded approximately 340 feet to the west and upgraded to a breaker-and-a-half ("BAAH") bus configuration, where each bay will have two elements (line or transformer connections) connected to three 115 kV circuit breakers. Using this configuration, only two breakers per BAAH bay are used at one time, allowing one breaker to be taken out of service without taking either of the two lines out of service. Additionally, the upgrade of Vierra Substation will allow for Howland Road Substation, located approximately 0.7 mile north of Vierra Substation and serving J.R. Simplot Company, to receive power directly from Vierra Substation instead of from the Vierra-Tracy-Kasson 115 kV Power Line, which is approximately 10.5 miles in length, thereby increasing the reliability of Howland Road Substation.

The California Independent Systems Operator ("CAISO") approved this project in its 2010-2011 Transmission Plan and, after reassessment in 2017, reaffirmed the approval in its 2017-2018 Transmission Plan. (*See* Exhibit E and Exhibit F.)

II. REGIONAL CONTEXT AND PROJECT COMPONENTS

A. Regional Context

1. Existing Regional Electric System

The heaviest electric load in this region is centered around the cities of Manteca and Lathrop, which are in the eastern and southeastern parts of the service area. These customers are served from the distant Tesla Substation, approximately 20 miles to the west, or the Tracy Combined Cycle Power Plant (formerly GWF Tracy Power Plant and referred to herein by that name), approximately five miles closer.

Power is transmitted to the load centers on four transmission paths that start at Tesla Substation and travel generally eastward on different routes toward Manteca Substation in the City of

Manteca. (*See* Figure 2.0-1: Existing and Proposed Tesla 115 kV System.) The paths (named for the substations they pass through) include:

- Tesla-Schulte-Lammers-Kasson 115 kV Power Line
- Tesla-Schulte-Kasson-Manteca 115 kV Power Line
- Tesla-Salado-Manteca 115 kV Power Line
- Tesla-Tracy-Kasson-Vierra-Manteca 115 kV Power Line

Much of the power for the Tesla 115 kV system is supplied by the GWF Tracy Power Plant, which connects directly into the Tesla-Schulte-Lammers-Kasson and Tesla-Schulte-Kasson-Manteca power lines east of Tesla Substation. The Tesla 115 kV system also receives stepped-down power at Tesla Substation from two 230/115 kV transformers.

The rest of the generation feeding Tesla Substation is connected to the Tesla-Stockton Cogen Junction 115 kV Power Line. This line begins at Stockton Cogen Junction, an open switch near the Stockton Cogen Substation and power plant approximately 25 miles northeast of Tesla Substation. The power line travels southerly approximately 10 miles to the San Joaquin River, where it is joined by the Ripon Cogen 115 kV Power Line, a 10-mile-long tap line from the Ripon Cogen Substation and power plant in the City of Ripon. The Tesla-Stockton Cogen Junction 115 kV Power Line then continues generally southwesterly from the river for approximately 15 miles to Tesla Substation, picking up additional power on the way from the Thermal Energy power plant approximately 4 miles east of Tesla Substation.

In the City of Lathrop, the Tesla-Stockton Cogen Junction 115 kV Power Line passes one mile west of Vierra Substation but does not currently connect to it. The substation is located at the southern edge of Lathrop just northwest of the City of Manteca and is connected to the Tracy-Kasson-Vierra and Manteca-Vierra 115 kV power lines extending from Tracy, Kasson and Manteca substations. Vierra, Tracy, Kasson and Manteca substations are directly or indirectly connected to Tesla Substation (making up parts of the Tesla-Tracy-Kasson-Vierra-Manteca 115 kV Power Line transmission path described above) and together serve power to over half of the electric load in the Tesla 115 kV system. At Vierra Substation, power is converted from 115 kV to 17 kV distribution voltage to serve area customers.

With electric generation and load located on opposite ends of the Tesla 115 kV system, heavy loading on sections of the four transmission paths between Tesla and Manteca substations could result from overlapping outages on two of the four transmission paths – known as a P6 planning event. If this were to happen within the existing 115 kV system, the remaining lines may not be able to handle the load.

2. Proposed Project

To improve system reliability and increase capacity by approximately 164 MW, PG&E proposes to construct a one-mile-long, double-circuit power line between the Tesla-Stockton Cogen Junction 115 kV Power Line and Vierra Substation. The new connecting line will provide a shortcut from the generation sources on the Tesla-Stockton Cogen Junction 115 kV Power Line through Vierra Substation to the Manteca load centers. It will also add a fifth transmission path for power to be transmitted from Tesla Substation to the load centers in the east and southeast of the service area. The fifth transmission path will add capacity to the system and reduce the loading on the existing four transmission paths, which will prevent overloads for any overlapping outages if a P6[1/] event takes two lines out of service.

1/ A category "P6" planning performance requirement, established by the North American Reliability Corporation (NERC), provides for purposes of this project that the electric system will operate reliably during the loss of two transmission circuits.

The project will upgrade Vierra Substation to a BAAH bus configuration to further improve reliability for the transmission paths connecting through Vierra Substation, and facilitate a direct connection to Howland Road Substation, located approximately 0.7 mile north of Vierra Substation.

B. Project Components

1. Power Line

The new power line between Vierra Substation and the existing Tesla-Stockton Cogen Junction 115 kV Power Line will be approximately one mile long and a double-circuit, composed of the Tesla-Vierra 115 kV Power Line and Vierra-Stockton Cogen Junction 115 kV Power Line. The power line will be supported by approximately 16 galvanized TSPs that range in height from approximately 80 to 90 feet above ground.

The new power line will originate at Vierra Substation, located in a primarily industrial area within the City of Lathrop north of State Route 120 and east of Interstate 5. It will extend approximately 1,000 feet west along the north side of Vierra Road, and then turn in a northwesterly direction for approximately 1,000 feet, crossing Union Pacific Railroad tracks at a perpendicular angle and paralleling the east side of D'Arcy Parkway. The alignment then turns west and extends along the south side of Christopher Way for approximately 2,000 feet, and then northwest along Nestle Way for approximately 800 feet to where it ties into the existing Tesla-Stockton Cogen Junction 115 kV Power Line on the west side of a private spur rail line serving the industrial park. (*See* Project Overview Map, attached as <u>Exhibit</u> A.)

2. Other Power Line Work

To enable the existing Tracy-Kasson-Vierra 115 kV Power Line to enter the expanded substation from the west, two double-circuit TSPs on the north side of Vierra Road, west of the substation expansion, will be replaced with one double-circuit TSP. Also, two single-circuit

TSPs at the southwest corner of the existing substation and one single-circuit TSP at the northwest corner of the existing substation will be replaced with four single-circuit TSPs on the west side of the substation expansion. These TSPs will range in height from approximately 75 to 85 feet.

Howland Road 115 kV Tap, a single-circuit line that currently branches off from the Tracy-Kasson-Vierra 115 kV Power Line at the northwest corner of the existing Vierra Substation, will be disconnected from the power line and connected directly into Vierra Substation. The southernmost wood pole on the Howland Road 115 kV Tap, which is approximately 38 feet in height, will be replaced with a light-duty steel pole approximately 57 feet in height, and a new TSP approximately 85 feet in height will be installed within the eastern portion of the substation expansion.

3. Substation Expansion

PG&E will acquire an approximately 3.4-acre parcel for the expansion of Vierra Substation, expanding the substation from 1.6 acres to a total of 5.0 acres to accommodate the new power line and substation modifications. The expansion will extend approximately 340 feet west of the existing substation and approximately 33 feet further back from Vierra Road than the existing substation. Substation modifications include converting the 115 kV bus into a four-bay BAAH bus arrangement and installing MPAC and battery buildings and a microwave communication tower.

A storm water retention pond will be constructed within the expanded substation, measuring approximately 300 feet long by 40 feet wide and 3 feet deep.

4. Additional Area Modifications

a. Remote End Work

The new line will be integrated into the existing system with new protection equipment at several area substations. These upgrades will occur within the existing substation fence lines and are expected to create minimal ground disturbance.

b. Telecommunications Facilities

Microwave towers or monopoles with dishes will be installed within the existing substation fence lines at Vierra, Kasson, Manteca, and Tracy substations. Microwave dishes will be installed on existing telecommunications towers at Mount Oso in northwestern Stanislaus County, approximately 6 miles northwest of the intersection of Del Puerto Canyon Road and Mount Oso Road, and at Highland Peak in southern Contra Costa County, approximately 4.5 miles west of the intersection of Morgan Territory Road and Manning Road. Additionally, antennas approximately 12 feet in length will be installed on existing microwave facilities at several third-party substations.

5. Staging and other Work Areas

Temporary staging areas within the project area will be used for a variety of purposes, including storing construction materials and equipment, parking vehicles and equipment, meeting areas, and as conductor pull and tension sites. Construction work areas will be located at or adjacent to the substation and around each pole along the project route. Approximately five pull and tension sites for installing the conductors will be located generally in line with the proposed power line alignment, typically at locations where the alignment changes direction. One light-type helicopter landing zone will be required for the approximately two days of helicopter operation to install the pulling line on the new TSPs. Construction vehicles are anticipated to access work areas and pull sites primarily by using existing paved roads.

III. THE APPLICANT

Since October 10, 1905, PG&E has been an operating public utility corporation, organized under the laws of the State of California. PG&E is engaged principally in the business of furnishing gas and electric service in California. PG&E's principal place of business is 77 Beale Street, San Francisco, California 94105.

Communications with regard to this Application should be addressed to:

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Incorporated herein by reference is a certified copy of PG&E's Articles of Incorporation, effective April 12, 2004, which was filed with the Commission in connection with PG&E's Application No. A.04-05-005 on May 3, 2004.

A copy of PG&E's most recent proxy statement dated April 10, 2018, was filed with the Commission on May 15, 2018, with Application 18-05-014 and is incorporated herein by reference. Copies of PG&E's most recent financial statements (contained in the Form 10-Q Quarterly Report filed on May 3, 2018, by PG&E Corporation and the Pacific Gas and Electric Company, for the period ending March 31, 2018), were filed with the Commission on May 15, 2018, with Application No. 18-05-014 and are incorporated herein by reference.

IV. ADDITIONAL INFORMATION REQUIRED BY SECTION IX (B) OF GO 131-D:

Pursuant to Rule 2.4 (b) of the Commission's Rules of Practice and Procedure, PG&E has submitted a PEA, which is attached as Exhibit B to this Application. The following information is required by Section IX.B of GO 131-D:

a. *A description of the proposed power line and substation facilities, including the proposed power line route; proposed power line equipment, such as tower design and appearance, heights, conductor sizes, voltages, capacities, substations, switchyards, etc., and a proposed schedule for authorization, construction, and commencement of operation of the facilities.*

A description of the proposed project, route, and components is contained in Section II.B above and in Chapter 2 of the PEA, Exhibit B. A Preliminary Project Schedule is attached as Exhibit C to this application.

b. *A map of the proposed power line routing or substation location showing populated areas, parks, recreational areas, scenic areas, and existing electrical transmission or power lines within 300 feet of the proposed route or substation.*

A project map showing the project route and existing power lines and populated areas within 300 feet of the project is attached as Exhibit A; *see also* Figures 2.0-2 and 2.0-3 in Chapter 2 of the PEA, Exhibit B. There are no parks, recreational or scenic areas near the project alignment, or State Scenic Highways or county or local scenic roadways that will be affected by the project.

c. *Reasons for adoption of the power line route or substation location selected, including comparison with alternative routes or locations, including the advantages and disadvantages of each.*

PG&E reviewed and studied alternative routes for the new power line within a study area approximately 4.6 square miles in size. Since the line would need to connect the Tesla-Stockton Cogen Junction 115 kV Power Line with the existing (to be expanded) Vierra Substation, the study area boundaries were generally Interstate Highway 5 on the west, East Louise Avenue on the north, a line approximately 0.70 miles east of Vierra Substation, and a line south of State Route 120. (*See* map attached as Exhibit G.) An additional consideration was connecting the new line to the Tesla-Stockton Cogen Junction line south of the Tesla Motors' Substation to decrease that substation's line exposure from approximately 35 miles to approximately 9 miles.

After screening for potential route corridors and seeking stakeholder feedback, 12 corridors were identified for review. Further evaluation, route reviews and stakeholder outreach eliminated 7 of these routes due to visual impacts from lines on each side of the road, Union Pacific Railroad opposition to a line parallel to the railroad tracks, and land use constraints associated with proposed land use developments. Five retained routes were then studied by PG&E engineering, as outreach and evaluation continued. These included routes entitled Christopher Way, Nestle Way, Guthmiller, Guthmiller 120 and West Gateway. (*See* map attached as Exhibit G.) Two consisted of options in the connection point to the Tesla-Stockton Cogen Junction 115 kV Power Line; the Nestle Way route is an option extending from the Christopher Way route, and the Guthmiller Road route is an option extending from the Guthmiller 120 route.

The retained routes all extend in a westerly direction from Vierra Substation, paralleling the north side of the Vierra-Tracy-Kasson 115 kV Power Line. The Christopher Way and Nestle Way routes then cross into an area that is already developed (water treatment plant and warehousing); the Guthmiller and West Gateway routes are in an area that is currently being planned for development (light industrial [warehousing] and commercial, and road improvements).

For all retained routes, the topography is generally flat; the highest elevation is where D'Arcy Parkway crosses the UPRR embankment and SR 120. While SR 120 is not a scenic route, the alternatives along Christopher Way and Nestle Way are less visible to traffic driving along the highway. The Guthmiller and West Gateway alternatives are also slightly longer than the Christopher Way and Nestle Way routes, and involve fewer landowners. No special-status plants were identified in the targeted survey area of the field east of D'Arcy Parkway during a survey conducted on May 25, 2017 (Christopher Way and Nestle Way routes). After the survey was conducted, the City of Lathrop initiated construction activities within the field, converting it to percolation basins and grading the entire area.

