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.

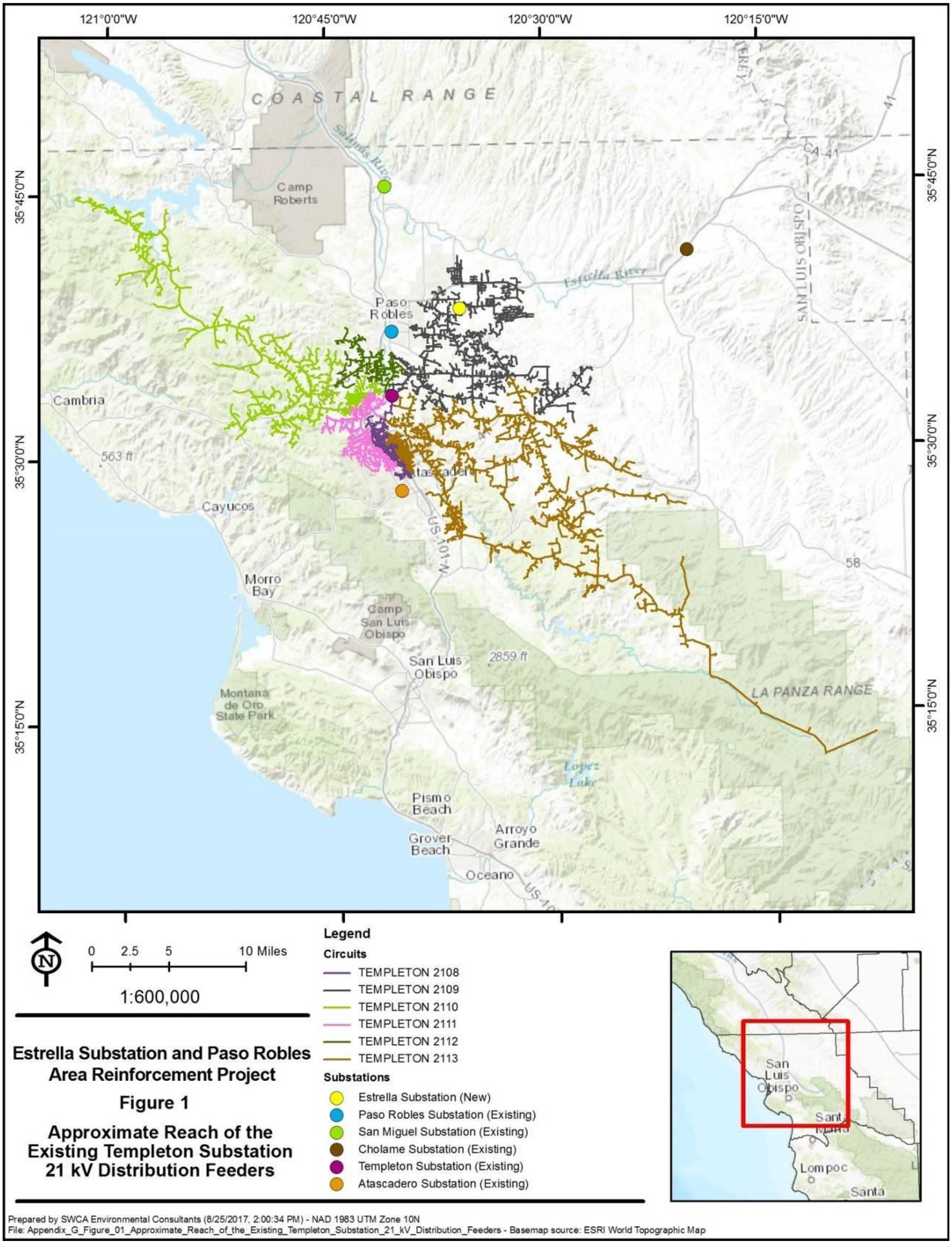
Templeton Substation has lengthy 21 kV feeders that can carry 73% more load and experience one-third less voltage drop than the 12 kV feeders from the other area substations because of their higher operating voltage. Even though Templeton Substation is south of Paso Robles and Paso Robles Substation, 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 of the Paso Robles DPA 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 are lost).

In addition, the areas north of SR-46 and south of the Paso Robles 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.

The Templeton 2109 main line serving much of east Paso Robles, both north and south of SR-46, experienced five sustained outages and nine momentary outages in the 5 years between February 2012 and February 2017. 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, Five-Year Outage History of Templeton 21 kV Feeders (February 2012 to February 2017) 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.

[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.)

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

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 build-out (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 2017.

