Updated
Appendix G.
Distribution Need Analysis

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DISTRIBUTION SUBSTATION NEED ANALYSIS – PASO ROBLES DPA

I. LIMITATIONS IN THE EXISTING DISTRIBUTION SYSTEM

A. Reliability

The Paso Robles Distribution Planning Area (DPA) encompasses the communities of San Miguel, Paso Robles, Templeton, Creston, Atascadero, and Santa Margarita. Pacific Gas and Electric Company (PG&E) serves approximately 47,000 households and businesses (also referred to as customer connections[1]) within this DPA at 12 kilovolt (kV) and 21 kV primary voltage through four substations: San Miguel (70/12 kV), Paso Robles (70/12 kV), Templeton (230/21 kV), and Atascadero (70/12 kV). Bordering the Paso Robles DPA to the east is the Cholame DPA, which includes the communities of Shandon and Parkfield, and serves approximately 1,500 customer connections at 12 kV and 21 kV through one substation: Cholame Substation (70/12 and 70/21 kV). The two DPAs are connected by one long 12 kV circuit tie between a San Miguel Substation distribution line (feeder) and a Cholame Substation feeder. Twelve existing 21/12 kV pad-mounted transformers in the field (outside of substations) in the Paso Robles DPA provide the existing circuit ties between 21 kV and 12 kV feeders, and three existing 21/12 kV pad-mounted transformers in the field provide the existing 21-to-12 kV ties in the Cholame DPA.

Reliable distribution systems consist of substations located at regular intervals and sized correctly in terms of capacity and number of feeders to cover the area between substations without overextending some substations and underutilizing others. The Paso Robles DPA is not currently in line with these system goals.

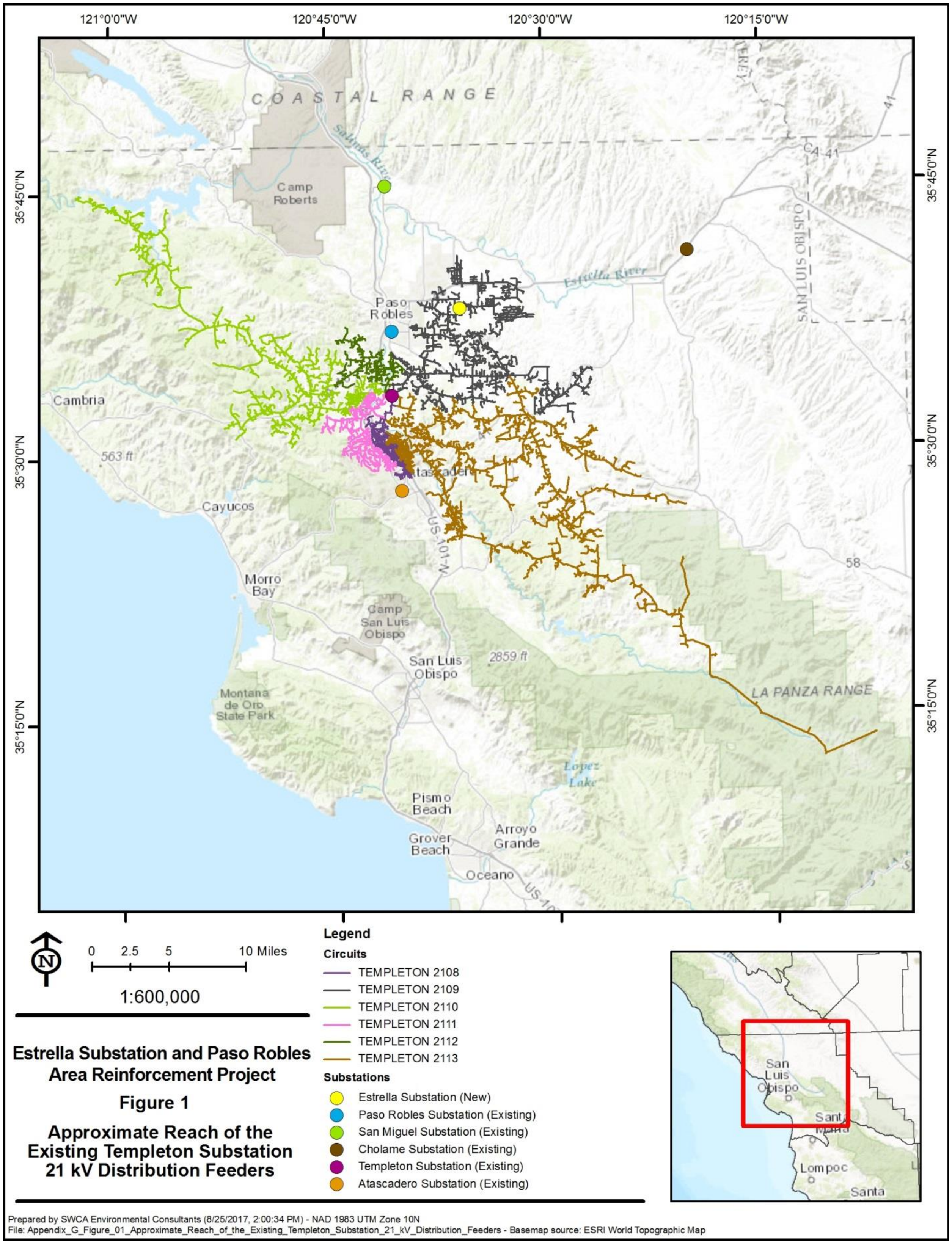
Templeton Substation has lengthy 21 kV feeders that can carry 73% more load and experience one-third less voltage drop than the 12 kV feeders from the other area substations because of their higher operating voltage. Even though Templeton Substation is south of Paso Robles and Paso Robles Substation, its 21 kV feeders extend several miles east and north of Paso Robles Substation, serving much of east Paso Robles as well as areas south and west of Paso Robles. (*See* Figure 1. Approximate Reach of the Existing Templeton Substation 21 kV Distribution Feeders.)

Because 21 kV feeders are no more reliable than 12 kV feeders in terms of line length or area served, service reliability on a 21 kV feeder is sacrificed by extending its reach to take advantage of its superior voltage performance, or adding more customers and load to take advantage of its superior capacity. Tripling the length of a feeder increases exposure to outages by 300%. Adding 73% more customers increases the number of customers experiencing an outage by 73%.

Put simply, if a line is three times as long, it will have three times as much exposure to potential outages such as car-pole accidents or vegetation/storm-related line failures as compared to a line 1/3 as long. Multiple feeders are already planned from Estrella Substation and could be installed from Templeton Substation if Estrella Substation were not built. The length of these feeders is determined by the various routes from Estrella or Templeton substations to the area of anticipated growth north of California State Route (SR-) 46 and south of Paso Robles Airport. For Templeton Substation, in particular, short feeders are not an option.

[1] Each customer connection connects to a home or business, representing many more customers than indicated by the number of connections.

Figure 1. Approximate Reach of the Existing Templeton Substation 21 kV Distribution Feeders



If an accident takes out a long line feeding a remote load center, it is likely that many more customers would be affected than if the line were served from a local source. This is due to additional customers that must be served between the distant substation and the load center. In order to serve an area with a series of shorter feeders, a closer substation site is required; in this case, Estrella Substation is capable of serving the growth area with shorter feeders. The use of longer but more segmented feeders from Templeton Substation, for example, would not be an effective reliability strategy because the urban areas with most of the demand would be at the far end of the feeders (i.e., on the last segment of main line that would be out of power whenever one of the many segments between it and the substation is lost).

In addition, the areas north of SR-46 south of the airport contain sensitive commercial-industrial businesses that not only require a high degree of service reliability, but also a high degree of power quality for sensitive processes such as light manufacturing and wine-making. Longer feeders result in increased line impedance, which degrades power quality, so commercial-industrial customers located in the growth areas in northern Paso Robles would have a generally higher level of power quality if served from a substation at Estrella as opposed to Templeton. Templeton Substation circuits currently have more than double the average electrical resistance compared to the average circuits for all PG&E substations in the service area.[2]

Many factors affect service reliability including line length, exposure of lines to traffic or vegetation, and line loading. Line length alone is not the only factor, but the longer the line, the more likely it is to traverse areas detrimental to service reliability and to affect more customers if the line goes out of service.

For these reasons, the long feeders from Templeton Substation have resulted in poor service reliability. For example, the Templeton 2109 main line serving much of east Paso Robles, both north and south of SR-46, has experienced five sustained outages and nine momentary outages over the past 5 years. These outages affected an average of just under 3,000 customer connections per event, with over 4,300 households and businesses affected in the largest event. Table 1 presents a 5-year outage history of main-line outages to the Templeton 21 kV feeders in Paso Robles, Atascadero, and Santa Margarita. All of the outages were a significant distance from Templeton Substation. The number of outages is relatively high for typical distribution main lines, but not unexpected in these areas due to the long express nature of the 21 kV feeders. Table 1 captures most of the sustained outages experienced by all customers in these areas; however, many customers experienced significantly more sustained outages due to more-localized outages on smaller lines extending from the main lines.

Table 1. Five-Year Outage History of Templeton 21 kV Feeders (February 2012 to February 2017)

Feeder Name	Area Served Where Outages Occurred	No. of Sustained Outages	No. of Momentary Outages	Average No. of Customer Connections Affected Per Event	Highest No. of Customer Connections Affected by an Event
Templeton 2108	Northern Atascadero	7	10	2,955	3,189
Templeton 2109	Northeast Paso Robles	5	9	2,957	4,325
Templeton 2110	Rural West Paso Robles	4	20	1,802	2,926
Templeton 2111	Western Atascadero	6	10	1,847	2,433
Templeton 2112	Southern Paso Robles	3	10	475	1,068
Templeton 2113	Santa Margarita	7	25	1,911	5,446

[2] For similar reasons, the distribution system in the Paso Robles DPA will have a higher hosting capacity for distributed energy resources (DER) if new distribution is added from Estrella Substation versus an expansion of the Templeton Substation distribution system. (See Section IV.C.)

B. Capacity

Ideally, the distribution feeder ties between distribution substations within a DPA can be used to transfer load between substations as well as restore service from one feeder to another in the event of outages on the distribution system. Because of this arrangement, forecasted overloads at one substation can be eliminated by transferring load to an adjacent substation. This process can continue until all possible load transfers are performed to allocate load to each transformer bank according to its capacity, and all substations within the DPA reach their maximum buildout (i.e., contain the maximum number and size of transformer banks and/or feeders). There is a practical limit in the ability to divide DPA load among all of the banks in exact proportion to their capabilities. Operating experience indicates that overloads become unavoidable when DPA load reaches approximately 95% of the total aggregate capacity of all of the substation banks. For this reason, PG&E normally defines available DPA capacity at 95% utilization, or 95% of its aggregate bank capacity. The available capacity within the Paso Robles DPA is 212.55 megawatts (MW) based upon 95% utilization.

In 2010, Paso Robles Substation reached its ultimate build out of three 70/12 kV, 30 megavolt-ampere (MVA) transformers. Templeton Substation currently consists of two 230/21 kV, 45 MVA transformers with lengthy distribution feeders that serve north and east beyond Paso Robles Substation. (*See* Figure 2. Current Distribution System.) Atascadero and San Miguel substations are single-transformer facilities (30 and 16 MVA, respectively) with limited space for expansion or 70 kV transmission constraints. San Miguel Substation, which has a limited transmission source for new distribution, would need to be completely rebuilt to support another distribution bank. It would still have a limited transmission source from Coalinga Substation and would be limited to only 18 MW in the event the feed from Estrella Substation or Paso Robles Substation is lost. Atascadero Substation (at the south end of the DPA and not shown in Figure 2) has no space at the substation to support another distribution transformer and, in addition, is far from the load growth that needs to be served.

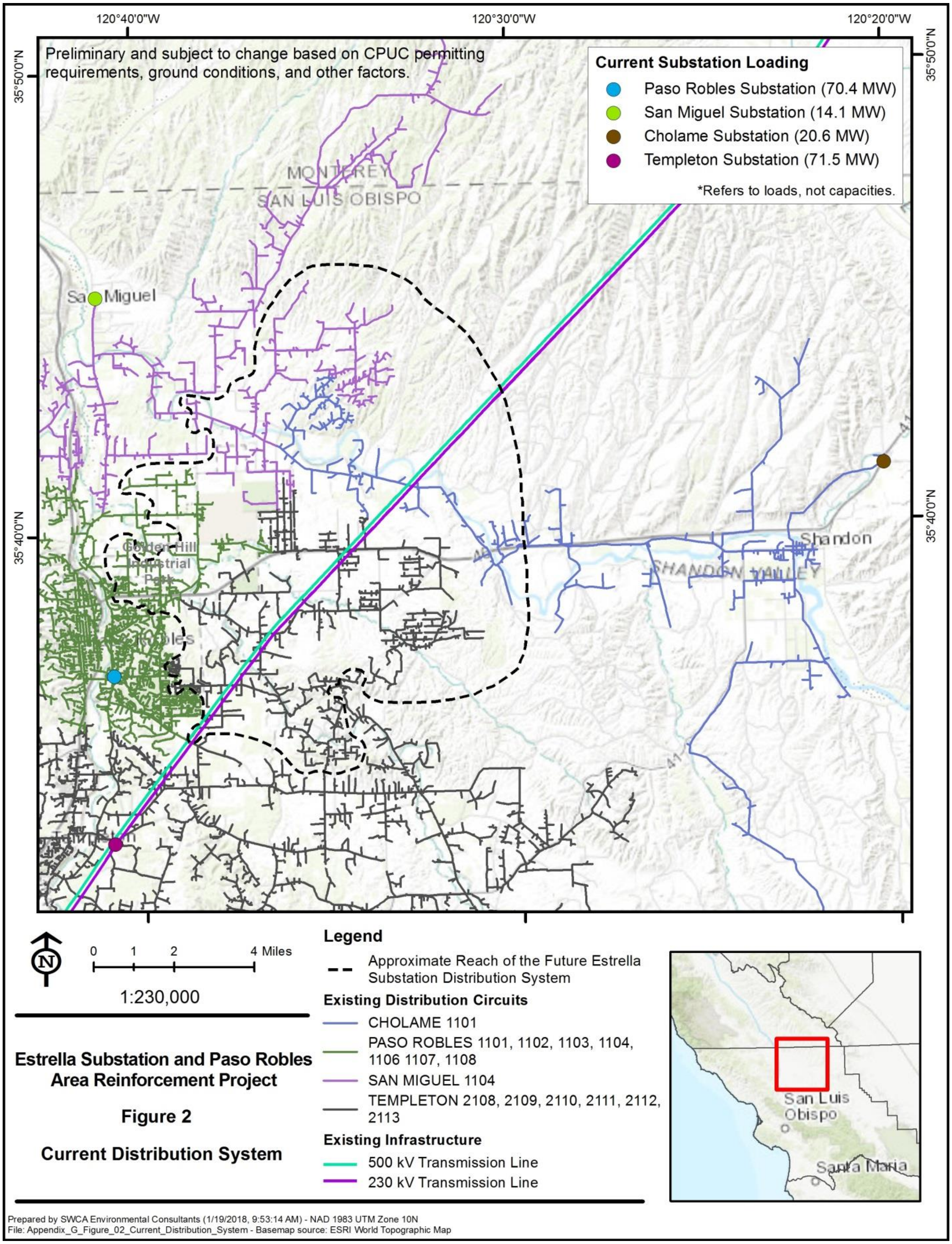
Table 2 below indicates substation historical capacities and historical peak loads for the Paso Robles DPA from 2007 to 2016.

Table 2. Historical Paso Robles DPA Capacity and Load

	Historical Capacity and Load (MW)									
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Historical Available DPA Capacity	182.46	197.51	197.51	212.55	212.55	212.55	212.55	212.55	212.55	212.55
Historical DPA Peak Load	179.44	169.40	164.40	158.73	150.69	173.98	180.63	164.72	169.33	190.14

Figure 2 illustrates the current distribution system and indicates all distribution lines whether they are looped or radial. In general, main lines with larger overhead and underground conductor sizes are part of looped systems, while lines with smaller conductor sizes are radial systems tapped off the looped main-line systems.

Figure 2. Current Distribution System



II. SITING OF NEW DISTRIBUTION SUBSTATION

A. Siting Principles

PG&E's distribution planning practices emphasize that the siting of a new substation or the addition of capacity at an existing substation should be done in a way that improves service reliability for the area, with the aim of locating substations at regular intervals and sizing them correctly to cover the area between substations without overextending some substations and underutilizing others. Thus, from an engineering perspective, the most important factors in distribution substation siting include:

1. Proximity of existing and forecasted electric load
2. Existing and future substation radius in miles from the substation for distribution facilities sphere of influence:
    a. 21 kV – Rural = 11 miles; Urban = 4 miles
    b. 12 kV – Rural = 7 miles; Urban = 3.5 miles
3. Proximity to existing transmission and distribution systems
4. Length and location of new transmission and distribution lines

(*See*, e.g., PG&E Planning Standard TD-3350P-09 (07/14/2014 (Rev.3)) (currently being updated) ("TD-3305P-09"), attached as Exhibit B.) TD-3305P-09 indicates that the "sphere of influence" of a substation is a radial distance in miles from the substation, a distance that varies with the voltage and rural or urban nature of the DPA. In 2007, PG&E distribution planners completed the process of designating all DPAs within the service area as being rural or urban/suburban for distribution planning purposes. The Paso Robles DPA was designated an urban/suburban area, which means that the population is over 60 persons per square mile. (*See* Guide for Planning Area Distribution Systems Document # 050864, dated 9/15/09 and revised 3/4/2010, (currently being updated) at pages 9 and 32, attached as Exhibit C.) Therefore, for a 21 kV distribution substation in an urban-designated DPA, the applicable radius is 4 miles.

In addition to engineering feasibility, many other factors drive substation siting decisions, including site suitability (*e.g.,* slope, access, proximity to flood zones, proximity to earthquake zones), site availability, land use, and environmental concerns. (*See, e.g.,* TD-3305P-09, Exhibit B, at 8-9.)

B. Location of Expected Load Growth

City of Paso Robles (City) planners are expecting strong industrial growth in the Paso Robles city limits north of SR-46 within the next 10 years and a resurgence of residential growth south of SR-46. City planners are estimating a 50% increase in the population of Paso Robles by 2045.

According to the City of Paso Robles Public Works Director, most of the industrial growth is expected to occur within the Golden Hill Industrial Park and directly south of Paso Robles Airport along Dry Creek Road, including the Aerotech Industrial Park now occupied by Advance Adapters, a maker of specialty parts for four-wheel drive vehicles. At this time, industrial growth is anticipated to be led by wine production. For example, within Golden Hill Industrial Park, San Antonio Winery, a large 1 MW facility, is now nearing completion. Justin Vineyards, owned by Wonderful Company (Pom Wonderful), operates a large new facility and is planning to expand as soon as the industrial park itself expands eastward toward Airport Road.

To the south of SR-46, approximately 2 miles east of Paso Robles Substation and 2.7 miles west of the Estrella Substation site, development of the 827-acre Chandler Ranch property is expected to begin soon.

The City has approved development of the first 154 acres of the ranch, and construction on the first 350 residences could start within 2 years.

Throughout Paso Robles, several new hotels or hotel expansions have received approval, with several now under construction. These include the new Oxford Suites Hotel, Pine Street Promenade Hotel, Hilton Garden Inn, Marriott Residence Inn, Sensario Gardens Entrada, Destino Hotel Resort, and Fairfield Inn.

C. Why Locate the New Substation within 2.2 Miles of the SR-46 230 kV Line Intersection?

The California Independent System Operator Corporation (CAISO) conducts a Transmission Planning Process each year, which builds upon the previous year's plan and studies the reliability of the electric system over a 10-year window. CAISO approved the development of a new 230/70 kV substation—Estrella Substation—and a new 70 kV power line to interconnect to the substation to improve reliability in San Luis Obispo County in its *2013–2014 Transmission Plan, Estrella Substation Project Description and Functional Specifications for Competitive Solicitation* (CAISO 2014). The project also included a distribution component. Through a competitive solicitation process, CAISO awarded the transmission-level substation project to NextEra Energy Transmission West LLC (NEET West) in its *Estrella Substation Project, Project Sponsor Selection Report* (CAISO 2015).

During this process, CAISO identified the location for the new substation as being within a 2.2-mile radius from the intersection of SR-46 and the Morro Bay-Gates/Templeton-Gates 230 kV transmission corridor, about 5 miles east of Paso Robles Substation. (*See* Figure 3. 2.2-Mile Substation Location Area.) This location was a result of a recommendation from PG&E's distribution planning engineers, based upon the siting principles described in Section II.A and the following considerations:

1. The anticipated growth areas are north and east of Paso Robles Substation, so the new distribution substation should be north and east of Paso Robles Substation in order to place the new distribution substation near the growth and keep new distribution feeders at a reasonable length.

2. Since the new distribution substation would be fed from the 230 kV transmission source, the new substation should be located along the Morro-Bay Gates 230 kV Transmission Lines to minimize costs and potential project impacts.

3. The locality known as "Estrella" offered the operational advantage of being located where long distribution lines from four existing substations ended. These substations are San Miguel, Paso Robles, Cholame, and Templeton. (*See* Figure 2. Current Distribution System.) Placing the substation in Estrella would make it possible to back feed and split in half long existing distribution lines from these four sources. (*See* Figure 4. Future Estrella Substation Distribution System.) Of the potential sites in Estrella, sites north of Estrella Road would place the new substation off in a northeast corner of the DPA, too far from the growth areas near Paso Robles Airport and Golden Hill Industrial Park, just south of the airport. For this reason, the northern-most site considered was a site where the 230 kV lines cross Estrella Road, approximately 2.2 miles northeast of SR-46 along the 230 kV right-of-way.

4. The southern-most site that distribution planning engineers felt was acceptable (not too close to Templeton or Paso Robles substations and not too far from the growth areas) was a site where Union Road comes close to the Morro Bay-Gates 230 kV Transmission Lines. This southern-most site, which NEET West ultimately selected, is within 2.2 miles south of the SR-46 and 230 kV line intersection.