Nestle Way was selected as the proposed route because it has the least environmental constraints. It is also the shortest route and only has four landowners. The Christopher Way route is the second preference for the proposed route – it is similar to the Nestle Way route, but the tie-in point is more complex due to the presence of a split railroad spur. The Guthmiller, Guthmiller 120, and West Gateway routes are all feasible alternatives, but a proposed freeway interchange on Guthmiller at SR 120 and warehouse land use planning on the West Gateway Route would create challenges with respect to pole placement as planning for those developments has yet to be finalized, whereas area along the Nestle Way route is already developed.

d. A listing of the governmental agencies with which proposed power line route or substation location reviews have been undertaken, including a written agency response to applicant's written request for a brief position statement by that agency. (Such listing shall include The Native American Heritage Commission, which shall constitute notice on California Indian Reservation Tribal governments.) In the absence of a written agency position statement, the utility may submit a statement of its understanding of the position of such agencies.

In addition to the discussion below, an overview of PG&E's outreach to government agencies and others is contained in Chapter 1, section 1.3.1 of the PEA.

<u>Native American Heritage Commission</u>

PG&E's consultant requested a search of the Sacred Lands File from the Native American Heritage Commission ("NAHC') in June 2016. The NAHC identified six tribal groups with traditional or historical ties to the region who may have information about Native American resources within the project area. On July 8, 2017, PG&E sent letters to contacts at six Native American tribes, requesting information on resources in the siting study area and inviting general comments or questions pertaining to the project. Follow-up letters were sent to the same contacts plus one additional tribal group on September 27, 2017. PG&E received a response from one tribe and reached out again to the remaining six tribes by email and telephone on October 18, 2017. (*See gen'ly* Appendix E, PEA.)

Ultimately, five of the seven tribal groups contacted responded to the request for information and comments: Buena Vista Rancheria of MiWuk Indians, California Valley Miwok Tribe, North Valley Yokuts Tribe, United Auburn Indian Community of the Auburn Rancheria and Wilton Rancheria. Four stated that they did not have specific concerns about the proposed project location but asked to be notified should any archaeological deposits be inadvertently discovered. One tribe, the United Auburn Indian Community of the Auburn Rancheria, requested additional project information and a meeting. PG&E provided this information and offered a potential meeting date in an email sent on October 26, 2017. In a later email communication, the tribe deferred to Wilton Rancheria.

City of Lathrop

On September 28, 2016, PG&E presented a project overview and shared the outreach plan for the project with City of Lathrop staff and officials. On October 11, 2016, the PG&E project team met with City of Lathrop staff, including the Community Development Director, City Engineer, City Manager, City Planner and others. During this meeting, PG&E provided an explanation of project purpose and need, process, and timeline. City staff provided feedback on upcoming development projects in the area, and expressed their preferred areas for the project. A follow-up briefing was conducted on December 15, 2016, with the City's Senior Planner. On April 11, 2017, PG&E provided an overview of the project to the Mayor of Lathrop, City Manager, Public Works Director, City Engineer and others. The meeting provided an overview of the project's purpose and identified the segments of the project that run in or adjacent to the City. In addition, PG&E provided a discussion of the study area and alternatives analysis.

PG&E requested the City's input regarding the project. On June 26, 2017, PG&E met with City of Lathrop staff and officials to review the further refined routes and share comments received from the community. During this meeting, staff expressed their preference for a route that is compatible with the City's current and future development plans. On December 7, 2017, PG&E met with City officials to review the proposed route. On December 12, 2017, the City of Lathrop sent a letter to PG&E documenting their support of expanding Vierra Substation and constructing a new 115 kV power line along the Nestle Way route.

City of Manteca

On December 15, 2016, PG&E met with staff from the City of Manteca to provide information on the project and solicit their input on local development and other issues. While City staff indicated they would provide written comments only if the project were located within its boundaries, they expressed no concerns regarding the project.

County of San Joaquin

On June 1, 2017, PG&E provided a project overview to the County of San Joaquin staff, explaining the outreach that had occurred to date and next steps in the permitting process. On July 1, 2017, this information was also provided to the San Joaquin County Board of Supervisors. No one from the County expressed particular concerns about the project.

Caltrans District 10

Beginning January 25, 2017, PG&E provided outreach to Caltrans District 10 providing project information and requesting Caltrans feedback. On April 21, 2017, Caltrans responded that they had received project information and stating there were no current issues.

Altamont Corridor Express (ACE Rail)

On May 11, 2017, PG&E provided project briefing materials and sent a request for Altamont Corridor Express ("ACE Rail") project plans within the study area. PG&E also provided further project information to ACE Rail in July and December 2017, updating staff on project status and location. On September 15, 2017, ACE Rail staff provided information about the ACEforward Project. They indicated that ACEforward would not impact PG&E's proposed project but committed to follow up after consulting with their design team. ACE Rail staff also expressed appreciation for PG&E's efforts to coordinate projects.

Livermore Amador Valley Transit Authority

On July 14, 2017, PG&E provided project overview information to the Livermore Amador Valley Transit Authority. The Transit Authority staff confirmed that they had no on-going or planned projects within the study area. They indicated there was no need for further meetings to discuss the project, and expressed no comments or concerns about it.

V. MEASURES TAKEN TO REDUCE EMF EXPOSURE

Section X(A) of GO 131-D requires that applications for a PTC include a description of the measures taken or proposed by the utility to reduce the potential exposure to electric and magnetic fields ("EMF") generated by the proposed facilities. In accordance with Section X(A) of GO 131-D, CPUC Decision No. D.06-01-042 ("EMF Decision"), and PG&E's EMF Design Guidelines prepared in accordance with the EMF Decision, PG&E has reviewed the project to determine available no-cost and low-cost magnetic field reduction measures to be incorporated in the design of the proposed project. The following measures will be incorporated to reduce the magnetic field strength levels from electric power facilities:

- Raise the height of four structures supporting the power line by 10 feet taller than otherwise required;

- Keep high current devices, transformers, capacitors, and reactors away from the substation property lines;
- For underground duct banks, the minimum distance should be 12 feet from the adjacent property lines or as close to 12 feet as practical;
- Locate new substations close to existing power lines to the extent practical; and
- Increase the substation property boundary to the extent practical.

The Commission's EMF Decision and PG&E's EMF Design Guidelines require PG&E to prepare a Field Management Plan ("FMP") that indicates the no-cost and low-cost EMF measures that will be installed as part of the final engineering design for the project. The FMP evaluates the no-cost and low-cost measures considered for the project, the measures adopted, and reasons that certain measures were not adopted. A copy of the Field Management Plan for this project is attached as Exhibit D.

VI. PUBLIC NOTICE

Pursuant to Section XI(A) of GO 131-D, notice of the Application will be sent to San Joaquin County, the cities of Lathrop and Manteca, San Joaquin County Board of Supervisors, the California Energy Commission, the State Department of Transportation and its Division of Aeronautics, the Secretary of the Resources Agency, CDFW, the Department of Public Health, the California Water Resources Control Board, the California Air Resources Board, the San Joaquin County Air Pollution Control District, the Central Valley RWQCB, the NAHC, the State Department of Transportation's District Office, the USFWS, the USACE, all owners of land within 300 feet of the proposed project (as determined by the most recent local assessor's parcel roll available to PG&E at the time the notice is sent), and any other interested parties that have requested such notification.

In accordance with Section XI(A)(2), within 10 days after filing the Application, PG&E will publish a notice of the Application once a week for two successive weeks in the Stockton Record. In accordance with Section XI(A)(3), PG&E will also post a notice of the Application on-site and off-site where the project is located. PG&E will deliver a copy of the notice to the CPUC Public Advisor and the CPUC's Energy Division in accordance with Section XI(A)(3) and will file a declaration of mailing and posting with the Commission within five days after completion.

VII. EXHIBITS

The following exhibits are attached and incorporated by reference to this Application:

Exhibit A: Project Overview Map

Exhibit B: Proponent's Environmental Assessment

Exhibit C: Preliminary Project Schedule

Exhibit D: EMF Preliminary Field Management Plan

Exhibit E: Excerpts from the 2010-2011 California ISO Transmission Plan

Exhibit F: Excerpts from the 2017-2018 California ISO Transmission Plan

Exhibit G: Alternative route map

VIII. CONCLUSION

PG&E respectfully requests that the Commission:

1. Issue a Decision and Order, effective immediately, granting PG&E a Permit to Construct the Vierra Reinforcement Project, adopting an appropriate environmental document for the project, and granting any other permission and authority necessary to construct, operate and maintain the project.

2. Authorize Energy Division to approve requests by PG&E for minor project modifications that may be necessary during final engineering and construction of the project so

long as Energy Division finds that such minor project modifications would not result in new significant environmental effects or a substantial increase in the severity of previously identified significant effects.

3. Grant such other and further relief as the CPUC finds just and reasonable.

Dated in San Francisco, California, this 6th day of June, 2018.

Respectfully submitted,

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By: *<u>/s/ Jo Lynn Lambert</u>*
JO LYNN LAMBERT

Attorneys for Applicant
PACIFIC GAS AND ELECTRIC COMPANY

SCOPING MEMO INFORMATION

Category:

Ratesetting. Pursuant to Rule 2.1(c) of the Commission's Rules of Practice and Procedure, the application must propose a category for the proceeding as defined in Rule 1.3. If none of the enumerated categories are applicable, proceedings will be categorized under the catch-all "ratesetting" category. (CPUC Rule 7.1 (e)(2).) The Commission has consistently found that applications for CPCNs and PTCs under GO 131-D do not fit within any of the enumerated categories and should therefore be considered as "ratesetting proceedings."

Need for hearing:

The CPUC has determined that issues related to project need and cost are not within the scope of PTC applications, leaving only environmental review as a relevant issue. No areas of environmental or other public concern are known. If concerns about the project are raised, PG&E recommends that a public participation hearing be held.

Issues:

None known.

Safety considerations:

The project will help to provide a reliable supply of electricity to the area, which enhances the safe and secure operation of schools, hospitals, public services, residences and businesses. PG&E workers will utilize construction BMPs to ensure the safety of workers and nearby residents throughout construction. PG&E will comply with all FAA and other legal requirements relating to helicopter safety. PG&E will prepare a WEAP and SWPPP and comply with all measures and applicable laws to address potential hydrological or hazardous materials safety issues.

Proposed Schedule:

See Exhibit C, attached.

VERIFICATION

I, the undersigned, declare:

I am an officer of PACIFIC GAS AND ELECTRIC COMPANY, a corporation, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

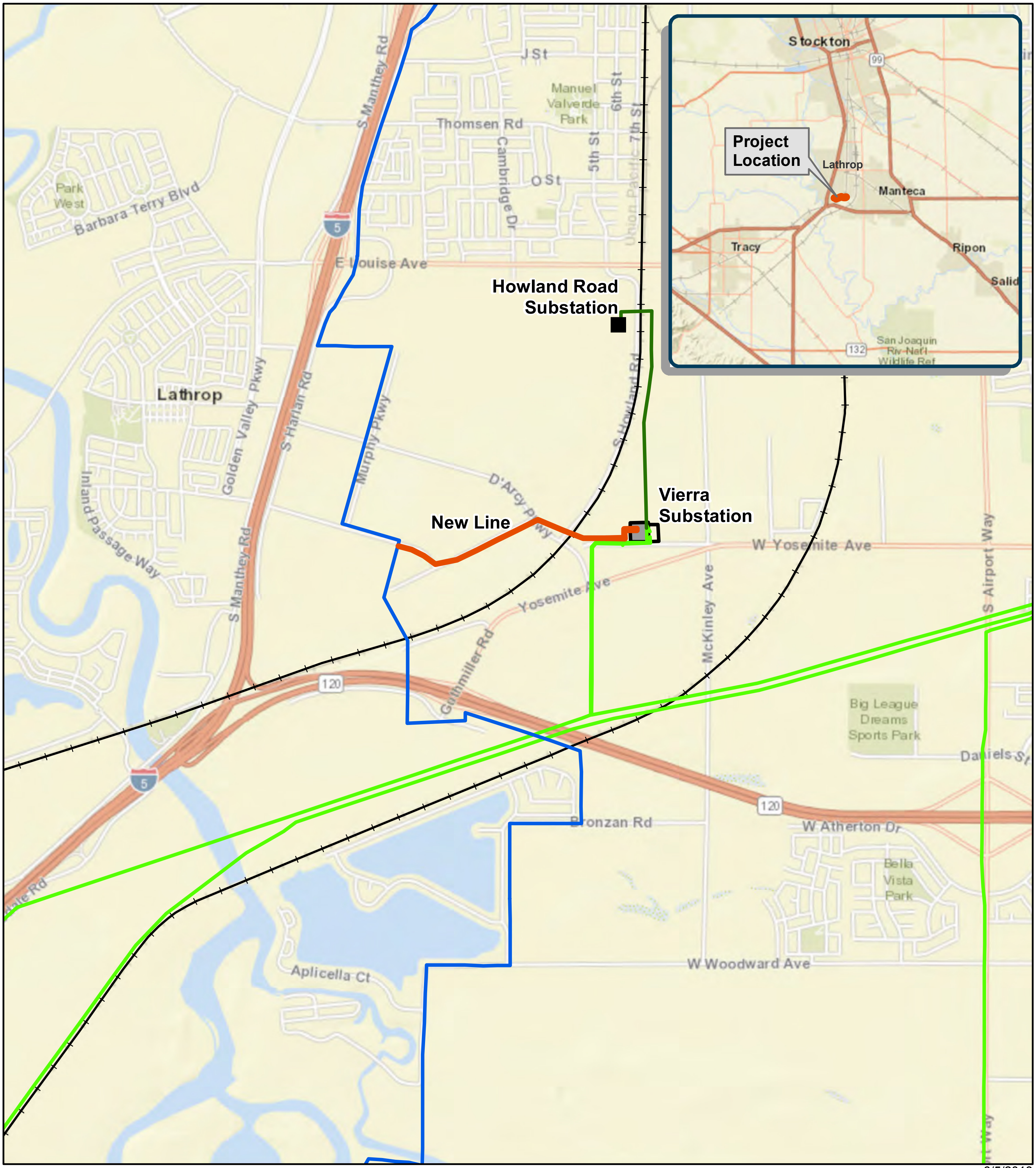
Executed on June 4, 2018 at San Francisco, California.