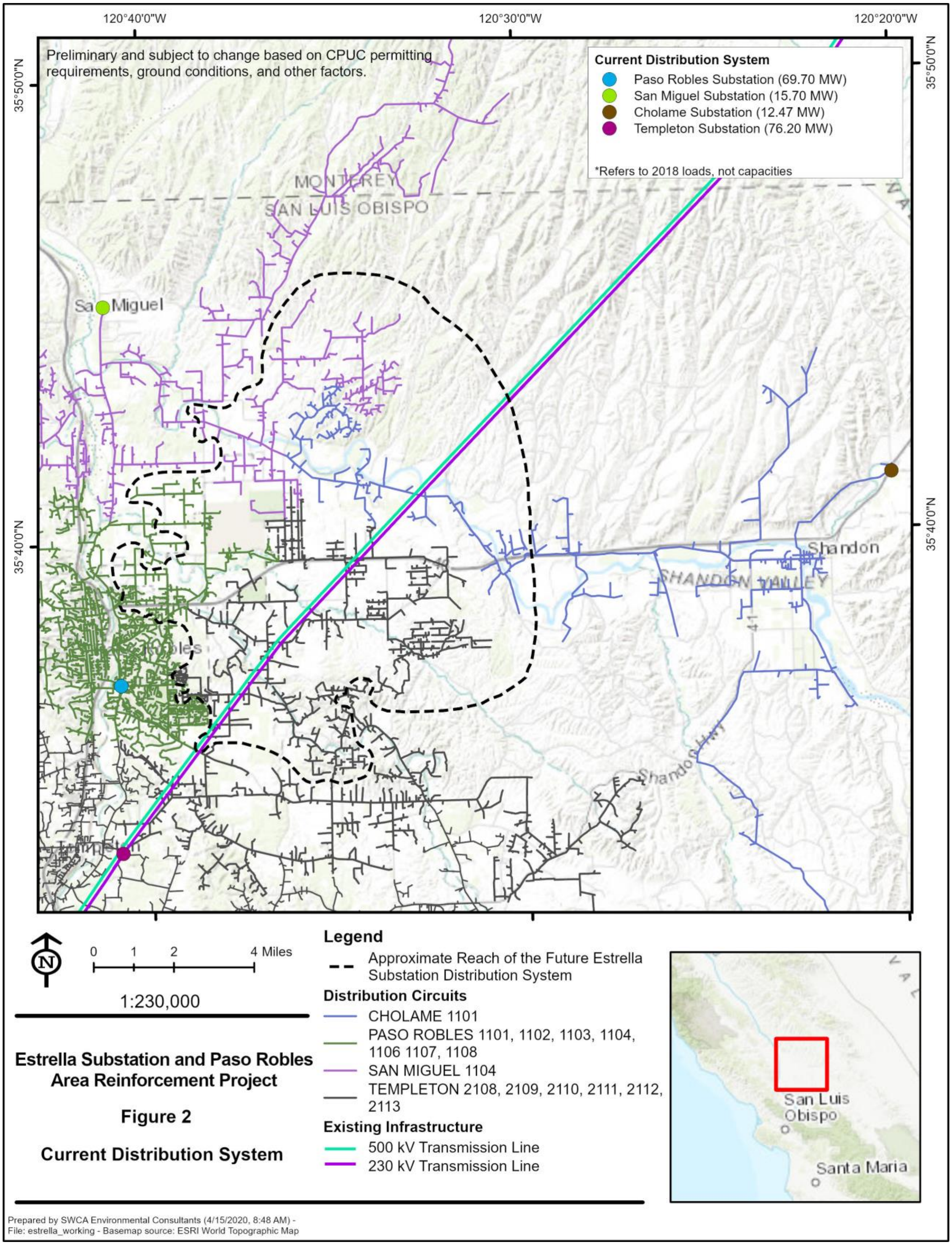
Figure 2 illustrates the current distribution system and indicates all distribution lines whether they are looped or radial. In general, main lines with larger overhead and underground conductor sizes are part of looped systems, while lines with smaller conductor sizes are radial systems tapped off the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

Table 2. Historical Paso Robles DPA Capacity and Load

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Historical Available DPA Capacity	182.46	197.51	197.51	212.55	212.55	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	164.74	169.33	185.50*	195.06	190.30

* The original 190.14 MW from 2016 has been corrected to reflect the true value of 185.50
Note: Paso Robles Bank 1 was replaced in 2010 with a 30 MVA transformer unit, bringing available DPA capacity to 212.55 MW.

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

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 8/15/18 and revised 6/1/18, at pages 10 and 34, attached as Exhibit B.) 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.

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. This is the future load center that the proposed project is intended to serve. At this time, industrial growth is anticipated to be led by wine production. San Antonio Winery, a large 1 MW facility, has been completed and is online with a planned expansion nearby. 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, with 1,300 residences expected to be built with-in the next 8 to 10 years.

Throughout Paso Robles, several new hotels or hotel expansions have received approval, with several now built or 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).[3] 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 4A. 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

[3] At the request of the CPUC, powerflow data for PG&E's 230 kV system is being provided separately to CPUC staff. This information has been deemed Critical Energy Infrastructure Information (CEII) by Federal Energy Regulatory Commission (FERC). It includes data concerning the local 230 kV system serving this area along with the load modeled for the years 2022 and 2027. Note that the Estrella Substation project is also already included in these models. After PG&E developed these base cases, they were then adopted by the CAISO as part of the 2017-2018 Transmission Planning Process (TPP).

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, the center of the future electric load 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 4A. 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 4B. Future Estrella Main Distribution Feeders.) However, only two new segments of distribution line would need to be constructed. These two segments are specifically identified on Figure 4B because they are the only gaps in the existing distribution system necessary to create one of the new feeders (Estrella 2). 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 4B are approximate locations, preliminary and subject to change. The segment of new line extending north from Estrella Substation, the southern segment to be added, is an accessible route along a farm road, and the northern segment to be added 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 Estrella 2 feeder to existing distribution on Mill Road. An additional segment of new line will be installed to extend the reach of the Estrella 2 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 4C shows how the three new 21kV feeders from Estrella would connect with existing feeders from the Paso Robles DPA substations.

