A. INTRODUCTION/OVERVIEW

This Draft Environmental Impact Report (EIR) has been prepared by the California Public Utilities Commission (CPUC) in accordance with the California Environmental Quality Act (CEQA) to inform the public and to meet the needs of local, state, and federal permitting agencies to consider the Tri-Valley 2002 Capacity Increase Project proposed by Pacific Gas and Electric Company (referred to in this document as PG&E Co. or "the Applicant"). The project proposed by PG&E Co. (the "Proposed Project") is described briefly below, and in detail in Part B of this EIR. This EIR does not make a recommendation regarding the approval or denial of the project; it is purely informational in content.

This EIR evaluates and presents the environmental impacts that are expected to result from construction and operation of PG&E Co.'s Proposed Project, and provides mitigation measures that, if adopted by the CPUC or other responsible agencies, could avoid or minimize the significant environmental impacts identified. In accordance with CEQA requirements, this EIR also identifies alternatives to the Proposed Project that could avoid or minimize significant environmental impacts associated with the project as proposed by PG&E Co. (including the No Project Alternative), and evaluates the environmental impacts associated with these alternatives. Based on this environmental impact assessment, as well as the relative sensitivities of impacts in the Tri-Valley region, this EIR identifies the Environmentally Superior Alternative as required by CEQA.

This EIR reflects input by government officials, other agencies, nongovernmental organizations and concerned members of the public during the EIR Scoping period following the CPUC's publication of the Notice of Preparation (NOP) of an EIR (April 22 to May 22, 2000, with written comments accepted until June 1, 2000). During this comment period, several public involvement activities were completed: distribution of the NOP and a scoping meeting notice, establishment of an Internet web page and a telephone hotline, three public scoping meetings, and meetings with interested local agencies (see additional details in Section G). Consultation with other agencies continued after the formal scoping period ended, as well.

A.1 HISTORY AND OVERVIEW OF PROPOSED PROJECT

California state law confers authority for the siting of certain regulated electric utility facilities, including PG&E Co. power lines and substations, on the CPUC and Local governments in California do not have discretionary authority over such projects. The CPUC has promulgated General Order 131-D to guide its permitting and oversight of electric facility siting, and requires utilities to confer and consult with local government in order to avoid or minimize conflicts with local land use, design and safety standards.

On November 22, 1999, PG&E Co. filed Application A-99-11-025 with the CPUC for a "Certificate of Public Convenience and Necessity" (CPCN) to construct the Tri-Valley 2002 Capacity Increase Project, in order to increase electric service to the Tri-Valley area by adding substations in North Livermore and Dublin, expanding the Vineyard Substation in Pleasanton, and installing about 23.5 miles of 230 kilovolt (kV) transmission lines to serve these substations. As required by CPUC rules, the Application included a Proponent's Environmental Assessment (PEA) of the environmental impacts which could result if the CPUC granted the requested CPCN, as well as alternatives considered by PG&E Co. to its Proposed Project. In April 2000, after receiving additional information from PG&E Co. necessary to undertaking a review of the project in compliance with CEQA, the CPUC accepted PG&E Co.'s application as complete and initiated its CEQA review as Lead Agency with the publication of the Notice of Preparation of an EIR. In parallel, the Assigned Commissioner issued his Ruling on the scope of the CPUC's "General Proceeding" to consider whether PG&E Co.'s application should be approved and under what conditions, which stated:

> *Public Utilities Code Sections 1001 and 1002 provide the basic scope for the CPUC's General Proceeding. In addition to the determination of need underlying the grant of a Certificate of Public Convenience and Necessity (CPCN), Section 1002 provides in pertinent part that the Commission, as a basis for granting any certificate pursuant to Section 1001, shall give consideration to: a) Community values; b) Recreational and park areas; c) Historical and aesthetic values; and d) Influence on the environment. The CPUC's General Order 131-D further prescribes that prior to issuing a CPCN, the Commission must find that the project promotes the safety, health, comfort and convenience of the public. … The effect of a proposed facility on property values is not, per se, an issue within scope. However, in considering the aesthetic and community values affected by a proposed facility, the impact on property values is indirectly considered. The cumulative and/or growth inducing impact that the project might have is also a matter within the scope. (Assigned Commissioner Bilas' Ruling, April 26,2000, pp. 4-5)*

The Commission will consider information in the EIR, as well as testimony and briefs filed in the General Proceeding, and public comment gathered in Public Participation Hearings, to form its decision on this Application by PG&E. For more information about the CPUC's decision-making process, please contact the CPUC's Public Advisor at (415) 703-2074; or e-mail at: public.advisor@cpuc.ca.gov, and see the CPUC's website at http://www.cpuc.ca.gov/divisions/pubadv.htm.

Previous CPUC Decisions

In 1988, the CPUC granted a CPCN to PG&E Co. to build and operate a 230 kV transmission system in the Pleasanton-Livermore Area. PG&E Co. filed its application for the Vineyard 230 kV Project in 1986, proposing to build 3.7 miles of overhead transmission line behind (the then-proposed) Ruby Hill development, then underground 1.6 miles along Vineyard Avenue into the (then) proposed 230 kV Vineyard Substation.

In 1987, the CPUC prepared a Draft and Final EIR, which looked at the following alternatives:

- Alternative 1, Route 1, Option 1 (somewhat similar to PG&E Co.'s current Proposed Project, but more overhead line): 4.7 miles total length, with 1.2 miles underground (more towards Bernal than current Proposed Project, Kottinger Ranch was in planning stages but not yet built).
- Alternative 2, Route 1, Option 2 (very similar to the current Proposed Project, but the overhead/underground transition station was closer to town): 5.1 miles total length and 1.9 miles underground.

- Alternative 3, Route 3, Option 2 (modification of the Proposed Ruby Hill route): 5.6 miles total length with 3.5 miles underground (the difference between this Alternative and the Proposed was that this would hit Vineyard Avenue a little farther east).
- Alternative 4, Route 4 (Vineyard Ave. all the way to Tesla corridor, ending west of Sycamore Grove Park): 5.6 miles long, all underground. This alternative was included in both the Draft EIR and the Final EIR but it was not fully analyzed for impacts. The Commission's Decision (see next paragraph) said "since the all-U.G. Alternative 4 was advanced after environmental field work was underway on the other alternatives, it was not possible in the time available to conduct a complete environmental review… a Supplemental EIR will be required if all-U.G. Alternate 4 is selected" (and it was selected).