/s/ Andrew Williams

Andrew Williams

Vice President, Land & Environmental Management

<u>EXHIBIT A</u>
PROJECT OVERVIEW MAP



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6/5/2018

New 115 kV Line to be Installed

Existing Tesla-Stockton Cogen Jct 115 kV

Howland Road 115 kV Tap

Existing Vierra Substation Footprint

Planned Vierra Substation Expansion

Other 115 kV Lines

Union Pacific Railroad

Exhibit A - Project Overview Map

Vierra Reinforcement Project

PG&E

0 1,000 2,000 4,000

Feet

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Results you can rely on

EXHIBIT B
PROPONENT'S ENVIRONMENTAL ASSESSMENT

Due to the large file size of this exhibit, it has been excluded from the electronic version and provided to the Docket Office on an Archival-Grade DVD for filing.

EXHIBIT C
PRELIMINARY PROJECT SCHEDULE

Exhibit C

VIERRA REINFORCEMENT PROJECT
PRELIMINARY PROJECT SCHEDULE

PTC Application submitted	June 2018
Protests and Notice of deficiencies, if any	July 2018 – October 2018
Response to any deficiencies and data requests	August 2018 – December 2018
Application complete	October 2018
Draft Mitigated Negative Declaration (MND) released	January 2019
Close of Public Review Period	February 2019
Mitigated Negative Declaration (MND) adopted (no later than 180 days (6 months) from complete application per CEQA Guidelines § 15107)	April 2019
MND Adopted and PTC Decision Approved and Effective	Summer 2019
Acquisition of secondary permits	March 2019 – August 2020
Acquisition of land rights as needed	March 2019 – August 2020
Materials Procurement	January 2019 – August 2020
Initial Notice to Proceed / Construction Begins	Spring 2020 – 2021
Construction Complete	Spring 2022 – 2023
Project Operational	Spring 2022 – 2023

<u>EXHIBIT D</u>
EMF FIELD MANAGEMENT PLAN

PRELIMINARY TRANSMISSION EMF MANAGEMENT PLAN
VIERRA REINFORCEMENT PROJECT

A. TRANSMISSION COMPONENT

I. GENERAL DESCRIPTION OF PROPOSED PROJECT

Project Name: Vierra Reinforcement Project

Project Lead: Josh Hinkey, P.E., P.M.P.

Scope of Work:

PG&E proposes to upgrade the electric transmission system in the cities of Lathrop and Manteca by expanding the existing Vierra Substation, located in the City of Lathrop in San Joaquin County. The Vierra Reinforcement Project (project) will also include the construction of a new 115 kilovolt (kV) power line composed of two circuits, Tesla-Vierra 115 kV Power Line and Vierra-Stockton Co-gen Junction 115 kV Power Line, collocated on a single alignment of tubular steel poles (TSPs) between Vierra Substation and the existing Tesla-Stockton Co-Gen Junction 115 kV Power Line, located west of Vierra Substation in the City of Lathrop.

The project involves looping the Tesla-Stockton Co-Gen Junction 115 kV Power Line into the Vierra 115 kV bus, which will benefit the Tesla 115 kV system—and the 60 kV systems it feeds at Kasson, Manteca, and Salado substations—by providing more capacity and better reliability. As part of the project, Vierra Substation will be upgraded from a loop bus configuration to a breaker-and-a-half (BAAH) bus, and the feed from Vierra Substation to Howland Road Substation will be changed to a radial (single source) feed. The project is one of several area system upgrades that will benefit more than 120,000 residential and business customers in the cities of Manteca and Lathrop and surrounding areas by providing greater reliability.

- Power Line Construction. An approximately 1-mile-long, double-circuit 115 kV power line will be installed on approximately 16 TSPs.

Base Cost of Transmission Line Proposed Project:

The estimated total cost of the Proposed Project (without the EMF mitigation benchmark budget and excluding contingency) is approximately $7,000,000. Four percent of this estimated total cost is approximately $280,000.

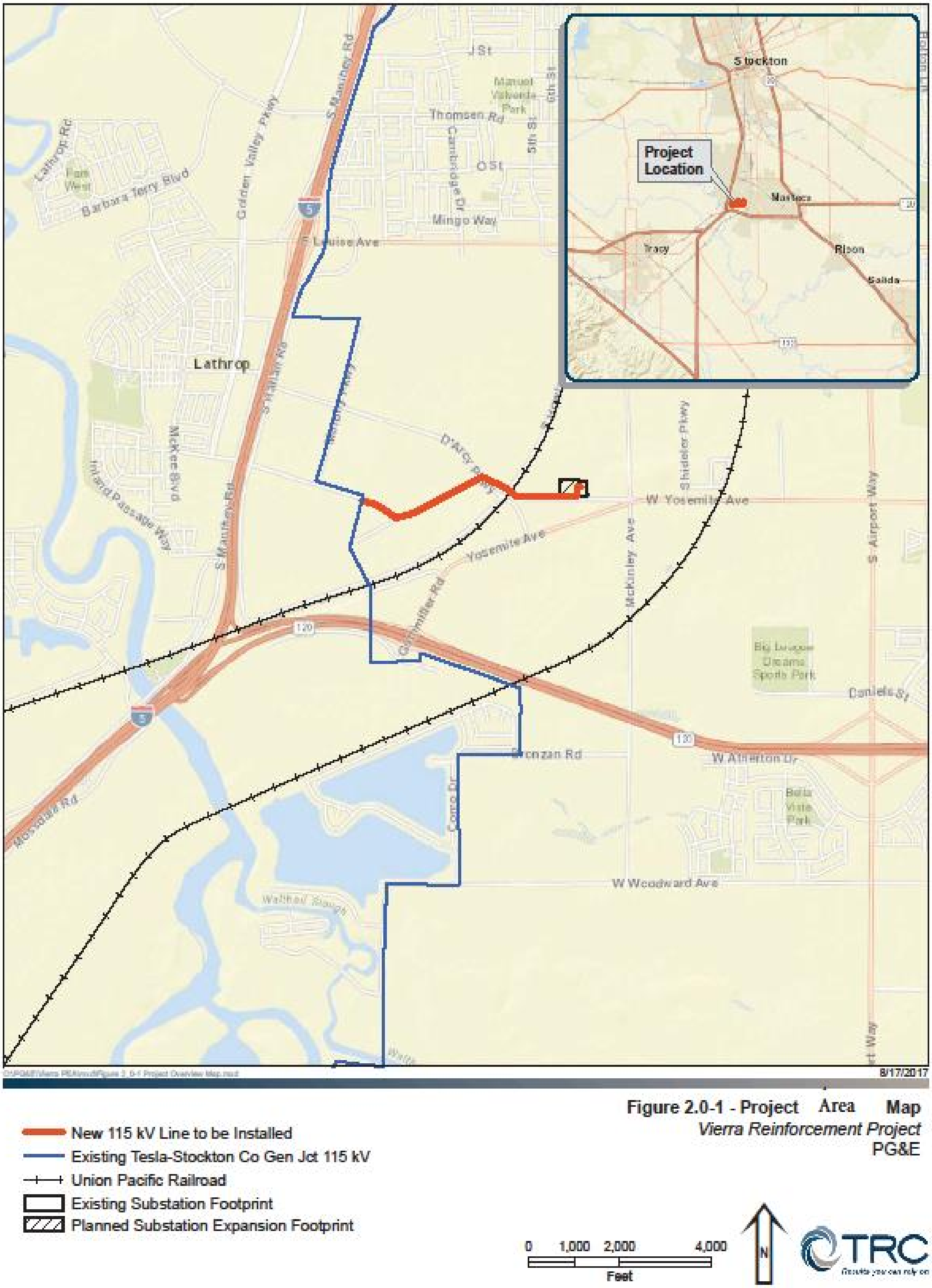


Figure 2.0-1 - Project Area Map
Vierra Reinforcement Project
PG&E

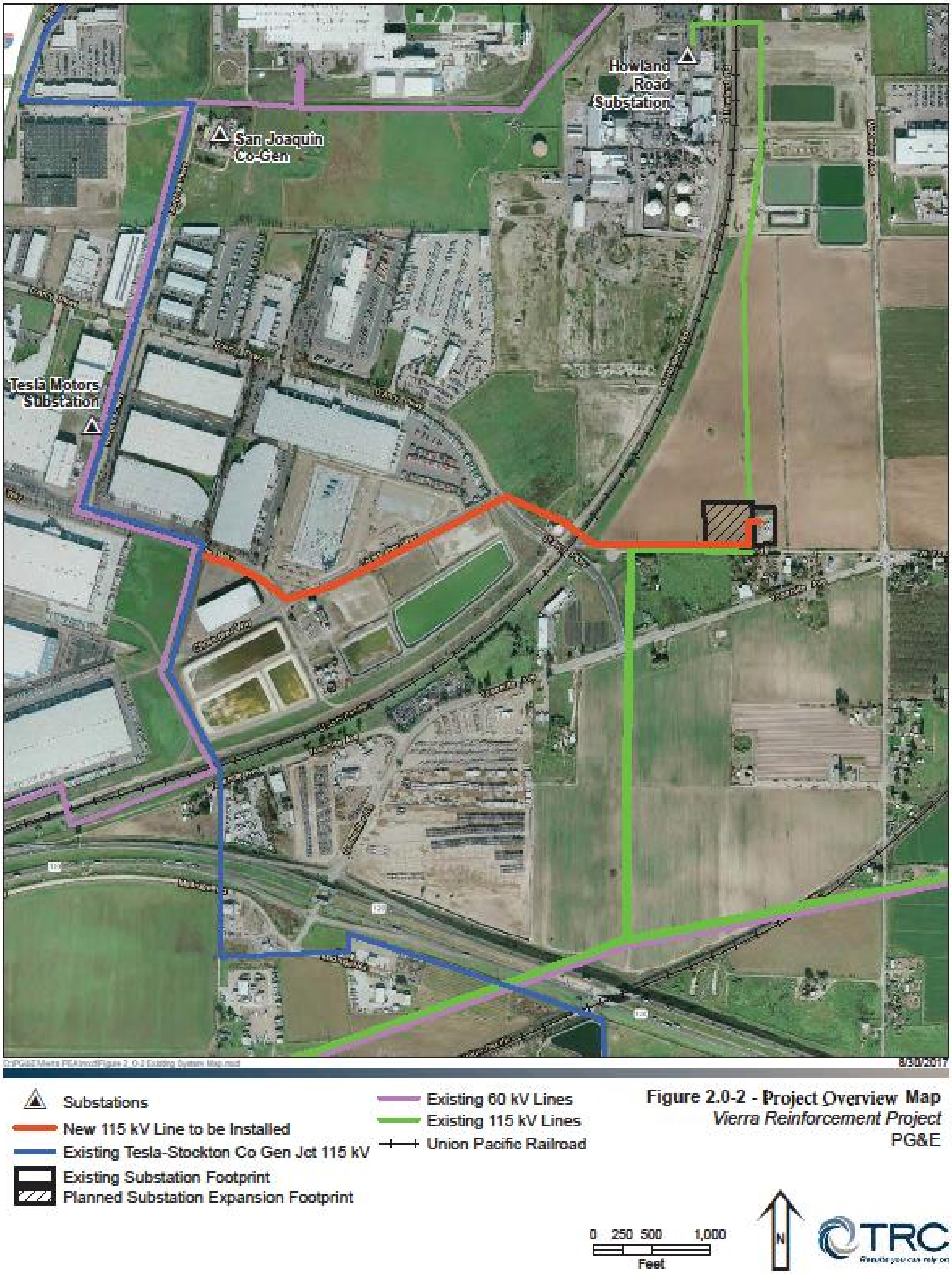


Figure 2.0-2 - Project Overview Map
Vierra Reinforcement Project
PG&E

II. BACKGROUND: CPUC DECISION 93-11-013 AND EMF POLICY

On January 15, 1991, the CPUC initiated an investigation to consider its role in mitigating the health effects, if any, of electric and magnetic fields (EMF) from utility facilities and power lines. A working group of interested parties, called the California EMF Consensus Group, was created by the CPUC to advise it on this issue. It consisted of 17 stakeholders representing citizens groups, consumer groups, environmental groups, state agencies, unions, and utilities. The Consensus Group's fact-finding process was open to the public, and its report incorporated concerns expressed by the public. The Consensus Group's recommendations were filed with the Commission in March 1992.

In August 2004 the CPUC began a proceeding known as a "rulemaking" (R.04-08-020) to explore whether changes should be made to existing CPUC policies and rules concerning EMF from electric transmission lines and other utility facilities.

Through a series of hearings and conferences, the Commission evaluated the results of its existing EMF mitigation policies and addressed possible improvements in implementation of these policies. The CPUC also explored whether new policies were warranted in light of recent scientific findings on the possible health effects of EMF exposure.