Figure 3. 2.2-Mile Substation Location Area

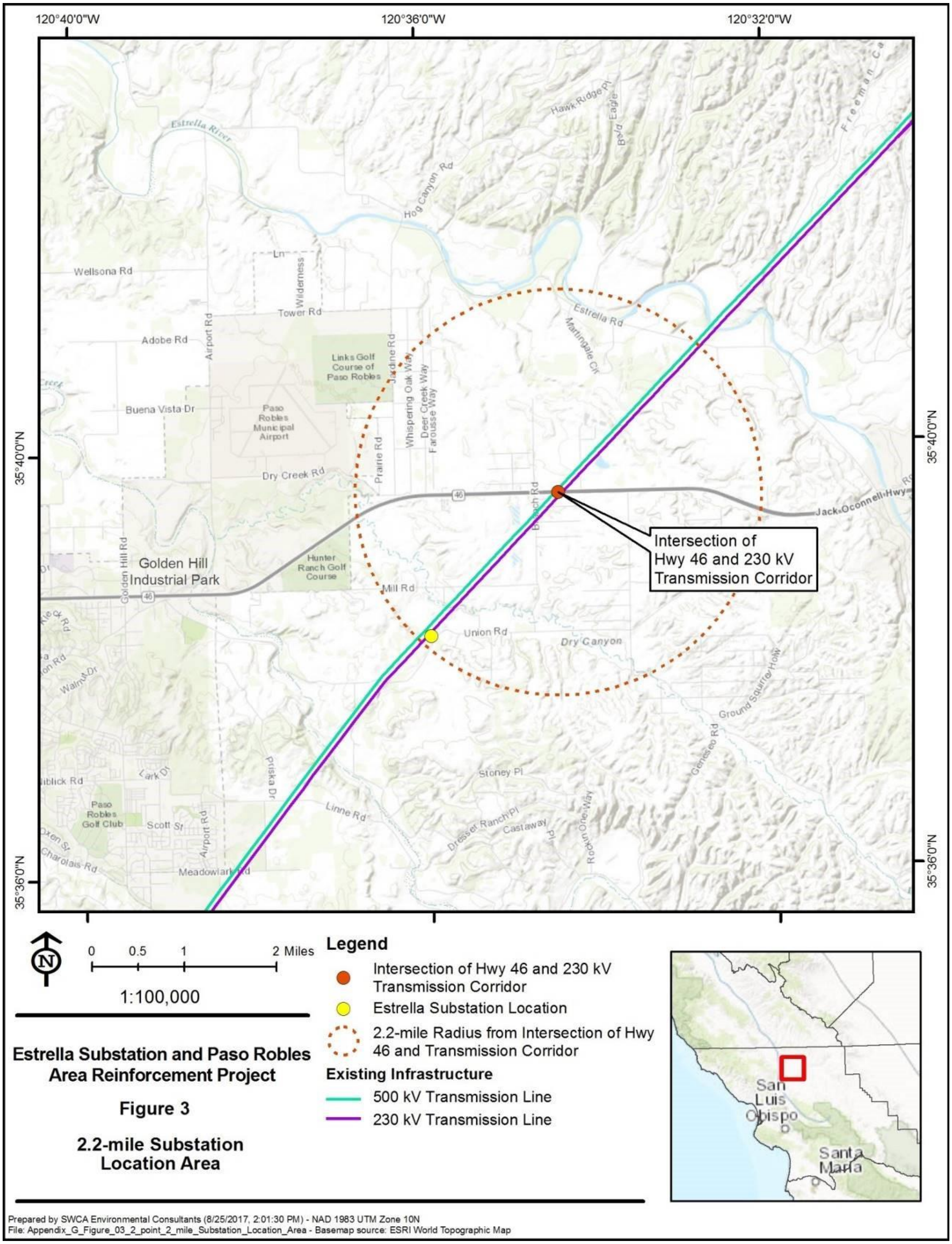


Figure 4A. Future Estrella Substation Distribution System