In summary, from a distribution perspective, the Estrella Substation site location is near the Dry Creek Road area south of Paso Robles Airport and the Golden Hill Industrial Park in northern Paso Robles, where large-demand businesses are expected to be constructed. It is also at a location very well-suited for connecting to existing distribution feeders. Adding distribution capacity at or near the Estrella Substation site will improve service reliability by allowing feeders from Templeton, Paso Robles, San Miguel, and Cholame substations to be significantly reduced in their reach and therefore significantly reduced in their exposure to outages. The new, high-growth areas can be served directly from the new distribution substation. The Estrella Substation site is far closer to the anticipated growth areas than Paso Robles Substation, and has largely established feeder routes already in place. (*See* Figure 4. Future Estrella Substation Distribution System.) Templeton Substation is several miles farther south from Paso Robles Substation and far from the expected load growth. Neither Paso Robles nor Templeton substations would provide favorable locations for additional distribution capacity.

If distribution facilities are built at the proposed Estrella Substation site, PG&E proposes to install three 21 kV feeders from Estrella Substation. (*See* Figure 4. Future Estrella Substation Distribution System.) However, only two new segments of distribution line would need to be constructed. These two segments are specifically identified on Figure 4 because they are the only gaps in the existing distribution system necessary to create one of the new feeders (Mill Road Central). All other distribution lines that make up this feeder, and the other two Estrella feeders, are existing lines. The new feeder locations shown on Figure 4 are approximate locations, preliminary and subject to change. The segment of new line extending from Estrella Substation, the southern segment, is an accessible route along a farm road, and the northern segment is within a franchise location. (Geographic Information Systems [GIS] data provided to the California Public Utilities Commission (CPUC) follows the centerline of these roadways, since the line locations are not yet known.) These routes appear feasible based on a preliminary review of land and environmental factors. The southern segment is 0.6 mile of new distribution line installed in a utility easement on private property to the north of the Estrella site to connect the Mill Road Central feeder to existing distribution on Mill Road. An additional segment of new line will be installed to extend the reach of the Mill Road Central feeder to serve the new load anticipated in northern Paso Robles. This northern segment would be approximately 1.1 miles long if installed along SR-46. New overhead distribution lines are typically supported by 18 poles per mile; therefore, a total of 1.7 miles of new distribution line would typically require about 31 new wood poles.

Figure 3. 2.2-Mile Substation Location Area

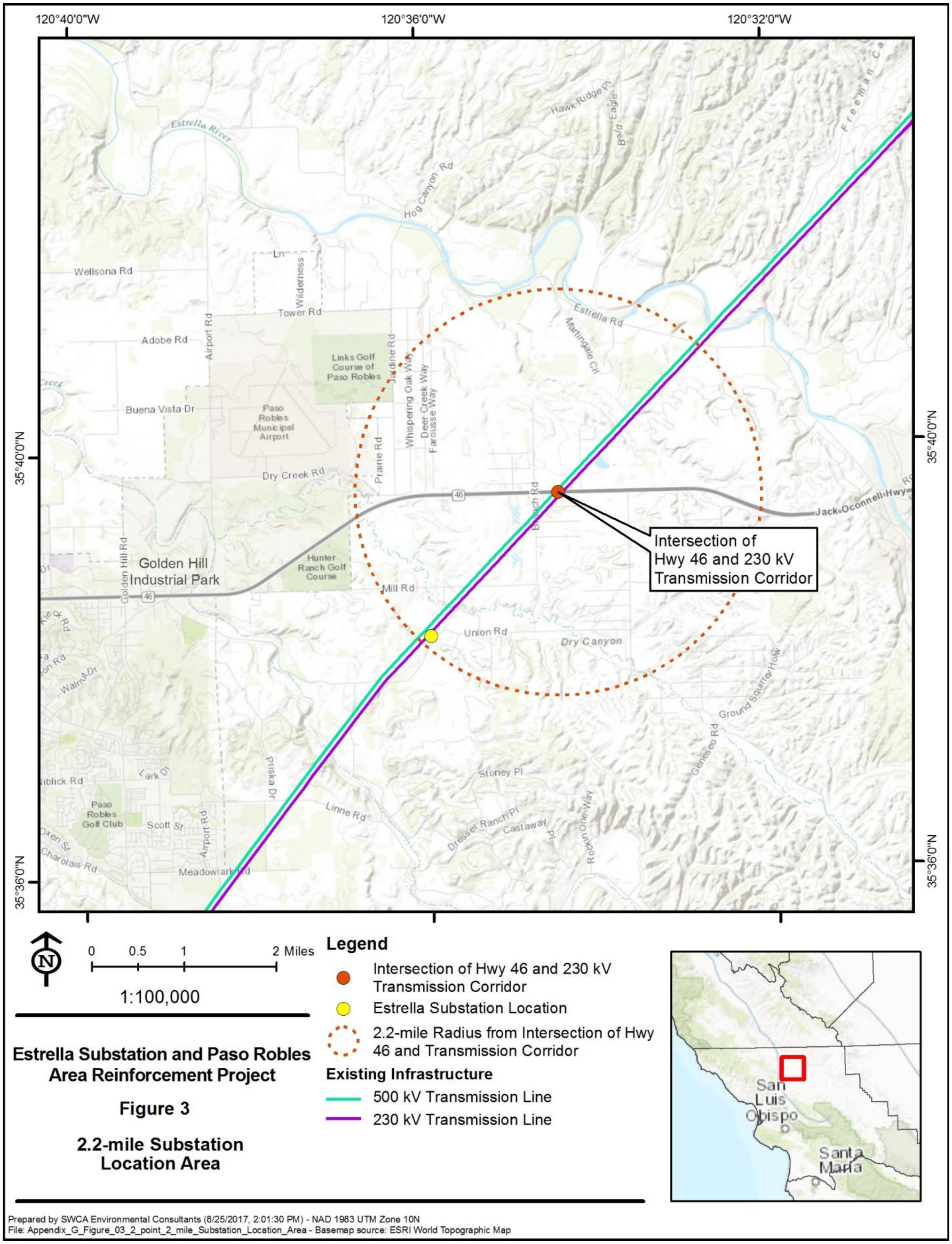
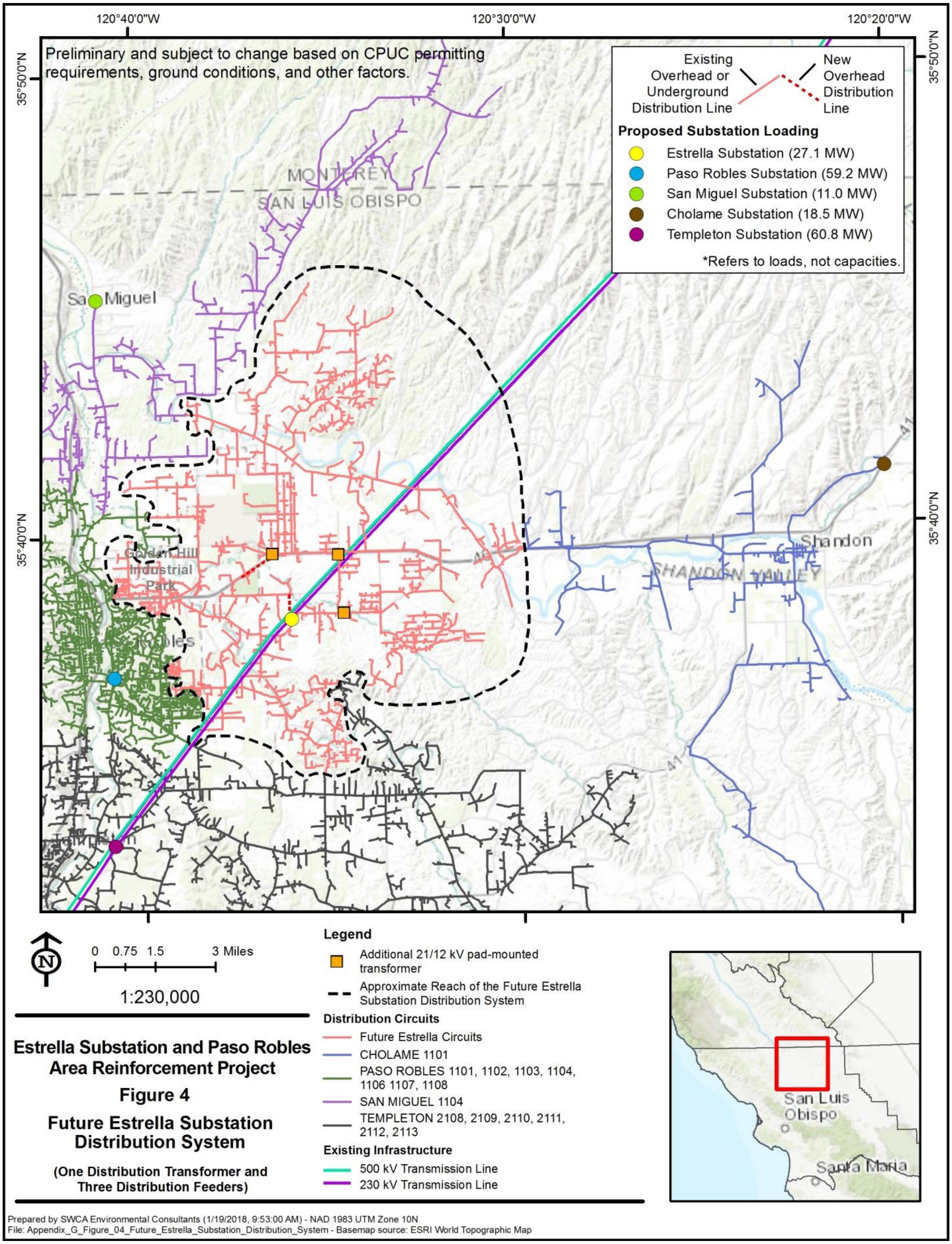


Figure 4. Future Estrella Substation Distribution System



III. TIMING OF NEW DISTRIBUTION SUBSTATION

A. Predictive Factors for Electrical Load Growth

Two primary factors will drive the timing for construction of the new distribution substation: 1) normal growth in area electrical demand; and 2) large block loads. Modeling is used to predict normal electrical demand growth within a DPA, based upon many factors, including historic growth patterns, pending business service applications, and—for the first time in 2017—distributed energy resources (DER) estimates. Large block loads, which are generally associated with new business interconnections of 1 MW or more, are difficult to predict accurately due to short lead times and must also be considered because they can significantly accelerate the need for new distribution capacity.

PG&E utilizes the LoadSEER forecasting tool to predict growth in area electrical demand within a DPA for a 10-year period into the future. LoadSEER incorporates the most-recent 13 years of substation historical peak-load data. The Paso Robles DPA forecast uses non-coincident peak-load data for each substation bank taken in the field from within a 2- to 3-day window during the most severe heatwave of each summer. The 1-in-10 forecast assumes a 90th percentile hot summer with higher-than-average temperatures and intense heat waves. PG&E's goal is to maintain a distribution system that is capable of serving its customers during hot summers without overloads and outages. The Paso Robles DPA is an interior area, sensitive to summer heat with very significant residential and commercial air-conditioning load as well as industrial refrigeration load for the wine industry. Consequently, the 1-in-10 DPA forecast for the DPA must be used to adequately predict DPA capacity needs.

The LoadSEER forecast does not account for all large future block loads; unfortunately, large block loads associated with new business interconnections often have short lead times that cannot be anticipated in the LoadSEER modeling. Thus, distribution planners not only review electric demand modeling, but also watch and plan for the possibility of large-demand business applications that will exceed predicted electrical demand.

B. LoadSEER Forecasts

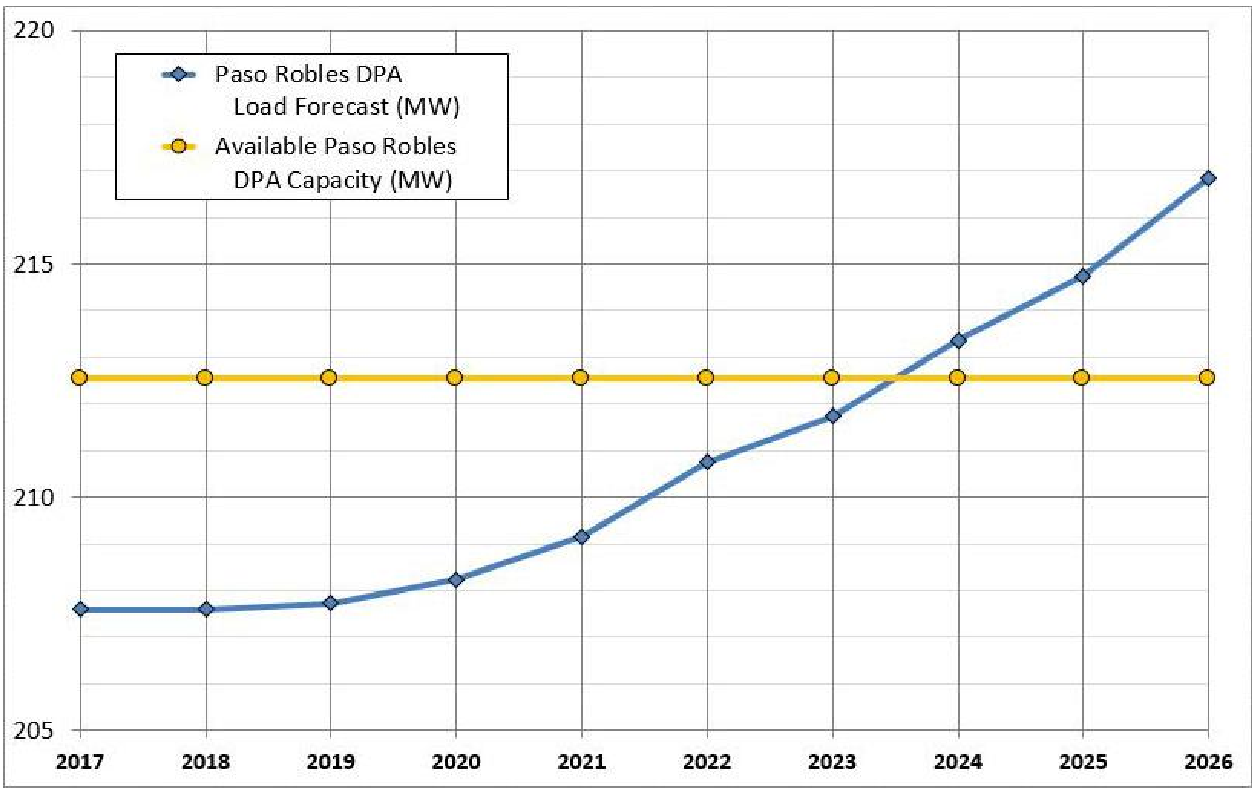
In a ruling on August 9, 2017, the CPUC provided direction to PG&E and other utilities on how to integrate DER[3] growth scenarios into their distribution planning forecasts in order to better determine the need and timing for new distribution projects. CPUC President Michael Picker, who issued the ruling, is the Assigned Commissioner in several proceedings involving distribution resource plans that utilities are required to submit under Public Utilities Code Section 769. His ruling described the current practice in which the California Energy Commission (CEC) uses utility distribution load and DER growth forecasts to prepare and adopt the California Energy Demand forecast in its biannual Integrated Energy Policy Report (IEPR). Due to what the ruling refers to as a "current misalignment of their schedules," the most recently adopted IEPR forecast is the 2016 Update, which relies on 2015 DER forecast data. Nevertheless, because "the CEC's IEPR process is structured to thoroughly vet forecasting issues of a technical, and sometimes contentious, nature," and in order to be consistent and transparent in planning assumptions, the ruling finds that "the most suitable and defensible forecast data available at this time is the 2016 adopted IEPR forecast update." The decision also allows the utilities to make certain adjustments to the IEPR forecast based on the latest public data concerning local load growth, solar energy, and other factors. (*See gen'ly* Assigned Commissioner's Ruling on the Adoption of Distributed Energy Resources Growth Scenarios (Application (A.) 15-07-002 though A.15-07-008.)

[3] Public Utilities Code Section 769 defines DERs as "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies."

Applying the CPUC's guidance, PG&E's distribution planning engineers used the following methodology to update their earlier forecast. Using LoadSEER, they began with the 2016 adopted IEPR Update, which incorporated the mid-case of the 2015 DER forecast and substantially lower values for photovoltaic generation in the Paso Robles area than PG&E had previously utilized. They then added recent public data on planned new load, as listed in Table 6. (*See* Table 6, Section III.0 below.) The adjustments included an annual load adjustment for loss of the largest distributed generator on line at the time of the DPA peak to account for the worst-case N-1 contingency for the potential loss of this generation source. PG&E engineers then re-ran the LoadSEER forecast with the adjustments. The resulting LoadSEER forecast is shown in Figure 5.[4] Table 3 provides a breakdown of the Updated LoadSEER Forecast, and Table 4 provides a detailed load forecast by substation.

Figure 5. Updated LoadSEER Forecast, Paso Robles DPA

Description of Forecast	Forecasted Load (MW)									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Available Capacity	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55
LoadSEER Forecast	207.60	207.59	207.73	208.24	209.15	210.75	211.74	213.37	214.74	216.85



[4] Note that, other than the N-1 contingency described above, PG&E planning engineers included no further negative adjustments to the LoadSEER forecast for solar generation as part of the adjustments made for the 2016 IEPR forecast. Most solar is already accounted for in the IEPR forecast, so only an unusually large new project would merit inclusion. Moreover, the peak demand in the area has gradually moved from 4 or 5 p.m. to 5 or 6 p.m. over the last 10 years. In fact, the 2016 DPA peak occurred at 7 p.m. in late June, when the contribution of solar generation was only 2% of its maximum noon-time output. As peak shifts to later hours, the contribution of solar generation at the time of DPA peak becomes more and more negligible.

The Paso Robles DPA has an available capacity limit of 212.55 MW. (*See* Section II.B, above.) The updated LoadSEER forecast provided in Table 3 indicates that distribution demand in the Paso Robles DPA will outpace this capacity between 2023 (211.74 MW) and 2024 (213.37 MW), so that new distribution capacity will be needed in 2024.

Table 3. Breakdown of Updated LoadSEER Forecast

Description of Forecast	Forecast (MW) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Available Capacity	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55
IEPR Initial Demand Forecast	206.73	208.34	208.81	210.02	211.85	215.02	218.71	221.72	224.59	228.11
IEPR Total DER Adjustments	-2.07	-4.18	-6.35	-8.77	-10.66	-12.99	-16.31	-18.27	-20.02	-21.67
Total New Business Adjustments	2.92	3.41	5.25	6.97	7.94	8.70	9.32	9.90	10.15	10.39
Loss of Largest DG Adjustment	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Total LoadSEER Forecast	207.60	207.59	207.73	208.24	209.15	210.75	211.74	213.37	214.74	216.85

The Assigned Commission's August 9, 2017, ruling validates earlier concerns of PG&E planning engineers about relying on an aggressive DER forecast to predict when new distribution would be needed (*See* Appendix G at UG-11). According to the ruling, "the 2016 adopted IEPR forecast mid-case is the best source for 2017 Distribution Resource Plan Growth Scenarios trajectory case," which means using substantially lower DER forecast assumptions for the Paso Robles DPA than the CPUC had previously supported. The ruling also confirms that additional forecasting data will be needed to better predict distribution needs and timing going forward. The CPUC is continuing to study forecasting issues in the Section 769 proceedings and indicated its intent to obtain additional load data and other information from the CEC, CAISO, utilities, and other parties over the next few months. Ultimately, the CPUC aims to "establish a framework for establishing a consistent and reliable forecast on an annual basis." The ruling sets out the next steps to achieve that goal.

Table 4. Breakdown of Substation Capacities and Forecasted Loads, Paso Robles DPA

Substation / DPA	Available Capacity	Forecast (MW) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Atascadero Substation	29.70	29.63	29.73	29.57	29.62	29.89	29.77	29.70	29.68	29.69	29.76
Paso Robles Substation	89.10	81.04	81.00	81.09	81.54	81.54	82.63	83.38	84.65	85.82	85.48
Templeton Substation	89.10	81.74	81.70	82.01	82.37	83.05	83.66	84.12	84.45	84.58	86.93
San Miguel Substation	15.84	15.19	15.16	15.06	14.71	14.67	14.69	14.54	14.59	14.65	14.68
Paso Robles DPA	**212.55 (1)**	**207.60**	**207.59**	**207.73**	**208.24**	**209.15**	**210.75**	**211.74**	**213.37**	**214.74**	**216.85**

[1] The Aggregate Capacity of the four substations is 223.74 MW; however, a 95% utilization factor is applied to determine Available Capacity (also called Normal Area Capability). (*See* Section I.B and the Guide for Planning Area Distribution Facilities, document 050864, attached as Exhibit C.)

Please note that the MW values shown in the legends in Figure 2, Figure 4, and Figure 7 are loads, not capacities. These loads are only preliminary, based on 2016 distribution load flow studies, to illustrate project feasibility. Actual loads for the proposed circuit configurations will be higher at the time that new distribution facilities are needed.

At the CPUC's request, PG&E also provides the following Figure 6. Comparison of LoadSEER Forecasts, Paso Robles DPA, which provides the LoadSEER forecast with and without the latest CPUC guidance on distribution planning forecasts.