The CPUC completed the EMF rulemaking in January 2006 and presented these conclusions in Decision D.06-01-042:

- The CPUC affirmed its existing policy of requiring no-cost and low-cost mitigation measures to reduce EMF levels from new utility transmission lines and substation projects.
- The CPUC adopted rules and policies to improve utility design guidelines for reducing EMF, and established a utility workshop to implement these policies and standardize design guidelines.
- Despite numerous studies, including one ordered by the Commission and conducted by the California Department of Health Services, the CPUC stated "we are unable to determine whether there is a significant scientifically verifiable relationship between EMF exposure and negative health consequences."
- The CPUC said it will "remain vigilant" regarding new scientific studies on EMF, and if these studies indicate negative EMF health impacts, the Commission will reconsider its EMF policies and open a new rulemaking if necessary.

In response to a situation of scientific uncertainty and public concern, the decision specifically requires utilities to consider "no-cost" and "low-cost" measures, where feasible, to reduce exposure from new or upgraded utility facilities. It directs that no-cost mitigation measures be undertaken, and that low-cost options, when they meet certain guidelines for field reduction and cost, be adopted through the project certification process. PG&E was directed to develop, submit and follow EMF guidelines to implement the CPUC decision. According to the guidelines, four percent of total project budgeted cost is the benchmark used to determine "low-cost" in implementing EMF mitigation, and mitigation measures should achieve incremental magnetic field reductions of at least 15% at the edge of right-of-way (ROW).

III. PRIORITY AREAS WHERE LOW COST MEASURES ARE TO BE APPLIED

Surrounding Uses by Priority Category:

Pursuant to PG&E's "EMF Design Guidelines for Electrical Facilities", the mitigation of magnetic fields will be applied to the transmission lines in the following priority:

Land Uses Adjacent to Project Route:

Schools or Daycare: None.

Residential: Four structures.

Commercial/Industrial: Ten structures.

Recreational: None.

Undeveloped Land and/or Agricultural, Rural: One structure.

IV. No Cost and Low Cost Magnetic Field Mitigation

No Cost Field Reduction

Optimal phase configurations can be used as a field cancellation technique. The phases from one circuit of a multi-circuit line can be used to reduce the field from another circuit, thereby reducing the total magnetic field strength. For this reason, multi-circuit lines may have lower magnetic fields than single circuit lines.

Double circuit tower lines considered for optimal phasing:

Existing Phasing:

Tesla – Vierra 115 kV line -	(T,M,B) =	BCA
Vierra – San Joaquin Cogen 115 kV line -	(T,M,B) =	BCA

The double circuit Tesla – Vierra & Vierra – San Joaquin Cogen 115 kV lines are already optimally phased.

Base Case Load Flow:

Tesla – Vierra 115 kV: The maximum normal rating used for the base case calculation of the magnetic field is 427 Amps, flowing from Tesla substation to Vierra substation.

Vierra – San Joaquin Cogen 115 kV: The maximum normal rating used for the base case calculation of the magnetic field is 212 Amps, flowing from Vierra substation to Tesla Motors substation.

The load currents are assumed to be balanced at 120 electrical degrees separation between the three phases. The loads can vary significantly during the 24 hour day and /or throughout the year.

<u>Priority Areas where Low Cost Measures Should Be Considered</u>

Four structures in the residential land use area are considered for magnetic field reduction.

<u>Low Cost Magnetic Field Reduction Options</u>

Reducing magnetic field strength by increasing the distance from the source can be accomplished either by increasing the height or depth of the conductor from ground level. Furthermore, locating the power lines as far away from the edge of the ROW or as close to centerline as possible will result in lower field levels at the edge of the ROW. Calculations are based on normal peak current flow forecasted for 2023 and a minimum conductor height of thirty-one feet at midspan. Below are calculations showing magnetic field reductions from raising conductor heights an additional 10 feet more than needed to meet clearance requirements:

Table 1. Magnetic Field Reduction for Raising Conductor Height by Additional Ten Feet.

Segment	Base Case		Raise 10 Feet		Reduction	
	North ROW	South ROW	North ROW	South ROW	North ROW	South ROW
Tesla – Vierra Line	19.7 mG	9.1 mG	12.9 mG	7.0 mG	35%	23%

The purpose of magnetic field modeling is to evaluate relative effectiveness of various magnetic field reduction measures, not to predict magnetic field levels.

Table 2. Estimated Cost of Raising Conductor Height by Additional Ten Feet at Certain Locations

The following table identifies the no cost and low cost field mitigation measures for each line segment, including the reasoning for each, and the estimated cost to adopt the measure.

Project Segment (Pole/Tower ID #)	Location (Street, Area)	Adjacent Land Use	Reduction Measure Considered	Measure Adopted?	Reason(s) if not adopted	Estimated Cost to Adopt
Tesla – Vierra 115 kV line - Double Circuit with Vierra – San Joaquin Cogen 115 kV line						
004-014A to 5-2	Nestle Way	Industrial				
5-3 to 5-7	Christopher Way	Industrial				
5-8 to 5-9	D'Arcy Parkway	Industrial				
5-10	Vierra Road	Agriculture				
5-10	Vierra Road	Residential	Optimal Phasing	No	Already Optimal	
			Raise Conductor 10 Feet	Yes		$40,000

This FMP proposes to raise the height of four structures in the residential land use area by ten feet taller than required for meeting clearance requirements. The estimated cost of this mitigation is $40,000.

V. CONCLUSION: FIELD REDUCTION MEASURES SELECTED

The Vierra Reinforcement Project field management plan proposes to apply the following no cost and low magnetic field mitigation:

Raise the height of four structures in the residential land use area by ten feet taller than required for meeting clearance requirements. The estimated cost of this mitigation is $40,000.

VI. References

California Public Utilities Commission. 1993. Order instituting investigation on the Commission's own motion to develop policies and procedures for addressing the potential health effects of electric and magnetic fields of utility facilities. Decision 93-11-013. November 2.

California Public Utilities Commission. 2006. Order Instituting Rulemaking to update the Commission's policies and procedures related to electromagnetic fields emanating from regulated utility facilities. Decision 06-01-042 January 26.

Pacific Gas & Electric Company. 2006. EMF Design Guidelines for Electrical Facilities.

B. SUBSTATION COMPONENT

Vierra Reinforcement Project
Substation FMP Checklist

No.	NoCost and LowCost Magnetic Field Reduction Measures Evaluated for a Substation Project	Measures Adopted? (Yes/No)	Reason(s) if not Adopted
1	Keep high current devices, transformers, capacitors, and reactors away from the substation property lines.	Yes	
2	For underground duct banks, the minimum distance should be 12 feet from the adjacent property lines or as close to 12 feet as practical.	Yes	
3	Locate new substations close to existing power lines to the extent practical.	Yes	
4	Increase the substation property boundary to the extent practical.	Yes	
5	Other:		

EXHIBIT E

EXCERPTS FROM THE 2010-2011 CALIFORNIA ISO TRANSMISSION PLAN

California ISO
Shaping a Renewed Future

2010-2011 Transmission Plan

May 18, 2011
Approved by ISO Board of Governors

2.7.4.5 Stockton/Stanislaus Division Thermal Concerns Mitigations

Hammer-Country Club 60 kV Line, Stagg-Country Club Nos. 1 & 2 and Stagg-Hammer 60 kV Lines

An overload of the Hammer-Country Club 60 kV line was identified starting in 2015 under normal conditions and to currently exist under Category C contingency conditions. Existing overloads were identified on the Stagg-Country Club Nos. 1 & 2 and Stagg-Hammer 60 kV lines under Category C contingency conditions of the combined loss of any two out of three lines. To mitigate these overloads, PG&E submitted two projects through the 2010 request window, the Hammer-Country Club 60 kV Switch Project and the *Stagg-Hammer 60 kV Line Project*. The *Hammer-Country Club 60 kV Switch Project* consists of replacing the limiting switch on this line and re-rate a small section at the Country Club end. The *Stagg-Hammer 60 kV Line Project* consists of building a second 60 kV line between Stagg and Hammer substations approximately 4.2 miles in length. The switch replace project has an in-service date of May 2012 and the new line project has an in-service date of May 2014. The ISO determined that these projects are needed to mitigate the identified overloading concerns.

In the interim for the Category C overloads, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Tesla-Weber 230 kV Line

The Tesla-Weber 230 kV line was identified to overload starting year 2018 under normal conditions and starting in 2016 to overload under Categories B and C contingency conditions. Reconductoring this network line could be a solution. The most feasible implementation timeline for this upgrade is 2016 due to permitting and lead times. This plan, and other possible options, will be assessed further and included in a future ISO transmission plan.

Eight Mile – Tesla and Stagg - Tesla 230 kV Lines

The Eight Mile – Tesla and Stagg - Tesla 230 kV lines were identified to overload starting in year 2018 under Categories B and C contingency conditions. Re-rating these network lines could be a solution. There is ample time for the re-rate implementation before 2018. This plan, and other possible options, will be assessed further in a future ISO transmission plan.

Tesla – Manteca Area 115 kV Lines

There are four 115 kV lines emanating from the Tesla substation delivering power towards Salado and Manteca substations. There is a fifth 115 kV line that goes through Tracy and the sixth 115 kV line that connects co-generation in the area. The ISO previously approved the *Tesla 115 kV Capacity Increase Project* for some sections of the Tesla-Schulte and Lammers-Kasson 115 kV lines.

This year's assessment identified existing overloads on the Tesla-Salado-Manteca, Kasson 115/60 kV Transformer, Tesla-Tracy, Tesla-Schulte Switching Station, Tesla-Kasson-Manteca, Vierra-Tracy-Kasson, and Lammers-Kasson 115 kV lines as well as the Kasson-Louise and Manteca-Louise 60 kV lines under various Category C contingency conditions. To mitigate these overloads, PG&E submitted a project through the 2010 request window, *Vierra 115 kV Looping Project*, which proposes to loop the Tesla-Stockton Co-gen 115 kV line in to the Vierra substation. The project has an in-service date of May 2014. The ISO determined that this project is needed to mitigate the identified overloading concerns. The ISO also considered an SPS alternative to mitigate all Category C overloads identified in this area and found that the SPS to be infeasible because it would require monitoring more contingencies than the SPS guideline would allow. The ISO further considered an alternative feasible SPS combined with required upgrades to mitigate all overloads and found this option to be more expensive compared to the *Table Mountain-Sycamore 115 kV Line Project*.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO staff will ensure that necessary operating procedures will be in place to meet reliability needs in 2011.

Lockeford-Industrial, Lodi-Industrial and Lockeford-Lodi 60 kV Lines

The Lockeford/Lodi area 60 kV lines are identified with existing overloads under various Category C contingency conditions. Also for the loss of the Country Club-Hummer 60 kV, the Mosher substation transfers to the Lockeford #1 60 kV line potentially overloading it. The Mosher substation has over 50 MW of load and, as such, it should have a looped service. For these potential overloads, presently there is an ongoing 2010 request window project which proposes to build a new 230/60 kV substation in the vicinity of the existing Industrial substation and also build two new 60 kV lines from the new substation to the Industrial substation. The ISO, working with PG&E, will evaluate different alternatives to bringing additional transmission capacity in to the Lodi area as a long-term solution. The most feasible project implementation, due to permitting and lead times is 2016. These plans will be assessed further in a future ISO transmission plan.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concerns. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Valley Spring No. 1 60 kV Line

The Valley Spring No. 1 60 kV line is identified to overload starting year 2020 under Category B contingency condition. This overload occurs when the Linden substation is transferred to this line due to an outage of the Weber-Mormon Junction 60 kV line. Reconductoring this line could be a solution. There is ample time for permitting, procurement and installation before 2020. This plan, and other possible options, will be assessed further in a future ISO transmission plan.

West Point-Valley Springs 60 kV Line

The ISO identified an existing overload on the West Point-Valley Springs 60 kV line under a Category B contingency condition. The ISO previously approved a project in the 2010 transmission plan to reconductor this line but since this is a remote radial line built though rough terrain with no back-up sources, the reconductoring work cannot take place without interrupting electric service to customers at Electra, West Point, and Pine Grove for approximately 1-2 months. Because of this issue, PG&E submitted a project through the 2010 request window, the *West Point-Valley Springs 60 kV Line Project*, which consists of building a new 60 kV line from Valley Springs to Pine Grove substation. The project has an in-service date of December 2013. The ISO determined that this project is needed to mitigate identified overloading concerns

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Stanislaus-Manteca No. 2 115 kV Line

The Stanislaus-Manteca No. 2 115 kV line was identified with an existing overload under a Category C contingency. The solution includes developing an operating solution to reduce generation at Stanislaus following the first contingency. The most feasible implementation timeline is 2011.

Stanislaus-Melones-Manteca No. 1 115 kV Line

The Stanislaus-Melones-Manteca No.1 115 kV line was identified with an existing overload under a Category C contingency. Solutions include obtaining a short-term rating and developing an operating solution to reduce generation at Stanislaus following the contingency or to install an SPS for the same action. The most feasible implementation timeline for this upgrade is 2012.

Stockton 'A'-Lockeford-Bellota No. 2 115 kV Line

The ISO identified an existing overload on the Stockton 'A'-Lockeford-Bellota No. 2 115 kV line under a Category C contingency condition. Solution includes developing an operating solution to re-adjust the system following the first contingency or to install an SPS to curtail load following the second contingency. The most feasible implementation timeline for this upgrade is 2012.

2.7.4.6 Stockton/Stanislaus Division Voltage Concerns Mitigations

The ISO identified an existing low voltage at Lockeford 230 kV bus under a Category B contingency condition. The ISO also identified existing low voltages at Stagg and Eight Mile 230 kV buses under Category C contingency conditions. The solution includes installing voltage support in the area. The most feasible implementation timeline for this upgrade is 2015 due to permitting and lead times. In the interim, the ISO recommends that an operating procedure be developed to address any potential reliability concerns.