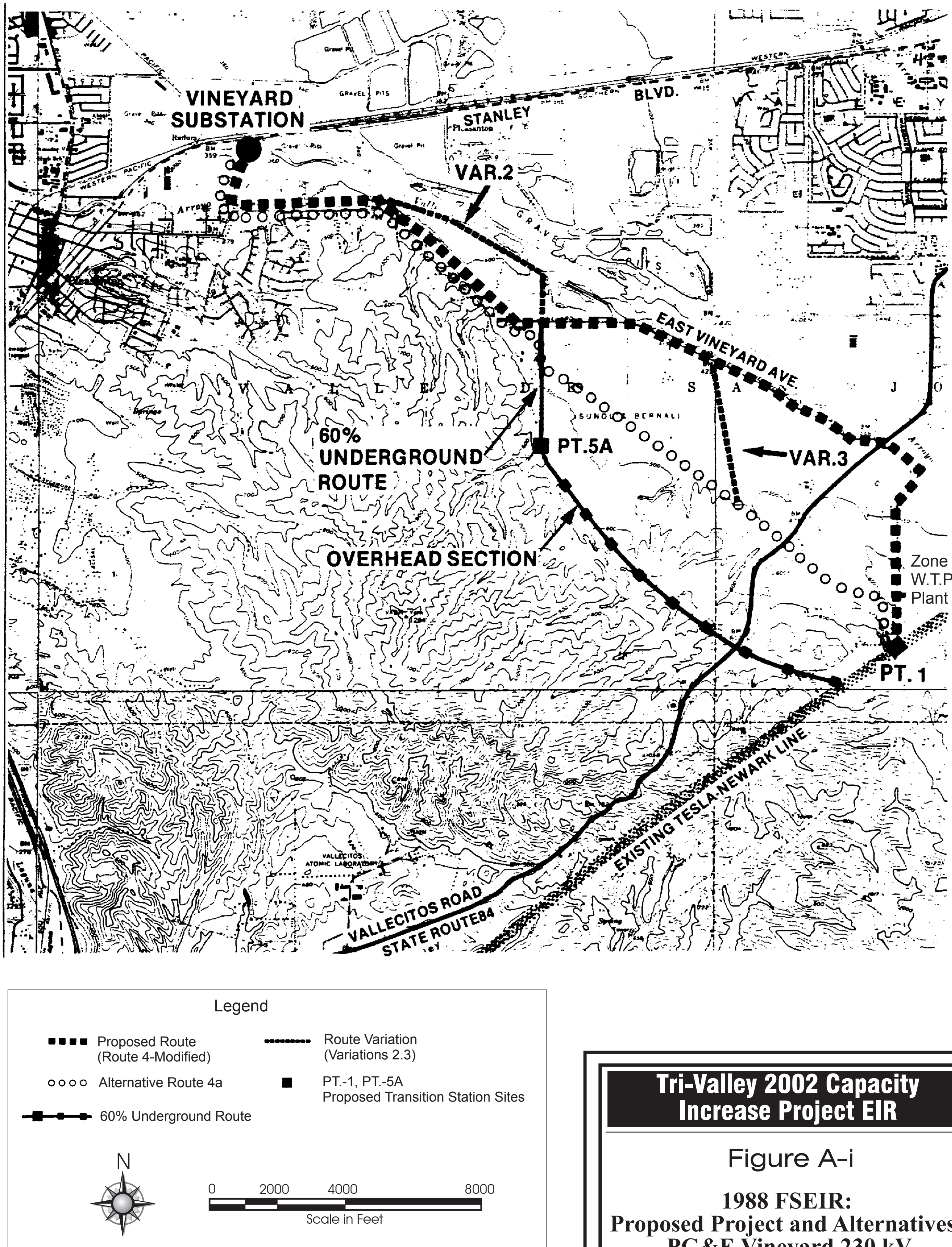
On January 28, 1988 the CPUC granted a Certificate of Public Convenience and Necessity (D.88-01-067) to PG&E Co. for the "all-underground Alternate 4" (the "all Vineyard Avenue" route). The CPCN was subject to two conditions and some other requirements:

- PG&E Co. to comply with the Final EIR's mitigation measures
- PG&E Co. to comply with any Supplemental EIR mitigation measures developed for Alternative 4
- PG&E Co. was ordered to prepare a study comparing Alternative 4 with the potential expansion of the San Ramon Substation (which PG&E Co. said it would do rather than the all-underground alternative)
- CPUC Staff was ordered to prepare a Supplemental EIR on Alternative 4 within 90 days of receiving information from PG&E Co.
- PG&E Co. was ordered to submit an updated cost estimate
- CPUC Staff was to review PG&E Co.'s cost
- Authorization was good for two years (construction to begin within two years).

In 1988, the CPUC prepared a Draft and Final Supplemental EIR which evaluated the environmental impacts of the all underground, all Vineyard Avenue Alternative 4 it had previously approved, as well as four variations of this route, including a "60 % Underground Route" (see Figure A-i, for the Proposed Project and Alternatives considered in the Supplemental EIR) and the No Project Alternative. A San Ramon Substation Alternative to expand the San Ramon Substation in order to supply loads in Pleasanton was not considered in the Supplemental EIR because the (then) Division of Ratepayer Advocates found that the San Ramon Substation Alternative would be $2.1 million more expensive on a net present value basis than the all-underground (Alternative 4) project and $6.1 million more than the "60% underground" alternative. The Final SEIR found that Route 4a, a variation of the "Proposed Project" (Alternative 4 in the previous CPUC order) was Environmentally Superior.

According to PG&E Co. (Response to ALJ's Ruling, 11/21/00, pp. 2-3):

> "Subsequently, PG&E determined that this alternative for the subject project was not cost effective. This determination was based, in part, on the fact that undergrounding the entire route could not be justified under the California Environmental Quality Act, and because that alternative would have cost 50 percent more than the Proposed Project, which included only 1.6 miles of undergrounding. See Interim Order, p. 2. In addition, PG&E had determined that an alternative to the project consisting of constructing the Vineyard Substation with a connection to the existing 60 kilovolt ("kV") wood pole transmission system, was available and would be far more cost effective. PG&E estimated that 8 to 10 years of growth in Pleasanton could be accommodated by using the then existing 60 kV system and



Source: CPUC, Final Supplemental EIR, 10/88.

Tri-Valley 2002 Capacity Increase Project EIR

Figure A-i

**1988 FSEIR:
Proposed Project and Alternatives,
PG&E Vineyard 230 kV**

Aspen Environmental Group

> transferring capacity from PG&E's San Ramon Substation via new distribution feeders at less cost than the all underground 230 kV plan that the CPUC had authorized under the Interim Order.
>
> On June 28, 1989, with only six months left before the 1988 CPCN would expire (The Interim Order stated that the CPCN granted thereunder would expire if construction on that project did not begin within two years from the date it was issued, or by January 28, 1990), PG&E filed a petition to modify the Interim Order. This petition sought to extend the CPCN for 10 years. Subsequently, at a September 25, 1989 pre-hearing conference on the Petition for Modification of the Interim Order, PG&E informed the Commission that, having concluded that the All Underground Alternative 4 was infeasible, PG&E was withdrawing its request to extend the CPCN. See September 25, 1989 Prehearing Conference Transcript ("PHC") at 34-35. Instead, PG&E informed the Commission that it intended to develop the Vineyard Substation, but without the 230 kV transmission lines as originally proposed. Id. The new substation would provide temporary capacity reinforcement and allow some expansion of the 60 kV system. Under General Order 131-C ("G.O. 131-C"), the controlling authority at the time, construction of the substation for connection to a 60 kV system did not require a CPCN. G.O. 131-C only required certification for lines over 200 kV. See G.O. 131-C, § VII."