Figure 6. Comparison of LoadSEER Forecasts, Paso Robles DPA[5]

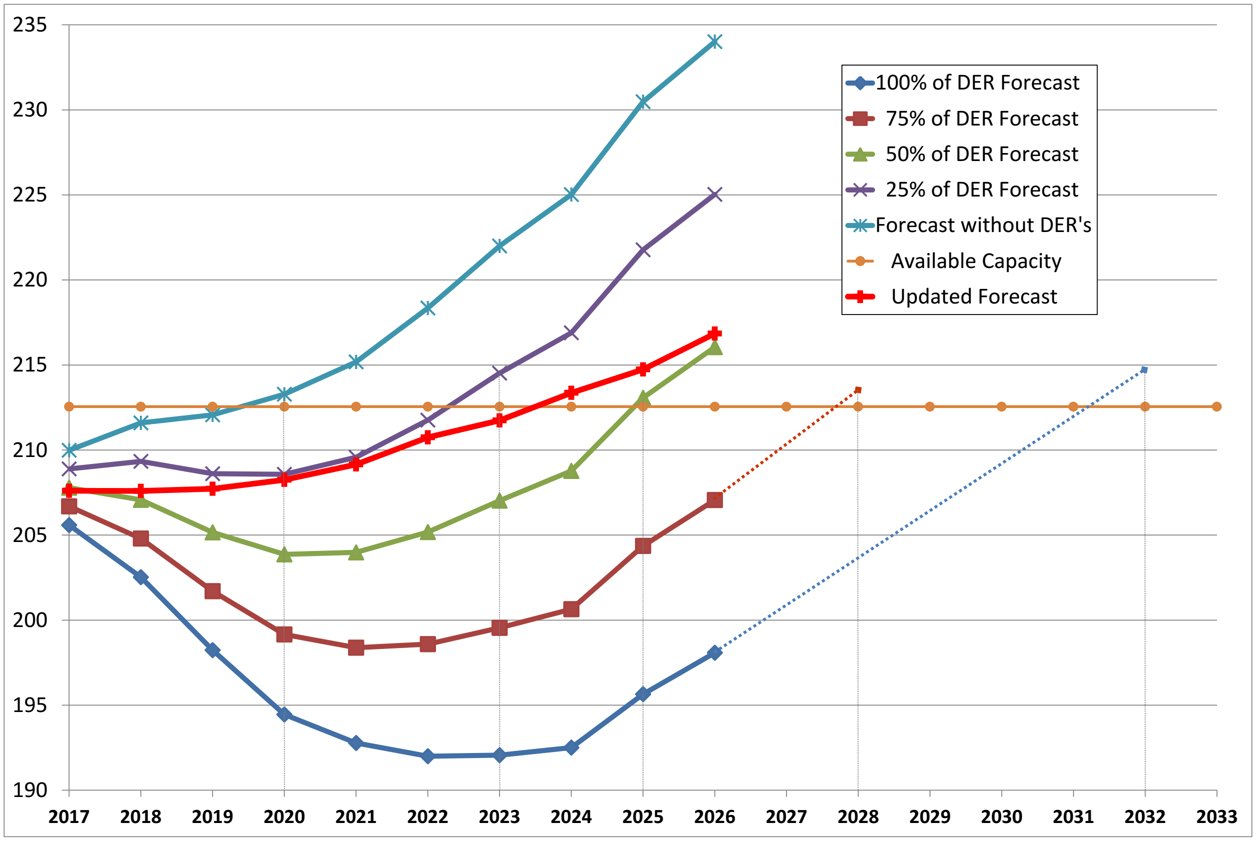


Table 5. Previous 1-in-10 LoadSEER Forecast Incorporating Varying Percentages of the DER Forecast

Description of Forecast	Available Capacity	Forecasted Load (MW)									
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
100% DER Forecast	212.55	205.59	202.53	198.24	194.45	192.78	192.00	192.06	192.51	195.65	198.08
75% DER Forecast	212.55	206.69	204.80	201.70	199.16	198.38	198.59	199.55	200.64	204.36	207.06
50% DER Forecast	212.55	207.79	207.07	205.16	203.87	203.98	205.18	207.03	208.77	213.07	216.05
25% DER Forecast	212.55	208.89	209.33	208.61	208.57	209.58	211.76	214.52	216.89	221.77	225.03
Non-DER Forecast	212.55	209.99	211.60	212.07	213.28	215.18	218.35	222.00	225.02	230.48	234.01

C. Large Block Loads

As recommended by the CPUC ruling, the updated LoadSEER forecast provided here incorporates additional large new business loads that were not included in the 2016 IEPR Update forecast. (*See* Table 6.) These new large loads, based on publicly available data from the City of Paso Robles, include business development applications that have been filed, are in process, or were recently approved.

[5] The first five forecasts in Figure 6 used the previous 1-in-10 LoadSEER forecast for the Paso Robles DPA and then incorporated 100%, 75%, 50%, 25%, and none of the DER forecast estimates in PG&E's 2015 Distribution Resource Plan (DRP). The forecasts using 25% and none of the DER forecast estimated when available capacity would be reached by following a rough trajectory based on the last 3 points in each projection. (See also Table 5, which provides the data numerically.) The updated forecast in Figure 6 follows the CPUC's ruling of August 9, 2017, concerning how utilities should integrate DER growth scenarios into their distribution planning forecasts in order to better determine the need and timing for new distribution projects.

Future load centers, incorporating this latest public load data, are shown on Figure 7, which also illustrates the proposed Estrella distribution system designed to serve this load. The challenge with these types of fast-paced developments is the short lead-time in planning for the increased electrical demand. In most cases, PG&E learns of these large-load interconnections only 18 to 24 months in advance of operation, from receiving an application to providing service. Of the factors that affect DPA capacity, large new business growth is the most likely to accelerate the need for new distribution capacity and is the most difficult to predict.

Table 6. Large-Load Adjustments for Paso Robles DPA

Project Identification Number	Project Name and Description	Year Received/ Approved	Expected Completion Date	Estimated Demand (MW)
1	Beechwood Specific Plan (SP) – 862 Dwelling Units (DUs); 64,000 square feet (commercial)	Received 2016	Information Not Available (INA)	1.357
2	Furlotti Annexation (Paso Robles Gateway Project) South Vine Street – 97 DUs; 464,000 square feet (commercial); 425 hotel rooms	Received 2016	INA	1.035
3	San Antonio Winery Production Facility – 85,951 square feet (commercial)	Approved 2015	2016	0.987
4	South Chandler Ranch General Plan Amendment (GPA)/SP – 560 DUs	Received 2017	INA	0.840
5	Erskine Industrial GPA/Map/Water Supply Evaluation (WSE) – 622,000 square feet (commercial)/Justin Winery Expansion	Received 2015	INA	0.622
6	Tract 2549 – 41 DUs	Received 2013	INA	0.522
7	Firestone Warehouse Development Plan Amendment – 59,000 square feet commercial	Received 2016	INA	0.300
8	River Oaks 2 GPA/SP Amendment/WSE – 271 DUs	Approved 2016	INA	0.407
9	Rancho Fortunato Event Center	Received 2014	INA	0.343
10	Vina Robles Vineyards – 80,680 square feet (commercial)	Approved 2014	INA	0.343
11	Meridian Winery Red Tank Farm Expansion	Pending	INA	0.300
12	Mission Gardens – 85 DUs	Received 2015	INA	0.295
13	Erskine GPA/Rezone of 38 Highway 46 and Paso Robles Blvd – 250,000 square feet (commercial)	Received 2017	INA	0.250
14	Southgate Center (Paris Precision) Building and Site Modifications – 215,000 square feet (commercial)	Approved 2017	INA	0.215
15	Templeton Ranch – 100 DUs	Received 2014	2017	0.214

Project Identification Number	Project Name and Description	Year Received/ Approved	Expected Completion Date	Estimated Demand (MW)
16	Vina Robles Amphitheater/Hotel – 95,000 square feet (commercial), 80 hotel rooms	Received 2003	INA	0.175
17	Arjun (Blue Oaks) Apartments – 142 DUs	Approved 2017	INA	0.142
18	Oaks Assisted Living – 101 bed, 89,000 square feet (commercial)	Received 2015	INA	0.140
19	Terra Linda Farms – 200 horsepower agricultural pump	Received 2016	INA	0.120
			Subtotal:	**8.806**

Source: City of Paso Robles Community Development Department, Project "Pipeline" Report, July 19, 2017

Figure 7. Future Estrella Substation Distribution System, Large-Load Adjustments, and Future Load Centers

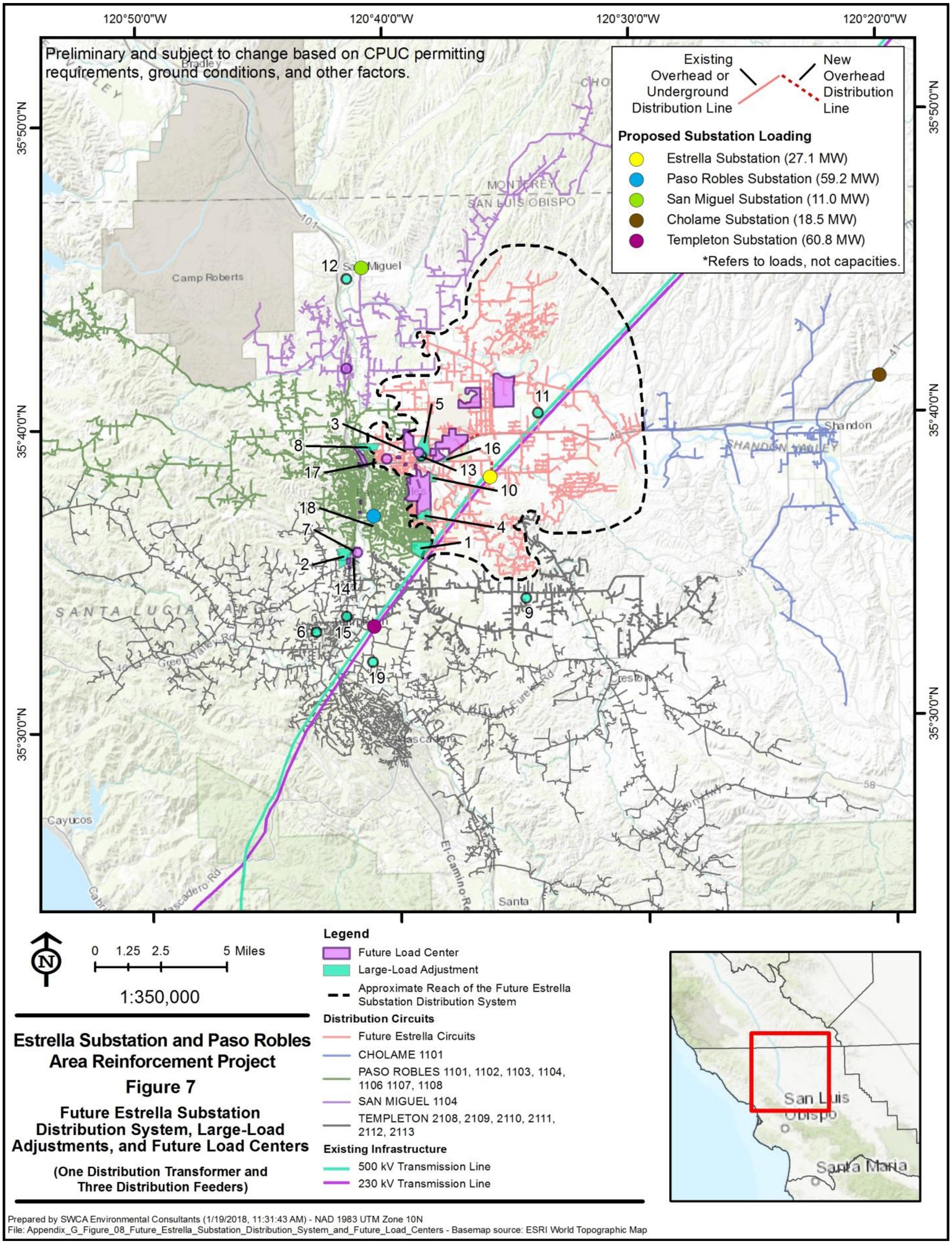


Table 7 below indicates substation capacities and loads for the Paso Robles and Cholame DPAs before and after distribution facilities are added at Estrella Substation. The loads correspond to the proposed circuit configurations indicated in Figure 2, Figure 4, and Figure 6 of the August 2017 Appendix G and are based on 2016 distribution load flow studies to illustrate project feasibility. Actual loads for the proposed circuit configurations will be higher at the time that new distribution facilities are needed.

Table 7. Approximate Breakdown of Substation Capacities and Loads Before and After the Addition of Estrella Substation

Substation	Available Capacity (MW)	Substation Load Before (MW) (1)	Load Transfers (MW) (1)				Substation Load After (MW) (1)
Estrella	29.70	-----	+11.20	+3.10	+2.10	+10.70	27.10
Paso Robles	89.10	70.40	-11.20	-----	-----	-----	59.20
San Miguel	15.84	14.10	-----	-3.10	-----	-----	11.00
Cholame	24.75	20.60	-----	-----	-2.10	-----	18.50
Templeton	89.10	71.50	-----	-----	-----	-10.70	60.80

[1] Substation loads and load transfer amounts are based on 2016 CYMDIST Load Flow Data. Distribution Load Flow studies in the PowerWorld PWD format or in GE EPC format are not available. PG&E uses CYMDIST from CYME for distribution load flows. The latest CYME load flows are based on Summer 2016 peak loads and model load conditions for Summer 2017 through Summer 2019.

Underestimating the amount of available capacity to serve such loads could threaten sensitive industrial customers with major business losses. Manufacturing- or process-oriented businesses are very sensitive to interruptions in electric power that can interrupt assembly processes and cause damage to assembly equipment, costly delays for clean-up and restart, and losses of entire batches of product. Wineries, a growing industry in the area, are particularly sensitive to power outages. If PG&E receives a new business application for a large load in this area, it may exhaust all of the remaining area capacity, or initiate other commercial-industrial load growth that together could quickly outpace capacity. If this were to happen without the Estrella project in place, PG&E may be unable to permit, secure necessary land rights, and construct additional distribution capacity in time to prevent significant overloads throughout the DPA—at Paso Robles and San Miguel substations in particular.

IV. ESTRELLA PROJECT DISTRIBUTION BENEFITS

A. DPA Capacity Increase

Since the Paso Robles DPA is reaching the limits of its distribution substation capacity, the distribution system is vulnerable. Two unknowns will drive the timing of the need for additional distribution capacity: the amount of DER demand reduction and the addition of large-load interconnections. If DER demand reduction is slow to materialize or if new, large business load is added in Paso Robles, the DPA capacity limits could quickly be reached or exceeded. PG&E's new 70 kV substation at Estrella Substation provides a location for future 21 kV distribution facilities where they are most likely to be needed, and can most easily be constructed and integrated with the existing system. Without the Estrella Substation location, there may be insufficient time to put new distribution capacity in place to prevent significant overloads throughout the DPA, especially at Paso Robles and San Miguel substations.

Adding a new 70/21 kV transformer with three new distribution feeders connected to existing feeders near Estrella Substation can be accomplished in only 4 months and provide approximately 28 MW[6] of additional capacity. The new distribution facilities at Estrella Substation will alleviate overloads within the DPA by creating additional distribution capacity, thus enabling distribution planning engineers to appropriately load substation transformer banks and transfer distribution load throughout the DPA to address needs as they arise.

[6] Assumes a 95% utilization factor.

No other distribution is planned within the foreseeable future, although there will be room at Estrella Substation for an additional two distribution banks as needed. If these two additional distribution banks and six feeders were added, the ultimate distribution capacity would be approximately 85 MW, assuming a 95% utilization factor.

While large block loads and DER estimates both inject uncertainty into the planning process, one thing is certain: distribution substation facilities will be needed sometime within 5 to 15 years, and could be needed very quickly in response to one or more large-load interconnections that could materialize at any time. The Estrella project supports this critical future need.

B. Distribution System Reliability Improvements and Operational Flexibility

The addition of a future 70/21 kV source in the Paso Robles DPA at Estrella Substation will not only increase the available capacity of the DPA, but will also allow a feeder configuration from the new substation that will reduce feeder length and provide back-ties to existing distribution feeders from San Miguel, Paso Robles, and Templeton substations. (*See* Figure 4. Future Estrella Substation Distribution System.) Estrella Substation is located near the growth areas south of Paso Robles Airport, enabling the future distribution substation to serve the expected load growth directly through much shorter distribution feeders than could be extended from existing substations. Moreover, with three feeders from the new distribution bank connected into the existing distribution system, Estrella Substation will have direct feeder ties to all substations within the Paso Robles DPA except Atascadero Substation, providing valuable system redundancy. The Paso Robles DPA benefits from the central location of Templeton Substation, with six 21 kV feeders extending north and south to provide strong ties to both Paso Robles and Atascadero substations. The future 21 kV substation at Estrella will also provide a strong tie to Templeton Substation, which will allow cascading transfers north to south or south to north through Templeton Substation to take advantage of available capacity wherever it exists within the DPA.

The future distribution substation at Estrella will also provide a new distribution source closer to Cholame Substation, which serves 1,500 customer connections within the Cholame DPA through a 27-mile radial transmission line from Arco Substation in the San Joaquin Valley. The proposed project provides a future opportunity to add an additional transmission line to Cholame Substation to create a looped circuit to improve reliability and operational flexibility on the 70 kV system. This line would likely be constructed within 2 to 3 years after Estrella Substation is built. The existing 27-mile radial line must be cleared for maintenance every 18 to 24 months, requiring most of the 1,500 customers to be notified of multiple planned outages over a several-day period because there is no alternate 70 kV transmission source for the substation. The alternative to planned outages is to install temporary generation at Cholame Substation during these maintenance periods; however, the cost to do this is approximately $1 million every 18 to 24 months. Moreover, aside from the maintenance periods, the service reliability for all 1,500 customers is negatively impacted during normal system configuration (when all facilities are in service) because of the single transmission source. The Estrella 230/70 kV substation would provide a second transmission source approximately 17 circuit miles from Cholame Substation that could be used to eliminate the maintenance clearances and improve service reliability for all customers served by Cholame Substation. In addition, a future 21 kV distribution feeder from Estrella Substation to Cholame Substation could provide a cost-effective temporary solution to the transmission maintenance problem until such time that the 70 kV line could be built.

The ability to establish strong circuit ties and load relief from a new substation to multiple existing substations will provide uniform load relief as well as optimize operating flexibility and emergency restoration throughout the Paso Robles and Cholame DPAs.

C. Distribution System Renewables Hosting Capacity

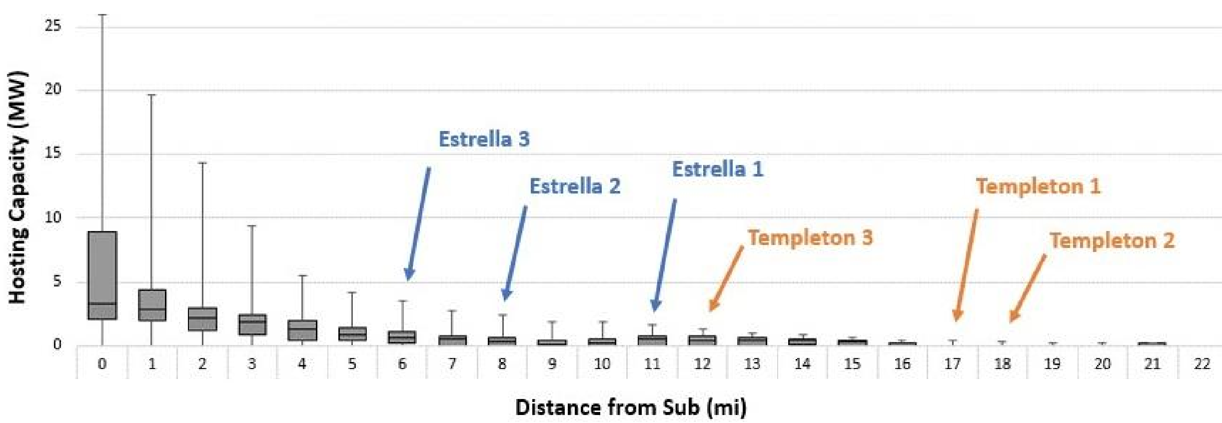
The addition of a distribution substation at the Estrella site would have the additional benefit of supporting DER hosting capacity for the Paso Robles DPA. Hosting capacity, which is the ability to integrate DER with limited investments, significantly decreases with electrical resistance and/or circuit distance from a substation and, thus, has a strong dependency on circuit length. Demonstration projects in R.14-08-013, the Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, have shown that increases in circuit length can significantly impede hosting capacity and limit new DER. (*See, e.g.,* PG&E's Demonstration Projects A and B Final Reports, filed December 27, 2016, at 78, 87 and 91, filed December 27, 2016, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M171/K806/171806890.PDF.)

Templeton circuits currently have more than double the average electrical resistance compared to the average circuits for all PG&E substations in the service area. The proposed Estrella circuits (average length 9 miles) would average approximately 56% less electrical impedance across all circuits than the proposed Templeton circuits (average length 16 miles). (*See* Figure 8). Serving new growth areas by extending distribution lines from Templeton Substation would limit new opportunities for DER.

Figure 9 illustrates the available DER hosting capacity at the end of each proposed distribution circuit coming from Estrella and from Templeton. Note, circuits coming from Templeton would have very little ability to add DER at the end of the circuits due to the length (resistance) of these circuits, while circuits originating at Estrella would have considerably more DER hosting capacity.

Figure 8. Average Electrical Impedance across Circuits

Figure 9. Circuit DER Hosting Capacity versus Distance from Substation



As seen in Figure 9, the proposed Templeton circuits can have near zero hosting capacity due to the distance from the substation. Establishing a new substation at Estrella, in which existing circuit lines (Templeton and Paso Robles substations) can be broken up and have shorter lengths, will ensure additional hosting capacity for the Paso Robles DPA and lower integration costs to adopt future DER in this area.

V. ADDITIONAL DISTRIBUTION QUESTIONS AND ANSWERS

A. Why Not Expand Distribution at Paso Robles Substation?

Placing additional distribution facilities at Paso Robles Substation is not a viable option. Although the growth in demand is in Paso Robles, load in many northern areas of Paso Robles is currently being served with lengthy feeders from Templeton Substation; Paso Robles Substation has limited capacity and its existing 12 kV feeders cannot accommodate future growth in northern Paso Robles.

Adding a fourth distribution bank at Paso Robles Substation is not possible due to space constraints. For the same reason, replacing the 30 MVA banks with 45 MVA banks is not feasible because there is insufficient space to install additional feeders. PG&E has no existing mobile transformer support or emergency replacement transformers for 70/12 kV 45 MVA banks in any event.

Even if Paso Robles Substation had additional capacity and could install feeders within the substation, there is no easy route for new feeders to extend beyond the substation to reach the northern growth areas in Paso Robles. This is a congested urban area with existing 12 kV distribution lines. New feeders would likely be of an express nature, with most of the load being sensitive industrial customers at the ends of the feeders. Because of the congestion, new feeders would either need to be combined with existing overhead feeders on double-circuit overhead routes, increasing the likelihood and extent of outages for new and existing customers served by those lines, or placed in lengthy, expensive underground routes. Either choice would be challenging and costly.

B. Why Not Expand Distribution at Templeton Substation?

While it would be possible to serve additional distribution load from Templeton Substation, this would result in increased costs and decreased reliability. PG&E's distribution planning practices caution against adding distribution capacity at a location that will degrade service reliability. Since reliable distribution systems consist of substations located at regular intervals and sized correctly for the surrounding load between substations, adding more capacity and more 21 kV feeders at Templeton Substation would be a large step in the wrong direction. While the existing 21 kV Templeton 2109 Feeder serves areas well north of Paso Robles Substation, it does not serve the growth areas near Paso Robles Airport. This feeder is forecasted to be loaded at over 80% of its capacity in 2018, limiting its ability to be extended to serve the additional load near the airport. This means that additional long or longer new feeders from Templeton Substation would be required to serve the anticipated growth areas north of SR-46. (*See* Figure 1. Approximate Reach of the Existing Templeton Substation 21 kV Distribution Feeders.)