Request Window Submission - Kirkwood Meadows Public Utility District (KMPUD) 115 kV Interconnection

KMPUD and the Kirkwood Community are physically isolated from any large regional electric service utility. Kirkwood is currently being served by local diesel-fired generators, which are owned and operated by KMPUD. KMPUD's customer base is comprised of residential homes, commercial operations, and the Kirkwood Ski Resort, which is its largest single customer. Due to the increased electric demand, KMPUD is proposing to interconnect to PG&E's transmission system. To facilitate this interconnection, PG&E submitted a project through the 2010 request window, the *KMPUD 115 kV Interconnection Project*, which proposes to interconnect KMPUD's proposed facilities by tapping onto the existing Salt Springs – Tiger Creek 115 kV line adjacent to Salt Springs PH. This tap line will be 2.3 miles long. The project is expected to cost between $2M and $4M.

The ISO has reviewed the interconnection facilities proposed by PG&E and has determined that they will allow the load to be reliably interconnected to the ISO controlled grid. There are no reliability upgrades or additions to the ISO controlled grid that will be triggered by the tap line and associated facilities. Thus, the ISO has determined that this proposed load interconnection to the PG&E 115 kV system may proceed without modification. The radial tap line will not be under the ISO's operational control.

2.7.5 KEY CONCLUSIONS

The 2010 reliability assessment of the PG&E Central Valley area revealed several reliability concerns. These concerns consist of thermal overloads and low voltages under normal, Categories B and C contingency conditions. Also one Category C contingency resulted in the power flow divergence indicating potential area-wide voltage collapse.

The problems identified in this 2010/2011 assessment are very similar to those found in the last year's assessment. There were three new projects approved in the 2010 transmission plan, which eliminated one normal, one Category B and three Category C overloads identified in the last year's assessment. To address the identified thermal overloads and low voltage concerns, the ISO-proposed a total of 30 transmission solutions and received nine transmission project proposals through the request window. ISO also completed evaluation of one ongoing project from the last year's request window. However, some of these proposed request window projects serve the purpose of more than one ISO-proposed solutions. These are:

- Hammer –Country Club 60 kV Line Switch Replacement Project;
- Cortina No. 3 60 kV Line Reconductoring;
- West Point –Valley Springs 60 kV Line Project;
- South of Palermo 115 kV Reinforcement Project;
- Stagg –Hammer 60 kV Line Project;
- Vierra 115 kV Looping Project;
- Rio Oso –Atlantic 230 kV Line Project;
- Vaca Dixon-Davis Voltage Conversion;
- Lodi Area 230 kV Substation Project; and
- Drum –Grass Valley –Weimar 60 kV Line Project.

The ISO has determined eight projects to be needed (1 through 8 in the list above), and the remaining two (9 and 10 in the list above) have ongoing status requiring further information.

The projects determined to be needed will carry forward into the 2011/2012 planning cycle and will be included in the planning assumptions.

8.2 Transmission Projects Found to Be Needed in The 2010/11 Planning Cycle

In the 2010/2011 transmission planning process, the ISO determined that 32 transmission projects, submitted through the ISO 2010 request window, were needed to mitigate identified reliability concerns. Table 8.2-1 is the summary of these 32 transmission projects. In addition, the ISO also identified one policy-driven project (category 1) to be recommended to the ISO Board of Governors for approval (please see Table 8.2-2).

Table 8.2-1: New reliability projects found to be needed

No	Project Name	Project Sponsor(s)	Project Cost ($ Million)	Service Area	Type of Submission	In-Service Date
1	Reconductor TL663, Mission-Kearny	SDG&E	$17.9M	San Diego	Reliability Project	6/1/2015
2	Reconductor TL670, Mission-Clairemont	SDG&E	$14.7M	San Diego	Reliability Project	6/1/2015
3	Reconductor TL676, Mission-Mesa Heights	SDG&E	$18.6M	San Diego	Reliability Project	6/1/2015
4	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	$9M	San Diego	Reliability Project	6/1/2013
5	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	$33.6M	San Diego	Reliability Project	6/1/2013
6	TL644, South Bay-Sweetwater: Reconductor	SDG&E	$8.9M	San Diego	Reliability Project	6/1/2013
7	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	$16.9M	San Diego	Reliability Project	6/12/2012
8	Southern Orange County Reliability Upgrade Project - Alternative 3 (Rebuild Capistrano Substation, construct a new SONGS-Capistrano 230 kV line and a new 230 kV tap line to Capistrano)	SDG&E	$365M	San Diego	Reliability Project	6/1/2015
9	New Sycamore - Bernardo 69 kV line	SDG&E	$30M	San Diego	Reliability Project	6/1/2015
10	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	$3-6M	Fresno/Kern	Reliability Project	5/1/2013

No	Project Name	Project Sponsor(s)	Project Cost ($ Million)	Service Area	Type of Submission	In-Service Date
11	Wilson 115 kV Area Reinforcement	PG&E	$35-45M	Fresno/Kern	Reliability Project	5/1/2015
12	West Point - Valley Springs 60 kV Line Project	PG&E	$20-25M	North/Central Valley	Reliability Project	12/1/2013
13	Vierra 115 kV Looping Project	PG&E	$10-15M	North/Central Valley	Reliability Project	5/1/2014
14	Rio Oso - Atlantic 230 kV Line Project	PG&E	$30-40M	North/Central Valley	Reliability Project	5/1/2016
15	Table Mountain – Sycamore 115 kV Line	PG&E	$25-35M	North/Central Valley	Reliability Project	5/1/2015
16	Stagg – Hammer 60 kV Line	PG&E	$5-10M	North/Central Valley	Reliability Project	5/1/2014
17	South of Palermo 115 kV Reinforcement Project	PG&E	$80-100M	North/Central Valley	Reliability Project	5/1/2014
18	Cottonwood-Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project	PG&E	$43-57M	North/Central Valley	Reliability Project	5/1/2016
19	Oro Loma 70 kV Area Reinforcement	PG&E	$35-45M	Fresno/Kern	Reliability Project	5/1/2015
20	Oro Loma - Mendota 115 kV Conversion Project	PG&E	$25-35M	Fresno/Kern	Reliability Project	5/1/2015
21	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	$1-5M	Greater Bay	Reliability Project	5/31/2013
22	Mesa-Sisquoc 115 kV Line Reconductoring	PG&E	$5-10M	Central Coast/Los Padres	Reliability Project	5/31/2014
23	Kerchhoff PH #2 - Oakhurst 115 kV Line	PG&E	$25-35M	Fresno/Kern	Reliability Project	5/1/2015
24	Lemoore 70 kV Disconnect Switches Replacement	PG&E	$1-3M	Fresno/Kern	Reliability Project	5/1/2013
25	Hammer – Country Club 60 kV Switch Replacement	PG&E	$1-2M	North/Central Valley	Reliability Project	5/1/2012
26	Jefferson-Stanford #2 60 kV Line	PG&E	$25-35M	Greater Bay	Reliability Project	5/31/2014
27	Gill Ranch Gas Storge 115 kV Interconnection	PG&E	$11.8M	Fresno/Kern	Reliability Project	5/1/2011
28	Fulton 230/115 kV Transformer	PG&E	$10-14M	Humboldt,North Coast/Bay	Reliability Project	5/1/2014

No	Project Name	Project Sponsor(s)	Project Cost ($ Million)	Service Area	Type of Submission	In-Service Date
29	Cayucos 70 kV Shunt Capacitor	PG&E	$5-10M	Central Coast/Los Padres	Reliability Project	5/31/2014
30	Cortina No.3 60 kV Line Reconductoring Project	PG&E	$4-7M	North/Central Valley	Reliability Project	5/1/2013
31	Cascade 115/60 kV No.2 Transformer Project and Cascade - Benton 60 kV Line Project	PG&E	$20-30M	North/Central Valley	Reliability Project	5/1/2014
32	Vaca – Davis Voltage Conversion Project	PG&E	$70-107M	North/Central Valley	Reliability Project	5/1/2015

The following table 8.2-2 provides a list of policy-driven transmission project found to be needed in the ISO 2010/2011 planning cycle. The ISO has determined that WECC Path 42 and Devers – Mirage 230 kV Upgrades to qualify for category 1 policy-driven project for recommendation to the ISO Board of Governors for approval. For further discussion on this category 1 project, please refer to chapter 5 of the transmission plan.

Table 8.2-2: Category 1 Transmission Upgrades

No.	Name of Project	Description of Project
1	Path 42 and Devers – Mirage 230 kV Upgrades	This is a joint transmission upgrade on IID's portion of Path 42 (i.e. IID's portion on the Coachella Valley – Devers and Coachella Valley – Ramon 230 kV lines) and SCE's Devers – Mirage and Mirage – Ramon 230 kV lines. Considered upgraded path rating, subject to further WECC review and approval as part of its path rating study process, is 1,440 MW.

8.3 Policy Driven Transmission Projects To Be Evaluated in The Next Planning Cycle (2011/2012)

Table 8.3-1 lists category 2 policy-driven transmission upgrades to be evaluated further in the 2011/2012 planning cycle. For further discussions on these category 2 transmission upgrades, please see chapter 5 of the transmission plan.

Table 8.3-1: Category 2 Transmission Upgrades

No.	Name of Project	Description of Project
1	Install Reactive Supports at Various SDG&E's 230 kV Substations	Install a total of 400 MVAr reactive power support at Sycamore, Mission, and Talega 230 kV Substations
2	Third Miguel 500 kV Transformer	Install third 500/230 kV transformer at Miguel Substation
3	Upgrade El Dorado – Pisgah 500 kV Series Capacitors	Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)
4-8	Upgrade and construct new transmission lines in Fresno area:	1) Build the new Midway - Gregg 500 kV line 2) Reconductor Gregg - Herndon 230 kV line 3) Reconductor Warnerville - Wilson 230 kV line 4) Reconductor Barton - Herndon 115 kV line 5) Reconductor Manchester - Herndon 115 kV line

8.4 2010 Request Window Submittals

During the 2010/2011 planning cycle, the ISO 2010 request window was open from October 11, 2010, to December 10, 2010. During this time, 118 submittals were received which included proposals related to reliability, economic study requests, LCRIF, and merchant transmission projects. After screening review, 107 submittals remained in the ISO 2010 request window (see summary of this list in Table 8.4-1). Submittals were also made for operating procedures and System Protection Systems (SPS) which do not need ISO approval and were not required to be submitted through the request window. Finally, some projects were submitted as informational items; the intent of which is to provide the ISO information on items which are being considered by the PTOs for future submittal and for maintenance related projects for terminal equipment replacement[42].

[42] SDG&E submitted terminal equipment replacement projects to the ISO for informational only.

Table 8.4-1: 2010 Request Window Submittals

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
1	Telegraph Canyon 138kV Capacitor Addition	SDG&E	SDG&E	Reliability Project	4/1/2011	Project approval	Needs further evaluation	Chapter 2 - SDG&E
2	Reconductor TL663, Mission-Kearny	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
3	Reconductor TL670, Mission-Clairemont	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
4	Reconductor TL676, Mission-Mesa Heights	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
5	Reconductor TL631, El Cajon-Los Coches	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Needs further evaluation	Chapter 2 - SDG&E
6	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Yes	Chapter 2 - SDG&E
7	TL698E, Pala-Monserate Tap	SDG&E	SDG&E	Reliability Project	?	Information Only	N/A	Chapter 2 - SDG&E
8	TL642A, South Bay-Montgomery Tap - Terminal Equipment	SDG&E	SDG&E	Reliability Project	?	Information Only	N/A	Chapter 2 - SDG&E
9	TL603B, Sweetwater-Sweetwater Tap - Terminal Equp.	SDG&E	SDG&E	Reliability Project	?	Information Only	N/A	Chapter 2 - SDG&E
10	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Yes	Chapter 2 - SDG&E
11	TL691C, Pendleton-Avocado Tap: Terminal Equipment	SDG&E	SDG&E	Reliability Project	?	Information Only	No approval needed. Project submitted as informational item	Chapter 2 - SDG&E
12	TL644, South Bay-Sweetwater: Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Yes	Chapter 2 - SDG&E
13	TL6916, Sycamore-Scripps Overload Mitigation/ New TL 6942 Sycamore - Miramar 69 kV Line	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
14	TL6912 - Reconductor San Luis Rey-Pendleton	SDG&E	SDG&E	Reliability Project	6/1/2020	Project approval	Needs further evaluation	Chapter 2 - SDG&E
15	TL693 San Luis Rey-Melrose:Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E
16	TL694A San Luis Rey - Morro Hill Tap:Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2012	Project approval	No	Chapter 2 - SDG&E
17	TL680B - Melrose-Melrose Tap: Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	No	Chapter 2 - SDG&E
18	TL691B - Monserate-Avocado Tap: Terminal Equipment	SDG&E	SDG&E	Reliability Project	?	Information Only	No approval needed Project submitted as informational item	Chapter 2 - SDG&E
19	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	SDG&E	Reliability Project	6/12/2012	Project approval	Yes	Chapter 2 - SDG&E
20	TL633 Benardo-Rancho Carmel Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2012	Project approval	Needs further evaluation	Chapter 2 - SDG&E
21	Upgrade Mission 138/69 kV Transformer Banks 51 and 52	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Needs further evaluation	Chapter 2 - SDG&E
22	TL6915&6924 Sycamore-Pomerado #1 & #2: Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E
23	TL648, Poway-Rancho Carmel: 69 kV Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E
24	TL682 Rincon-Warners Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2012	Project approval	No	Chapter 2 - SDG&E
25	TL13835B Reconductor Laguna Niguel - Talega Tap	SDG&E	SDG&E	Reliability Project	6/1/2020	Project approval	Needs further evaluation	Chapter 2 - SDG&E
26	TL689A Bernardo-Felicita Tap: short-term mitigation	SDG&E	SDG&E	Reliability Project	?	Information Only	No approval needed; project submitted as informational item	Chapter 2 - SDG&E