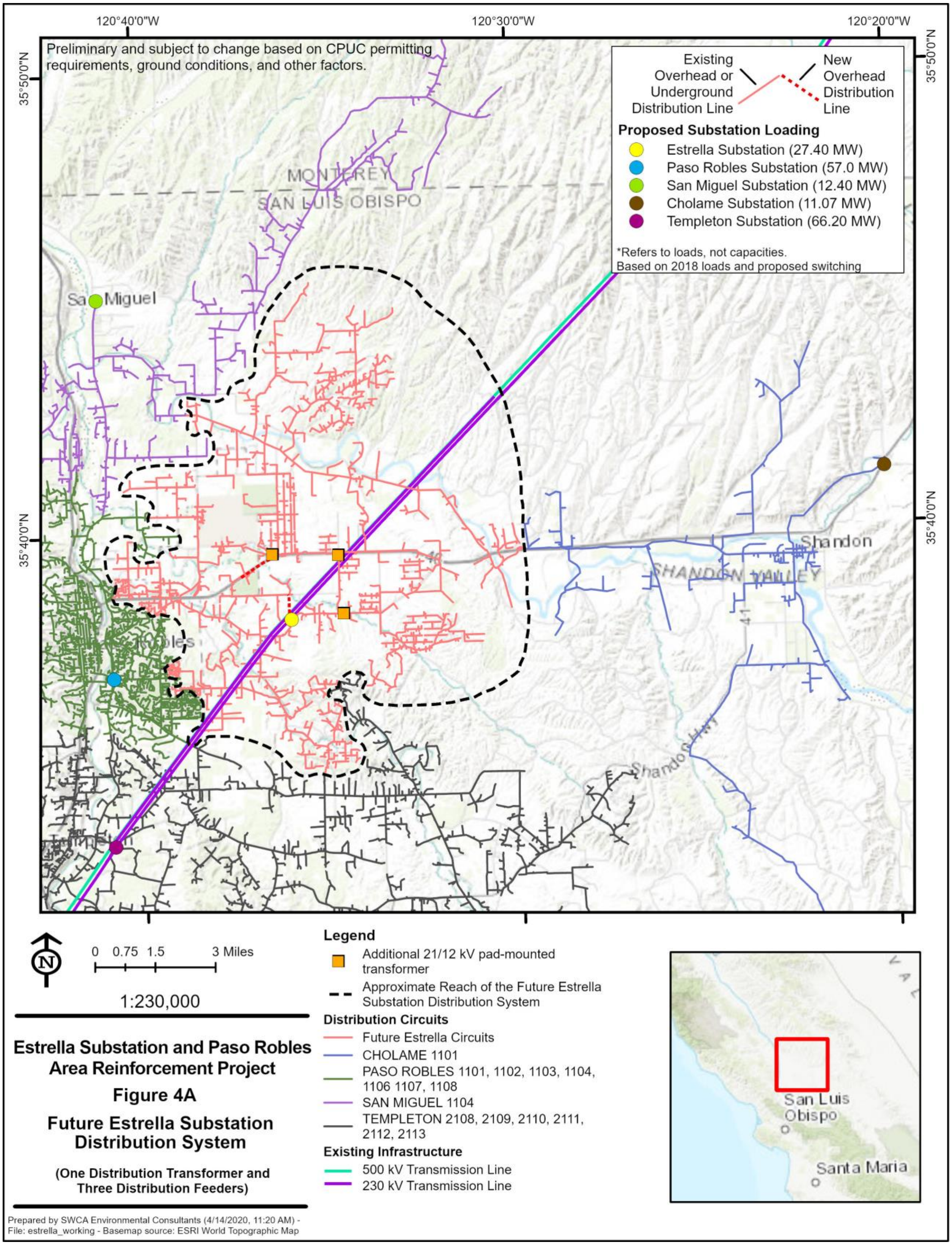


Figure 4B. Future Estrella Main Distribution Feeders

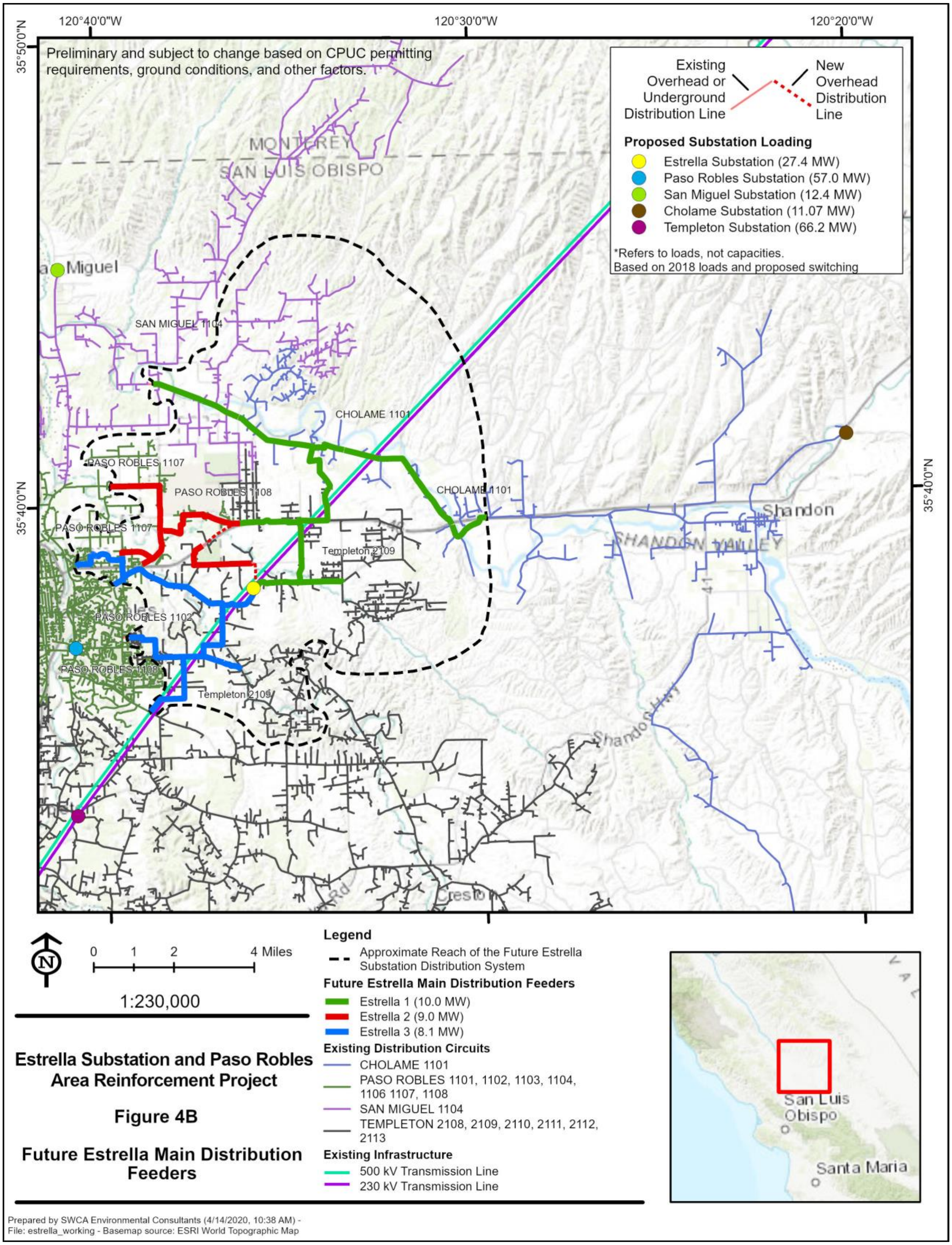
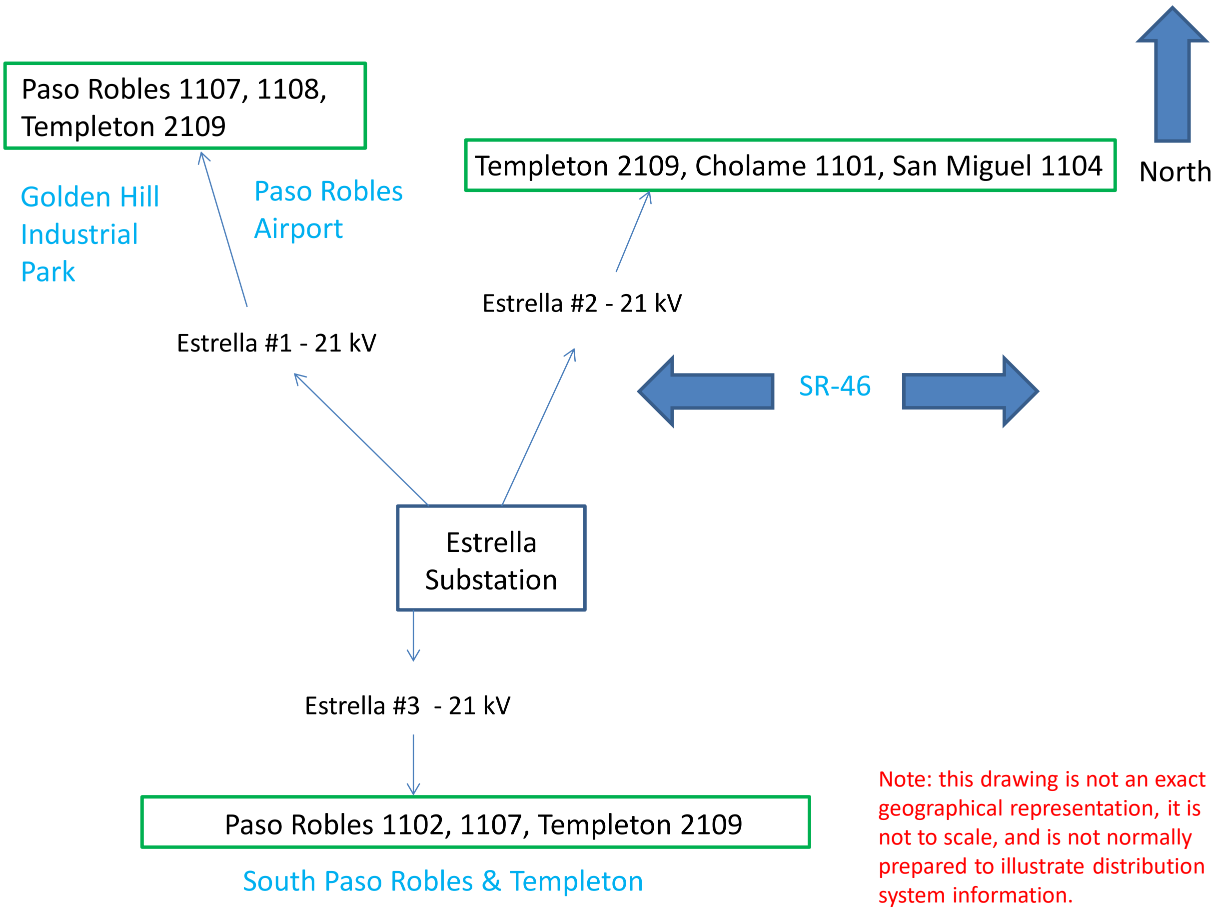