Both the Estrella and Templeton options provide two feeders that extend to the area of anticipated growth north of SR-46 and south of Paso Robles Airport. The Estrella option provides two new 21 kV feeders, Union Road South and Mill Road Central, that meet near the intersection of Golden Hill Road and Wisteria Lane: 35º 39' 0.5" North (N) and 120º 39' 29" West (W) (35.6501,-120.6581). The Templeton option also would provide two 21 kV feeders that meet at this intersection, the Existing Templeton 2109 and a longer version of Mill Road Central. For comparison purposes, Golden Hill and Wisteria will be considered the "growth area." The precise location of potential new feeders is estimated for this discussion.

PG&E proposes to install three 21 kV feeders from Estrella Substation when the distribution substation facilities are constructed (*See* Figure 4. Future Estrella Substation Distribution System). Based on preliminary design, the first Estrella feeder—"Estrella 1"—will consist of 1.67 circuit miles of new or reconductored distribution line and a total main-line length of 11.76 circuit miles (including 10.09 circuit miles of existing line). The second Estrella feeder—"Estrella 2"—will consist of 6.14 circuit miles of new or reconductored distribution line and a total main-line length of 8.54 circuit miles. The third Estrella feeder—"Estrella 3"—will consist of 3.54 circuit miles of new or reconductored distribution line and a total main-line length of 5.96 circuit miles. [7]

If distribution facilities were to be added at Templeton Substation when additional capacity becomes necessary, an equivalent system would include three new 21 kV feeders as well as 4.35 circuit miles of new or reconductored distribution line on the existing Templeton 2109 Feeder, which is already routed toward the area of anticipated growth north of SR-46. The new and reconductored line on the Templeton 2109 would be required to clear a route for two of the new 21 kV feeders and to extend Templeton 2109 capacity further into the anticipated growth area. The first new 21 kV feeder from Templeton—"Templeton 1"—would consist of 15.41 circuit miles of new or reconductored distribution line and a total main-line length of 17.12 circuit miles (including 1.71 circuit miles of existing line). The role of the Rural Areas East feeder would be to absorb 11 MW of existing Templeton 2109 load to free up 2109 capacity since the 2109 Feeder already extends to the growth area. The second new feeder from Templeton—"Templeton 2"—would consist of 10.57 circuit miles of new or reconductored distribution line and a total main-line length of 18.13 circuit miles. The third new feeder from Templeton—"Templeton 3"—would consist of 12.20 circuit miles of new or reconductored distribution line and a total main-line length of 14.60 circuit miles.[8]

The construction of Estrella Substation will also require three additional 21/12 kV pad-mounted transformers in the field to provide circuit ties between 21 kV and 12k V feeders (*See* Figure 4. Future Estrella Substation Distribution System). The equivalent distribution system from Templeton Substation would require four additional 21/12 kV pad-mounted transformers.

The shorter route from Estrella to the growth area, Union Road South, is 4.58 circuit miles and the longer route, Mill Road Central, is 7.77 circuit miles. The Templeton option provides one new 21 kV feeder to the growth area and does circuit work to release capacity on an existing Templeton 21 kV feeder, 2109, that extends from Templeton to the growth area. The shorter route to the growth area at Golden Hill and Wisteria from Templeton Substation is the Existing Templeton 2109, which is 11.70 circuit miles and takes much of the same route as the Union Road South feeder from Estrella. The longer route from Templeton to the growth area, also called Mill Road Central, is 13.83 circuit miles and follows much of the same route as the Mill Road Central route from Estrella.

Both shorter routes from Estrella and Templeton to the growth area, Union Road South from Estrella and Existing 2109 from Templeton, meet at the intersection of Union Road and Penman Springs Road: 35º 37' 48.5" N and 120º 36' 51.5" W (35.6302,-120.6143). From this point onward, the routes are identical all the way to the growth area. The route from Templeton to the meeting point at Union and Penman Springs is 7.12 circuit miles longer than the route from Estrella to the meeting point. This is a significant difference, 155% longer, making Estrella far closer to the growth area.

Similarly, both longer routes to the growth area, Mill Road Central from Estrella and Mill Road Central from Templeton, meet at a common point on Mill Road: 35º 38' 41" N and 120º 37' 12.5" W (35.6447,-120.6202), and from this point on the routes are identical all the way to the growth area. The route from Templeton to the common point on Mill Road is 6.02 circuit miles longer than the route from Estrella. This is also a significant difference, 78% longer, again making Estrella far closer.

[7] All estimates are provided for purposes of discussion, based upon preliminary design and subject to change.

[8] All estimates are provided for purposes of discussion, based upon preliminary design and subject to change.

Long feeders are problematic for several reasons. First, as explained previously, long feeders are less reliable simply because of their length and potential for outages that affect many customers (see Table 1). Adding new long feeders from Templeton Substation to northern Paso Robles would further degrade system reliability. Second, in this case, the new feeders would likely be mainly express feeders with much of their load at the end of the line, which would result in most or all customers on the line experiencing an outage if there is trouble anywhere along the lengthy feeder. Third, accessible and maintainable distribution routes north out of Templeton Substation to Paso Robles are limited, and would require lengthy double- or possibly even triple-circuit overhead lines in order to reach areas in Paso Robles. While it is sometimes necessary to place distribution lines on double-circuits, it is not ideal because distribution poles are wood and typically close to roadways. When cars hit wood poles, they generally knock out service; when cars hit poles carrying double- or triple-circuits, customers on multiple circuits may lose power. In areas along busy roadways, such as some areas north of Templeton Substation, cars travel at high speeds and wood poles close to roadways are especially vulnerable. With poles carrying multiple lines, a single car-pole accident could take out two or three 21 kV feeders, knocking out power to a significant number of customers.

In theory, new electric demand south of Paso Robles Airport could be served from Paso Robles Substation, with new distribution feeders out of Templeton Substation taking over additional load in Paso Robles to free up capacity for the new growth. Cascading load within a well-connected DPA can be a useful tool in many circumstances, so long as service reliability is maintained; however, service reliability is substantially reduced whenever one substation's feeders are overextended and another substation's feeders are either underutilized or doubled-up because they are confined to only one direction of travel. In this case, although cascading load from Paso Robles Substation to Templeton Substation and then adding load at Paso Robles Substation is a possible option, it would once again require long feeders from Templeton Substation to pick up load well north of Paso Robles Substation and then require existing Paso Robles feeders to be rerouted to the new growth areas near the airport. As explained previously, rerouting feeders northeast from Paso Robles Substation to the growth areas near the airport would be especially challenging.

In either case, installing additional, lengthy distribution feeders from Templeton Substation would further compromise reliability in a distribution system that is already out of balance. As explained in Section IV.C, longer feeders also negatively affect power quality due to power impedance. Templeton Substation circuits currently have more than double the average electrical resistance compared to the average circuits for all substations in the PG&E service area.

PG&E is aware of no distribution planning standard that determines whether a feeder is too long to provide reliable service, or how much risk of car-pole accidents is acceptable. However, car-pole accidents can cause sustained outages affecting thousands of customers, presenting a serious threat to service reliability. Distribution planners strive to minimize this risk.

C. What Solar Projects Have Been Developed or Will Come Online within the Next 10 Years in the Paso Robles DPA?

Table 8 indicates the expected solar projects to come online in the next 10 years, as well as those that have been connected within the last 5 years. The table identifies the projects that connected to the transmission system, as well as those that have connected or will connect to the distribution system. As indicated in Section IV.C, extended circuits coming from Templeton Substation would have very little ability to add new renewable energy generation at the end of the circuits due to the length and resistance of these circuits, while circuits originating at Estrella Substation would have considerably more solar generation hosting capacity.

Table 8. Solar Projects in Paso Robles DPA

Queue	Project	Fuel	Actual In-Service Date	Size (MW)	Distribution / Transmission	Substation
Projects in Paso Robles DPA – In Service within the Last 5 Years						
166	California Valley Photovoltaic (First Solar)	Solar	9/5/2013	210	Transmission	Templeton
239	Carrizo Solar Farm II (California Valley Solar Ranch)	Solar	1/7/2013	250	Transmission	Templeton
0397-WD	2103 – Hill (Pristine Sun)	Solar	1/8/2015	0.75	Distribution	Templeton
0443-WD	2059 – Creston 2 Scherz (Pristine Sun)	Solar	1/30/2014	0.5	Distribution	Templeton
0384-WD	Vintner Solar Project	Solar	1/6/2014	1.5	Distribution	Templeton
0394-WD	2056 – Jardine	Solar	3/3/2014	1.0	Distribution	Paso Robles
Projects in Paso Robles DPA – In Service within the Next 10 Years						
1596-RD	Firestone Walker Inc.	Solar	To Be Determined (TBD)	1.7	Distribution	Templeton
1529-RD	City of Paso Robles	Solar	TBD	3.7	Distribution	Paso Robles
Not Applicable (NA)	Airport 4 MW Solar Project	Solar	TBD	4	Distribution	Paso Robles/ Future Estrella
NA	Firestone Walker Inc. 1.68 MW Solar Project	Solar	TBD	1.68	Distribution	Templeton
NA	Vitner Solar LLC 1500 kW Solar Project	Solar	TBD	1.5	Distribution	Templeton
NA	Pristine Sun Fund 7 LLC 996 kW Solar Project	Solar	TBD	0.996	Distribution	Paso Robles
NA	Paso Robles Public Schools 786 kW Solar Project	Solar	TBD	0.786	Distribution	Paso Robles
NA	J Lohr Winery Corporation 642.8 kW Solar Project	Solar	TBD	0.6428	Distribution	Paso Robles/ Future Estrella
NA	Templeton Unified School District 636 kW Solar Project	Solar	TBD	0.636	Distribution	Templeton
NA	Meridian Vineyards 620 kW Solar Project	Solar	TBD	0.620	Distribution	Templeton
NA	Paris Precision LLC 504 kW Solar Project	Solar	TBD	0.504	Distribution	Templeton
NA	Niels Udsen 500 kW Solar Project	Solar	TBD	0.5	Distribution	San Miguel

VI. REFERENCES

CAISO. 2014. *2013-2014 CAISO Transmission Planning Process, Estrella Substation Project Description and Functional Specifications for Competitive Solicitation.* June 26, 2014. Online: www.pge.com/includes/docs/pdfs/safety/pasorobles/PasoRobles_CAISO_ProjectDescription.pdf. Accessed November 5, 2016.

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City of Paso Robles. Project "Pipeline" Report. July 19, 2017. Online: http://www.prcity.com/government/departments/commdev/planning/pdf/2017.07.19.Project-Pipeline-Report.pdf. Accessed January 17, 2018.

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Exhibit A. Deficiency Items Update Locations

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Deficiency Item	Location of Updates in Appendix G
Appendix G (1) and (1.1.)	Entire Updated Appendix G
Appendix G (2) and (2.1)	Section III.A Section III.B Table 2 Table 3 Table 4 Figure 2 Figure 4 Figure 6
Appendix G (3) and (3.1)	Section II.C Section V.B Figure 4 Information on the battery storage alternative is not yet available.
Appendix G (4) and (4.1)	Section II.A Section IV.A Exhibit B
Appendix G (5)	Section III.B Figure 5
Appendix G (6) and (6.1)	Section IV.C Section V.B
Appendix G (7) and (7.1)	Table 6 Figure 7 Footnote 4
Appendix G (8) and (8.1)	Section V.B
Appendix G (9) and (9.1)	Section I.A Section V.B Figure 4 Geographic Information System (GIS) data will be provided in electronic format. Information on the Templeton alternative is not yet available.
Appendix G (10) and (10.1)	Figure 2 Figure 4
Appendix G (11) and (11.1)	GIS data will be provided in electronic format.
Appendix G (12) and (12.1)	Figure 6 Footnote 5
Appendix G (13) and (13.1)	Section IV.B
Appendix G (14)	Information on battery storage is not yet available.
Appendix G (15)	Information on battery storage is not yet available.
Appendix G (16)	Table 8 Information on battery storage is not yet available.

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Exhibit B. Planning Standard TD-3350P-09 (07/14/2014 (Rev.3)) (currently being updated)

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Property Review – Coordinating, Leasing, Selling, Acquiring, and Naming

Summary

This utility procedure provides uniform practices for the following activities associated with substation property:

- Coordinating proposed third-party uses, projects, and activities (including leasing, licensing, and grants of easements).
- Reviewing substation properties for potential sale.
- Reviewing the need to acquire substation properties in the future.
- Naming substations.
- Transferring assets.
- Managing gas pipelines on substation property.

Level of Use: Informational

Target Audience

The target audience includes the following Pacific Gas and Electric Company (PG&E) personnel:

- Electric maintenance.
- Engineering.
- Operations.
- Planning.
- Shared services.
- Generation and revenue development.
- Gas transmission and distribution (GT&D).
- Any other employees involved with coordinating third-party substation property projects.

Safety

This procedure provides instructions to help prevent unsafe facility installations on substation properties, including information for avoiding accidental dig-ins to gas pipelines.

Perform all work associated with property reviews in accordance with Utility Standard SAFE-1001S, "Safety and Health Program Standard," and the *Code of Safe Practices*.

Property Review – Coordinating, Leasing, Selling, Acquiring, and Naming

Before You Start Review the latest version of the following documents and information:

- Substation property map.
- Adjacent landowner parcel tax data.
- Substation ultimate and general arrangement outdoor drawings.

Table of Contents

Procedure Steps

1 Coordinating Third-Party Projects Involving Substation Property

1.1 The manager in charge of asset strategy must review and approve all proposed jobs involving substation property that are not initiated by asset strategy personnel (including facilities on customer-owned property).

1.2 Job reviews ensure that all proposed improvements, equipment, and facilities meet the following requirements:

- Safe installation of equipment.
- Coordination with other work at the same station.

Property Review – Coordinating, Leasing, Selling, Acquiring, and Naming

1.2 (Continued)

- Integration with the existing substation design, including the following elements:
  - Ground grids.
  - Physical clearances and mobile equipment access.
  - Coordination with future substation expansion plans (ultimate site plan).
  - Compliance with existing standard designs.
  - Permanent access for inspection, normal station maintenance and operation, and emergency response.
  - Compliance with applicable regulations and local agency requirements.

1.3 Third-party inquiries or land and environmental management (L&EM) personnel must initiate a review of substation property for proposed third-party use before making commitments allowing such use.

1.4 Third-party inquires are directed to the local L&EM office. L&EM personnel assign a land agent to coordinate requests and to ensure that asset strategy personnel review proposed uses in accordance with PG&E's land services (LS) *"Leases From" Manual for Corporate Real Estate.*

2 Reviewing Substation Properties for Potential Sale

2.1 Third-party inquiries or corporate real estate (CRE) personnel initiate a review of substation property for potential sale (for surplus property candidates) before disposition.

2.2 Third-party inquiries are directed to the transaction supervisor in charge of CRE personnel. CRE personnel request that asset strategy personnel review the substation property for potential sale. See Attachment 1, "Reviewing Substation Property for Potential Sale," (flowchart).

2.3 The substation asset management engineer (SAM engineer) requests that transmission planning (TP), distribution planning (DP), and transmission/substation maintenance and construction (T/S M&C) personnel review the substation's long-term operational and planning impact in the event the property is sold.

2.4 The SAM engineer reviews (with appropriate PG&E personnel) any rights that must be retained for existing or planned facilities if the substation property is sold (for example, easements for existing or proposed lines crossing the property).

2.5 Based upon the reviews in Step 2.3 and Step 2.4 above, the asset manager replies to CRE personnel with a final recommendation to either sell or keep the property.

2.6 Some substation property sales may involve only a portion of the property. This is usually in situations where an agency (Caltrans, county, or city) needs a portion of the property in fee for an improvement project, such as road widening. The majority of these partial acquisitions are made under the threat of eminent domain.

3 Leasing Cellular Sites

3.1 General Information

PG&E actively leases and licenses its substation properties to third parties for a number of uses. Asset strategy employees (along with the employees listed in Section 8, "Coordinating Tasks," starting on Page 15) ensure that proposed third-party uses do not adversely affect the electric system or interfere with the maintenance, utility operations, or future expansion of substations. These employees review and approve each proposed use. Asset strategy personnel have final approval.

3.2 General Requirements

1. Reviews and Approvals – PG&E's new revenue development (NRD) personnel coordinate reviews and approvals between different PG&E groups and are the main contacts for the cellular company.

2. Documentation – The cellular company must submit three sets/copies of all documents to NRD personnel.

3. NRD Approval – NRD approval is required before the cellular company may seek city, county, and/or state, as well as Air Quality Management District (AQMD) permits and approvals. PG&E performs an initial walkdown of each proposed site. After PG&E approves the walkdown, the cellular company submits the final plans to NRD personnel for final approval, as set forth in Item 10, "Design Approval," on Page 5.

4. Environmental Assessment – PG&E's local environmental specialist, along with the environmental representative of the cell site, completes a Phase-1 environmental assessment during the planning phase of the project, if needed or required.

5. Business Emergency Plans – PG&E files locally-required business emergency plans with the appropriate certified unified programming agency (CUPA) covering the disclosure of chemicals such as battery acid and, if applicable, diesel fuel.

6. Setback – PG&E maintains all local government jurisdiction setback requirements.

7. Fencing – The cellular site must be separately fenced when it is located on PG&E substation property. The fence and gate must be constructed so that cellular company employees cannot pass through the substation fenced property for site visits, maintenance, or to refuel stand-by generators.

8. Power Supply – A distribution source outside the substation fenced property provides electrical power for cellular sites. The cellular company contacts the local service planning department to obtain power, in accordance with Electric Rule 16, "Service Extensions."

Property Review – Coordinating, Leasing, Selling, Acquiring, and Naming

3.2 (Continued)

9. Grounding – As a part of NRD procedures, the existing substation facility grounding study must be updated and revised. The cellular site is separately grounded, unless applied technology services (ATS) personnel (in consultation with asset strategy personnel) determine that a separate grounding is not required. ATS personnel provide the cellular company with a grounding design plan to ensure the proposed facility is safely grounded. These grounding studies are initiated during the initial phase of the NRD cellular site approval process.

10. Design Approval – The cellular company is responsible for all required designs, plans, permits, and approvals and must submit such documents to NRD personnel for approvals.

11. At a minimum, the following requirements must be incorporated into the cellular facility design for the location or site:

    - Design for wind, seismic, and other environmental factors.
    - Spills prevention control and countermeasures (SPCCs).
    - Hazardous materials business plans (HMBPs).
    - Noise control, fire control, air quality, and business emergency plans.

12. The cellular company submits the following documents to NRD personnel:

    - Arrangement drawings of the proposed cellular site for initial review and approval.
    - Final design drawings of the cellular site approved for construction to update drawings and documents, including SPCC and HMBP plans, fire preplans, substation outdoor general arrangement, and grounding drawings.
    - Certification (the Checklist) – Certification stating that all required permits (including drawings, plans, and documentation) have been obtained before starting construction.

3.3 Stand-By Generator Installation Requirements

1. Generator and Tank – Use only diesel engine/generator assemblies with an Underwriters Laboratories (UL)-2200 listing and a fuel tank with a UL-2085 listing (with double-walled fuel storage no greater than 250 gallons [gal]). The fuel tank must be California State Fire Marshall (CASFM)-approved. The diesel engine must conform to Environmental Protection Agency (EPA) Tier 1 non-road emission regulations.

3.3 (Continued)

2. Sound Level – The generator operation sound level must meet all local, city, county, and Occupational Safety and Health Administration (OSHA) requirements. Noise surveys and studies are required for each cellular site where a noise ordinance applies to the site, in areas near employees, or in residential and commercial areas. Implement all recommended noise abatement and mitigation measures, including the installation of sound enclosures.

3. Testing – Limit testing of the diesel stand-by generator (preferably during normal business hours) to less than 60 minutes per month or as permitted by the local administrating agency, whichever is less. Provide copies of any permits issued by an air pollution control district (APCD) to PG&E's local environmental specialist.

4. Diagram – Submit single-line diagrams of the stand-by generator, transfer switch, etc., to PG&E for review and approval. This includes the generator's technical specifications.

5. California Fire Code – The diesel generator/fuel tank design and refueling operations must comply with California Fire Code –Title 24: Part 9, Article 79, "Flammable and Combustible Liquids," requirements.

6. Hazardous Materials Storage – Do not store any materials other than those used for operating equipment (including the generator fuel tank) at the site.

7. Power Transfer – Use the open transition method (namely, "break before make") to transfer the power supply between the PG&E source and stand-by generator. The transfer is made through a double-throw transfer switch or an interlock scheme that prevents the PG&E source and stand-by generator from operating in parallel.

8. Fence – The diesel generator/fuel tank combination must be enclosed by a minimum 8-foot (ft) high fence on all four sides with a locked pedestrian access gate. If the fence is part of the substation perimeter fence, the top of the fence must be made of barbed wire, per Numbered Document 059660, "Fence Elevations and Notes – Property Fence and Gates."

9. Installation Outside Substation Fence – If the proposed stand-by generator installation is on substation property but outside the substation fence and substation ground grid, the stand-by generator fence enclosure must be located at least 30 ft away from any existing transmission towers (unless it is located in the tower's footprint). The grounding and exact location must be in accordance with transmission line policies and guidelines for this application.

10. Installation Inside Substation Fence – If the proposed stand-by generator installation is on substation property and inside the substation fence where the substation ground grid resides, the stand-by generator fence enclosure must be at least 15 ft away from any existing transmission towers (unless it is located in the tower's footprint) and substation equipment or structures. Grounding requirements determine the exact location.

Property Review – Coordinating, Leasing, Selling, Acquiring, and Naming

3.3 (Continued)

11. Clearance from Combustible Materials – Maintain a minimum 5 ft clearance from the diesel generator/fuel tank to all combustible materials.

12. SPCC and HMBP Plans – Contractors must submit signed certifications that all appropriate plans and permits are submitted or obtained and will be provided to NRD personnel.

13. Modifications after Installation – After initial NRD approval and installation of a stand-by generator, no modifications or alterations are allowed to any equipment, fuel storage, wiring, etc. associated with the stand-by generator system without NRD personnel first approving the plans. The Certification (Checklist) statement is required with all modification applications.