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
27	Modified-SOCRUP Project	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes (Alternattive to project submittal is recommended)	Chapter 2 - SDG&E
28	Los Coches Substation 230 kV Expansion	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Needs further evaluation	Chapter 2 - SDG&E
29	New Sycamore - Bernardo 69 kV line	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
30	2009 Grid Assessment Category C Violations listings	SDG&E	SDG&E	Other	-	Information Only	No approval needed Project submitted as informational item	Chapter 2 - SDG&E
31	Reconfigure TL23013 and TL23028	SDG&E	SDG&E	Reliability Project	6/1/2011	Project approval	No	Chapter 2 - SDG&E
32	Install Synchronous Condensers at Mission, Penasquitos, and Talega 230 kV Substations	SDG&E	SDG&E	Reliability Project	6/1/2013 6/1/2016 6/1/2019	Project approval	Needs further evaluation	Chapter 2 - SDG&E
33	Antelope A Bank Operating Procedure	SCE	SCE	Reliability Project	6/1/2013	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
34	Bailey Operating Procedure	SCE	SCE	Reliability Project	3/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
35	Big Creek Existing RAS Modification	SCE	SCE	Reliability Project	9/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
36	Garnet Operating Procedure	SCE	SCE	Reliability Project	3/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
37	Lancaster OP & RAS	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
38	Neenach Selective Service	SCE	SCE	Reliability Project	12/31/2013	Project approval	No	Chapter 2 - SCE
39	North of Lugo Operating Procedures	SCE	SCE	Reliability Project	Spring 2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
40	Palmdale Remedial Action Scheme	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
41	Path 26 Existing RAS Modification	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
42	Rector RAS Modification	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
43	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	Fresno/Kern	Reliability Project	5/1/2013	Project approval	Yes	Chapter 2 - PG&E
44	Midway-Gregg 500 kV Line	PG&E	Fresno/Kern	Reliability Project	12/31/2018	Project approval	No	Chapter 2 - PG&E

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
45	Wilson 115 kV Area Reinforcement	PG&E	Fresno/Kern	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E
46	Wheeler Ridge Junction 230 kV Substation	PG&E	Fresno/Kern	Reliability Project	5/1/2020	Information Only	No approval needed Project submitted as informational item	Chapter 2 - PG&E
47	West Point - Valley Springs 60 kV Line Project	PG&E	North/Central Valley	Reliability Project	12/1/2013	Project approval	Yes	Chapter 2 - PG&E
48	Vierra 115 kV Looping Project	PG&E	North/Central Valley	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
49	Rio Oso - Atlantic 230 kV Line Project	PG&E	North/Central Valley	Reliability Project	5/1/2016	Project approval	Yes	Chapter 2 - PG&E
50	Table Mountain - Sycamore 115 kV Line	PG&E	North/Central Valley	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E
51	Stagg - Hammer 60 kV Line	PG&E	North/Central Valley	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
52	South of Palermo 115 kV Reinforcement Project	PG&E	North/Central Valley	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
53	Cottonwood-Red Bluff No. 2 60 kV Line Project Red Bluff Area 230/60 kV Substation Project	PG&E	North/Central Valley	Reliability Project	5/1/2016	Project approval	Yes	Chapter 2 - PG&E
54	Oro Loma 70 kV Area Reinforcement	PG&E	Fresno/Kern	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E
55	Pittsburg - Clayton #2 115 kV Line Project Moraga-Lakewood 115 kV Reconductoring Project Lakewood-Meadow Lane - Clayton 115 kV Reconductoring Project	PG&E	Greater Bay	Reliability Project	5/31/2015	Project approval	No	Chapter 2 - PG&E
56	Oro Loma - Mendota 115 kV Conversion Project	PG&E	Fresno/Kern	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E

EXHIBIT E
EXCERPTS FROM THE 2010-2011 CALIFORNIA ISO TRANSMISSION PLAN

California ISO
Shaping a Renewed Future

2010-2011 Transmission Plan

May 18, 2011
Approved by ISO Board of Governors

2.7.4.5 Stockton/Stanislaus Division Thermal Concerns Mitigations

Hammer-Country Club 60 kV Line, Stagg-Country Club Nos. 1 & 2 and Stagg-Hammer 60 kV Lines

An overload of the Hammer-Country Club 60 kV line was identified starting in 2015 under normal conditions and to currently exist under Category C contingency conditions. Existing overloads were identified on the Stagg-Country Club Nos. 1 & 2 and Stagg-Hammer 60 kV lines under Category C contingency conditions of the combined loss of any two out of three lines. To mitigate these overloads, PG&E submitted two projects through the 2010 request window, the Hammer-Country Club 60 kV Switch Project and the *Stagg-Hammer 60 kV Line Project*. The *Hammer-Country Club 60 kV Switch Project* consists of replacing the limiting switch on this line and re-rate a small section at the Country Club end. The *Stagg-Hammer 60 kV Line Project* consists of building a second 60 kV line between Stagg and Hammer substations approximately 4.2 miles in length. The switch replace project has an in-service date of May 2012 and the new line project has an in-service date of May 2014. The ISO determined that these projects are needed to mitigate the identified overloading concerns.

In the interim for the Category C overloads, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Tesla-Weber 230 kV Line

The Tesla-Weber 230 kV line was identified to overload starting year 2018 under normal conditions and starting in 2016 to overload under Categories B and C contingency conditions. Reconductoring this network line could be a solution. The most feasible implementation timeline for this upgrade is 2016 due to permitting and lead times. This plan, and other possible options, will be assessed further and included in a future ISO transmission plan.

Eight Mile – Tesla and Stagg - Tesla 230 kV Lines

The Eight Mile – Tesla and Stagg - Tesla 230 kV lines were identified to overload starting in year 2018 under Categories B and C contingency conditions. Re-rating these network lines could be a solution. There is ample time for the re-rate implementation before 2018. This plan, and other possible options, will be assessed further in a future ISO transmission plan.

Tesla – Manteca Area 115 kV Lines

There are four 115 kV lines emanating from the Tesla substation delivering power towards Salado and Manteca substations. There is a fifth 115 kV line that goes through Tracy and the sixth 115 kV line that connects co-generation in the area. The ISO previously approved the *Tesla 115 kV Capacity Increase Project* for some sections of the Tesla-Schulte and Lammers-Kasson 115 kV lines.

This year's assessment identified existing overloads on the Tesla-Salado-Manteca, Kasson 115/60 kV Transformer, Tesla-Tracy, Tesla-Schulte Switching Station, Tesla-Kasson-Manteca, Vierra-Tracy-Kasson, and Lammers-Kasson 115 kV lines as well as the Kasson-Louise and Manteca-Louise 60 kV lines under various Category C contingency conditions. To mitigate these overloads, PG&E submitted a project through the 2010 request window, *Vierra 115 kV Looping Project*, which proposes to loop the Tesla-Stockton Co-gen 115 kV line in to the Vierra substation. The project has an in-service date of May 2014. The ISO determined that this project is needed to mitigate the identified overloading concerns. The ISO also considered an SPS alternative to mitigate all Category C overloads identified in this area and found that the SPS to be infeasible because it would require monitoring more contingencies than the SPS guideline would allow. The ISO further considered an alternative feasible SPS combined with required upgrades to mitigate all overloads and found this option to be more expensive compared to the *Table Mountain-Sycamore 115 kV Line Project*.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO staff will ensure that necessary operating procedures will be in place to meet reliability needs in 2011.

Lockeford-Industrial, Lodi-Industrial and Lockeford-Lodi 60 kV Lines

The Lockeford/Lodi area 60 kV lines are identified with existing overloads under various Category C contingency conditions. Also for the loss of the Country Club-Hummer 60 kV, the Mosher substation transfers to the Lockeford #1 60 kV line potentially overloading it. The Mosher substation has over 50 MW of load and, as such, it should have a looped service. For these potential overloads, presently there is an ongoing 2010 request window project which proposes to build a new 230/60 kV substation in the vicinity of the existing Industrial substation and also build two new 60 kV lines from the new substation to the Industrial substation. The ISO, working with PG&E, will evaluate different alternatives to bringing additional transmission capacity in to the Lodi area as a long-term solution. The most feasible project implementation, due to permitting and lead times is 2016. These plans will be assessed further in a future ISO transmission plan.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concerns. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Valley Spring No. 1 60 kV Line

The Valley Spring No. 1 60 kV line is identified to overload starting year 2020 under Category B contingency condition. This overload occurs when the Linden substation is transferred to this line due to an outage of the Weber-Mormon Junction 60 kV line. Reconductoring this line could be a solution. There is ample time for permitting, procurement and installation before 2020. This plan, and other possible options, will be assessed further in a future ISO transmission plan.

West Point-Valley Springs 60 kV Line

The ISO identified an existing overload on the West Point-Valley Springs 60 kV line under a Category B contingency condition. The ISO previously approved a project in the 2010 transmission plan to reconductor this line but since this is a remote radial line built though rough terrain with no back-up sources, the reconductoring work cannot take place without interrupting electric service to customers at Electra, West Point, and Pine Grove for approximately 1-2 months. Because of this issue, PG&E submitted a project through the 2010 request window, the *West Point-Valley Springs 60 kV Line Project*, which consists of building a new 60 kV line from Valley Springs to Pine Grove substation. The project has an in-service date of December 2013. The ISO determined that this project is needed to mitigate identified overloading concerns

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Stanislaus-Manteca No. 2 115 kV Line

The Stanislaus-Manteca No. 2 115 kV line was identified with an existing overload under a Category C contingency. The solution includes developing an operating solution to reduce generation at Stanislaus following the first contingency. The most feasible implementation timeline is 2011.

Stanislaus-Melones-Manteca No. 1 115 kV Line

The Stanislaus-Melones-Manteca No.1 115 kV line was identified with an existing overload under a Category C contingency. Solutions include obtaining a short-term rating and developing an operating solution to reduce generation at Stanislaus following the contingency or to install an SPS for the same action. The most feasible implementation timeline for this upgrade is 2012.

Stockton 'A'-Lockeford-Bellota No. 2 115 kV Line

The ISO identified an existing overload on the Stockton 'A'-Lockeford-Bellota No. 2 115 kV line under a Category C contingency condition. Solution includes developing an operating solution to re-adjust the system following the first contingency or to install an SPS to curtail load following the second contingency. The most feasible implementation timeline for this upgrade is 2012.

2.7.4.6 Stockton/Stanislaus Division Voltage Concerns Mitigations

The ISO identified an existing low voltage at Lockeford 230 kV bus under a Category B contingency condition. The ISO also identified existing low voltages at Stagg and Eight Mile 230 kV buses under Category C contingency conditions. The solution includes installing voltage support in the area. The most feasible implementation timeline for this upgrade is 2015 due to permitting and lead times. In the interim, the ISO recommends that an operating procedure be developed to address any potential reliability concerns.

Request Window Submission - Kirkwood Meadows Public Utility District (KMPUD) 115 kV Interconnection

KMPUD and the Kirkwood Community are physically isolated from any large regional electric service utility. Kirkwood is currently being served by local diesel-fired generators, which are owned and operated by KMPUD. KMPUD's customer base is comprised of residential homes, commercial operations, and the Kirkwood Ski Resort, which is its largest single customer. Due to the increased electric demand, KMPUD is proposing to interconnect to PG&E's transmission system. To facilitate this interconnection, PG&E submitted a project through the 2010 request window, the *KMPUD 115 kV Interconnection Project*, which proposes to interconnect KMPUD's proposed facilities by tapping onto the existing Salt Springs – Tiger Creek 115 kV line adjacent to Salt Springs PH. This tap line will be 2.3 miles long. The project is expected to cost between $2M and $4M.

The ISO has reviewed the interconnection facilities proposed by PG&E and has determined that they will allow the load to be reliably interconnected to the ISO controlled grid. There are no reliability upgrades or additions to the ISO controlled grid that will be triggered by the tap line and associated facilities. Thus, the ISO has determined that this proposed load interconnection to the PG&E 115 kV system may proceed without modification. The radial tap line will not be under the ISO's operational control.

2.7.5 Key Conclusions

The 2010 reliability assessment of the PG&E Central Valley area revealed several reliability concerns. These concerns consist of thermal overloads and low voltages under normal, Categories B and C contingency conditions. Also one Category C contingency resulted in the power flow divergence indicating potential area-wide voltage collapse.

The problems identified in this 2010/2011 assessment are very similar to those found in the last year's assessment. There were three new projects approved in the 2010 transmission plan, which eliminated one normal, one Category B and three Category C overloads identified in the last year's assessment. To address the identified thermal overloads and low voltage concerns, the ISO-proposed a total of 30 transmission solutions and received nine transmission project proposals through the request window. ISO also completed evaluation of one ongoing project from the last year's request window. However, some of these proposed request window projects serve the purpose of more than one ISO-proposed solutions. These are:

- Hammer –Country Club 60 kV Line Switch Replacement Project;
- Cortina No. 3 60 kV Line Reconductoring;
- West Point –Valley Springs 60 kV Line Project;
- South of Palermo 115 kV Reinforcement Project;
- Stagg –Hammer 60 kV Line Project;
- Vierra 115 kV Looping Project;
- Rio Oso –Atlantic 230 kV Line Project;
- Vaca Dixon-Davis Voltage Conversion;
- Lodi Area 230 kV Substation Project; and
- Drum –Grass Valley –Weimar 60 kV Line Project.