Figure 4C. One-Line Diagram, Future Estrella Substation Distribution Feeders



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-load adjustments. 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-load adjustments, 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 12 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 forecast for the DPA must be used to adequately predict DPA capacity needs.

The LoadSEER forecast does not account for all large future loads; unfortunately, large-load adjustments 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.

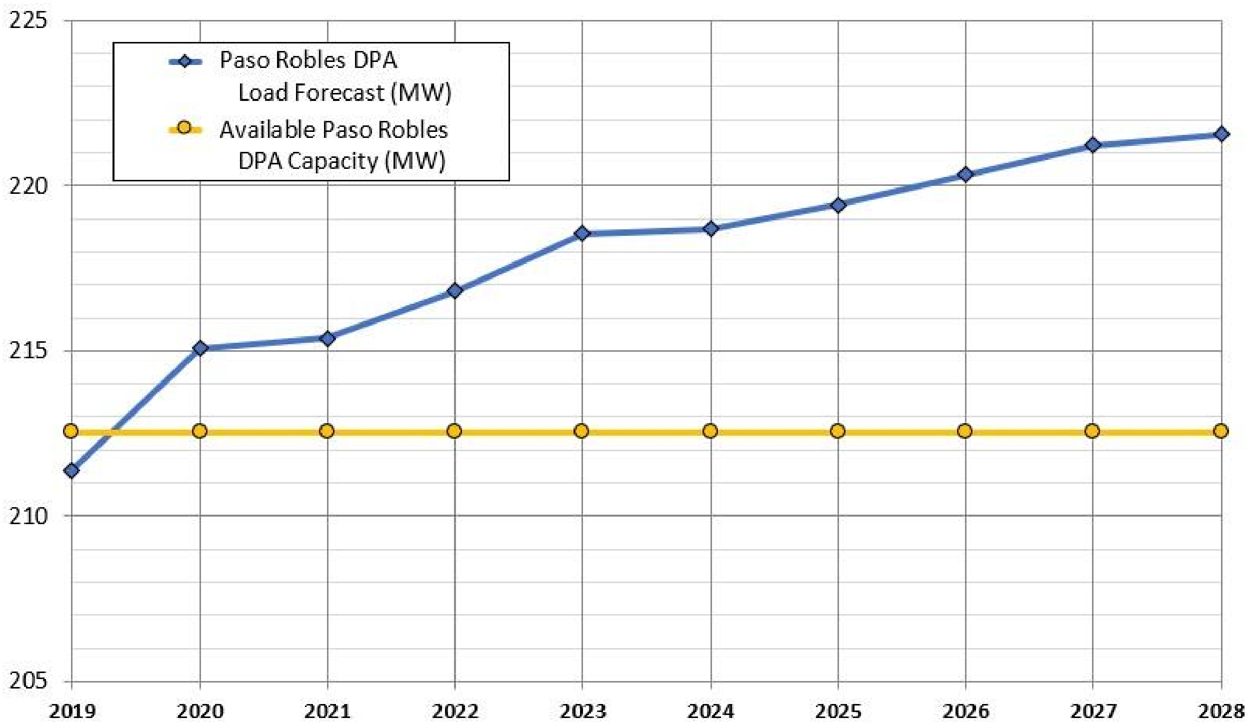
B. LoadSEER Forecasts

PG&E's distribution planning engineers used the following methodology for the 2019 LoadSEER forecast. Using LoadSEER, they began with the 2017 adopted IEPR Mid Baseline-Low Additional Achievable Energy Efficiency (AAEE) Update. They then added planned new loads based on received requests for service, as listed in Table 6A. (*See* Table 6A, Section III.C 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.

[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 IEPR forecast. Most solar is already accounted for in the IEPR forecast, so only an unusually large new distribution solar 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 2018 DPA peak occurred at 7 p.m. in late July, when the contribution of solar generation was only 3% 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. Battery storage could potentially extend solar power's hours of operation, although PG&E is not aware of any plans for solar battery storage. (*See* Section V.D.3 for a discussion of solar battery storage as an alternative to a distribution substation.)

Figure 5. Updated LoadSEER Forecast, Paso Robles DPA

Description of Forecast	Forecasted Load (MW)									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Available Capacity	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55
LoadSEER Forecast	211.38	215.07	215.38	216.82	218.56	218.70	219.42	220.33	221.23	221.56



The Paso Robles DPA has an available capacity limit of 212.55 MW. (*See* Section II.B, above.) The updated LoadSEER forecast provided in Figure 5 and Table 3 indicates that distribution demand in the Paso Robles DPA will outpace this capacity by 2020 (212.64 MW), so that new distribution capacity will be needed in 2020.