14. Installed Stand-by Generators List – NRD personnel must maintain a current list of stand-by generators installed on PG&E properties, right of ways, and/or easements with site names and locations.

3.4 Other Terms and Conditions

1. Contractual – Execute site license agreements to the master agreements for both the antenna location and associated equipment to limit PG&E liability for storing and potentially damaging any hazardous substance.

2. Air Quality – Provide a copy of the air quality permit from the local AQMD agency to NRD personnel before installing cellular equipment.

3. Property Rights – If any cellular company equipment is placed at a facility or property where PG&E does not own the underlying land in fee, the placement of a cellular site and any stand-by generator are subject to the property owner’s approval. This information must be re-negotiated and included in an appropriate communications site license agreement exhibit. In addition, NRD personnel must approve the cellular site installation and any generator/fuel tank installation, per the requirements outlined in this procedure.

4. Environmental Disturbance – If additional ground space is required or an area must be disturbed further, review each cellular site to obtain a PG&E environmental clearance and re-verify any existing sites.

5. Costs – Bill all costs incurred by PG&E to the cellular company after a stand-by generator is installed or upgraded, including but not limited to the following services:

    - Site visits.
    - Drawings/document reviews and approvals.
    - Construction inspections.

Property Review – Coordinating, Leasing, Selling, Acquiring, and Naming

3.4 (Continued)

- PG&E drawings/document updates.
- SPCC plan reviews, modifications, and re-certifications.

6. Liability – PG&E is not liable for any abnormal events resulting from normal cellular facility emergency maintenance and refueling operations, including but not limited to PG&E outages, personal injury, fire, explosion, and hazardous material discharge.

4 Acquiring Property for Future Substations

4.1 General Information

1. This section establishes procedures for evaluating the need to acquire property for a future substation that has not been granted a permit to construct (PTC) or certificate of public convenience and necessity (CPCN) by the California Public Utilities Commission (CPUC). PG&E must apply for a PTC or CPCN on a case-by-case basis.

2. The senior area planner and local planning personnel ensure that the following tasks are completed to acquire future substation property:

   - Prepare a 5-year plan for the area, taking into consideration all possible alternatives for serving load in the area.
   - Work with PG&E personnel associated with the following functions to determine load-serving alternative costs: TP, electric system engineering, asset strategy, and CRE.
     - Costs must include but are not limited to interconnection costs, transmission reinforcement costs, land costs for various sites, substation costs, and distribution costs.
     - L&EM personnel prepare a site feasibility study for the properties in and around the area to determine land availability and cost.

4.2 General Requirements

The senior area planner, local planning personnel, land representative, TP personnel, and substation engineering personnel ensure that the evaluation criteria described below are met:

1. Complete the following initial site screening criteria for all potential new substation sites:

   - Physical size and suitability of sites for facilities, such as topography, proximity to earthquake fault rupture or flood zones, slope, access, existing easements, property boundaries – generally 2.5+ acres for a three-bank station.
   - Availability of sites not currently planned for development.

4.2 (Continued)

2. Use the following site evaluation criteria to review the specifics for each site that passes the initial site screening criteria (Step 4.2.1 on Page 8):

   a. Engineering Feasibility

      - Proximity of existing and forecasted electric load.
      - Existing and future substation radius in miles from the substation for distribution facilities sphere of influence:
         - 21 kV – Rural = 11 miles; Urban = 4 miles
         - 12 kV – Rural = 7 miles; Urban = 3.5 miles
      - Proximity to existing transmission and distribution (T&D) systems.
      - Length and location of new T&D lines.
      - Number of new towers or poles.
      - Number of highway, street, and/or railroad crossings.
      - Easement width.

   b. Land Use

      - City and county land use and zoning designations.
      - Existing ownership.

   c. Environmental Concerns

      - Proximity to sensitive biological resources.
      - Proximity to streams, wetlands, and floodplains.
      - Potential for landscaping and screening.
      - Vegetation removal for safety standards.
      - Necessity for transmission line creek crossings.
      - Archeological or cultural significance.
      - Visual, electromagnetic field (EMF), and noise concerns.
      - Geologic and seismic concerns.
      - Past land use analysis.

4.2 (Continued)

d. Acquisition and Construction Costs

- Purchase of land.
- Purchase of transmission line, distribution line, and third-party easements.
- Preparation of site (grading, landscaping, fencing, etc.).
- Construction of transmission facilities.
- Construction of distribution lines.
- Construction of substation facilities.
- Mitigation measures.
- Environmental testing and mitigation.

3. After all costs are developed and the above criteria are met, develop a preliminary economic analysis (taking into account all feasible alternatives for serving load in the area).

4. If the most economic alternative is a new substation, ensure that the following tasks are completed:
   - All the requirements set forth in this Section 4.2, "General Requirements," (starting on Page 8) are met.
   - Land use agencies and local jurisdictions are consulted.

5. Determine if the preferred site is within a volatile real estate market area where property values are appreciating rapidly and/or all available properties are being developed quickly.

6. Prepare a project analysis, which includes the information in the following Step 7, and forward that project analysis to the area engineering and planning director for routing and approval.

7. Provide the following information in the same format as a standard project analysis, including recommendations, background, and alternatives considered:
   - The load growth projection for the area, including the 5-year plan.
   - The preliminary economic analysis for alternatives to the 5-year plan.

4.2 (Continued)

- A summary copy of the site feasibility study prepared by LS personnel.
- A Geographic Information System (GIS) map showing existing and alternative substations, sphere of influence, existing area served (circuits emanating from the substation in one color), and geographic landmarks.
- An advance authorization.

5 Naming Substations

5.1 PG&E assigns substation names based on adjacent geographic locations. This naming convention aids personnel in locating and navigating to the location. The naming convention also provides consistency over a long period of time, as well as useful information deduced from names based on certain regularities.

5.2 To select a name for a new substation, the SAM engineer and other project team members perform the following tasks:

1. The SAM engineer coordinates with the project engineer (PE) and other project team members (if necessary) to review a detailed geographic map of the area.
2. The substation naming and nomenclature conventions are described in Attachment 2, "Substation Naming Conventions."
3. The SAM engineer reviews the proposed name with corporate communications personnel to confirm that there are no issues that could adversely affect local residents or agencies.
4. The SAM engineer obtains approval from the director in charge of asset strategy personnel.
5. The asset development supervisor notifies the Engineering Library System (ELS) of any new substation names at the end of each quarter.
6. The ELS contact adds the new name to the appropriate dropdown menus for indexing drawings in ELS and sends an email confirmation back to the asset development supervisor.
7. The asset development supervisor notifies business planning and project engineering supervisors of the new name.

6 Transferring Assets

6.1 This section covers cases where ownership of a piece of substation property is transferred to a distribution line. This typically occurs when unit substations are replaced with electrically equivalent, pad-mounted distribution line equipment.

6.2 Annual recurring expense savings are realized for the following reasons:

- Environmental compliance – SPCC plans not required for distribution line equipment.
- Maintenance compliance – Mandated monthly inspections for substation equipment are no longer required.
- Security compliance – Rules for distribution line equipment are less strict than for station equipment.

6.3 Capital savings are significant because a distribution line solution may be a fraction of the cost compared to a substation solution.

6.4 The roles and responsibilities of various work groups are as follows:

Substation and T-line Asset Strategy – Asset strategy personnel prepare the estimate (work order) to record the removal and retirement of substation assets and the addition of distribution line assets. See Attachment 1, "Reviewing Substation Property for Potential Sale," for instructions from capital accounting on how to properly account for this change in asset ownership. However, be aware that using a single work order restricts tracking costs to one major work category.

Substation and T-line asset strategy personnel notify the following work groups to take action:

1. Transmission Operations – Substation

   Remove the asset from the asset registry and archive the maintenance plans in SAP/WM.

2. Distribution Operations

   - Include the new distribution asset with the maintenance plans in the asset registry.
   - Perform maintenance and inspections per distribution maintenance practices.
   - Replace the substation lock with a distribution line lock.
   - For security purposes and at the request of distribution line personnel, the station fence may remain in place.

3. Environmental Services

   - Update the SPCC plan showing distribution equipment.
   - Inform city/other agencies about the update to the SPCC plan, as appropriate.

7 Gas Pipelines on Substation Property

7.1 This section provides instructions for addressing gas pipelines on new and existing electric substation property, including switching stations.

7.2 New Substations

1. The best strategy is to avoid purchasing properties for new substations that contain gas pipelines. The next best strategy is to keep the gas pipeline on the edge of the property at least 25 ft outside of and away from the ultimate build out of the substation fence. If the fence is less than 25 ft from the pipeline, initiate a pipeline study as described in Section 7.4, "Pipeline Study," below.

2. Asset strategy personnel must pre-approve exceptions for rare, special cases where the pipeline is within 25 ft of the fenced area of a new substation. The assigned ground grid expert at applied technology services (ATS) and gas personnel must perform an intensive ground grid review of all exceptions.

7.3 Existing Substations

1. When a major substation project is initiated for any substation with gas pipeline on the property, initiate a study similar to how a ground grid study is initiated, per Numbered Document 073114, "Grounding."

2. Use GIS to locate pipelines on substation properties for preliminary scoping purposes only. Establish actual pipeline locations by performing an on-site investigation, per Utility Procedure TD-3320P-16, "Substation Excavation Procedure."

3. Charge funding and mitigation costs to the capital project initiating the study. Address gas pipeline issues in the job walkdown notes, per Utility Procedure TD-3330P-01, "Job Walkdown."

7.4 Pipeline Study

1. The ATS ground grid expert performs a pipeline study, with concurrence from gas personnel.

2. Details on electric and gas considerations for the pipeline study are found in the documents listed in the Reference Documents section on Page 18 of this procedure.

3. The single-point-of-contact for gas personnel is the manager of pipeline engineering. The manager of pipeline engineering coordinates responses from corrosion engineering, integrity management, and pipeline engineering personnel.

7.5 Electrical Considerations for Pipeline Study

1. Check the arcing distance. Make sure the pipeline is outside the soil arcing distance from the edge of any pipe to any ground grid or grounded foundation. Typically, that distance is 12–15 ft, but must be specifically calculated.

7.5 (Continued)

2. Check the induction distance. Make sure the induced currents from electric overhead lines, underground lines, or the ground grid do not impact cathodic protection. Pipeline coating (for example, epoxy) is a factor in determining the acceptable induced voltage and currents on the pipeline during normal and fault conditions, as well as pipeline coating stress voltage. From a design point of view, it is best if the electric lines cross perpendicular to the gas pipeline. In addition, make sure the requirement for electrical overhead clearances are met, per Numbered Document 470591, "Electrical Clearances for 60 kV, 70 kV, 115 kV, and 230 kV Overhead Transmission Lines."

3. Gas Review – This study must include a review by gas personnel of corrosion engineering, integrity management, and pipeline engineering. The single-point-of-contact for gas pipelines in substations (the manager of pipeline engineering) coordinates the gas review. Pipeline coating (for example, epoxy) is a factor in determining the acceptable induced voltage and currents on the pipeline during normal and fault conditions, as well as pipeline coating stress voltage.

4. The asset strategy engineer comments on the following considerations:

    a. Future expansion plans for the station in relation to the pipeline location.

    b. The assurance that gas inspectors have proper accessibility to perform routine inspections per the Department of Transportation (DOT) and CPUC. In general, gas inspectors require escorted access into the fenced area of the substation and the ability to safely maintain and inspect the length of the pipe.

7.6 Gas Pipeline Considerations for Study

1. The gas pipeline study must address access to gas lines for excavation, maintenance, and inspection purposes. This typically means adequate setback of fences, structures, foundations, and equipment to ensure there is ongoing access to the gas lines. Excavation may require up to 20 ft of working clearance from a transmission pipeline.

2. Structures cannot be built over the gas lines. Fences are one common exception because they are easy to remove.

3. Check the alternating current (ac) corrosion risk. Make sure the pipeline is not at an increased risk of corrosion.

4. Check clearances. See Code of Federal Regulations – Title 49 (49 CFR): Part 192.325, for structures, hazards, etc.

    a. Install each transmission line with at least 12 inches (305 millimeters [mm]) of clearance from any other underground structure not associated with the gas transmission line. If this clearance cannot be attained, protect the transmission line from damage that may result from the proximity to other structures.

7.6 (Continued)

b. Install each main with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that may result from the proximity to other structures.

5. Check induced currents. 49 CFR: Part 192.467 (f) states:

"Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices."

This requirement is covered by Section 7.4, "Pipeline Study," on Page 13.

8 Coordinating Tasks

PG&E employees involved with the following functions are responsible for coordinating the tasks involved with the substation property projects described in this procedure:

- Project management (PM).
- Transmission planning (TP).
- Distribution planning (DP).
- System protection.
- System automation.
- Gas distribution.
- Telecom and network services.
- Transmission/substation maintenance and construction (T/S M&C).
- Electric system engineering (ESE).
- Land services (LS).
- New revenue development (NRD).
- Service planning.
- Environmental services (ES).
- Applied technical services (ATS).
- Gas pipeline engineering.

8 (Continued)

The following PG&E employees are responsible for reviewing substation properties for potential sale:

- Substation asset management engineer (SAM engineer).
- TP engineer.
- DP engineer.
- Electric system reliability planning manager.
- Corporate real estate (CRE) transaction supervisor.
- Substation maintenance.

END of Instructions

Definitions

Code of Federal Regulations (CFR): The federal agency that governs gas pipelines.

Corporate real estate (CRE) personnel: PG&E employees who provide real estate services, including planning and managing facilities-related projects, aligning business strategies with real estate solutions, and operating and maintaining facilities.

Economic Analysis Software Package (EASOP): Standard economic software used for evaluating capital plant additions provided by financial planning and analysis personnel.

Geographic Information System (GIS): A computerized system capable of developing customized maps that display geographic features (such as lakes and rivers) and objects (such as pipes and stations). GIS technology integrates common database operations, including queries and statistical analyses, making it possible to add layers of information to these maps.

Substation property: Any facilities and land located within a substation property line.

Implementation Responsibilities

The electric standards senior consulting engineer broadcasts this procedure to affected personnel after it is published on the TIL website.

Governing Document

Utility Standard TD-3350S, "Substation and Transmission Line Asset Strategy and Reliability"

Compliance Requirement/ Regulatory Commitment

Code of Federal Regulations – Title 49 (49 CFR): Transportation, Part 192, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards"

Reference Documents

California Fire Code –Title 24: Part 9, Article 79, "Flammable and Combustible Liquids"

Code of Safe Practices

Electric Rule 16, "Service Extensions"

"Leases From" Manual for Corporate Real Estate

Numbered Document 059660, "Fence Elevations and Notes – Property Fence and Gates"

Utility Standard SAFE-1001S, "Safety and Health Program Standard"

The following references pertain to Section 7, "Gas Pipelines on Substation Property," starting on Page 13:

Electric:

- Numbered Document 068177, "Overhead Transmission Line Design Criteria"
    - "Joint Use Corridors" (Page 12)
    - "Induction Distance Criteria" (Page 12)
    - "Arc Distance Criteria" (Page 12)
- Numbered Document 073114 – "Grounding"
    - Appendix B, "Ground Grid Analysis Process and Funding for PG&E Projects" (Page 12)
- Numbered Document 470591, "Electrical Clearances for 60 kV, 70 kV, 115 kV, and 230 kV Overhead Transmission Lines"
- Utility Procedure WP1902, "Evaluating Uses of Company Transmission Line Easements by Others"
    - Attachment 1, Section 10, "Pipelines" (Page 4)
- Utility Procedure TD-3320P-16, "Substation Excavation Procedure"
- Utility Procedure TD-3330P-01, "Job Walkdown"

Gas:

- Code of Federal Regulations Title 49 (49 CFR)
  - Part 192.325, "Underground clearance"
  - Part 192.467, "External corrosion control: Electrical isolation"

Electric and Gas:

- *Electric & Gas Service Requirements* (Greenbook)
- *PG&E Rights-of-Way Management Plan*[1]

Appendices	NA
Attachments	Attachment 1, "Reviewing Substation Property for Potential Sale" Attachment 2, "Substation Naming Conventions"
Document Recision	This utility procedure cancels and supersedes Utility Procedure TD-3350P-09, "Property Review – Coordinating, Leasing, Selling, Acquiring, and Naming," dated 03/13/2013.
Approved By	Eric Corona, Manager
Document Owner	Tom Rak, Manager

[1] Currently under revision

Property Review – Coordinating, Leasing, Selling, Acquiring, and Naming

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Revision Notes

Where?	What Changed?
Section 5	Replaced part of Section 5.2 with new Attachment 2.

Exhibit C. Guide for Planning Area Distribution Systems Document # 050864, Dated 9/15/09 and Revised 3/4/2010 (currently being updated), with Appendix A, List of all DPAs and their Area Designations

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PG&E	**Guide for Planning Area Distribution Facilities**		**050864**
Asset Type:	Electric Distribution	**Function:**	Planning
Issued by:	**Electric Distribution Engineering & Planning**	**Date:**	9/15/09

Rev. #01. Guideline G-12009 added to this document, appendix D.

Rev. #00: This document has been created to replace PG&E Guideline G12004 which was approved by Placido Martinez on 4/23/2009.

1.0 PURPOSE AND SCOPE

PG&E's distribution system planning guidelines have evolved substantially throughout the company's history. This revision to the guideline contains procedural changes designed to meet demand and improve reliability for our customers through development of both distribution substation and distribution line infrastructure.

This document is a guide for planning distribution substation and feeder capacity to supply our customers. It includes methods and criteria for determining the adequacy of existing electric distribution system capacity and forecasting the need for additional facilities. Techniques for economic analysis of alternative plans to provide additional distribution system capacity, detailed facility design, and transmission system planning criteria are outside the scope of this guide.

Distribution system planning is complex and dependent upon many variables. No simple set of rules can be applied automatically to provide the best solution to every planning problem. This guide must be used with judgment. Deviations from the planning process should be rare. Recommendations which include deviating from the planning processes described in this guide must be approved by the appropriate distribution planning manager.

Application of the procedures described in this guide will result in project proposals to expand distribution system substation and line capacity. All proposed projects will be evaluated, prioritized on a system wide basis, and considered for inclusion in the five year expenditure plan. PG&E management will determine individual project implementation timing through the annual budgeting and prioritization process.

2.0 ACRONYMS AND TERMS

Major acronyms and terms used in this document are defined and listed below.

2.1 Acronyms

CAISO - California Independent System Operator

CEE - Customer Energy Efficiency

CPCN - Certificate of Convenience and Public Necessity

DG - Mobile Distributed Generation

DPA - Distribution Planning Area

EASOP - Economic Analysis Software Program

ECCO - Electric Control Center Operations

EDSA - Electric Distribution System Analysis, relational database of system facilities

ESD – Engineering Standard Drawing

FDRCAL - Feeder Calculation Planning Program

IEEE - Institute of Electrical and Electronics Engineers

GIS – Geographic Information System

KPF - Manufacturer name of an overhead switch

KW - Kilowatt

KVAR – Kilovar

LG2004 - Load growth projection program, utilizes Excel software program

LTC - Load Tap Changer

MW - Megawatt

MVA - Megavolt Amperes

MVAR - Megavolt Amperes Reactive

NPV - Net Present Value

NOC - Notice of Construction

OM&C - Operations, Maintenance and Construction

PF - Power Factor

PTC - Permit to Construct

PVRR - Present Value Revenue Requirements

SCADA - Supervisory Control and Data Acquisition

WAT - Weighted Average Temperature

2.2 Definition of Terms

Area Load: The highest sum of individual bank and/or feeder peak loads serving the area during a four-consecutive-week time frame in the season being considered. This sum must be adjusted to accurately reflect any load transfers experienced during the same time frame, thus ensuring these loads are not added more than once.

Bank: One or more three-phase transformers, or three or more single-phase transformers, interconnected to operate as a single unit, to supply three-phase load. A bank is considered firm if it includes a spare transformer so its normal capability is not reduced if any transformer in the bank fails. A spare transformer is defined as a transformer available at the location that can be used in an emergency.

Block Load: An unusually large, single load added to or removed from an area. A load change should not be treated as a block load unless (a) it changes the total area load by at least 1.5%, **and** (b) individual load changes of similar or greater magnitude occur only infrequently in the area and are not normal factors in area growth.

Residential subdivisions will not be treated as block loads unless it can be demonstrated that they substantially change the growth characteristics of the area, **and** they accelerate the need for a bank or feeder capacity increase within the five-year planning window.

CAISO: The California Independent System Operator.

Certificate of Public Convenience and Necessity (CPCN): Projects installing facilities at greater than 200 kV require a CPCN by the California Public Utilities Commission. The CPCN requires an environmental review and may include hearings before an administrative law judge.

Company: Pacific Gas and Electric Company

CPUC: California Public Utilities Commission

Customer Parallel Generation: Permanently installed generation devices interconnected to the distribution system.

Design Weather Event: A weather-related event of high temperatures that statistically occurs no more than once every 10 years[1].

Distribution: Facilities operated at voltages less than 50 kV, as defined by the CPUC.

Distribution Planning Area (DPA): An area with a defined capacity and historical load. A DPA is used to provide a consistent basis for analyzing capacity, loads and investments.

Effective Emergency Capability of a Transformer Bank: The capability of a bank to supply load during emergency conditions, considering transmission input and feeder outlet limitations as well as emergency capability of the bank itself, and any other station equipment (such as regulator, LTCs, disconnects, bus, etc.). When limited by feeder outlets, the effective emergency capability of a bank is the sum of the emergency capabilities of the feeders that would be connected to it during an emergency condition, but not to exceed the actual emergency rating of the bank itself. (This may be a different number of feeders than are normally connected to the bank, if the emergency is an outage of another bank in the same station.)

Effective Normal Capability of a Transformer Bank: Capability of a bank to supply load during normal conditions, considering transmission input and feeder outlet limitations, in addition to the normal capability of the bank itself and any other station equipment (such as regulator, LTCs, disconnects, bus, etc.). When limited by the feeder outlets, the effective normal capability of a bank is the sum of the normal capabilities of the feeders connected to it.

[1] CAISO and Industry Standard

Emergency Area Capability: The sum of the effective emergency capabilities of the banks and/or feeders remaining to supply the area when the largest non-firm bank is out of service, multiplied by the emergency area utilization factor.

Emergency Area Utilization Factor: Ratio of the area load (that can be picked up by switching in the event of an outage of a non-firm bank without overloading any system component) to the sum of the effective emergency capabilities of the banks and/or feeders remaining to supply the area when the largest non-firm bank is out of service, both in MW. A .95 utilization factor (UF) is to be used, unless otherwise specified.