As a result, the Application was dismissed by the CPUC on December 14, 1989, and the CPCN expired.

All of the routes considered in this previous proceeding before the CPUC will be discernable in the routes which have been considered for the Pleasanton Area in this latest EIR on a project before the CPUC to increase electric service in the Tri-Valley area. The intervening decade has wrought changes in the setting and circumstances, most notably the development of substantial housing and other development in the routes previously considered. However, many of the same options are still relevant, as you will see as you continue reading this EIR.

A.2 PURPOSE AND NEED FOR THE PROPOSED PROJECT

In its Application and PEA, PG&E Co. states that its Proposed Tri-Valley 2002 Capacity Increase Project is needed to serve the projected electric demand of existing and approved development in the Cities of Dublin, Livermore, Pleasanton and San Ramon, and in portions of unincorporated Alameda and Contra Costa Counties adjacent to these cities (see Figure B-1). PG&E Co.'s stated objectives for its Proposed Project are (PEA, 1999):

- **Meet Electric Demand:** Relieve the electric system deficiency that will occur in the Tri-Valley area by the year 2002, and ensure the ability of the system to safety and reliably serve the area before any interruptions in service or emergency conditions result from this deficiency. (This is PG&E Co.'s fundamental objective.)
- **Comply with Planning Criteria:** Ensure that the Tri-Valley area transmission system will continue to meet the California Independent System Operator (CAISO) Grid Planning Criteria for safety and reliability, as well as meet the Planning Standards and Guidelines of the North American Electric Reliability Council (NERC). (This objective must be met in achieving the first one.)

As stated in the Scoping Report, the focus of this EIR is to assess the potential environmental impacts of PG&E Co.'s Proposed Project, not the need for said project. This EIR does not intend to provide conclusions about the need for the Proposed Project nor its compliance with CAISO or NERC standards. *Such findings shall be made by the CPUC through its associated General Proceeding on* *whether PG&E Co. should be granted a Certificate of Public Convenience and Necessity (CPCN) to construct and operate the Proposed Project. As with the entirety of this EIR, it is solely an informational document for decision-makers and the public; not a decisional document. Project Need does affect the comparison of alternatives and the identification of the Environmentally Superior Alternative in accordance the requirements of CEQA (see Part D herein).*

A.2.1. ELECTRICITY DEMAND IN THE AREA

Demand for electric energy in the Tri-Valley area has been increasing rapidly over the past five years. Many of the substation facilities used to provide service to the area are approaching, or have exceeded, their respective limits, necessitating the construction of additional facilities in order to continue to reliably serve within the area, as documented in PG&E's recent response to ALJ ruling (11/21/00, Exhibit C). The area is currently undergoing a considerable influx of high tech industry similar to that which occurred in the San Jose area over the past 10 years, and in fact much of this influx is spillover from the San Jose area. During the latter half of the 1990s, the San Jose area experienced growth in excess of 100 megawatts (MW) in some years, with electric load growth averaging approximately 5.5% to 6.0% annually[1].

For the period from 1996 to the summer of 2000, actual Tri-Valley area load grew by approximately 35 MW/yr or about 7.9% annually. During the past three years (1998-2000) the growth rate was approximately 8.9% annually[2]. Based on historical data, the area's projected economic outlook, and known customer development plans, PG&E Co. has forecasted that the electrical demand for the Tri-Valley area will grow at an average rate of 46 MW/year during the next five years, resulting in approximately a 7.2% annual growth rate. This projected rate of growth is slightly below the five-year historical rate experienced in the area but within a range of reasonable expectation, based on current economic growth activity within the area.

Review of the PG&E load projections for the area did not indicate any significant issues relative to the overall rate of area load growth. When viewed from the perspective of past load growth in the area and similar experience in the San Jose area, the forecasted growth is judged to be within a reasonable range of accuracy. As with all forecasts, final accuracy will be determined by numerous events beyond the control of PG&E Co., such as the recent passage of Measure D, discussed next. To the extent that area economic activity slows, projection for one year may be moved out in time by one or two years.

Measure D

As this DEIR was being finalized, the national and local elections were held in which Alameda County's Measure D was approved by the voters. This measure will affect future development in the East County planning area and alter some of the growth assumptions behind the need for the Proposed Project. Effective upon certification of the election, Measure D amends the East County Area Plan

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1 Aspen Environmental Group, PG&E Northeast San Jose Transmission Reinforcement Project Draft EIR, 2000.

2 PG&E Co., October 16, 2000 reply to Aspen data request.

(ECAP), the adopted General Plan governing development in the Dublin and Pleasanton areas and the rest of Alameda County east of those cities. Altogether, Measure D deletes 31 existing programs and policies from the ECAP, adds 12 new ones, and modifies 26 others. Among its many provisions, the measure amends the County Urban Growth Boundary and increases restrictions on development outside the boundary; reserves more land for agriculture and less land for urban development; and withdraws the County's participation in the North Livermore planning process. Because the North Livermore area is outside the modified Urban Growth Boundary (UGB) and no urban land use designations are permitted outside the UGB, the measure effectively blocks the County's approval of the proposed development of 12,500 homes, as planned for in the North Livermore Specific Plan.

In addition, Measure D designates the entire North Livermore area outside the City of Livermore's incorporation limits as a North Livermore Intensive Agriculture Area, and precludes urbanization of the area. Agricultural parcels may be subdivided, but only to a minimum 20-acre size for cultivated agricultural production, and upon preparation of an environmental impact report and economic analysis and the Board of Supervisors making the following findings:

- That there will be an adequate, sustainable, safe supply of water for projected cultivated agriculture and other uses;
- That cultivation and irrigation will not cause significant harm to groundwater, soil, biota, or other environmental qualities (including visual qualities); and
- That the parcels, with cultivated agriculture, will be economically viable.