Table 3. Breakdown of Updated LoadSEER Forecast

Description of Forecast	Forecast (MW)									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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	203.97	207.78	209.81	213.10	216.49	218.54	221.41	224.38	227.67	230.31
IEPR Total DER Adjustments	-0.57	-0.98	-3.50	-5.95	-8.21	-10.64	-13.02	-15.33	-17.64	-19.96
Total New Business Adjustments	7.98	8.27	9.07	9.66	10.26	10.81	11.04	11.27	11.22	11.21
Total LoadSEER Forecast	211.38	215.07	215.38	216.82	218.56	218.70	219.42	220.33	221.23	221.56

Table 4. Breakdown of Substation Capacities and Forecasted Loads, Paso Robles DPA[1]

Substation/DPA	Available Capacity	Forecasted (MW)									
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Atascadero Substation[2]	29.70	29.93	30.09	30.16	30.43	30.26	30.05	29.95	29.88	29.92	29.74
Paso Robles Substation	89.10	78.06	81.15	81.18	81.06	81.10	80.91	81.13	81.43	81.72	82.01
Templeton Substation	89.10	84.51	84.93	85.11	86.36	88.10	88.62	89.11	89.67	90.19	90.37
San Miguel Substation[3]	15.84	18.88	18.90	18.93	18.97	19.10	19.12	19.23	19.35	19.40	19.44
Paso Robles DPA	**212.55[4]**	**211.38**	**215.07[5]**	**215.38**	**216.82**	**218.56**	**218.70**	**219.42**	**220.33**	**221.23**	**221.56**

[1] Except for the Paso Robles DPA Available Capacity, none of these numbers have been adjusted to account for the 95% utilization factor, which is the basis for determining Available Capacity.

[2] While additional distribution capacity at or near Templeton Substation could be utilized to relieve and serve load presently on Atascadero Substation, doing so would not address growth in and around Paso Robles like the Estrella Substation option. Moreover, all three Atascadero distribution circuits are located south and west of Templeton Substation. Load transfers from one or more Atascadero distribution circuits would require a new, or reinforced existing, Templeton distribution circuit in the direction of Atascadero Substation. Furthermore, Templeton Banks 2 and 3 are currently forecast to be overloaded in 2026 and 2023, respectively, reducing options for relieving overloads at Atascadero Substation.

[3] Available capacity at Paso Robles Substation could be utilized to relieve the projected San Miguel Substation overload, but would require rearrangement of existing circuit configurations to consolidate adequate capacity from multiple banks, as well as substantial circuit reinforcement to reduce loading at San Miguel Substation. The proposed location of Estrella Substation and the initial distribution circuit routes would enable load transfers off of San Miguel Substation.

[4] 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 the Guide for Planning Area Distribution Facilities Document # 050864, attached as Exhibit B.)

[5] Multiple large new business customers are planned to come online in 2020, as well as continued commercial and residential growth within the city of Paso Robles. The result of expected new business load additions is a sharp increase in projected load between 2019 and 2020.

Please note that the MW values shown in the legends in Figure 2, Figure 4A, Figure 7A, and Figure 7B are loads, not capacities. These loads are only preliminary, based on 2018 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]

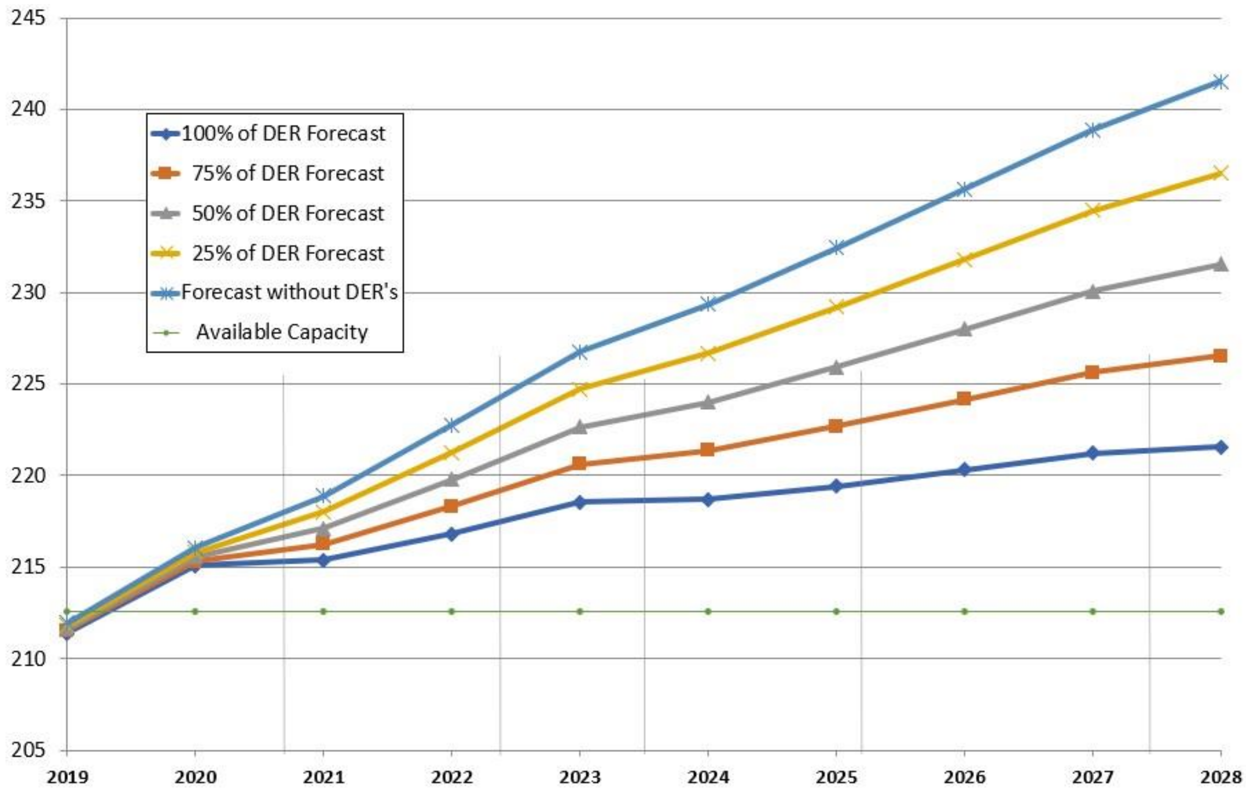


Table 5. Previous 1-in-10 LoadSEER Forecast Incorporating Varying Percentages of the DER Forecast

Description of Forecast	Available Capacity	Forecasted Load (MW)									
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
100% DER Forecast	212.55	211.38	215.07	215.38	216.82	218.56	218.70	219.42	220.33	221.23	221.56
75% DER Forecast	212.55	211.52	215.32	216.26	218.31	220.61	221.36	222.68	224.16	225.64	226.55
50% DER Forecast	212.55	211.67	215.56	217.13	219.79	222.66	224.02	225.94	227.99	230.06	231.54
25% DER Forecast	212.55	211.81	215.81	218.01	221.28	224.71	226.68	229.19	231.82	234.47	236.53
Non-DER Forecast	212.55	211.95	216.05	218.88	222.76	226.76	229.34	232.45	235.65	238.88	241.52

As demonstrated in Figure 6, electrical system forecasts vary with the facts and assumptions that go into them. PG&E's load forecasts are updated annually with the latest peak load data, using the most current load growth indicators available at the time of the forecast. However, forecasts are estimates, not precise predictors of what will happen but rather tools to determine when new facilities are expected to be required.