Emergency Conditions: Conditions that exist *after* switching to restore service following an unplanned loss of a bank or feeder and *before* repair or replacement of the bank or feeder.

Firm Substation Transformer: A bank is considered firm if it includes a spare transformer so its normal capability is not reduced if any transformer in the bank fails. A spare transformer is defined as a transformer available at the substation that can be placed in-service during an emergency.

Load Factor: The ratio of the average load over a designated time period to the peak load in that period.

Mobile Distributed Generation (DG): Temporarily installed generation devices located on the distribution system. These devices are installed, when economic, to defer capacity increases.

Net Present Value (NPV): The economic measure used to evaluate alternatives when customer revenues are not common to all alternatives, or when customer value of service (VOS) is a factor in determining project viability. NPV should be used in conjunction with PVRR.

Normal Area Capability: The sum of the effective normal capabilities of all banks and/or feeders supplying an area, multiplied by the normal area utilization factor (UF).

Normal Area Utilization Factor: A factor used to reduce normal area capacity. The utilization factor helps ensure that individual pieces of equipment are not overloaded during normal operating conditions. A value of 0.95 should be used unless otherwise specified.

Normal Conditions: Conditions are considered normal when all transmission and distribution facilities are available for service as planned and are serving their normal loads.

Notice of Construction (NOC): Projects installing facilities where the project was included in an EIR as part of a non-Company construction project, county or city general plan or some other non-Company legal document. Projects reconductoring an existing transmission line which remains at the existing transmission voltage only require a NOC.

Normal Capability: Normal capability of banks and feeders based on the ampacity ratings of equipment during normal operating conditions.

Permit to Construct (PTC): Projects installing new facilities at 50 kV or greater, but less than 200 kV, require a PTC by the California Public Utilities Commission. This requirement does not apply to adding new facilities at a substation already having facilities operating at the projects' proposed transmission voltage. The PTC requires an environmental review as part of the filing. A PTC does not generally require hearings, as does a CPCN.

Power Factor: The ratio of real power (MW) to apparent power (MVA).

Present Value Revenue Requirement (PVRR): The preferred economic measure by which projects measure alternatives against each other when customer revenues are common to all alternatives. The PVRR measure provides the revenue requirement that each project should receive within the regulatory process. PVRR should be used in conjunction with NPV.

Reserve Capacity: The capacity reserved for a customer under a special facility agreement during specific operating conditions. Although the terms of the agreement can vary, reserve capacity typically means a backup source will be readily available during specific operating conditions.

Standby Capacity: Capacity reserved for customers on standby rates.

Summer Peaking: An area's summer peak occurs from April 1 through October 31, and when capacity additions typically are required to meet future summer peaks.

Trend Line Adjustment: A positive block load adjustment equal to the difference of the last year's peak load, less the trend line load for the same year. The trend line adjustment must meet the same criteria as block load criteria "a." A trend line adjustment is never negative.

Weighted Average Temperature (WAT): A three-day weighted maximum temperature.

Winter Peaking: An area's seasonal peak that occurs from November 1 through March 31 and when capacity additions typically are required to meet future winter peaks.

3.0 REFERENCES

Below are some of the various drawings and reference document that may be used to assist with this guideline.

3.1 PG&E Drawings

Document Title	Document Number
Ampacity of Insulated Aluminum Cables	050166
Ampacity of Insulated Copper Cables	050167
Ampacity of Overhead Line Conductors	030559
Application and Control of Capacitors on Distribution lines	039586
Ampacity of Outdoor Bus Conductors	067909
Capacitors for Distribution Lines	028425
Electrical Characteristics of Overhead and Underground Distribution Conductors	045314
Distribution System Voltage Regulation	027653
Guide for Loading Distribution Substation Transformers and Regulators	032441

Document Title	Document Number
Overcurrent Protection for Distribution Lines	038718A
Phase Balance on Primary Circuits	045316
Preferred MVA Rating for Distribution Substation Transformers	036526
Guide for the Analysis and Correction of Voltage Fluctuations on Distribution Circuits	041624

3.2 Standards, Guidelines and other documents

Bulletin 2001-PGM-3

Protection Handbook

Reliability Section of the Electric Planning Manual

Standard S2401, "Substation Load Information And Power Factor"

Standard D-S0460, "Capacity Planning for Electric Distribution Systems"

Guideline G12058, "Evaluating Mobile Distributed Generation"

Guideline D-G0069, "Substation Siting and Acquisition"

Information Bulletin IB0248, "Distribution Power Transformer Ratings"

Planning Guide for Small Dispersed Generation - 061887

Utility Guideline G12112, "Conductor Rerate Process for Overhead Distribution Circuits"

WP2903, "Operating Procedures and Ratings for Overhead Distribution Switching Devices"

WP2904, "Operating Procedures and Ratings for Underground Distribution Switching Devices"

4.0 PLANNING GUIDELINE AND CRITERIA

The goal of the planning process is to safely and economically expand electric distribution system capacity in support of PG&E's reliability goals as we strive to improve customer satisfaction.

4.1 Basic Criteria

Capital investments in the distribution system will be made so that forecast loads can be supplied without:

A. loading any substation or distribution facilities beyond their normal capability during normal conditions or emergency capability during emergency conditions, and

B. allowing the voltage on the non-express portion of any feeder to deviate from the applicable voltage limits under either normal or emergency conditions, as per the Distribution System Voltage Regulation Drawing 027653 and Electric Rule 2, and

C. risking interruptions to service that would be unreasonable in their frequency, extent and/or duration.

4.1.1 Provision for Unplanned Outage of Facilities

A distribution system consisting of substation banks and interconnected feeders supplying high or medium density (urban or suburban) areas should be engineered to include sufficient interconnections and emergency capability so that, in the event of an outage of any bank or feeder outlet, all service can be restored within a reasonable time by switching. For the failure of individual substation transformers there should be sufficient emergency transformer capacity available from the remaining area substation transformers and adequate distribution system ties to enable restoration of all customers within a reasonable amount of time during peak load conditions. For the failure of individual feeder outlets, a reasonable restoration time during peak load conditions is generally possible if three feeders adjacent to the faulted feeder have adequate emergency capacity to allow load transfers from the faulted feeder. Limiting normal feeder load to 75% of emergency capability will generally provide adequate capacity for loss of feeder outlet contingencies.

Electric distribution systems supplying low density (rural) areas often do not have sufficient interconnections enabling all service to be restored prior to making repairs, placing spare equipment in service, or deploying mobile equipment.

In those locations where Distribution Automation (DA) is being considered and technologies enabling automatic load transfers are proposed, the distribution system must be designed to ensure adequate emergency capacity and voltage support to facilitate automatic service restoration.

4.1.2 Utilization Factor

In order to meet the basic criteria that no facility is to be loaded above its capability, some facilities will be loaded less than their capability. There are practical limitations on the ability to forecast load distribution within a Distribution Planning Area (DPA) and to divide the area load among the banks and feeders in exact proportion to their capabilities. It is not usually practical to achieve a utilization factor higher than 0.95 for either normal or emergency operating conditions in a DPA. To achieve the basic planning criteria, a 0.95 utilization factor will be applied to prevent overloads of individual major components of the system. This utilization factor shall be used in calculating normal or emergency capability for an area. One exception is in single bank DPA's where a 1.0 utilization factor should be used. In some cases, detailed analysis reveals that overloads cannot be avoided using a utilization factor of 0.95. This indicates the 0.95 utilization factor is not practical for the particular conditions of the area and additional facilities may be needed.

4.1.3 Load Power Factor

PG&E generally designs its distribution system to operate at 0.99 lagging power factor at the low side of transformer banks during peak load conditions. For DPA level planning, a load power factor of 0.99 is assumed unless more specific information can be demonstrated. As described in Standard S2401, "Substation Load and Power Factor," it is the practice, where practical and economical, to improve the power factor of distribution loads to 0.99 lagging or higher at the low-side of distribution substation banks. This practice generally applies to the power factor at times of system peak and local area peak to help avoid increasing bank or feeder capacity. The California Independent System Operator (CAISO) requires the transmission-level power factor at the high voltage side of each substation to be between 0.97

lagging and 0.99 leading at all times. Generally, a 0.02 decrease in power factor at peak load conditions may be assumed from the bank low side (distribution) to the bank high-side (transmission). While CAISO requirements focus on the power factor at the grid interconnection point, it is beneficial, when possible, to correct the power factor on each individual distribution feeder.

5.0 APPLICATION

PG&E's service territory includes large urban population and work centers, suburban communities, and vast rural areas in Northern and Central California. The distribution systems supplying power to our customers in urban/suburban areas are dramatically different than the systems serving rural areas. As noted in the planning criteria, system planning and design considerations are different for urban/suburban distribution systems when compared to rural distribution systems. This differentiation is necessary due to the characteristics of the distribution systems.

Appropriate application of emergency condition criteria is identified at the DPA level. Each DPA is designated as urban/suburban or rural as shown in Appendix A. All substation transformers and feeders contained within a given DPA are identified as urban, suburban or rural consistent with the DPA designation. Census data, distribution system characteristics, and future growth potential were considered during the designation process. Changes to DPA designation will be considered on a case by case basis and must be approved by the appropriate distribution planning manager.

The process of designating DPA's as urban, suburban or rural was completed in 2007. This decision was based upon a combination of population density and engineering judgment. A GIS analysis of PG&E distribution feeder location and population density was completed. Each distribution feeder was assigned as serving high, medium or low population density areas as defined by > 1000 people per square mile, between 61 and 999 people per square mile, and 60 people or less per square mile, respectively. DPA's with distribution feeders that predominantly serve high or medium population areas were designated as urban or suburban DPA's. DPA's with distribution feeders that supply predominantly low density population areas were designated as rural DPA's.

In order to prevent or minimize the potential for overloading substation or distribution equipment beyond their applicable capability, PG&E engineers are required to analyze and forecast the distribution system loads at the DPA level, the individual substation bank and feeder level, and at the feeder component level. These analyses are performed with the system configured for both normal and various emergency operating conditions. The engineer compares forecasted system load and voltage conditions to the planning criteria and identifies deficiencies that cannot be mitigated by modifying equipment settings or load transfers. Alternative solutions for mitigating these deficiencies are identified and preferred solutions are recommended for implementation.

Providing adequate system capacity and consistent circuit design are important considerations for the overall reliability of the distribution system. PG&E's distribution engineers should consider reliability performance in all phases of the planning process. Decisions on switching, the layout of a new distribution feeder, where to place additional sectionalizing devices and protective device settings can have a significant impact on the reliability experienced by our customers. The engineer should always consider system exposure as well as customer exposure when making design decisions.

5.1 DPA Planning

The forecasting of load growth on the distribution system is performed at the DPA level. PG&E engineers utilize many factors including historical loading conditions, new load additions, and load transfers to develop their load forecasts. The forecasts are then compared to the applicable area normal and emergency capabilities. DPA level planning includes developing annual load projections for a six year period and identifying potential area wide capacity deficiencies. The engineer must perform this analysis and identify area wide capacity deficiencies early so that the project and expenditure can be planned well in advance of the need to mitigate the problem. For example, construction of a new substation typically requires five to six years of lead time.

A normal area capacity study is performed by comparing forecasted area total load to the effective normal area capacity for any one particular year. A normal area capacity deficiency exists when the forecasted load exceeds the effective normal area capacity.

An emergency area capacity study is performed by assuming the loss of the largest non-firm substation bank within the area, less the maximum load that can be transferred out of the area. An area emergency capacity deficiency exists when (1) the remaining load is greater than the net area emergency capacity with 24 hour emergency transformer bank ratings in effect or (2) the remaining load is greater than the remaining net area capacity after the largest available mobile transformer has been placed into service and all other transformers have been returned to normal capacity ratings. The deployment and installation time for a mobile transformer is generally assumed to be 24 hours. After a mobile is deployed all facilities should be loaded at or below their respective normal capabilities. In order to avoid a normal capacity deficiency after a mobile transformer has been deployed it may be necessary to limit normally planned load on individual transformers or on a group of transformers.

Generally, in urban and suburban areas, there should be sufficient 24 hour emergency transformer capacity and adequate distribution system ties to enable restoration of all customers within a reasonable amount of time with a reasonable number of transfers.

Rural substations are often designed with firm single phase transformers and separate voltage regulation equipment. This design facilitates service restoration in the event of transformer outages and is intended to enable regulator maintenance without de-energizing the entire transformer bank. In many cases there are inadequate distribution circuit ties capable of facilitating restoration of all customers during a substation transformer bank outage. Complete restoration of service is not possible until substation capacity has been replaced by an on site spare transformer or installation of a mobile transformer.

5.2 Individual transformer bank and feeder planning

Once the area load forecast has been determined, loads on individual transformer banks and distribution feeders are projected using two year bank and feeder switching plans. These detailed switching plans are used to cascade DPA level load growth to the individual bank and feeder facilities that combine to comprise the DPA. The load forecasts for the next two peak seasons are assigned to the appropriate facilities and then the forecasted load is compared to the appropriate normal or emergency capacity.

The two year bank and feeder switching plan process is necessary to identify localized bank and feeder deficiencies that cannot be identified as part of the DPA level planning process. In addition, the supporting load flow models prepared to reflect the switching plans for the next two peak seasons identifies feeder component deficiencies that require mitigation.

A study to analyze individual bank and feeder loading under normal conditions is performed by comparing forecasted bank and feeder loads to their effective normal capacity. A localized normal substation transformer bank deficiency exists when the forecasted load is in excess of the normal capacity of the transformer bank. Similarly, a localized normal distribution feeder deficiency exists when the forecasted load exceeds the effective normal capability of the feeder. In urban and suburban areas normally planned load on distribution feeders should be limited to 75% of the feeder's emergency capacity.

Multiple studies are required to identify localized emergency transformer capacity deficiencies. The failure of each individual substation transformer bank in the DPA must be analyzed, one at a time, to determine if a deficiency exists after all possible transfers out of the area have been made. Two year bank and feeder switching plans are used to document the load transfers out of and within the DPA for each case and load flow models are prepared to validate the feasibility of the transfers. A localized emergency transformer capacity deficiency exists when (1) all customers cannot be picked up using emergency equipment ratings and existing distribution feeder ties with a reasonable amount of switching or (2) all customers cannot be picked up following the installation of the largest mobile transformer available for the application and returning all other equipment to normal capabilities.

As part of this analysis, the engineer must consider the rating of the mobile transformer planned for deployment in each emergency scenario. There are substations in the system where mobile transformers cannot be installed due to access limitations or low side voltage differences. In these instances the distribution system must be planned so that the load can be supplied using normal capabilities with the largest transformer out of service. In addition, there are cases where the transformer's normal rating exceeds the size of the largest available mobile transformer. In order to avoid a normal deficiency after a mobile transformer has been deployed it may be necessary to limit normally planned load on individual transformers or on a group of transformers.

For urban and suburban transformer banks, a reasonable restoration time during peak load periods is generally possible if banks and feeders adjacent to the faulted bank have sufficient emergency capacity to allow up to 5-10 load transfers from the faulted bank to these adjacent banks and feeders, utilizing the most efficient switching available. All possible load transfers within the capability of the available resources will be performed to restore as many customers as possible until a spare, mobile, transportable or on-site replacement transformer is in service.

Multiple studies are also required to identify deficiencies associated with the loss of individual feeders. Emergency feeder planning is completed by assuming the failure of each feeder outlet, one at a time, to determine if a deficiency exists. Two year bank and feeder switching plans are used to document the load transfers for each case and load flow models are prepared to validate the feasibility of the transfers. A localized feeder emergency capacity deficiency exists when all customers cannot be adequately restored using emergency equipment ratings and existing distribution feeder ties.

For urban and suburban feeders, a reasonable restoration time is generally possible if three feeders adjacent to the faulted feeder have sufficient emergency capacity and adequate ties to allow load transfers from the faulted feeder in three manual load transfers. In locations where DA is deployed with automatic service restoration capability more than three transfers can be considered when economic.

Network substations are a special case. These substations consist of transformer banks that operate in parallel with transformers generally of the same size and impedance. Network substations are to use their normal substation transformer capability ratings during a bank loss because of their inherent automatic fault isolation/load transfer schemes, the importance of the load served, and their required repair/replacement time. For the same reasons, network circuits (typically interconnected in groups of only six feeders supplied from the same substation) are designed so that upon loss of one feeder all loads will continuously be supplied from the remaining five feeders using normal capacity ratings.

5.3 Feeder component planning

Loads projected on individual distribution feeders during development of the two year bank and feeder switching plans for normal conditions must be accurately modeled to ensure individual components are loaded within their normal capacity and voltages remain within allowable limits. This is done by verifying the circuit models and preparing load flow studies for each distribution feeder in each DPA. Studies will be prepared for each of the next two peak seasons based upon the loads identified in the two year bank and feeder switching plan. Feeder models created for the next peak season will primarily be used for operations and validation of previous assumptions. Models prepared for the second peak season will be used to identify deficiencies and to justify capacity projects.

As noted above, load flow models will also be prepared for the emergency system conditions and switching arrangements required for the loss of individual substation transformer banks and feeder outlets. This must be done to ensure individual components are loaded within their emergency capacity and voltages remain within allowable emergency voltage limits.

6.0 SELECTION OF STUDY AREA

The need for additional substations and/or feeder capacity is determined by analyzing the relationship between anticipated future loads and the capability of the facilities within a study area. PG&E’s 70,000 square mile service territory is divided up into approximately 250 DPA’s. These DPA’s were selected based upon the methodology described in this section of the Guide for Planning Area Distribution Facilities.

The first step in performing an analysis of growth is to select appropriate boundaries for the study area. In the vast majority of cases it is appropriate to use the existing DPA boundaries. However, in rare cases, the engineer must modify existing DPA boundaries to perform an accurate analysis. Any modification to DPA boundaries must be approved by the appropriate distribution planning manager.

An ideal study area has a uniform load distribution and load growth rate, a single primary distribution voltage, strong distribution ties among the substations within the area and no possible ties to substations outside the area. Ideal areas are rare, but boundaries should be selected to create an area as close to ideal as possible.

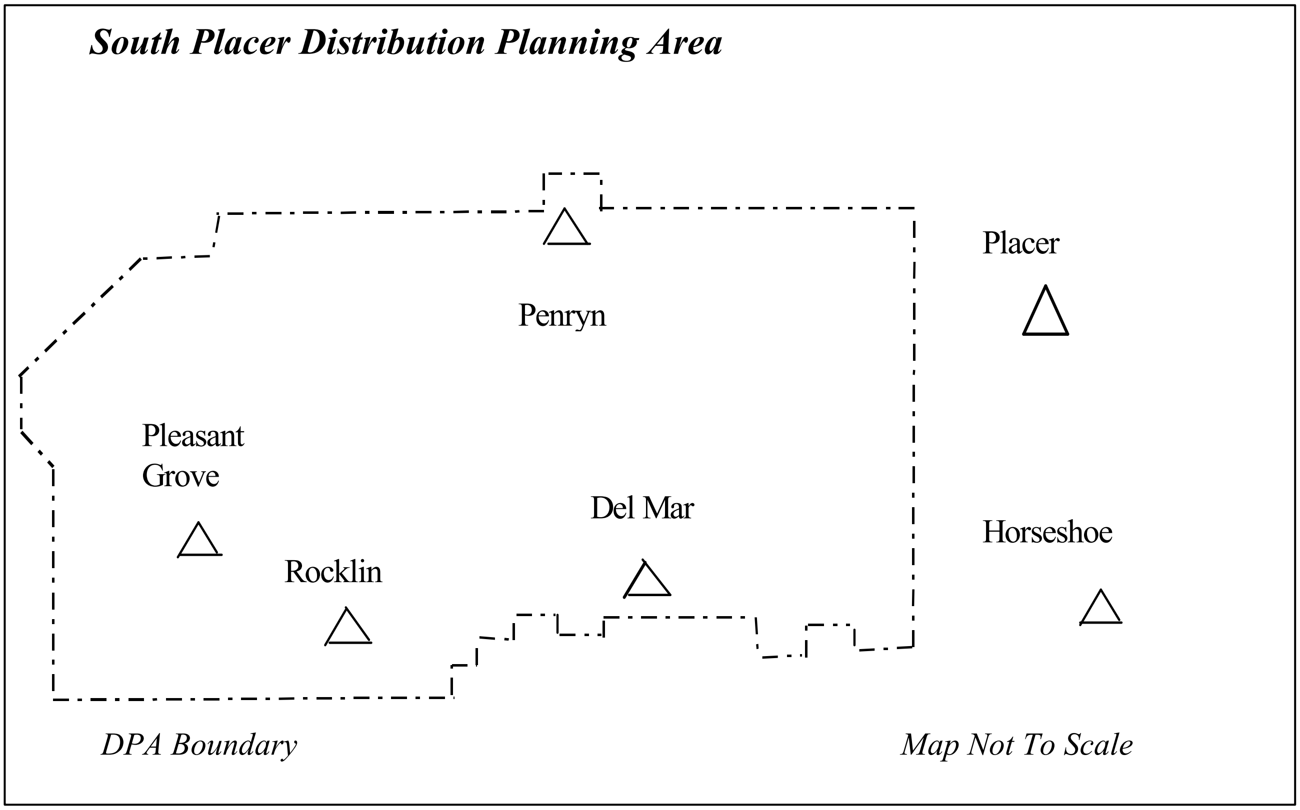
Frequently it is necessary to include more than one primary distribution voltage within a study area. A typical example is a 4 kV system supplying the older portion of a city, which is surrounded by a 12 kV system supplying the newer portion of the city. Both systems must be considered as a single study area because loads can be transferred between them, either by conversions from 4 kV to 12 kV, or by the installation of 12-4 kV step-down capacity.

If there are no existing or potential ties to the area distribution system, and no potential load transfers from or to it, substations and the loads they supply should not be considered part of a study area, even though they are surrounded by other substations and loads. For example, single customer substations are usually omitted from area studies because area load cannot be supplied from them, except in unusual cases.

Obstacles that prevent or restrict distribution ties across them are ideal area boundaries. This includes natural obstacles such as large bodies of water and uninhabited mountain and desert areas. It also includes artificial obstacles such as areas served by foreign distribution systems, airports and some parks.

The purpose of the study should also be considered when selecting the study area. For periodic reviews of loads and resources, relatively large areas are ordinarily used because the work of analyzing potential load transfers across area boundaries is minimized by a large area study. But, to analyze particular problems, which may not be revealed by such general reviews, it is sometimes desirable to define smaller areas and study them in more detail.