However, Measure D does not prevent the City of Livermore from annexing the area (subject to approval by the Local Agency Formation Commission) and proceeding with development plans without the County's participation. City staff indicate that, in fact, the City of Livermore is likely to continue with the North Livermore planning process that was initiated in the early 1990s with preparation of the *North Livermore General Plan Amendment*.[3]

On December 4, 2000, PG&E Co. responded to the CPUC ALJ's Ruling requiring PG&E Co.'s analysis of the effect of Measure D on the projected load demand for the Tri Valley project area, and specifically for the Livermore distribution planning area (at pp. 3-4):

> "…in the fall of 1999, when PG&E was preparing the Application for the Project, including the PEA, "no growth" and "slow growth" measures were pending in the Tri Valley Area. Thus, PG&E was well aware of the possibility that restrictions such as Measure D could be put into place. As demonstrated in the PEA, regardless of such measures, including Measure D, the Project is necessary to prevent overloads in the Tri Valley Area, including the Livermore-Las Positas 21 kilovolt ("kV") Distribution Planning Area ("DPA"). In any case, the only development proposal included in the PEA's projections (as future, not already-approved, growth) for the Livermore-Las Positas DPA now prohibited by Measure D, is the development envisioned by the North Livermore Specific Plan (the "NLSP"). The removal of the development envisioned by the NLSP would result in approximately 600 fewer homes per year than were included in PG&E's projections (assuming those homes are not built nearby or elsewhere in the Tri Valley Area). This equates to approximately 4.2 MW per year. Even without the NLSP,

[3] William Kettler, Associate Planner, City of Livermore, personal communication, November 9, 2000.

however, PG&E's 1998 load forecasts show that in 2002, the Livermore-Las Positas DPA load would reach 140.9 megawatts ("MW"). The 2002 normal capacity of the Livermore-Las Positas DPA was anticipated to be 136.6 MW. Thus, as demonstrated by PG&E's 1998 forecasts, even without any contribution from the NLSP or any other development in areas now "off-limits" under Measure D, the Livermore 21kV DPA is expected to be overloaded by 2002, and possibly 2001.

PG&E's most recent load forecasts confirm that, regardless of Measure D, the Project is needed by 2002, if not sooner, and in fact, show that the situation has worsened since the PEA was prepared. PG&E's 1998 projection of Livermore-Las Positas DPA load for 1999, based on approved projects only (i.e., not including any growth that Measure D would now prohibit) was 107.7 MW, but the actual load turned out to be 119.7 MW. PG&E's 1998 projection for Livermore-Las Positas DPA load in 2000 was 120.8 MW, also based on approved projects only. The actual 2000 load was 123.8 MW. Thus, the electric demand in the Livermore-Las Positas 21 kV DPA has already grown at a faster rate than anticipated in the PEA.

PG&E's most recent load forecasts, based on those 1999 and 2000 actual load figures, indicate that without any development prohibited by Measure D, the 2002 load will be 154.7 MW, or 13.8 MW more than anticipated in the 1998 forecasts. Thus, PG&E's updated load forecasts further demonstrate that the urgent need projected in 1998 remains present, even without any of the development prohibited by Measure D, and that, due to the faster than expected load growth already occurring, the projected overloads may occur sooner than originally anticipated."

A.2.2. THE ELECTRIC SYSTEM IN THE TRI-VALLEY AREA

An electric power system consists of power plants, transmission substations, distribution substations, and overhead or underground electric lines. Power is delivered from the generating plants to customers through wires and cables, but the power is converted to higher and lower voltages several times for different purposes. At the generating plants, the electric power is "stepped up" to a higher voltage, known as the transmission voltage. Stepping up to a higher voltage reduces the amount of current that flows through the wires, and therefore allows the power to be delivered more efficiently from the generating plants to the major load centers with fewer and smaller wires. Once the power has been delivered to the major load centers, it is "stepped down" to a lower voltage for delivery to individual customers, known as distribution voltage. Transmission and distribution substations are used to "step up" or "step down" the voltage and to route the power over the transmission and distribution lines. In the PG&E transmission system, power is transmitted at 500, 230, 115, 70, and 60 kV.

In the Tri-Valley area, the electric power is transmitted to the regional substations at voltages of 230 kV and 60 kV. The power is then distributed to customers using overhead or underground distribution lines at voltages of 12 kV or 21 kV**.** The local delivery system, usually at 12 or 21 kV, is further stepped down for individual customer use (i.e., at transformers mounted on distribution line poles or installed underground).

A.2.2.1. Existing Transmission System

As illustrated in Figure A-1, eight 230 kV transmission circuits run along the perimeter of the Tri-Valley area. (Note that Transmission Lines are conventionally named for their termination points; e.g., the Contra Costa-Newark Line originates from the Contra Costa Power Plant, near Antioch, and terminates at the Newark Substation.) Four of these 230 kV circuits run northwest of the Tri-Valley

Figure A-1 **Placeholder**
Existing Regional Transmission System

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Figure A-1 **Placeholder**
Existing Regional Transmission System

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area: the Pittsburg-Moraga #3 circuit, the Pittsburg-Newark circuit, and the Contra Costa-San Mateo #1 and #2 circuits. Two 230 kV circuits run along the eastern and southern edges of the Tri-Valley area: the Contra Costa-Newark #1 and #2 circuits. These six 230 kV circuits deliver power from the Pittsburg and Contra Costa power plants to Bay Area load centers. Two of these circuits (Pittsburg-Moraga #3 and Contra Costa-Newark #1) deliver power to the Tri-Valley area. In addition to these six 230 kV circuits, two circuits skirt the southern edge of the Tri-Valley area: the Tesla-Newark and the Tesla-Ravenswood 230 kV circuits. These circuits deliver power from the 500 kV/230 kV Tesla Substation to Bay Area load centers. The PG&E 500 kV system is part of the Western States power grid, which interconnects inter- and intrastate power plants.

There are presently three sources of power into the Tri-Valley 60 kV system. Two of these sources are served from the 230 kV lines described above: the 230/60 kV, 88 megavolt amperes (MVA) transformer at the San Ramon Substation (which is served from the Pittsburg-Moraga #3 line), and the 230/60 kV, 90 MVA transformer at the Las Positas Substation (which is served from the Contra Costa-Newark #1 line). The third source into the Tri-Valley 60 kV system is the 115/60 kV, 75 MVA transformer at the Newark Substation.

A.2.2.2 Existing Distribution System

PG&E Co. currently provides service to Tri-Valley loads from twelve substations located throughout the area. (See Figure A-2) Four of these facilities are dedicated to serve single large customers (BART/East Dublin, Kaiser, Iuka and the customer-owned Cal-Mat Substation), with the remaining eight substations serving the remainder of the regional loads. Equipment at a number of these substations is approaching, or in some cases has exceeded, normal operating limits. In a number of cases, available exit routes for distribution lines from the substations have been exhausted. In other cases, the existing substation transformation has reached, or will shortly reach, its rating.