[5] Figure 6 is no longer relevant to the LoadSEER forecast, except for the 100% DER plot, but it is being provided at the request of the CPUC. 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). (*See* also Table 5, which provides the data numerically.) The CPUC has directed utilities to use the 100% DER forecast based on the currently approved IEPR.

The information contained in Table 3 indicates that, in 2020, demand for the DPA could reach 215.07 MW at peak, exceeding available capacity for the DPA by 2.52 MW. As explained above, that forecast is based on the 2017 IEPR, the planned new load identified in Table 6A, and the worst-case contingency for the largest distributed generator on line at the time of the DPA peak. This forecast is based on the 2018 recorded peak load, using the non-coincident peak load data for each substation bank in the DPA.

C. Large-Load Adjustments

The updated LoadSEER forecast provided here incorporates additional large new business loads that were not included in the prior forecasts. (*See* Table 6A.) These large loads are based on requests for service from new or existing customers within the Paso Robles DPA, and serve to target growth on specific distribution banks and circuits, as part of the forecast.

They represent specific customer loads that PG&E and city planners believe have a high probability of becoming operational within the timeframe provided by the customers. Large-load adjustments that were added to the LoadSEER forecast are shown on Figure 7A and listed in Table 6A, 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 for an electrical connection 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.

PG&E has also obtained other information from the City of Paso Robles and elsewhere on projects that have been proposed and have the potential to be built in the future. These other future proposed projects are shown in Figure 7B[6] and listed in Table 6B. These projects have not been added as adjustments into the LoadSEER forecast, but could be added in the future. Large-load adjustments and other future proposed projects can occur anywhere in the DPA, and are not always near identified future load centers. Future load centers are the general locations identified by local agencies as likely to have concentrated and sizeable future load growth. Here, the primary future load center identified by the City of Paso Robles is near Dry Creek Road south of Paso Robles Airport and the Golden Hill Industrial Park in northern Paso Robles, where city planners expect large-demand businesses to be located. (*See* Sections II.B and II.C.)

Table 6A. Large-Load Adjustments for Paso Robles DPA

Project Identification Number	Project Name and Description	Year Received/ Approved	Expected Completion Date	Estimated Demand (MW)	Project Status
1	Trinchero Winery	Received 2018	Information Not Available (INA)	1.680	INA
2	Beechwood Specific Plan – 862 Dwelling Units; 64,000 square feet	Received 2016	INA	1.357	Under Review
3	Firestone Wastewater Treatment Plant	Received 2017	INA	0.900	INA

[6] Earlier versions of Figure 7 mislabeled Other Future Proposed Projects as Future Load Centers. While there is overlap, they are not the same and that error has now been corrected. Several Other Future Proposed Projects were removed in the January 2018 version of Figure 7 in order to eliminate duplications with Large-Load Adjustments (Figure 7A) and solar projects, projects unrelated to the future Estrella Distribution System, and projects for which there was no information. All but the duplicate projects have been added back into the current version, and others have been added based on new information.

Project Identification Number	Project Name and Description	Year Received/ Approved	Expected Completion Date	Estimated Demand (MW)	Project Status
4	South Chandler Ranch General Plan Amendment Specific Plan – 1,293 Dwelling Units	Received 2017	INA	0.840	Approved
5	5151 Jardine Road – RV Resort	Received 2018	INA	0.750	INA
6	The Oaks at Paso Robles Retirement Home	Received 2018	INA	0.500	INA
7	River Oaks 2 General Plan Amendment / Specific Plan Amendment / Water Supply Evaluation – 271 Dwelling Units	Approved 2016	INA	0.407	Under Review
8	Justin Winery Expansion	Received 2018	INA	0.311	INA
9	Booker Vineyard and Winery	Received 2018	INA	0.330	INA
10	Meridian Winery Red Tank Farm Expansion	Pending	INA	0.300	INA
11	Paso Market Walk	Received 2018	INA	0.288	INA
12	1310 Las Tablas Road	Received 2018	INA	0.262	INA
13	Erskine General Plan Amendment / Rezone of 38 Highway 46 and Paso Robles Blvd – 250,000 square feet	Received 2017	INA	0.250	On Hold
14	Southgate Center (Paris Precision) Building and Site Modifications – 215,000 square feet	Approved 2017	INA	0.215	Under Construction
15	Vina Robles Hotel – 80 hotel rooms	Received 2003	INA	0.080	Under Review
16	Blue Oaks Apartments Phase II – 71 Dwelling Units	Approved 2017	INA	0.071	Under Construction
17	Tesla Charging Station (Paso Robles)	Received 2019	2020	2.500	Pending
18	Electrify America Electric Vehicle Charging Station 1	Received 2019	2019	1.000	Pending
19	Recargo Vehicle Charging Station	Received 2019	2019	0.400	Pending
--*	Carpenter Residence	Received 2018	INA	0.571	INA
			Total:	**13.012**	

Source: City of Paso Robles Community Development Department 2019
* The location of this project could not be identified and is thus not shown in Figure 7A.