DPA boundaries are also used for census tract overlays, and for several other data gathering projects throughout PG&E. For this reason, DPA boundaries will be permanently modified only once a year. As noted above, approval of the appropriate distribution planning manager is required to change DPA boundaries. The Performance Analysis department needs to be notified of any permanent DPA boundary changes so that the modifications can be reflected in our computer systems.


South Placer Distribution Planning Area
Penryn
Placer
Pleasant Grove
Del Mar
Horseshoe
Rocklin
DPA Boundary
Map Not To Scale

7.0 LOAD FORECASTING

To plan for enough resources to supply the load in an area, it is necessary to forecast future magnitude and distribution of these loads as accurately as possible. Such forecasts are usually based on projections of the historical growth trend and the existing load distribution within the area. DPA load forecasts are created based upon the latest seven years of data. Adjustments to the forecast are made considering load and domestic customer transfers into or out of the area and addition or removal of block loads. All available information is reviewed using a consistent statistical analysis method.

The need to forecast future loads and assign load to specific facilities is intended to allow adequate time to address capacity deficiencies where needed in order to prevent overloading of facilities. While PG&E's planning process is designed to minimize equipment overloads, transformer, feeder or component overloads can occur due to metering device inaccuracies, system load flow model inaccuracies or during weather conditions which exceed PG&E's design weather event. Forecasting models that include temperature as a variable do not use the highest recorded historical temperature event as the basis for forecasting future loads.

A traditional linear regression analysis is used to forecast future area loads using the latest version of the distribution load growth program. Accurate load forecasting also requires engineering judgment and an understanding of the factors influencing growth within a DPA. These factors can include the economy, land use plans and limitations, and customer usage characteristics.

When temperature is used as a regression variable for forecasting in summer peaking areas, a 1 in 10 maximum weighted average temperature (WAT) value will be used as the projected temperature. The 1 in 10 WAT is calculated empirically using actual WAT data as follows.

i. For weather stations with 50 years of temperature data

- 1 in 10 WAT = average the 4th, 5th, and 6th highest actual WAT

ii. For weather stations with 10 years of temperature data

- 1 in 10 WAT = average the 1st, 2nd, and 3rd highest actual WAT

PG&E does not plan for the worst case (highest historical temperature) event so some overloading of equipment should be expected in years where temperatures exceed the 1 in 10 design weather event.

The Company prefers to utilize temperature based forecasting models for DPA's that are temperature sensitive. When more than one forecasting model yields statistically valid, reasonable regressions and one of the regressions uses temperature as a variable, the distribution engineer should generally select the temperature based regression for forecasting future load.

UO Guideline G12009 provided detailed information regarding the use of the distribution load forecasting tool. The original guideline has been cancelled, but the information has been updated and included in Appendix D of this document.

7.1 Determine load growth rate using historical data

Load forecasts are based upon a single or multi-variable regression model comparing area substation loads against data such as year, temperature, domestic customer totals, economic information, or other pertinent data.

The principal source of substation load data is gathered during periodic substation inspections, which include maximum MW and MVAR thermal demands of each bank during the time frame studied. The demand readings must be adjusted for any load transfers so the readings represent only demands in the territory ordinarily supplied by each substation transformer bank.

Other sources of useful load data include recording charts of MW and MVAR load installed on most banks, maximum ampere demands on each feeder, SCADA load data, and other remote metering devices. Thermal demand meters use monitoring that matches the heating constant of the windings within the transformer. They typically are called 15-minute thermal demand meters. If a constant, continuous load is supplied, these meters will record 90% of the load after the first 15 minutes, and 99% of the load after 30 minutes. To maintain accurate and consistent loading information, all other metering sources that use real-time loading information are to be calibrated or modeled using calculations to closely mimic the characteristics of a 15-minute thermal demand meter.

Every year maximum temperature data is gathered for each DPA from an appropriate weather station as identified by PG&E meteorologists. WAT is calculated for each DPA and the Geographic Information System (GIS) is populated with the data. The engineer needs to enter the actual WAT data into the load growth program. The actual WAT is calculated as follows each year:

$10\% \times T_1$	T_1 is the maximum temperature of the first hot day
$20\% \times T_2$	T_2 is the maximum temperature of the second hot day
$+\ 70\% \times T_3$	T_3 is the maximum temperature of the third hot day (peak load day)
T_{3DAve}	T_{3DAve} is the maximum three-day weighted average temperature

The number of domestic customers supplied from the substations within a DPA is a proxy for population growth. Domestic customers are entered into the distribution load growth program using seven years of historical domestic customer totals. The load growth program also allows the engineer to add and subtract the number of domestic customers transferred into and out of the area as part of a load transfer.

In addition, the distribution load growth program can accommodate two additional variables for regression against load. Some possible uses for these variables could be available land, housing starts, yearly rainfall, gross domestic product or some other local economic indicator.

Analyze historical load data and determine the growth rate through use of the following procedure.

A. Determine the season in which the annual area load will control the timing of additional facility requirements. Most area loads will have pronounced peaks in the summer (April through October) or winter (November through March) that definitely control the timing of additional facility requirements. A few areas may have seasonal peaks and seasonal growth rates in which it is not clear which season will control the timing of additional facility requirements. Separate load projections should be made for *each* season that might control the timing of additional facility requirements. The term, "peak load" refers here to peak load during the season being considered.

B. Determine the peak area load for each of the last seven years by computing the highest sum of individual bank and/or feeder peak loads serving the area during a four-consecutive-week time frame in the season being considered. In many cases, the substation banks within a DPA peak on the same day. However, the engineer must be aware of block load additions or large loads, which may not have been on at peak, but which need to be considered to accurately forecast future area loads (i.e., agricultural loads, manufacturing plants, etc.).

C. Adjust the area peaks (except the oldest) as necessary for: 1) load transfers into or out of the area, 2) block loads in the area added or removed during the period being studied, 3) customer planned shutdowns, 4) CAISO-directed load curtailments (refer to Appendix C), and 5) temperatures in excess of 1 in 10 temperatures as directed by the distribution planning managers (Actual load and temperature data should be recorded in the load growth program. Adjustments to the data, as necessary, should be accounted for separately and documented in the "Notes" section) . The method for adjusting is as follows.

   a. Load transfers added to the area are added to all of the peaks that occurred before that addition. Load transfers removed from the area are subtracted from all of the peaks occurring before that removal.

   b. Block loads not subject to growth are added or subtracted as constant amounts.

   c. Loads that are subject to growth are added or subtracted in decreasing amounts as they are projected back in time.

   d. Single year adjustments, such as a CAISO directed load curtailment, are made in the year they occur without impacting area totals in other years.

D. Account for customer parallel generation status, reserve and standby capacity customer status during the peak load period.

   a. Accurately reflect the status of significant local distributed generation facilities within the planning area during peak conditions. Assuming the customer parallel generation is off-line, the normal capacity of the DPA, individual bank or feeder facilities should not be exceeded. This also applies to multiple parallel generators when a single event (under frequency or momentary operation) will automatically remove the generators from the system. This generally does not apply to net metered customer generation facilities.

b. Accurately reflect the status of customers, if any, who have a reserve capacity agreement that can transfer load into or out of the study area. Under a special facility agreement, capacity reserved by the Company for customers needing a higher level of reliability under specific operating conditions must be accounted for in load growth studies and load flow models.

E. Review prior years' historical load growth packages to ensure that block loads and load transfers are consistent between yearly load growth packages. Historical block loads must be reviewed to validate whether or not the load met the block load criteria. If the block load did not materialize as planned it should not be treated as a block load. A comment about the block load not meeting the 1.5% criteria is to be added to the Notes section of the load growth projection (include name, year and original projected load).

F. Determine the growth rate. The distribution load growth tool generates multiple linear regressions. In addition, the tool also determines the statistical validity of each regression and recommends which models can be used.

a. For agricultural DPA's, use the most statistically valid model. If the most statistically valid model does not generate results which can be supported, document the justification for using a less valid regression model in the "Notes" section of the distribution load growth program.

b. Determine whether the DPA is temperature sensitive. If the DPA is not temperature sensitive, regressions using temperature as a variable should not be used.

c. In almost all cases, all seven years of data should be used to determine the growth rate.

d. It is appropriate to discount year(s) from a projection when supported by external events such as the 2001 energy crisis. It is not appropriate to discount years to solely improve statistical correlation. When discounting is used, a minimum of 5 years of load data must be included in the regression. Discounting can be useful to demonstrate a change in the growth rate (a knee in the curve). Approval from the appropriate distribution planning manager is required to discount years in a DPA projection.

e. In cases where a statistically valid projection cannot be achieved, excluding agriculatural areas, utilize the Operation Revenue Requirements forecasting model (ORRQ model) for the Bay or Non-Bay Area as appropriate.

f. If the historical growth rate cannot continue through the study period, the growth rate should be modified accordingly. This generally applies to longer-range planning studies for areas which are experiencing rapid growth where usable land will become scarce and the area will become built out.

7.2 Forecast Future Loads

The following procedure should be used to forecast future loads:

A. Project the load to future years using the growth rate determined above.

B. Make adjustments to the projected loads for anticipated future load transfers, block load additions and/or removals and reserve capacity contracts as necessary. Block load additions and/or removals and reserve capacity contracts not subject to growth should be added or subtracted as constant amounts. Transferred loads assume the same growth rate as the study area and are added or subtracted in increasing amounts. If the transferred loads do not approximate the above, the appropriate load adjustments should be made for each individual year.

C. Compare the latest peak to the trend line for the same year. If the trend line value is less than the actual peak, a trend line adjustment may be required if it meets block load criteria “a)”. A block load increase equal to the difference between the actual peak and the trend line value should be added to the forecasted loads. Trend line adjustments are applied as a block load increase in the first projected year and only when using the load versus year projection model. These load adjustments allow for a more accurate projected load which result in a reduced risk of loading equipment in excess of their normal rating. Prior year trend line adjustments should be removed from the load projection model.

D. A trend line adjustment allows planning for the forecasted growth, using the latest peak load and trend line growth rate. This adjustment is made only when a significant difference in load is evident (meeting the block load criteria). Projecting off the latest peak in these instances decreases the likelihood that individual substation transformers will be loaded in excess of their normal ratings.

E. Develop a two year bank and feeder projection for the DPA.

   a. A two year bank and feeder projection allocates DPA level projected loads to individual banks and feeders for each of the next two peak seasons. The sum of the loads projected on the individual substation transformers in a DPA for each of the next two peak seasons should be equal to the corresponding DPA trend line loads. Growth is assigned to the substation transformers and distribution feeders based upon the judgement and experience of the distribution engineer.

   b. Adjust each bank or feeder projected load for anticipated transfers, block load additions and/or removals, and any reserve capacity contracts.

8.0 CAPABILITY OF FACILITIES

The normal and emergency capability ratings of the facilities which combine to form the distribution system represent the maximum load the facilities are capable of supplying under normal and emergency operating conditions.

The capability of distribution substations to supply area load generally is determined by the capability of the substation transformer banks in the area. In some cases, either the capability of the transmission facilities supplying the station, other substation equipment (such as a disconnect device, regulator, bus, etc.) or the aggregate capability of the distribution feeders or equipment can impose a lower limit on the amount of load the station can supply.

Each station transformer bank and each feeder has a normal and an emergency capability. Normal and emergency capabilities typically are determined by the temperature rise limitations of the transformer and feeder components. Therefore, these capabilities are higher in winter than in summer, and the summer capabilities may be higher in cool coastal areas than in warmer interior areas. The emergency capability generally is higher than the normal capability. In some cases, the limitation of a feeder could be the setting of protective relays rather than the thermal rating of a component.

Installation of a substation transformer larger than the largest available mobile transformer for an application may require the distribution engineer to limit planned normal loading on the substation transformer. This is necessary to prevent undesirable situations when substation transformer failures occur.

8.1 Substation Bank and Regulator Capability

ESD 032441 (revision 8) "Guide for Loading Substation Transformers and Regulators" and UO Guideline G13173, "Distribution Power Transformers and Regulators Re-Rating and Operating Criteria" specify loading limitations for PG&E's substation transformers. ESD 023441 and G13173 are currently being revised by Substation Asset Strategy. Information Bulletin 0248 (IB 0248) has been approved in the interim. IB-0248 supersedes certain aspects of both ESD 032441 and G13173.

Prior to the approval of IB-0248, individual substation transformer banks and regulators could be grouped in one of three categories: (1) a transformer bank which had received a customized rating either increasing or decreasing the capability of the bank, (2) transformer banks manufactured before 1998 that had not received a customized rating, or (3) transformer banks manufactured after 1998 that had not received customized ratings. Normal and emergency operating capabilities for transformer banks with customized ratings are published individually by Substation Asset Strategy. MVA ratings for all other transformer banks were determined by multiplying the nameplate rating of the equipment times the applicable factor found in UO Guideline G13173 or ESD 032441.

Significant changes to substation transformer rating policies are being implemented through IB-0248. Many substation transformers in the PG&E system have received customized ratings from Substation Asset Strategy that allows normally planned load levels above nameplate. PG&E plans to eliminate all such ratings through a transition plan to be completed prior to the summer season of the year 2011. Existing transformer ratings will remain in effect until capacity is added in the substation or 2011, whichever occurs first. When the transition has been completed all transformers will be rated in accordance with IB 0248. There will no longer be bonus ratings, differentiation based upon pre or post 1998 manufacturing, or differentiation between coastal and interior temperature districts.

Prior to the summer of 2011 when additional transformer capacity is added at a substation all other transformers in the substation will be returned to a nameplate based rating as described in

IB-0248. Electric distribution planning is responsible for initiating any additional projects needed to complete this transition before the summer of 2011 or the winter of 2011/2012. Please note that implementation of IB 0248 by 2011 before the summer of 2011 is subject to funding availability.

The normal capability of a power transformer is defined as the load level at which the operating temperatures reach the limits for normal transformer life expectancy. A transformer loaded to its full normal capability rating may bring in a temperature alarm(s), as the typical alarm is set 5°C below the normal limit. The alarm is an indication that the normal temperature limit is being approached.

	55°C Rise Transformer	**65°C Rise Transformer**	**65°C Rise Transformer (1)**
Top Oil Temperature Alarm Setting	80°C	90°C	100°C
Top Oil Temperature **NORMAL LIMIT**	**85°C**	**95°C**	**105°C**
Hotspot Temperature Alarm Setting	105°C	120°C	125°C
Hotspot Temperature **NORMAL LIMIT**	**110°C**	**125°C**	**130°C**

(1) Applies to transformers re-rated with the new loading criteria of 105°C top oil (also known as "Bonus Rating").

Loading transformer banks beyond the allowable hot-spot temperature can reduce the transformer life and lead to future significant capital replacement costs. Loading beyond the top oil temperature may cause pressure relief valves to operate, which can lead to imminent bank failure due to loss of oil cooling and may create a safety hazard.

Unless there is prior approval from the manager of Substation Asset Strategy and the appropriate distribution planning manager emergency equipment ratings are to be reserved only for situations involving the loss of distribution equipment within the planning area. Emergency ratings allow for loss of life increased above normal levels, while maintaining a safety margin to prevent an immediate catastrophic failure of the equipment.

The following guidelines have been developed for operating during emergencies. Top oil temperature is used because oil temperature is an actual measurement, whereas hotspot temperature is derived from oil temperature, plus a factor proportional to load current. The limits given below are based on acceptable loss of life, based on the emergency rating temperature limits:

TOP OIL AND HOT SPOT TEMPERATURE OPERATING GUIDELINES

Level	55C Rise Transformer		65C Rise Transformer		65C Rise Transformer (1)		Action
	TOP OIL	HOT SPOT	TOP OIL	HOT SPOT	TOP OIL	HOT SPOT	
1	80°C / 85°C(2)	105°C / 110°C(2)	90°C / 95°C(2)	120°C / 125°C(2)	100°C / 105°C(2)	125°C / 130°C(2)	Alarm Setting. Plan strategies to transfer load if Level 2 is forecast.
2	95°C	120 °C	105°C	135°C	105°C	135°C	Should not exceed for more than 3 hrs. Transfer load if necessary. Notify the maintenance supervisor.
3	100°C	125°C	110°C	140°C	110°C	140°C	Do not exceed. Take immediate action to reduce load.

(1) Applies to transformers re-rated with the new loading criteria of 105°C top oil (also known as “Bonus Rating”).
(2) Modified alarm settings.

Single-phase substation equipment, including high-side transmission fuses and single-phase transformer banks, should be de-rated by 5% to account for phase unbalance. Substation transformers located more than 3,300 feet above sea-level should be de-rated as outlined in IEEE Standard C57.91-1995 unless specified by the manufacturer.

There may be times when the substation asset manager will approve, on a case by case basis, loading of substation facilities in excess of the normal rating established by IB 0248. Increased ratings will only be allowed in cases there is minimal risk to the equipment. One example where this may be appropriate is to respond to large customer initiated load increases that will occur before a capacity increase project can be planned and implemented. Another example where an increased rating may be appropriate is to facilitate difficult clearances of adjacent facilities.

8.2 Feeder Outlet Capability

The component that limits the capability of a feeder typically is one of the following: the substation transformer, circuit breaker or switches associated with it, underground or overhead outlet conductors, current transformers, metering or the phase overcurrent relay setting. Each component should be checked to determine the amount of current it can carry under normal and emergency operating conditions. The phase overcurrent relay minimum trip settings must be higher than the maximum load current. Maximum load is determined by dividing the phase minimum trip by 1.2 to determine their maximum load carrying capability, as outlined in the Protection Handbook. In some cases, it will be possible to increase current carrying capability at a relatively small cost by replacing the limiting component or modifying the feeder protective scheme. Meters may also need to be replaced so they can be read within the range of their scale.

Feeder circuit breakers should not be assigned summer ratings above 100% of nameplate under any conditions. However, under winter emergency conditions, feeder breakers can be loaded to 110% of their nameplate rating if the breaker is in good condition and the rating is approved by Substation Asset Strategy. If the breaker is not in good condition, it may be necessary to establish lower limits which will be determined by Substation Asset Strategy. Substation disconnect switches should not be loaded above 100% under normal operating conditions, but may be loaded to 120% of their nameplate rating under emergency operating conditions for both the summer and winter seasons. Substation conductors, disconnects, current transformers and vacuum circuit breakers should be de-rated by 5% to account for phase unbalance. Do not apply the phase unbalance multiplier to oil circuit breakers. Refer to Engineering Standard 067909, “Ampacity of Outdoor Bus Conductors” for ratings of substation bus conductors and equipment drops.

8.3 Conductor and Related Distribution Equipment Capability

The ampacity of overhead conductors and underground cables are provided in Engineering Standard Drawings (ESD) 030559, 050166, 050167 and in Information Bulletin 2001PGM-3, “Primary Distribution Cable Ratings”. Loading conductor or cables above the ratings provided in these documents can cause failures, damage to the equipment, or other unfavorable conditions that may result in General Order 95 or 128 infractions.

Overhead conductor ratings for all overhead distribution conductors have been determined assuming a 2 foot per second wind speed. Specific conductors can have an increased rating assigned depending on the geographic location of the wire to ampacity ratings determined assuming 3 or 4 foot per second wind speed. UO Guideline G12112, “Conductor Re-rate Process for Overhead Distribution Circuits” must be followed before assigning an ampacity rating above the 2 foot per second wind speed values for normal or emergency operating conditions. The ampacity of overhead conductors, overhead switches and single-phase regulators should be de-rated by 5% to allow for phase unbalance.

Increased ratings for overhead distribution lines to ampacity ratings determined using 3 or 4 foot per second wind speed is effective in deferring capital investment. However, the impact, if any, of loading specific line sections above the 2 foot per second normal rating on emergency operations must be understood. Use of increased ratings should be considered when analyzing emergency switching conditions in order to minimize transfers. In all cases, specific processes must be followed as described in G12112 before the increased ratings can be assigned and utilized.

Underground cables dissipate heat into surrounding substructures, cables, and earth. Because all cables in a duct contribute to the heating, a phase unbalance multiplier is not needed for cables in underground duct and in risers. However, multiple circuits in the same trench or circuits in separate trenches located less than 6-feet apart must be de-rated to account for the mutual heating effect. In addition, the presence of more than two circuits in any one structure poses specific reliability risks, therefore, it is preferable to have no more than two mainline circuits in the same trench. Multiple trenches should be spaced at least 6 feet apart to reduce potential dig-ins, limit mutual heating and the need to further de-rate cables.

Normal feeder outlet capability can be increased above 600 amps, as long as all line equipment ratings have been considered. Balance the phases of feeders in accordance with Section 2.16, "Phase Balancing" located in the Electric Planning Manual to maintain loading within capabilities. The ratings of some typical line equipment are discussed below.

8.4 Air Switches and Disconnects

Type	Manufacturer	Manufacture Dates	Continuous Current Rating	Emergency Rating
All	KPF [1]	All	400 amp 600 amp	600 amp (8 hr) 800 amp (8hr)
Under Arm Side Break	Cooper/Kearny	Pre-Nov 2003 After Nov 2003	720 amp 900 amp	900 amp (24 hr) 1233 amp (24 hr)
Under Arm Side Break	S&C	All	900 amp	1233 amp (24 hr)
PT 57 HSB	All	All	600amp	828 amps (24 hr)

1 - "KPF" switches also can be upgraded to 800 amps continuous by replacing the contacts.

8.5 Overhead Line Protective and Voltage Regulation Devices

Reclosers and sectionalizers are limited to their nameplate ratings, unless further limited by their phase minimum settings or in-line disconnects. Refer to ESD 015239 for capabilities of line regulators and ESD 036903 for capabilities of line boosters.

8.6 Padmounted and Sub-Surface Line Devices

Trayer 600 amp underground switches and interrupters have the following ratings:

- continuous current and load break rating: 600 amps (circuits > 75% load factor)
- peak load capability and load break rating: 720 amps (circuits < 75% load factor)
- 24-hour emergency rating and load break rating: 800 amps

Padmounted switches (PMH-3, 6, 9, and 11's) have the following ratings:

- continuous current and load break rating: 600 amps
- 8-hour emergency rating and load break rating: 725 amps

Padmounted Interrupter (600 amp unit)

- continuous current and load break rating: 600 amps
- Elastimold 8 hour emergency rating: 900 amps
- G&W 8 hour emergency rating: 800 amps

All other underground switches are limited to their nameplate ratings. Underground connectors, straight splices, elbows and riser terminations are rated at the same ampacity as the largest cable they are designed to be used with.