Over 80% of the area load is currently served from three substations (San Ramon, Vineyard and Las Positas). San Ramon and Las Positas (in Livermore) stations are served from the 230kV transmission system and are equipped with 230-21kV transformation. The Vineyard station in Pleasanton is served via an area 60kV system. Transformation at this station is from 60kV to 21kV. Distribution loads in these areas are served from 21kV distribution feeders. Increasing the loadings on the San Ramon and Las Positas stations will result in overloading of existing transformation and will also require establishment of additional distribution feeder routes. The 60kV transmission system feeding the Vineyard station is overloaded during summer peak periods, necessitating the need to operate the station connected radial on the 60 kV system, rather than in a more secure networked configuration. If additional load is to be served from these sites, extensive internal upgrading would be required. However, adequate exit routes for distribution circuits may not be available and in many cases the new loads to be served are located remotely from the existing sites.

Much of the new load is projected to be located to the north of Interstate 580 and to the east of Interstate 680, which may best be served via establishment of new substation sites within the growth area. Two new substations (Dublin and N. Livermore substations) have been proposed by PG&E Co.

and alternative sites for each have also been evaluated in this EIR. In the case of the Vineyard substation, the issue is providing for a more secure and robust method of serving the substation electrically.

A.2.3. Regional Transmission Overview and Planning Criteria

The transmission system serving the Tri-Valley area is part of the PG&E Co.-owned, CAISO-operated grid. This CAISO-operated grid presently consists of the transmission systems previously operated by PG&E Co., Southern California Edison and San Diego Gas & Electric Companies. Pursuant to state legislation (AB 1890), these three, largest investor-owned systems in the state (which are regulated by the CPUC) have turned operational control of their transmission systems over to the CAISO. The ownership and planning responsibility for these systems continue to rest with the investor-owned utilities. This statewide network of transmission is interconnected with other systems in surrounding states, and together they form part of the Western System Coordinating Council (WSCC) system. Members of the WSCC subscribe to certain minimum operating reliability requirements and planning criteria. In addition to WSCC planning criteria, the CAISO has adopted certain reliability and planning criteria that to a large extent incorporate the WSCC criteria and NERC planning standards. The planning criteria set out by WSCC generally pertains to how one interconnected system plans and operates with adjacent systems, while NERC planning standards set down planning criteria for both the overall interconnected transmission system and for local service to internal loads, such as those in the Tri-Valley area.

The transmission system planning process generally assesses system operations under both normal and contingency conditions. Under both of these situations, system conditions such as transmission line loadings and voltages are studied to determine if they are within specified limits. System parameters are checked under both “normal” and “emergency” conditions. Under normal conditions the system is modeled, as it would be configured for normal operations, presumably with all facilities in operation. The system is then reconfigured to represent one or more facilities out of operation, simulating the occurrence of a system emergency. Each system element is rated for both normal and emergency operations and the loadings on each element are checked relative to the respective normal or emergency rating, as appropriate. In general, planning criteria require that all system elements be operated within applicable ratings (normal or emergency rating as determined by system status). When an overloaded element is identified, options for relief of the overloaded condition are identified. Options can range from the relatively simplistic, such as adjusting generation (supply), to highly complex and capital-intensive construction projects.

A.2.4. Electric Power System Requirements

In its Proposed Project, PG&E Co. identified a “Phase I” whereby the North Livermore, Dublin and Vineyard substations would be initially fed from the Contra Costa–Newark, No. 2, 230kV line. The Phase I plan is to loop the Contra Costa–Newark, No 2, circuit into each of these sites.

Figure A-2 **Placeholder**
Existing Tri-Valley Power Lines and Substations

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Figure A-2 **Placeholder**
Existing Tri-Valley Power Lines and Substations

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As "Phase 2" of its proposal, PG&E Co. also identified the need for a new 230kV line to bring power into the area, which would ultimately be used to feed the North Livermore and Dublin Substations. This line is not initially necessary (i.e., in Phase 1), but is projected to be required two or three years after the North Livermore and Dublin stations were energized. This Phase 2 proposal consists of a double circuit, 230kV line, designed to connect the new North Livermore and Dublin stations directly to the PG&E substation at Tesla. This Phase 2 line would relieve projected overloads on the Contra Costa–Newark No. 2 line, as well as eliminate low voltage at the new North Livermore and Dublin stations during outages on the Contra Costa end of the Contra Costa-Newark line.

Recent modeling of the electric system for the 2005 time frame, conducted jointly by the CAISO and PG&E Co., indicates that as a result of subsequent system modifications (primarily the construction of the second Tesla-Newark 230kV line planned by the CAISO for operation in 2001) the overload and voltage problems previously identified may no longer be a problem[4]. *The need for the Phase 2 portion of the Proposed Project in the 2005 time frame is questioned at this time*. In addition, the Switching Station Alternative considered in this EIR (see Section C.13.1) would remove one or two of the three project substations (Vineyard, Dublin, North Livermore) from the Contra Costa–Newark No. 2 line, thereby unloading that line and also potentially eliminating the need for construction of a "Phase 2" line to Tesla. The development and siting of new generation within the greater San Francisco Bay area will also play a role in the ultimate need for this line. Therefore, the need for this facility will ultimately be a function of the alternatives selected by the CPUC and built by PG&E Co., as well as the development of additional electrical generation supply throughout the Bay Area to more adequately support the region's transmission grid.

Peak electricity demands throughout California are expected to continue to increase between now and 2005. This increasing peak demand in California in combination with unusually high temperatures and the shrinking availability of imports from the rest of the Western region (due to similar demand, temperature and other factors, such as Northwest hydroelectric generation constraints) is seriously challenging California's supply of electric generation. The precise manner in which California's anticipated load growth will be accommodated in the future cannot reasonably be specified. The response to this energy demand/supply challenge will continue to be the focus of the CPUC and other agencies and organizations responsible for California's energy infrastructure. As was cited frequently in reports, public statements and legislation during the summer of 2000, additional power plants and related transmission lines are needed, and several have been approved by the California Energy Commission (CEC), with many more currently in the permitting process. The exact size, mix and location of facilities that will ultimately be approved to meet California's growing energy needs is speculative. However, it is assumed that new generation facilities to serve the State's (and specifically, the Bay Area's) electricity needs will be constructed by 2005.

[4] Paul Scheuerman, Notes of October 13, 2000, meeting with CAISO and PG&E Co.

A.2.5 REGIONAL GENERATION SUPPLY

Many of the proposed thermal power plants going through the CEC permitting process would use the "combined cycle" process, in which electricity is created from combustion turbines and steam turbines. Natural gas is burned to fire the combustion turbines. Exhaust heat from the combustion turbines is then used to generate steam in heat recovery steam generators (HRSGs), which in turn drives the steam turbine electricity generator. The combined cycle process is considered to be "state of the art" in that it creates electricity more efficiently and creates less pollution than conventional thermal power systems, which is different than in past decades.

Several thermal power plants in the Bay Area have either been permitted by the CEC or are currently going through the CEC permitting process. On average, CEC permitting takes from 1-2 years[5], before construction may start (other required state and federal permits, as well as local building permits, must also be first obtained). If constructed, the combined potential output of these plants represents approximately 4,100 MW of additional power that would be available to the transmission grid within the next five years.