The ISO has determined eight projects to be needed (1 through 8 in the list above), and the remaining two (9 and 10 in the list above) have ongoing status requiring further information.

The projects determined to be needed will carry forward into the 2011/2012 planning cycle and will be included in the planning assumptions.

8.2 Transmission Projects Found to Be Needed in The 2010/11 Planning Cycle

In the 2010/2011 transmission planning process, the ISO determined that 32 transmission projects, submitted through the ISO 2010 request window, were needed to mitigate identified reliability concerns. Table 8.2-1 is the summary of these 32 transmission projects. In addition, the ISO also identified one policy-driven project (category 1) to be recommended to the ISO Board of Governors for approval (please see Table 8.2-2).

Table 8.2-1: New reliability projects found to be needed

No	Project Name	Project Sponsor(s)	Project Cost ($ Million)	Service Area	Type of Submission	In-Service Date
1	Reconductor TL663, Mission-Kearny	SDG&E	$17.9M	San Diego	Reliability Project	6/1/2015
2	Reconductor TL670, Mission-Clairemont	SDG&E	$14.7M	San Diego	Reliability Project	6/1/2015
3	Reconductor TL676, Mission-Mesa Heights	SDG&E	$18.6M	San Diego	Reliability Project	6/1/2015
4	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	$9M	San Diego	Reliability Project	6/1/2013
5	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	$33.6M	San Diego	Reliability Project	6/1/2013
6	TL644, South Bay-Sweetwater: Reconductor	SDG&E	$8.9M	San Diego	Reliability Project	6/1/2013
7	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	$16.9M	San Diego	Reliability Project	6/12/2012
8	Southern Orange County Reliability Upgrade Project - Alternative 3 (Rebuild Capistrano Substation, construct a new SONGS-Capistrano 230 kV line and a new 230 kV tap line to Capistrano)	SDG&E	$365M	San Diego	Reliability Project	6/1/2015
9	New Sycamore - Bernardo 69 kV line	SDG&E	$30M	San Diego	Reliability Project	6/1/2015
10	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	$3-6M	Fresno/Kern	Reliability Project	5/1/2013

No	Project Name	Project Sponsor(s)	Project Cost ($ Million)	Service Area	Type of Submission	In-Service Date
11	Wilson 115 kV Area Reinforcement	PG&E	$35-45M	Fresno/Kern	Reliability Project	5/1/2015
12	West Point - Valley Springs 60 kV Line Project	PG&E	$20-25M	North/Central Valley	Reliability Project	12/1/2013
13	Vierra 115 kV Looping Project	PG&E	$10-15M	North/Central Valley	Reliability Project	5/1/2014
14	Rio Oso - Atlantic 230 kV Line Project	PG&E	$30-40M	North/Central Valley	Reliability Project	5/1/2016
15	Table Mountain – Sycamore 115 kV Line	PG&E	$25-35M	North/Central Valley	Reliability Project	5/1/2015
16	Stagg – Hammer 60 kV Line	PG&E	$5-10M	North/Central Valley	Reliability Project	5/1/2014
17	South of Palermo 115 kV Reinforcement Project	PG&E	$80-100M	North/Central Valley	Reliability Project	5/1/2014
18	Cottonwood-Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project	PG&E	$43-57M	North/Central Valley	Reliability Project	5/1/2016
19	Oro Loma 70 kV Area Reinforcement	PG&E	$35-45M	Fresno/Kern	Reliability Project	5/1/2015
20	Oro Loma - Mendota 115 kV Conversion Project	PG&E	$25-35M	Fresno/Kern	Reliability Project	5/1/2015
21	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	$1-5M	Greater Bay	Reliability Project	5/31/2013
22	Mesa-Sisquoc 115 kV Line Reconductoring	PG&E	$5-10M	Central Coast/Los Padres	Reliability Project	5/31/2014
23	Kerchhoff PH #2 - Oakhurst 115 kV Line	PG&E	$25-35M	Fresno/Kern	Reliability Project	5/1/2015
24	Lemoore 70 kV Disconnect Switches Replacement	PG&E	$1-3M	Fresno/Kern	Reliability Project	5/1/2013
25	Hammer – Country Club 60 kV Switch Replacement	PG&E	$1-2M	North/Central Valley	Reliability Project	5/1/2012
26	Jefferson-Stanford #2 60 kV Line	PG&E	$25-35M	Greater Bay	Reliability Project	5/31/2014
27	Gill Ranch Gas Storge 115 kV Interconnection	PG&E	$11.8M	Fresno/Kern	Reliability Project	5/1/2011
28	Fulton 230/115 kV Transformer	PG&E	$10-14M	Humboldt,North Coast/Bay	Reliability Project	5/1/2014

No	Project Name	Project Sponsor(s)	Project Cost ($ Million)	Service Area	Type of Submission	In-Service Date
29	Cayucos 70 kV Shunt Capacitor	PG&E	$5-10M	Central Coast/Los Padres	Reliability Project	5/31/2014
30	Cortina No.3 60 kV Line Reconductoring Project	PG&E	$4-7M	North/Central Valley	Reliability Project	5/1/2013
31	Cascade 115/60 kV No.2 Transformer Project and Cascade - Benton 60 kV Line Project	PG&E	$20-30M	North/Central Valley	Reliability Project	5/1/2014
32	Vaca – Davis Voltage Conversion Project	PG&E	$70-107M	North/Central Valley	Reliability Project	5/1/2015

The following table 8.2-2 provides a list of policy-driven transmission project found to be needed in the ISO 2010/2011 planning cycle. The ISO has determined that WECC Path 42 and Devers – Mirage 230 kV Upgrades to qualify for category 1 policy-driven project for recommendation to the ISO Board of Governors for approval. For further discussion on this category 1 project, please refer to chapter 5 of the transmission plan.

Table 8.2-2: Category 1 Transmission Upgrades

No.	Name of Project	Description of Project
1	Path 42 and Devers – Mirage 230 kV Upgrades	This is a joint transmission upgrade on IID's portion of Path 42 (i.e. IID's portion on the Coachella Valley – Devers and Coachella Valley – Ramon 230 kV lines) and SCE's Devers – Mirage and Mirage – Ramon 230 kV lines. Considered upgraded path rating, subject to further WECC review and approval as part of its path rating study process, is 1,440 MW.

8.3 Policy Driven Transmission Projects To Be Evaluated in The Next Planning Cycle (2011/2012)

Table 8.3-1 lists category 2 policy-driven transmission upgrades to be evaluated further in the 2011/2012 planning cycle. For further discussions on these category 2 transmission upgrades, please see chapter 5 of the transmission plan.

Table 8.3-1: Category 2 Transmission Upgrades

No.	Name of Project	Description of Project
1	Install Reactive Supports at Various SDG&E's 230 kV Substations	Install a total of 400 MVAr reactive power support at Sycamore, Mission, and Talega 230 kV Substations
2	Third Miguel 500 kV Transformer	Install third 500/230 kV transformer at Miguel Substation
3	Upgrade El Dorado – Pisgah 500 kV Series Capacitors	Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)
4-8	Upgrade and construct new transmission lines in Fresno area:	1) Build the new Midway - Gregg 500 kV line 2) Reconductor Gregg - Herndon 230 kV line 3) Reconductor Warnerville - Wilson 230 kV line 4) Reconductor Barton - Herndon 115 kV line 5) Reconductor Manchester - Herndon 115 kV line

8.4 2010 Request Window Submittals

During the 2010/2011 planning cycle, the ISO 2010 request window was open from October 11, 2010, to December 10, 2010. During this time, 118 submittals were received which included proposals related to reliability, economic study requests, LCRIF, and merchant transmission projects. After screening review, 107 submittals remained in the ISO 2010 request window (see summary of this list in Table 8.4-1). Submittals were also made for operating procedures and System Protection Systems (SPS) which do not need ISO approval and were not required to be submitted through the request window. Finally, some projects were submitted as informational items; the intent of which is to provide the ISO information on items which are being considered by the PTOs for future submittal and for maintenance related projects for terminal equipment replacement[42].

[42] SDG&E submitted terminal equipment replacement projects to the ISO for informational only.

Table 8.4-1: 2010 Request Window Submittals

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
1	Telegraph Canyon 138kV Capacitor Addition	SDG&E	SDG&E	Reliability Project	4/1/2011	Project approval	Needs further evaluation	Chapter 2 - SDG&E
2	Reconductor TL663, Mission-Kearny	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
3	Reconductor TL670, Mission-Clairemont	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
4	Reconductor TL676, Mission-Mesa Heights	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
5	Reconductor TL631, El Cajon-Los Coches	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Needs further evaluation	Chapter 2 - SDG&E
6	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Yes	Chapter 2 - SDG&E
7	TL698E, Pala-Monserate Tap	SDG&E	SDG&E	Reliability Project	?	Information Only	N/A	Chapter 2 - SDG&E
8	TL642A, South Bay-Montgomery Tap - Terminal Equipment	SDG&E	SDG&E	Reliability Project	?	Information Only	N/A	Chapter 2 - SDG&E
9	TL603B, Sweetwater-Sweetwater Tap - Terminal Equp.	SDG&E	SDG&E	Reliability Project	?	Information Only	N/A	Chapter 2 - SDG&E
10	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Yes	Chapter 2 - SDG&E
11	TL691C, Pendleton-Avocado Tap: Terminal Equipment	SDG&E	SDG&E	Reliability Project	?	Information Only	No approval needed. Project submitted as informational item	Chapter 2 - SDG&E
12	TL644, South Bay-Sweetwater: Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Yes	Chapter 2 - SDG&E
13	TL6916, Sycamore-Scripps Overload Mitigation/ New TL 6942 Sycamore - Miramar 69 kV Line	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
14	TL6912 - Reconductor San Luis Rey-Pendleton	SDG&E	SDG&E	Reliability Project	6/1/2020	Project approval	Needs further evaluation	Chapter 2 - SDG&E
15	TL693 San Luis Rey-Melrose:Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E
16	TL694A San Luis Rey - Morro Hill Tap:Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2012	Project approval	No	Chapter 2 - SDG&E
17	TL680B - Melrose-Melrose Tap: Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	No	Chapter 2 - SDG&E
18	TL691B - Monserate-Avocado Tap: Terminal Equipment	SDG&E	SDG&E	Reliability Project	?	Information Only	No approval needed Project submitted as informational item	Chapter 2 - SDG&E
19	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	SDG&E	Reliability Project	6/12/2012	Project approval	Yes	Chapter 2 - SDG&E
20	TL633 Benardo-Rancho Carmel Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2012	Project approval	Needs further evaluation	Chapter 2 - SDG&E
21	Upgrade Mission 138/69 kV Transformer Banks 51 and 52	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Needs further evaluation	Chapter 2 - SDG&E
22	TL6915&6924 Sycamore-Pomerado #1 & #2: Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E
23	TL648, Poway-Rancho Carmel: 69 kV Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E
24	TL682 Rincon-Warners Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2012	Project approval	No	Chapter 2 - SDG&E
25	TL13835B Reconductor Laguna Niguel - Talega Tap	SDG&E	SDG&E	Reliability Project	6/1/2020	Project approval	Needs further evaluation	Chapter 2 - SDG&E
26	TL689A Bernardo-Felicita Tap: short-term mitigation	SDG&E	SDG&E	Reliability Project	?	Information Only	No approval needed; project submitted as informational item	Chapter 2 - SDG&E

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
27	Modified-SOCRUP Project	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes (Alternattive to project submittal is recommended)	Chapter 2 - SDG&E
28	Los Coches Substation 230 kV Expansion	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Needs further evaluation	Chapter 2 - SDG&E
29	New Sycamore - Bernardo 69 kV line	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
30	2009 Grid Assessment Category C Violations listings	SDG&E	SDG&E	Other	-	Information Only	No approval needed Project submitted as informational item	Chapter 2 - SDG&E
31	Reconfigure TL23013 and TL23028	SDG&E	SDG&E	Reliability Project	6/1/2011	Project approval	No	Chapter 2 - SDG&E
32	Install Synchronous Condensers at Mission, Penasquitos, and Talega 230 kV Substations	SDG&E	SDG&E	Reliability Project	6/1/2013 6/1/2016 6/1/2019	Project approval	Needs further evaluation	Chapter 2 - SDG&E
33	Antelope A Bank Operating Procedure	SCE	SCE	Reliability Project	6/1/2013	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
34	Bailey Operating Procedure	SCE	SCE	Reliability Project	3/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
35	Big Creek Existing RAS Modification	SCE	SCE	Reliability Project	9/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
36	Garnet Operating Procedure	SCE	SCE	Reliability Project	3/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
37	Lancaster OP & RAS	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
38	Neenach Selective Service	SCE	SCE	Reliability Project	12/31/2013	Project approval	No	Chapter 2 - SCE
39	North of Lugo Operating Procedures	SCE	SCE	Reliability Project	Spring 2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
40	Palmdale Remedial Action Scheme	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
41	Path 26 Existing RAS Modification	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
42	Rector RAS Modification	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
43	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	Fresno/Kern	Reliability Project	5/1/2013	Project approval	Yes	Chapter 2 - PG&E
44	Midway-Gregg 500 kV Line	PG&E	Fresno/Kern	Reliability Project	12/31/2018	Project approval	No	Chapter 2 - PG&E