Having established the normal and emergency operating capabilities of feeders in amperes, they can be converted to kVA using the following multiplication factors:

Nominal Circuit Voltage	**4160**	**4800**	**12000**	**17000**	**20780**
Multiply by	7.57	8.73	21.82	30.92	37.80

The multiplying factors are based on input voltage to the feeder of 126 on 120 V base. The multiplier of 0.95 used to account for the effect of phase unbalance is not included.

9.0 PLANNED NORMAL LOADING CONSIDERATIONS

There are locations in the PG&E system where transformers larger than 45 MVA are in service. For many years PG&E has been limiting new and replacement substation transformers to 45 MVA to match the size of our largest mobile transformers.   In some interior area applications, experience has shown that a 45 MVA mobile transformer can only supply approximately 42 MVA of load during high ambient temperature conditions. There are also many situations where the largest mobile transformer planned for a particular application is much smaller than 45 MVA. The distribution engineer needs to understand which mobile transformer is planned for use in the event of the failure of individual transformers in their assigned areas and prepare emergency plans accordingly.

PG&E will continue to limit substation transformer bank size to a maximum of 45 MVA consistent with our maximum mobile transformer size. However, as a last resort, in order to provide adequate emergency substation transformer capacity it may be necessary to install transformers larger than 45 MVA in certain substations. These situations will be considered for approval on a case by case basis and the normal load allowed on transformers larger than the largest applicable mobile transformer may need to be limited to prevent unsatisfactory emergency conditions.

For example, a DPA with three 75 MVA substation transformers at 21kV (total normal capacity without restrictions of 211.6 MW at 95% utilization and 99% power factor) and no ties to adjacent facilities for use during emergency conditions will need to have a normal load limit established. If one of the three transformers fails in service, the ratings of the remaining two transformers will be 97.5 MVA for the first 24 hours while a mobile transformer is being deployed and will return to nameplate thereafter. Area emergency capacity during the first 24 hours is 183.4 MW (75 MVA x 2 x 1.3 x .95 x .99). After a 45 MVA mobile is installed, area capacity will also be 183.4 MW ((75 MVA + 75 MVA + 45 MVA) x 0.95 x 0.99)). In order to prevent undesirable conditions the normally planned load must be limited to 183.4 MW. For this particular case, 183.4 MW represents 86.7% of the unrestricted normal area capability.

9.1 Detailed Procedures

Whether additional facilities are needed in an area is determined by following the steps listed below. Each year these steps shall be completed for all DPA's for the summer peaking season. DPAs with winter peak loads that exceed the summer peak loads will be analyzed for both winter and summer critical capacity deficiencies. The steps can be summarized by the following flowchart:

Figure 1 - Typical Planning Flowchart

DPA Planning
Using the latest version of the Distribution Load Growth Program, prepare six-year growth projections for each DPA, and compare forecasted loads to the appropriate normal capability. Develop alternatives to mitigate deficiencies.

↓

Normal Bank and Feeder Planning
Develop two-year bank and feeder load projections and compare forecasted loads to the effective normal capability. Prepare feeder load flow studies and switching plans. Develop alternatives to mitigate deficiencies.

↓

Emergency Bank Loss Planning
Evaluate the loss of each substation bank and develop detailed switching plans for the upcoming peak season. Identify deficiencies and develop alternatives to resolve the identified deficiencies.

↓

Emergency Circuit Loss Planning
Evaluate the loss of each circuit outlet, develop detailed switching plans for the upcoming peak season, identify deficiencies and develop alternatives to solve deficiencies.

9.1.1 DPA Planning

Step 1 Select the appropriate boundaries for the DPA to be studied. Refer to the Selection of Study Area Section.

Step 2 For each future year to be studied, forecast the magnitude of the area load using the latest version of the distribution load growth program. Refer to the Load Forecasting Section.

Step 3 Determine the normal and emergency capability of each bank within the DPA. Refer to the Capability of Facilities section. Utilize normal planned load limitations when appropriate.

Step 4 Evaluate the normal area utilization factor for each future year to be studied. A 0.95 utilization factor should be used unless a detailed study indicates different values are appropriate.

Step 5 Determine the projected area deficiencies using the applicable area capability and utilization factors. Determine whether any of these deficiencies can be corrected by load transfers out of the area in lieu of increasing the capability of area facilities.

Step 6 Formulate alternative plans to correct the deficiencies indicated by Step 5 that cannot be corrected by cost-effective load transfers. Include in the plans minor expenditures for feeder ties, reinforcements, and/or switches necessary to enable the transfers.

Step 7 Evaluate alternative plans and select an overall preferred plan to serve the area in the future. If preferred plan involves constructing a new substation, refer to Guideline D-G0069, "Substation Property Siting and Acquisition." Include capacity additions in the Six Year Plan section of the load growth program.

9.1.2 Normal Bank and Feeder Planning

NOTE: It is expected that feeder additions and all major reconductoring or other significant reconstruction projects necessary to increase normal capacity on the distribution system will be identified, planned, and approved 13 months before the project needs to be operational. It is also expected that transformer bank additions or replacements necessary to increase normal capacity are identified 24 months before the project needs to be operational so that long lead time equipment can be ordered. Approval for all transformer bank capacity increase projects is expected 13 months before each project needs to be operational. New substations require 5 to 6 years of lead time to allow for permitting, property acquisition and site development.

Step 8 Using the growth rate determined in Step 2 for each DPA, project the individual bank and feeder peak loads for the next peak season (first year of the "Two-year Bank and Feeder Planning" process). Include the appropriate facility additions planned for construction prior to the next peak season from the Six Year Plan.

Step 9 Compare the normal peak load on each bank and each feeder with the appropriate normal capability noting any overloads. Evaluate load transfers within and outside the area to relieve overloads.

Step 10 Prepare load flow models for the switching conditions determined in Step 9. Modify load flow models to include feeder component modifications expected to be in operation prior to the next peak season. Evaluate conductor loading and voltage levels.

Step 11 Formulate alternative plans to correct the deficiencies indicated by Steps 9 and 10 that cannot be corrected by load transfers. Consider new switches, power factor improvement, new feeder ties, reconductoring, converting load to a higher voltage, swapping feeders between transformer banks, and distributed generation.

Step 12 Adopt the preferred plans to correct the deficiencies identified in Steps 9 and 10. Finalize the first year of the Two-year Bank and Feeder Projections incorporating all new facilities and any projected facility needs into the five-year plan. This projection is the base case for the emergency bank and feeder loss planning described below.

Step 13 Repeat Steps 9 through 12 for the second year of the Two Year Bank and Feeder Planning process. In Step 11, additional feeders and adding substation transformer capacity options can also be considered.

9.1.3 Emergency Bank Loss Planning

NOTE: It is important to include all facility modifications planned for normal operation in all emergency planning scenarios.

Step 14 Assume an outage of each bank in each DPA for the upcoming peak load period. For each such outage determine the minimum switching necessary to restore service to as many customers as possible using but not exceeding emergency operational ratings and emergency voltage limits. Note any of the following unsatisfactory conditions: (1) the number of customers and number of MW of load left out of service after exhausting all transfers, (2) the number of transfers in excess of 5 to 10 manual transfers.

Step 15 If customers need to be left out of service until mobile or transportable transformers are deployed, investigate and identify locations where localized rotating outages can be implemented until all service can be restored. Document these locations along with the switching plan developed in Step 14.

Step 16 Emergency operational ratings are intended for use for up to 24 hours which is the amount of time assumed to be required for the deployment of mobile or transportable substation transformer banks. After the mobile resources have been installed, additional switching may be required to load facilities within their normal operating capability. There may be situations where, after the largest applicable mobile transformer has been installed, it is not possible to reduce loading within normal operating capabilities of the mobile transformer or other involved facilities. This is an unsatisfactory condition that must be identified and mitigated.

Step 17 Provide Substation Asset Strategy with a list of all emergency bank deficiencies for preparation of mobile/transportable transformer installation plans.

Step 18 Provide bank loss contingency plans to Electric Control Center Operations. These emergency contingency plans should be reviewed with the operators and stored in the control room.

Step 19 Formulate alternative plans to correct the deficiencies indicated in Steps 14 or 16. Submit a division wide emergency bank deficiency summary to the appropriate distribution planning manager for system wide prioritization purposes.

9.1.4 Emergency Feeder Loss Planning

NOTE: After all emergency bank loss planning for all DPAs is complete as outlined in Steps 14 through 19 engineers shall proceed with emergency feeder loss planning, as described in Step 20.

Step 20 Assume an outage of each feeder outlet during the upcoming peak load period. For each such outage determine the minimum switching necessary to restore service to as many customers as possible using but not exceeding emergency operational ratings and emergency voltage limits. Note any of the following unsatisfactory conditions: (1) the number of customers and number of MW of load left out of service after exhausting all transfers, (2) the number of transfers in excess of 3.

Step 21 If customers outside of the faulted line sections need to be left out of service until repairs are made, investigate and identify locations where localized rotating outages can be implemented until all service can be restored. It is assumed that the failed outlet can and will be replaced within 24 hours.

Step 22 Provide feeder loss contingency plans to Electric Control Center Operations. These emergency contingency plans should be reviewed with the operators and stored in the control room.

Step 23 Formulate alternative plans to correct the deficiencies indicated by Step 20. Submit a division wide feeder emergency deficiency summary to the appropriate distribution planning manager for system wide prioritization purposes.

10.0 PROJECT JUSTIFICATION REQUIREMENTS

Details on appropriate project justification can be found in the Electric Planning Manual, Chapter 10, “Project Justification”.

Project alternatives should provide equal or near equivalent capacity additions. For new circuits a minimum of two years of capacity investments is required. For banks (new or upgrades) a minimum of five years of capacity investments is required. For new substations a minimum of ten years of capacity investments is required.

New distribution substation projects (with or without a new transmission line) typically require a CPCN, PTC or NOC and need to be started far enough in advance to allow for the applicable permitting process to be completed. Permitting through the CPCN and PTC process can take as many as five years to complete.

11.0 CAPACITY PLANNING PROJECT REVIEW DETAIL

The project review summary, Appendix B, is to be used and submitted as part of the project justification for all projects greater than $300,000. This summary ensures that consistent processes are implemented for all larger capacity project justifications.

12.0 REVISION NOTES

Rev. 01 – 3/15/2010 – G-12009 cancelled and information added to Appendix D of this drawing.

Rev. 00 – 9/15/09 Converted PG&E Guideline G12004 back to the original Design Criteria drawing 050864

APPENDIX A

List of all Distribution Planning Areas and their Area Designation.

Distribution Planning Area Designation

Division	DPA	Designation
Central Coast	Carmel Valley 12kV	Rural
Central Coast	Gonzales	Rural
Central Coast	Hollister	Urban/Suburban
Central Coast	King City	Rural
Central Coast	Monterey 21kV	Urban/Suburban
Central Coast	Monterey 4kV	Urban/Suburban
Central Coast	Oilfields	Rural
Central Coast	Prunedale	Rural
Central Coast	Pt Moretti	Rural
Central Coast	Salinas (4/12 kV)	Urban/Suburban
Central Coast	Santa Cruz Area	Urban/Suburban
Central Coast	Seaside-Marina 12kV	Urban/Suburban
Central Coast	Soledad	Rural
Central Coast	Watsonville (12/21kV)	Urban/Suburban
Central Coast	Watsonville (4kV)	Urban/Suburban
De Anza	Cupertino	Urban/Suburban
De Anza	Los Altos (12 KV)	Urban/Suburban
De Anza	Los Altos (4kV)	Urban/Suburban
De Anza	Los Gatos	Urban/Suburban
De Anza	Mountain View	Urban/Suburban
De Anza	Sunnyvale	Urban/Suburban
Diablo	Alhambra	Urban/Suburban
Diablo	Brentwood	Urban/Suburban
Diablo	Clayton / Willow Pass	Urban/Suburban
Diablo	Concord	Urban/Suburban
Diablo	Pittsburg	Urban/Suburban
Diablo	Walnut Creek 12 kV	Urban/Suburban
Diablo	Walnut Creek 21 kV	Urban/Suburban
East Bay	Edes-J"	Urban/Suburban
East Bay	K-X	Urban/Suburban
East Bay	Richmond North	Urban/Suburban
East Bay	Richmond South	Urban/Suburban
East Bay	Station "C-D-L"	Urban/Suburban

Division	DPA	Designation
Fresno	Auberry	Rural
Fresno	Central Fresno	Urban/Suburban
Fresno	Clovis	Urban/Suburban
Fresno	Coalinga	Rural
Fresno	Corcoran	Rural
Fresno	Dunlap	Rural
Fresno	Figarden	Urban/Suburban
Fresno	Gates	Rural
Fresno	Henrietta	Rural
Fresno	Kerman	Rural
Fresno	Kettleman	Rural
Fresno	Kingsburg	Urban/Suburban
Fresno	Lemoore	Rural
Fresno	McMullin	Rural
Fresno	Reedley	Urban/Suburban
Fresno	Sanger	Rural
Fresno	South Fresno	Urban/Suburban
Fresno	Stone Corral	Rural
Fresno	Woodward	Urban/Suburban
Kern	Arvin	Rural
Kern	Blackwell	Rural
Kern	Carrizo Plains	Rural
Kern	Cuyama	Rural
Kern	Lamont	Rural
Kern	Lerdo	Rural
Kern	Mc Kittrick	Rural
Kern	Poso Mountain	Rural
Kern	Taft	Rural
Kern	Urban Bakersfield (East)	Urban/Suburban
Kern	Urban Bakersfield (NE)	Urban/Suburban
Kern	Urban Bakersfield (NW)	Urban/Suburban
Kern	Urban Bakersfield (SW)	Urban/Suburban
Kern	Wasco	Rural
Los Padres	Cholame	Rural
Los Padres	Lompoc	Rural
Los Padres	North Coast	Rural
Los Padres	Oceano	Urban/Suburban
Los Padres	Paso Robles	Urban/Suburban
Los Padres	San Luis Obispo	Urban/Suburban
Los Padres	Santa Maria	Urban/Suburban
Los Padres	Santa Ynez	Rural
Los Padres	Sisquoc	Rural
Mission	Fremont 12 kV	Urban/Suburban
Mission	Fremont 21 kV	Urban/Suburban

Division	DPA	Designation
Mission	Hayward 12 kV	Urban/Suburban
Mission	Livermore 21kV	Urban/Suburban
Mission	San Ramon - Vineyard	Urban/Suburban
Mission	Tri-Valley 12kV	Urban/Suburban
North Bay	Bahia (or Benicia)	Urban/Suburban
North Bay	Marin (Central)	Urban/Suburban
North Bay	Marin (Coastal)	Rural
North Bay	Marin (Northern)	Urban/Suburban
North Bay	Marin (Southern)	Urban/Suburban
North Bay	Monticello	Rural
North Bay	Napa	Urban/Suburban
North Bay	Silverado	Urban/Suburban
North Bay	Vallejo	Urban/Suburban
North Bay	Vallejo 24kV	Urban/Suburban
North Bay	Vallejo 4kV	Urban/Suburban
North Coast	Arcata	Urban/Suburban
North Coast	Bellevue / Cotati	Urban/Suburban
North Coast	Bridgeville	Rural
North Coast	Clearlake (East)	Rural
North Coast	Clearlake (West)	Rural
North Coast	Cloverdale / Geyserville	Rural
North Coast	Eureka	Urban/Suburban
North Coast	Fairhaven	Rural
North Coast	Fitch Mountain/Fulton	Urban/Suburban
North Coast	Garberville	Rural
North Coast	Hopland	Rural
North Coast	Maple Creek	Rural
North Coast	Mendocino Coast (North)	Rural
North Coast	Mendocino Coast (South)	Rural
North Coast	Middletown	Rural
North Coast	Newburg/Rio Dell (Fortuna)	Rural
North Coast	Orick/ Big Lagoon	Rural
North Coast	Petaluma	Urban/Suburban
North Coast	Petaluma 4 kV	Urban/Suburban
North Coast	Philo	Rural
North Coast	Potter Valley	Rural
North Coast	Santa Rosa	Urban/Suburban
North Coast	Sebastopol	Urban/Suburban
North Coast	Sonoma	Urban/Suburban
North Coast	Sonoma Coast	Rural
North Coast	Ukiah Valley	Rural
North Coast	Willits	Rural
North Coast	Willow Creek	Rural
North Valley	Antler 12 kV	Rural

Division	DPA	Designation
North Valley	Bucks	Rural
North Valley	Burney 12 kV	Rural
North Valley	Cedar Creek	Rural
North Valley	Chester	Rural
North Valley	Chico 12 kV	Urban/Suburban
North Valley	Clark	Rural
North Valley	Corning 12 kV	Rural
North Valley	Corning 4 kV	Rural
North Valley	Elk Creek	Rural
North Valley	French Gulch	Rural
North Valley	Gridley	Rural
North Valley	Lake Almanor	Rural
North Valley	McArthur	Rural
North Valley	Orland	Rural
North Valley	Oroville 12 kV	Urban/Suburban
North Valley	Oroville 4 kV	Urban/Suburban
North Valley	Paradise	Urban/Suburban
North Valley	Pit #3	Rural
North Valley	Pit #5	Rural
North Valley	Quincy	Rural
North Valley	Red Bluff	Urban/Suburban
North Valley	Redding 12 kV	Urban/Suburban
North Valley	Rising River 12 kV	Rural
North Valley	Volta	Rural
North Valley	Whitmore	Rural
North Valley	Wildwood	Rural
North Valley	Willows	Rural
Peninsula	Central Peninsula 12 kV	Urban/Suburban
Peninsula	Central Peninsula 21 kV	Urban/Suburban
Peninsula	Central Peninsula 4 kV	Urban/Suburban
Peninsula	NE Peninsula 4 kV	Urban/Suburban
Peninsula	North Pen East 12 kV	Urban/Suburban
Peninsula	North Pen West 12 kV	Urban/Suburban
Peninsula	South Pen East 12kV	Urban/Suburban
Peninsula	South Pen West 12 kV	Urban/Suburban
Peninsula	South Peninsula 4 kV	Urban/Suburban
Peninsula	West Peninsula 12 kV	Urban/Suburban
Sacramento	Davis	Urban/Suburban
Sacramento	Grand Island	Rural
Sacramento	North Colusa	Rural
Sacramento	Peabody	Urban/Suburban
Sacramento	South Colusa	Rural
Sacramento	Suisun / Cordelia	Urban/Suburban
Sacramento	Vacaville	Urban/Suburban

Division	DPA	Designation
Sacramento	West Sacramento	Urban/Suburban
Sacramento	Woodland	Urban/Suburban
Sacramento	Yolo / Colusa River Ag	Rural
Sacramento	Yolo AG (North)	Rural
Sacramento	Yolo AG (West)	Rural
San Francisco	Embarcadero (12kV)	Urban/Suburban
San Francisco	Embarcadero (35kV)	Urban/Suburban
San Francisco	Potrero	Urban/Suburban
San Francisco	S of Army (A HuntersPt)	Urban/Suburban
San Francisco	S of Army (H Martin 12kv)	Urban/Suburban
San Francisco	X (Mission)	Urban/Suburban
San Francisco	Y (Larkin)	Urban/Suburban
San Jose	Evergreen	Urban/Suburban
San Jose	Gilroy	Urban/Suburban
San Jose	Milpitas 12kV	Urban/Suburban
San Jose	Milpitas 21KV	Urban/Suburban
San Jose	Morgan Hill	Urban/Suburban
San Jose	San Jose (Downtown) 12kV	Urban/Suburban
San Jose	San Jose (Downtown) 4kV	Urban/Suburban
San Jose	San Jose (East)	Urban/Suburban
San Jose	San Jose (North) 12kV	Urban/Suburban
San Jose	San Jose (North) 21kV	Urban/Suburban
San Jose	San Jose (South) 12kV	Urban/Suburban
San Jose	San Jose (South) 21kV	Urban/Suburban
San Jose	San Jose (West)	Urban/Suburban
Sierra	Alleghany	Rural
Sierra	Apple to Echo	Rural
Sierra	Bear River	Rural
Sierra	Bonnie Nook/Shady Glen	Rural
Sierra	Central Nevada	Urban/Suburban
Sierra	Clarksville / Shingle Springs	Urban/Suburban
Sierra	Columbia Hill	Rural
Sierra	Diamond Spr / Placerville	Urban/Suburban
Sierra	Donner Summit	Rural
Sierra	Forest Hill	Rural
Sierra	Horseshoe	Urban/Suburban
Sierra	Lincoln	Urban/Suburban
Sierra	Marysville	Urban/Suburban
Sierra	Mtn Quarries	Rural
Sierra	Narrows	Rural
Sierra	New Yuba Foothills	Rural
Sierra	North Placer	Urban/Suburban
Sierra	Pike	Rural
Sierra	South Placer	Urban/Suburban

Division	DPA	Designation
Sierra	Yuba City	Urban/Suburban
Stockton	Angles Camp	Rural
Stockton	Clay	Rural
Stockton	Corral	Rural
Stockton	Jackson	Rural
Stockton	Linden 12 kV	Rural
Stockton	Lodi 12 & 21 kV	Rural
Stockton	Lodi 4 kV	Urban/Suburban
Stockton	Manteca 17 kV	Urban/Suburban
Stockton	Middle River	Rural
Stockton	North Stockton 12 kV	Urban/Suburban
Stockton	North Stockton 21 kV	Urban/Suburban
Stockton	North Stockton 4 kV	Urban/Suburban
Stockton	Salt Springs	Rural
Stockton	South Stockton 12 kV	Urban/Suburban
Stockton	South Stockton 4 kV	Urban/Suburban
Stockton	Tracy 12 kV	Urban/Suburban
Yosemite	Atwater	Urban/Suburban
Yosemite	Canal	Rural
Yosemite	Chowchilla	Rural
Yosemite	Indian Flat	Rural
Yosemite	Mariposa	Rural
Yosemite	Mendota	Rural
Yosemite	Merced 12kv	Urban/Suburban
Yosemite	Merced 21kv	Urban/Suburban
Yosemite	Merced Falls	Rural
Yosemite	Newhall	Rural
Yosemite	Newman	Rural
Yosemite	Oakdale	Urban/Suburban
Yosemite	Oakhurst	Rural
Yosemite	Oro Loma	Rural
Yosemite	Sonora	Rural
Yosemite	Spring Gap	Rural
Yosemite	Storey	Urban/Suburban
Yosemite	Westley	Rural