- The **Los Medanos Power Plant** (formerly Pittsburg District Energy Facility) is proposed by Pittsburg District Energy, LLC (a joint venture between the City of Pittsburg, Enron, and USS-Posco Industries), and was approved by the CEC on August 17, 1999. The power plant would include a combined-cycle combustion turbine generator with a nominal capacity of 500 MW. The plant would be located on a 12-acre site on East 3rd Street, west of the intersection of East 3rd Street and Columbia Street in the City of Pittsburg, Contra Costa County. The site is located on the northwest corner of the property owned by USS-Posco Industries. The project would require construction of ancillary facilities, including a new electric transmission line, natural gas pipeline, sewer line, and a reclaimed water line. Reclaimed water for turbine cooling would be supplied by the Delta Diablo Wastewater Treatment Facility located in the City of Antioch. The combined-cycle unit would be fueled by natural gas. It is expected that 10 percent of the generating capacity of the plant would be dedicated to USS-Posco Industries, while the remaining 90 percent would go to the power grid for distribution.
- The **Delta Energy Center** is proposed by the joint partnership of Calpine Corporation and San Francisco-based Bechtel Enterprises Inc., an affiliate of Bechtel Group Inc., and was approved by the CEC on February 9, 2000. The project is an 880 MW, natural gas-fired, combined cycle electric generation facility. The Delta Energy Center is proposed to be located on an undeveloped 20-acre parcel lot in the Dow Chemical Company facility located generally north and west of the Delta Diablo Sanitation District treatment facility. A new 3.3-mile, 230 kilovolt (kV) electric transmission line is proposed. This line will interconnect to the electric transmission system at the existing Pacific Gas and Electric Company substation near the Pittsburg Power Plant. The line will be aboveground as it runs in front of USS Posco, then will transition to underground along 8th Street. Water for the cooling towers will be secondary-treated wastewater from the Delta Diablo Sanitation District, which will receive additional treatment on the project site to comply with the requirements of the Department of Health Services. Water for steam production and domestic uses will be supplied by the Contra Costa Water District and transported in Dow's existing 20-inch pipeline. All plant discharges will be sent back to the Delta Diablo Sanitation District for disposal in its existing discharge pipe. Approximately 200,000lb/hr of saturated steam will be supplied to Dow Chemical in a 0.7- mile aboveground insulated carbon steel pipeline. Condensate will be returned in an uninsulated pipe carried on the same structures.
- The **Moss Landing Power Plant Project** is proposed by Duke Energy Moss Landing LLC. On May 7, 1999, Duke Energy filed an Application for Certification (AFC) seeking approval to construct and operate the proposed 1,060-MW power plant at the existing Moss Landing Power Plant site that was previously operated

[5] Note that AB 970 effective January 1, 2001, will reduce CEC permitting for "extra-clean" plants to six months.

by Pacific Gas and Electric Company for about 50 years, and purchased by Duke Energy. This site is located at the intersection of Highway 1 and Dolan Road, east of the community of Moss Landing near the Moss Landing Harbor. The project consists of replacing the existing electric power generation Units 1-5, (a total of 613 MW built in the 1950s and shut down in 1995), with two 530 MW, natural gas-fired, combined cycle, units. Each combined cycle unit consists of two natural gas fired combustion turbine generators (CTGs), two unfired heat recovery steam generators (HRSGs) and a reheat, condensing steam turbine generator (STG). Each combined cycle unit will use seawater for once-through cooling. Duke Energy also proposes to upgrade each of the existing Units 6 and 7 by 73 MW. The CEC Presiding Member's Proposed Decision was released on August 29, 2000.

- The **Metcalf Energy Center** is a proposed 600 MW power plant located in southern San Jose, California (Santa Clara County), approximately one-half mile west of the Pacific Gas and Electric Company's Metcalf substation. The plant will be constructed by Bechtel Enterprises Inc. and run by Calpine Corporation. If approved by the Commission, the project schedule calls for construction to begin in 2001, with the plant being operational by late 2002 or early 2003. The project will use two "F" technology industrial frame combustion gas turbine generators. The combined cycle power plant will be fueled by natural gas from an existing Pacific Gas and Electric Company backbone line located less than one mile from the site. For electrical transmission, the project will interconnect with an existing 230 kilovolt transmission line located less than 500 feet from the project site. The CEC's Final Staff Assessment was released on October 10, 2000, and the San Jose Planning City Council recommended that the project not be approved in late November 15, 2000. The CEC's hearings on the project will be held in January 2001.
- The **Contra Costa Power Plant (CCCP) Unit 8** is proposed by Southern Energy Delta LLC, (AFC filed January 31, 2000). The proposed CCPP Unit 8 Power Project will be a nominal 530 MW, natural gas-fired, combined cycle, combustion turbine power plant located within the existing Contra Costa Power Plant site complex in Contra Costa County, just north of the City of Antioch (Contra Costa County). The CCPP site occupies about 200 acres on Wilbur Avenue, one mile northeast of Antioch, on the southern shore of the San Joaquin River. Highway 4 and the Antioch Bridge are just east of the site. Immediately south and west of the site are existing industrial facilities. The river borders the north side, while a recreational marina, open space and additional industrial land uses occur east of the Proposed Project. . The proposed Unit 8 would occupy 20 acres of the northeast corner of the complex. Pacific Gas and Electric Company originally constructed the CCPP complex in 1951. Units 4 and 5 were added in 1953, while Units 6 and 7 were placed in operation in 1964. The original Units 1, 2 and 3 were retired in 1994, while Units 4, 5, 6 and 7 continue to be operational. The existing units are conventional natural gas-fired boilers that use once-through cooling. Existing power capacity is 680 MW. Southern Energy Delta purchased the CCPP from Pacific Gas and Electric Company in April 1999. CCPP Unit 8's combined cycle power unit would consist of two natural gas-fired combustion turbine generators, two heat recovery steam generators (HRSGs), and a steam turbine generator. The natural gas fuel for Unit 8 would be supplied by the existing gas pipeline. Cooling water for Unit 8 would be supplied by re-use of the cooling water from the existing Units 6 and 7. According to the applicant's project description, no net increase in water withdrawal from the San Joaquin River is anticipated. Additional project facilities would include two 195-foot tall exhaust stacks on the heat recovery generators, a 10-cell water cooling tower, a turbine building, storage tanks, a control building, and electrical power transformers and transmission facilities to interconnect with the existing switchyard on the CCPP site complex. As described by the applicant, no additional electric transmission lines outside of the CCPP complex are needed to transmit Unit 8's electricity to the regional transmission grid. Southern Energy Delta proposes to begin construction in 2001, and start operation of CCPP Unit 8 by 2003. The CEC released its Preliminary Staff Assessment on November 7, 2000.
- The **Potrero Power Plant Unit 7** is proposed by Southern Energy of California (SECAL). The facility will operate in conjunction with the existing 360-MW (MW) Potrero Power Plant located in southeast San Francisco, which SECAL purchased from Pacific Gas and Electric Company in April 1999. The existing Potrero Power Plant consists of three 52 MW combustion turbines (Units 4, 5 and 6), and one 206-MW steam turbine (Unit 3). The proposed Unit 7 would be a 540 MW natural gas-fired, combined cycle power generating facility. Pollution controls include Selective Catalytic Reduction (SCR) systems to control the emissions of oxides of nitrogen (NOx), and two CO catalysts to control carbon monoxide emissions. Aqueous ammonia, which is already used at Unit 3, will be used as the reagent in Unit 7's SCR system.