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
45	Wilson 115 kV Area Reinforcement	PG&E	Fresno/Kern	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E
46	Wheeler Ridge Junction 230 kV Substation	PG&E	Fresno/Kern	Reliability Project	5/1/2020	Information Only	No approval needed Project submitted as informational item	Chapter 2 - PG&E
47	West Point - Valley Springs 60 kV Line Project	PG&E	North/Central Valley	Reliability Project	12/1/2013	Project approval	Yes	Chapter 2 - PG&E
48	Vierra 115 kV Looping Project	PG&E	North/Central Valley	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
49	Rio Oso - Atlantic 230 kV Line Project	PG&E	North/Central Valley	Reliability Project	5/1/2016	Project approval	Yes	Chapter 2 - PG&E
50	Table Mountain - Sycamore 115 kV Line	PG&E	North/Central Valley	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E
51	Stagg - Hammer 60 kV Line	PG&E	North/Central Valley	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
52	South of Palermo 115 kV Reinforcement Project	PG&E	North/Central Valley	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
53	Cottonwood-Red Bluff No. 2 60 kV Line Project Red Bluff Area 230/60 kV Substation Project	PG&E	North/Central Valley	Reliability Project	5/1/2016	Project approval	Yes	Chapter 2 - PG&E
54	Oro Loma 70 kV Area Reinforcement	PG&E	Fresno/Kern	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E
55	Pittsburg - Clayton #2 115 kV Line Project Moraga-Lakewood 115 kV Reconductoring Project Lakewood-Meadow Lane - Clayton 115 kV Reconductoring Project	PG&E	Greater Bay	Reliability Project	5/31/2015	Project approval	No	Chapter 2 - PG&E
56	Oro Loma - Mendota 115 kV Conversion Project	PG&E	Fresno/Kern	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E

<u>EXHIBIT F</u>
EXCERPTS FROM THE 2017-2018 CALIFORNIA ISO TRANSMISSION PLAN

California ISO

2017-2018
TRANSMISSION PLAN

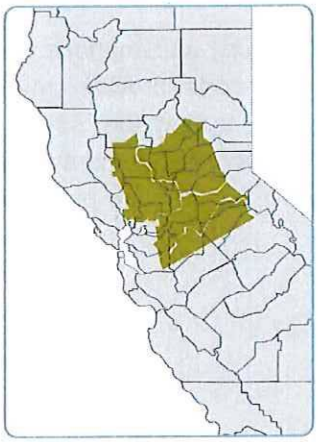
March 22, 2018

Board Approved

2.5.4 Central Valley Area

2.5.4.1 *Area Description*

The Central Valley area is located in the eastern part of PG&E's service territory. This area includes the central part of the Sacramento Valley and it is composed of the Sacramento, Sierra, Stockton and Stanislaus divisions as shown in the figure below.



Sacramento Division

The Sacramento division covers approximately 4,000 square miles of the Sacramento Valley, but excludes the service territory of the Sacramento Municipal Utility District and Roseville Electric. Cordelia, Suisun, Vacaville, West Sacramento, Woodland and Davis are some of the cities in this area. The electric transmission system is composed of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. Two sets of 230 and 500 kV transmission paths make up the backbone of the system.

Sierra Division

The Sierra division is located in the Sierra-Nevada area of California. Yuba City, Marysville, Lincoln, Rocklin, El Dorado Hills and Placerville are some of the major cities located within this area. Sierra's electric transmission system is composed of 60 kV, 115 kV and 230 kV transmission facilities. The 60 kV facilities are spread throughout the Sierra system and serve many distribution substations. The 115 kV and 230 kV facilities transmit generation resources from north-to-south. Generation units located within the Sierra area are primarily hydroelectric facilities located on the Yuba and American River water systems. Transmission interconnections to the Sierra transmission system are from Sacramento, Stockton, North Valley, and the Sierra Pacific Power Company (SPP) in the state of Nevada (Path 24).

Stockton Division

Stockton division is located east of the Bay Area. Electricity demand in this area is concentrated around the cities of Stockton and Lodi. The transmission system is composed of 60 kV, 115 kV and 230 kV facilities. The 60 kV transmission network serves downtown Stockton and the City of Lodi. Lodi is a member of the Northern California Power Agency (NCPA), and it is the largest city that is served by the 60 kV transmission network. The 115 kV and 230 kV facilities support the 60 kV transmission network.

Stanislaus Division

Stanislaus division is located between the Greater Fresno and Stockton systems. Newman, Gustine, Crows Landing, Riverbank and Curtis are some of the cities in the area. The transmission system is composed of 230 kV, 115 kV and 60 kV facilities. The 230 kV facilities connect Bellota to the Wilson and Borden substations. The 115 kV transmission network is located in the northern portion of the area and it has connections to qualifying facilities generation located in the San Joaquin Valley. The 60 kV network located in the southern part of the area is a radial network. It supplies the Newman and Gustine areas and has a single connection to the transmission grid via a 115/60 kV transformer bank at Salado.

Historically, the Central Valley area experiences its highest demand during the summer season. Accordingly, system assessments in these areas included technical studies using load assumptions for the summer peak conditions.

2.5.4.2 *Area-Specific Assumptions and System Conditions*

The Central Valley Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured market participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Valley Area study are provided below.

Table 2.5-14 Central Valley load and generation assumptions

Base Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
CVLY-2019-SP	Baseline	2019 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	3,865	96	688	229	3,540	101	59	34	46	12	1,376	454	1,389	1,101	1,501	1,188
CVLY-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	3,995	159	807	273	3,563	103	59	34	46	12	1,376	454	1,389	1,099	1,501	1,181
CVLY-2027-SP	Baseline	2027 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	4,246	272	1,162	398	3,577	104	59	34	46	12	1,376	454	1,389	1,095	1,501	1,171
CVLY-2019-ML	Baseline	2019 spring light load conditions. Light load time - hours between 02:00 and 04:00.	1,354	66	688	0	1,288	101	59	34	46	0	1,376	138	1,389	891	1,501	1,237
CVLY-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time – weekend morning.	2,046	127	807	763	1,156	103	59	34	46	46	1,376	1,376	1,389	742	1,501	335
CVLY-2019-SP-PS	Sensitivity	2019 summer peak load conditions with peak-shift sensitivity	3,835	96	688	142	3,597	101	59	34	46	7	1,376	454	1,389	1,133	1,501	1,188
CVLY-2027-SP-PS	Sensitivity	2027 summer peak load conditions with peak-shift sensitivity	4,072	272	1,162	107	3,693	104	59	34	46	3	1,376	454	1,389	1,133	1,501	1,054
CVLY-2022-SP-PS-AAEE	Sensitivity	2022 summer peak load conditions with peak-shift and AAEE sensitivity	3,958	0	807	105	3,853	103	59	34	46	4	1,376	454	1,389	1,133	1,501	1,053
CVLY-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi renewable dispatch sensitivity	3,433	138	807	807	2,488	103	59	34	46	46	1,376	1,376	1,389	1,091	1,501	305
CVLY-2027-SP-QF	Sensitivity	2027 summer peak load conditions with QF retirement sensitivity	4,246	272	1,162	398	3,577	104	59	34	46	12	1,376	454	1,389	1,085	1,501	1,181

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with an exception of following approved projects which are not modeled in the base cases:

Table 2.5-15: Central Valley approved projects not modeled in base case

Project Name	TPP Approved In	Current ISD
Atlantic-Placer 115 kV Line	2012-2013 TPP	Dec-2021
Pease 115/60 kV Transformer Addition and Bus Upgrade	2012-2013 TPP	Mar-2020
Mosher Transmission Project	2013-2014 TPP	Oct-2019
Bellota 230 kV Substation Shunt Reactor	2015-2016 TPP	Dec-2020
Vaca – Davis Voltage Conversion Project	2010-2011 TPP	Apr-2025
Rio Oso – Atlantic 230 kV Line Project	2010-2011 TPP	Dec-2022
Vierra 115 kV Looping Project	2010-2011 TPP	Nov-2021
Stagg – Hammer 60 kV Line	2010-2011 TPP	Aug-2022
Rio Oso Area 230 kV Voltage Support	2011-2012 TPP	Apr-2021
Lockeford-Lodi Area 230 kV Development	2012-2013 TPP	Dec-2022

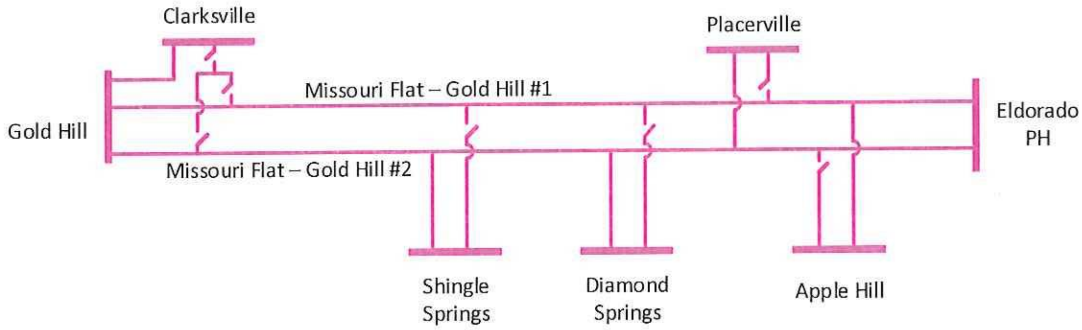
2.5.4.3 *Assessment Summary*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2017-2018 reliability assessment of the PG&E Central Valley Area has identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P0 to P7 contingencies most of which are addressed by previously-approved projects. The areas where additional mitigation requirement were identified are discussed below.

Gold Hill – El Dorado PH 115 kV system

Category P2-1 contingency overloads are identified on the Gold Hill – El Dorado PH 115 kV system. As shown in the diagram below, majority of the load pockets in the area are connected to Missouri Flat – Gold Hill #2 line. As a result, P2-1 overload occurs when the breaker at the Gold Hill end of the Missouri Flat – Gold Hill #2 line opens without a fault. Under this scenario, significant power will flow on Missouri Flat – Gold Hill #1 to supply all the load which will result in overload on the sections connected to El Dorado PH that have lower ratings.

Table 2.5-16: Gold Hill – El Dorado PH 115 kV system



To address the issue, ISO is recommending that as normal operation, the Shingle Springs load to be connected to Missouri Flat – Gold Hill #1.

Summary of review of previously-approved projects

There are 18 previously-approved active projects in the Central Valley Area, out of which 10 projects are not modeled in the study cases either due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. The 8 projects modeled in the study cases were found to have current needs consistent with the scope of the projects and no changes to those projects are recommended. Table below shows final recommendation for the 10 projects not modeled in the study cases:

Table 2.5-17: Recommendation for previously-approved projects not modeled in the study cases

Project Name	Recommendation
Bellota 230 kV Substation Shunt Reactor	Proceed with current scope
Vierra 115 kV Looping Project	Proceed with current scope
Rio Oso – Atlantic 230 kV Line Project	Cancel
Stagg – Hammer 60 kV Line	Cancel and install SPS
Atlantic-Placer 115 kV Line	Hold
Vaca – Davis Voltage Conversion Project	Revised scope
Pease 115/60 kV Transformer Addition and Bus Upgrade	Revised scope
Mosher Transmission Project	Revised scope
Rio Oso Area 230 kV Voltage Support	Revised scope
Lockeford-Lodi Area 230 kV Development	Revised scope

Details of the review of previously-approved projects not modeled in study cases are presented in Appendix B.

Below are the high level discussion of projects recommended to proceed with revised scope:

Stagg – Hammer 60 kV Line

The 2017-2018 reliabity assessment identified overloads for P2, P6, and P7 contingencies on the 60 kV system. The recommendation is to cancel the project and recommend PG&E to install a SPS to address the issue.

Atlantic-Placer 115 kV Line

The ISO is going to continue the review of the overall system needs in this area in the next planning cycle and evaluate alternatives that could potentially address all the issues in the area. The project was put on hold in the 2016-2017 TPP and is recommended to remain on-hold with further detailed assessment of the project and potential alternatives in the 2018-2019 TPP.

Vaca – Davis Voltage Conversion Project

There are overloads and voltage criteria violations in the 115 kV and 60 kV transmission system between Vaca Dixon, Davis, Rio Oso, and Brighton substations. However due to drop in load forecast, the criteria violations are not as severe compared to 2010-2011 TPP analysis when the Vaca – Davis Votlage Conversion Project was approved. The ISO is recommending approval of the "Vaca – Davis Voltage Conversion Project" (revised scope) and to rename the project to "Vaca Dixon Area Reinforcement".

Original Scope:

- Convert the 60 kV network between Vaca Dixon to Davis to 115 kV.
- 2010-2011 TPP estimated cost: $70 to $107 million
- Current estimated cost: $192 million

Revised Scope:

- Install 10 Mvar capacitor bank at Plainfield substation (2 x 5 Mvar capacitor banks)
- Replace Vaca Dixon 115/60 kV Bank #5 with higher rating transformer
- Replace the limiting elements of Dixon 60 kV substation
- Recommend PG&E to re-rate the Woodland – Davis 115 kV line and Rio Oso – West Sac 115 kV line and recommend PG&E to modifying existing SPSs or add new SPS to trip load for the P6 contingencies.
- 2017-2018 TPP estimated cost: $15 Million
- In-service Date: 2021

EXHIBIT G
ALTERNATIVE ROUTE MAP

LATHROP
Lathrop City Hall
115 kV
D'Arcy Pkwy.
5
Nestle Way
Christopher Way
Vierra
Vierra Rd.
West Yosemite Ave.
S Howland Rd.
Guthmiller Rd.
120
MANTECA
Potential Routes
Christopher Way Route
Nestle Way Route Option
Guthmiller Rd. Route
Guthmiller Rd. 120 Option
West Gateway Route
NORTH
No Scale
Legend
Existing 115 kV power line
Lathrop City Boundary
Manteca City Boundary
Existing Substation
Lathrop City Hall
Project Study Area