> Deliveries will be made by tanker trucks and stored in two identical, 20,000 gallon aboveground storage tanks; one tank will be used for Unit 7, the other will replace the existing Unit 3 storage. Interconnection with the high voltage transmission system would be through a proposed new Potrero Power Plant Switchyard, located onsite, and to two existing Pacific Gas and Electric Company substations: a direct interconnection to the adjacent Potrero Substation, and a separate underground interconnection to the Hunters Point Substation located approximately 1.8 miles to the south. The Potrero Unit 7 would be operated as a merchant power facility, selling its energy via direct sales agreements and in the spot market via the California Power Exchange. SECAL expects the Potrero Unit 7 to be operational by the summer of 2003. The CEC found the AFC (filed on May 31, 2000) "Data Adequate" on October 11, 2000, and the CEC is in the process of preparing the Preliminary Staff Assessment (expected in March 2001).

As this DEIR went to print, Calpine Corporation announced plans for the 1,100 MW East Altamont Energy Center east of Livermore, at the northeast tip of Alameda County in the Altamont Pass area. According to news accounts, one of the factors in Calpine's location decision was ready access to the Western Area Power Administration (WAPA) high-voltage transmission line and substation nearby. The same news account (the San Francisco Chronicle, December 12, 2000) noted that less than a mile south of the proposed plant site is the Mountain House development, 16,000-home project expected to break ground in 2001. Calpine has reportedly only just begun technical studies on environmental impacts and plant design.

A.2.6 LOCAL GENERATION ALTERNATIVES TO THE PROJECT

Two generation facilities of approximately 49 MW each in the vicinity of the Vineyard substation have been proposed in the City of Pleasanton. These facilities are undergoing environmental review by the City's Planning Department. In late November 2000, the Planning Commission of the City of Pleasanton adopted a resolution consisting of the following:

> (1) Requesting the City Council initiate a study of electrical power facilities and adoption of a local energy policy/strategy, and that at a minimum, the Planning Commission, as well as other interested members of the community be involved in the original scoping session, the recommendation of consultants, and the direction of work product; (2) requiring that a moratorium be placed immediately on any power generation plant applications if they applicants do not postpone these applications until completion of the study; (3) including in the recommendation that goes forward to the City Council the issues identified by the Planning Commission as being important to be included in the policy; and (4) deferring action on any CEQA process for any pending application until the study is completed.

This resolution will result in a delay in consideration of the two pending Pleasanton applications such that neither could be constructed prior to the summer of 2001. However, these facilities could be operational by the summer of 2002.

In addition to the two Pleasanton facilities, one under-50 MW facility in the City of Livermore (near the PG&E Co.'s Las Positas Substation) may also be proposed. These facilities are addressed in more detail in Sections B.6.1.4 and C.13.2.

The present and expected loading on the Vineyard station is such that the loss of a generator during peak load conditions would result in existing facility overloading to the point whereby it may be necessary to shed load in order to prevent damage to the existing facilities (i.e., controlled power outages). Furthermore, at the current rate of growth projected for the service area, the addition of one new generation facility (producing about 49 MW) would only defer the need for the transmission upgrade to 2003 (one year), as acknowledged by Enron, the developer of the Pleasanton Local Reliability Facility (Enron, 2000). Power flow studies incorporating the second proposed 49 MW generator are not available, but by logical extension, a reasonable assumption would be that this second facility could further defer the need for the Vineyard transmission upgrade by one additional year (to 2004).

The location of these local generators, adjacent to or near the Vineyard Substation, would have very little effect on the remainder of the project (Dublin and North Livermore Substations and associated transmission). Enron's transmission planning studies found that its proposed Local Reliability Facility would not provide adequate area voltage support if either the San Ramon or Las Positas transformers (at those substations) were out of service (Enron, 2000).

No power flow studies are available for the prospective Livermore generator. However, the prospective addition of a generator near the Las Positas substation in Livermore could actually compound the distribution limitations that this substation currently has.

A.2.7 ARROYO 230/60KV SUBSTATION

As an alternative to the development of 230kV transmission to the Vineyard Substation, the development of a 230/60 kV transformation station to the south of the Vineyard station and the upgrading and construction of new 60 kV transmission into the Vineyard Substation was suggested during EIR Scoping (see Section B.5.4). Supporting data provided by the proponent of this alternative (the City of Pleasanton) indicated that in the year studied (2002) some 60 kV facilities would be overloaded by 1% during normal peak conditions and by as much as 12% during contingency conditions. Additionally, the modeling provided by the City indicated that the 60kV bus voltages at area substations were low under normal peak and contingency conditions. While it may be possible to ignore the slight overload during normal conditions in 2002, this problem will only increase in magnitude with time, eventually requiring additional construction. Also, the overloads noted during contingency conditions do not appear to meet the NERC and CAISO planning criteria. The development of the proposed facility appears to be a short-term stopgap and not a viable long-term solution to the electricity supply problems at Vineyard substation (which was originally planned in 1986 as a 230 kV station, see Section A.1).

A.2.8. INTERRUPTIBLE LOAD PROGRAM

As an alternative to constructing various components of the project, the possibility of selective load-dropping during peak load periods was considered. During this past summer, the CAISO solicited bids for "interruptible load". This process took the form of two distinct but similar programs in which various loads (customers) would be paid to interrupt or curtail load during peak load conditions. The CAISO had targeted approximately 2,800 MW of statewide load for these programs. Initially, the

CAISO received bids totaling about 580 MW and currently actual statewide participation amounts to 55 MW. While there are many and varied reasons for the small amount of capacity that is participating in these CAISO programs, the results point to the fact that there are relatively small levels of load that can contribute in a manner that will effectively and reliably reduce peak loads. The failure to interrupt one's load at the times required is much the same as a local generator not being available or the occurrence of some other contingency. Given the level of constraints with the current PG&E system serving the Tri-Valley area, it is doubtful that interruptible load sufficient to solve these problems could be placed under contract.

A.3 AGENCY USE OF THIS DOCUMENT

Pursuant to Article XII of the Constitution of the State of California, the California Public Utilities Commission (CPUC) is charged with the regulation of investor-owned public utilities, including PG&E Co. The CPUC is the lead State agency for CEQA compliance in evaluation of the PG&E Co.'s proposed Tri-Valley 2002 Capacity Increase Project, and has directed the preparation of this EIR. This EIR will be used by the Commission, in conjunction with other information developed in the Commission's formal record, to act on PG&E Co.'s application for a Certificate of Public Convenience and Necessity (CPCN) for construction and operation of the Proposed Project. Under CEQA requirements, the CPUC will determine the adequacy of the Final EIR and, if adequate, will certify the document as complying with CEQA. The Commission will also act on PG&E Co.'s application for a CPCN; in accordance with CEQA, if it approves something other than the Environmentally Superior Alternative identified in the Final EIR, it must state why in a "Statement of Overriding Considerations," which is included in the Commission's decision on the application.

Several other state agencies will rely on information in this EIR to inform them in their decision over issuance of specific permits related to project construction or operation. In addition to the CPUC, state agencies such as the Department of Transportation, Department of Fish and Game, Regional Water Quality Control Board and Office of Historic Preservation would be involved in reviewing and/or approving the project. On the federal level, agencies with potential reviewing and/or permitting authority include the U.S. Army Corps of Engineers, Advisory Council on Historic Preservation, and the Occupational Safety and Health Administration. No local discretionary (e.g., use) permits are required, since the CPUC has preemptive jurisdiction over the construction, maintenance and operation of PG&E Co. facilities in California. PG&E Co. would still have to obtain all ministerial building and encroachment permits from local jurisdictions, and the CPUC's General Order 131-D requires PG&E Co. to comply with local building, design and safety standards to the greatest degree feasible, to minimize project conflicts with local conditions. The CPUC's authority does not preempt special districts, such as the Bay Area Air Quality Management District, other state agencies or the federal government.

Table A.3-1 lists the Federal, State, and local permits and authorization required for the Proposed Project.

Table A.3-1 Permits Required

Permits	Agency	Jurisdiction/Purpose
Federal Agencies		
Nationwide or Individual Permit (Section 404 of the Clean Water Act)	U.S. Army Corps of Engineers	Waters of the United States, including wetlands
Section 7 Consultation (through U.S. Army Corps of Engineer's review process)	U.S. Fish and Wildlife Service (USFWS)	Threatened and Endangered Species Biological Opinion
Section 106 of the NHPA Review (through U.S. Army Corp of Engineer's review process)	Advisory Council on Historic Preservation	Cultural Resource Management Plan (if appropriate)
State Agencies		
Certificate of Public Convenience and Necessity	CPUC	Overall project approval and CEQA review
National Pollutant Discharge Elimination System—General Construction Storm Water Permit	California Regional Water Quality Control Board, San Francisco Bay Region (RWQCB)	This permit applies to all construction projects that disturb more than 5 acres
Section 401 Water Quality Certification (or waiver thereof)	RWQCB	Requests RWQCB's certification that the project is consistent with state water quality standards
Endangered Species Consultation (through CEQA review process)	California Department of Fish and Game	Consultation on state-listed species; incidental take authorization (if required)
Section 1601 Streambed Alteration Agreement	California Department of Fish and Game	Dry boring under Arroyo Valle
Consultation (through CEQA review process)	State Historic Preservation Officer	Cultural resources management (if appropriate)
Authority to Construct/Permit to Operate	Bay Area Air Quality Management District	Air emission reduction and monitoring
Local Agencies		
Roadway Encroachment Permit	County of Alameda	Permit to install distribution lines in roadway right-of-way
Roadway Encroachment Permit	Cities of Livermore and Pleasanton	Permit to install distribution facilities in roadway right-of-way
Welding, Grading, and Building Permits	Cities of Livermore and Pleasanton	Permission to conduct welding, grading, and building activities

A.4 READER'S GUIDE

A.4.1 Incorporation by Reference

PG&E Co.'s Proponent's Environmental Assessment (Application No. 99-11-025), Pacific Gas and Electric Company, Tri-Valley 2002 Capacity Increase Project, contains certain information that is incorporated by reference in some of the sections of this document. This document is available for public review during normal business hours at the CPUC's Central Files (505 Van Ness Avenue, San Francisco), in local libraries (see Section G) and also via the Internet at: www.cpuc.ca.gov/environment/projects.htm (click on the Tri-Valley 2002 Capacity Increase Project).

A.4.2 Organization of this EIR

This EIR is organized as follows:

Executive Summary: A summary description of the Proposed Project, the alternatives, their respective environmental impacts and the Environmentally Superior Alternative.

Impact Summary Tables: A tabulation of the impacts and mitigation measures for the Proposed Project and alternatives.

Part A (Introduction/Overview): A discussion of the background, purpose and need for the project, briefly describing the proposed Tri-Valley 2002 Capacity Increase Project, and outlining the public agency use of the EIR and identifying the changes incorporated in the document.

Part B (Project and Alternatives Description): Detailed descriptions of the proposed Tri-Valley 2002 Capacity Increase Project, the alternatives evaluation process, description of alternatives considered but eliminated from further analysis and the rationale therefor, and description of the alternative projects and alignments analyzed in Part C.

Part C (Environmental Analysis): A comprehensive analysis and assessment of impacts (including cumulative impacts) and mitigation measures for the Proposed Project and several alternatives, including the No Project Alternative. This Part is divided into main sections for each environmental issue area (e.g., Air Quality, Biological Resources, Geology and Soils) that contain the environmental settings, impacts, and cumulative effects of the Proposed Project and each alternative. At the end of each issue area analysis, a Mitigation Monitoring Plan is provided. Section C.13 presents analysis of several additional alternatives (including Local Generation and the No Project Alternative), and analysis of the potential impacts of mitigation measures that would require use of rights-of-way not otherwise analyzed.

Part D (Comparison of Alternatives): Identification of the CEQA Environmentally Superior Alternative and a discussion of the relative advantages and disadvantages of the Proposed Project and alternatives.

Part E (Additional CEQA Considerations): A discussion of growth-inducing impacts, irreversible environmental changes, and cumulative impacts.

Part F (Proposed Mitigation Monitoring, Compliance, and Reporting Plan): A discussion of the CPUC's mitigation monitoring program requirements for the Proposed Project.

Part G (Public Participation): A brief description of the public participation program for this EIR.

Part H:
1. Glossary and Abbreviations
2. Preparers of EIR and Their Qualifications
3. Draft EIR Distribution

Appendix 1: Land Use Policy Consistency Analysis

Appendix 2: Technology and Environmental Assesment Guide on Underground HV Power Transmission, Year 2000 Update

Appendix 3: PG&E Co. Information on Underground Transmission Lines