Table 6B. Other Future Proposed Projects in the Paso Robles DPA

Project Identification Number	Project Name and Description	Year Received/ Approved	Expected Completion Date	Estimated Demand (MW)[7]	Project Status
1	Bellissimo Restaurant and Apartments – 4 Dwelling Units[8,9]	Received 2017	2019	0.006	Under Review
2	Black Oak Lodge Hotel – 60,000 square feet, 96 hotel rooms[10]	Received 2016	INA	0.156	Under Review
3	Buena Vista Village at San Antonio Winery – 4 Dwelling Units, 12,000 square feet[9]	Approved 2015	INA	0.018	INA
4	Cabernet Links Recreational Vehicle (RV) Resort – 290 RV spaces[10]	Received 2015	INA	0.290	Under Review
5	Cava Robles RV Resort – 332 RV spaces[10,10]	Approved 2016	2018	0.332	Under Construction
6	Destino Hotel Resort Amendment – 291 hotel rooms[10]	Received 2016	INA	0.291	Under Review
7	Estrella River Vineyard Agricultural Cluster Subdivision – 24.92 acres[11]	Received 2007	INA	0.150	INA
8	Fairfield Inn Development Plan Amendment – 119 hotel rooms[10]	Received 2016	INA	0.119	Under Review
9	Future Development (APNs 025-436-004, 025-436-037, 025-436-038, 025-481-020, 025-481-024, and 025-481-075)[11]	INA	INA	INA	INA
10	Golden Hill Industrial Park – Subdivision of 209 acres into 17 lots[11]	INA	INA	INA	INA
11	Golden Hill Retirement Project – 125 beds, 140,000 square feet[10]	Received 2008	INA	0.203	Under Review

[7] PG&E estimated based on available proposed project data.

[8] The Tribune 2017a.

[9] City of El Paso de Robles 2015a.

[10] Paso Robles Daily News 2017b.

[11] County of San Luis Obispo 2017.

Project Identification Number	Project Name and Description	Year Received/ Approved	Expected Completion Date	Estimated Demand (MW)[7]	Project Status
12	Homewood Suites Dallons Drive – 73,590 square feet, 105 hotel rooms[10]	Received 2016	INA	0.179	On Hold
13	Hyatt Place Hotel – 65,500 square feet, 116 hotel rooms[10,12]	Received 2016	2018	0.182	Under Review
14	New Commercial Customer beyond Fuse 7409[11]	Received 2012	2013	0.400	INA
15	North Chandler Ranch Vineyard Proposal – 300 Dwelling Units[10]	Received 2017	INA	0.450	INA
16	Oak Park Phase 3 Apartments – 75 Dwelling Units[10,13]	Received 2016	2018	0.113	Under Construction
17	Oak Tree Inn Addition – 50,000 square feet, 66 hotel rooms	Approved 2016	INA	0.116	INA
18	Oaks Hotel expansion – 66 hotel rooms[10]	Received 2015	INA	0.066	INA
19	Olive Oil Facility Expansion – 3,445 square feet[14]	Approved 2017	INA	0.003	INA
20	Paso Robles Public Market – 16,500 square feet[10,14]	Received 2017	2019	0.017	Under Construction
21	Paso Robles Water Recycling Plant (Expansion of Paso Robles Wastewater Treatment Facility)[15]	Approved 2017	2018	0.600	Under Construction
22	Paso Vista Resort – 2 Dwelling Units, 30,000 square feet, 226 hotel rooms[10]	Received 2015	INA	0.259	On Hold
23	Pine Street Promenade Amendment – 15,000+ square feet, 151 hotel rooms[10]	Received 2017	INA	0.166	Under Construction
24	Sensario Gardens Entrada – 280 hotel rooms[10]	Received 2004	INA	0.280	Under Construction

[12] Hyatt 2018.

[13] The Tribune 2016.

[14] The Tribune 2017b.

[15] Paso Robles Daily News 2017a.

Project Identification Number	Project Name and Description	Year Received/ Approved	Expected Completion Date	Estimated Demand (MW)[7]	Project Status
25	Tri-West Development – 4 Dwelling Units[16,17]	Approved 2015	INA	0.006	INA
26	Vines RV Resort – 6,850 square feet, 130 RV spaces[14]	Approved 2012	INA	0.137	INA
27	Wine Production Facility and Tasting Room – 36,000 square feet[14]	Approved 2012	INA	0.036	INA
28	Winery with production, tasting room, special events, and hospitality facilities – 23,000 square feet[14]	Approved 2015	INA	0.023	INA
29	Winery Expansion to include barrel storage buildings and office addition – 20,171 square feet[14]	Approved 2014	INA	0.020	INA
30	Hotel Alexa – 38 rooms; 23,765 square feet	Received 2019	INA	0.038	Under Review
31	Hotel Cheval – 20 rooms; 14,787square feet	Received 2019	INA	0.028	Under Review
32	Hotel Ava – 151 rooms; 118,283 square feet	Received 2018	INA	0.151	Pending
33	Westco Industrial Building – 3,948 square feet	Received 2018	INA	0.004	Under Construction
34	Wine Center – 4,127 square feet	Received 2019	INA	0.041	Under Review
35	Daniel Woodlands Industrial and Storage Facility – 85,000 square feet	Received 2019	INA	0.850	Under Construction
36	1518 Spring Street Mixed Use Development – 1,963 square feet commercial, 2,699 square feet residential	Received 2019	INA	0.006	Under Construction
37	Spur Co. New Commercial Development – 12,900 square feet	Received 2018	INA	0.013	Under Construction
38	Westco Truck Accessory and Installation Facility – 4,950 square feet	Received 2018	INA	0.050	Under Construction

[16] City of El Paso de Robles 2015b.

[17] City of El Paso de Robles 2015c.

Project Identification Number	Project Name and Description	Year Received/ Approved	Expected Completion Date	Estimated Demand (MW)[7]	Project Status
39	825 Mixed Use Development – 20 units, 40,000 square feet commercial	Received 2019	INA	0.060	Under Review
40	Vineyard Industrial Products – 5,000 square feet	Received 2019	INA	0.050	Under Review
41	OTR Four Trees Apartment Complex – 200 units	Received 2019	INA	0.200	Pending
42	Winery Expansion to increase tasting room operations, production, processing, and storage – 8,080 square feet[14]	Approved 2013	INA	0.008	INA
43	Winery Expansion to increase special event uses and associated facilities – 920 square feet[14]	Approved 2015	INA	0.001	INA
--*	Shell Building – 4,371 square feet	Received 2019	INA	0.004	Under Review
			Estimated Total:	**6.122**	

Sources: City of El Paso de Robles 2015a, 2015b, 2015c; City of Paso Robles Community Development Department 2019; County of San Luis Obispo 2017; Hyatt 2018; Paso Robles Daily News 2017a, 2017b; The Tribune 2016, 2017a, 2017b
* The location of this project could not be identified and is thus not shown in Figure 7B.

Figure 7A. Future Estrella Substation Distribution System, Large Load Adjustments

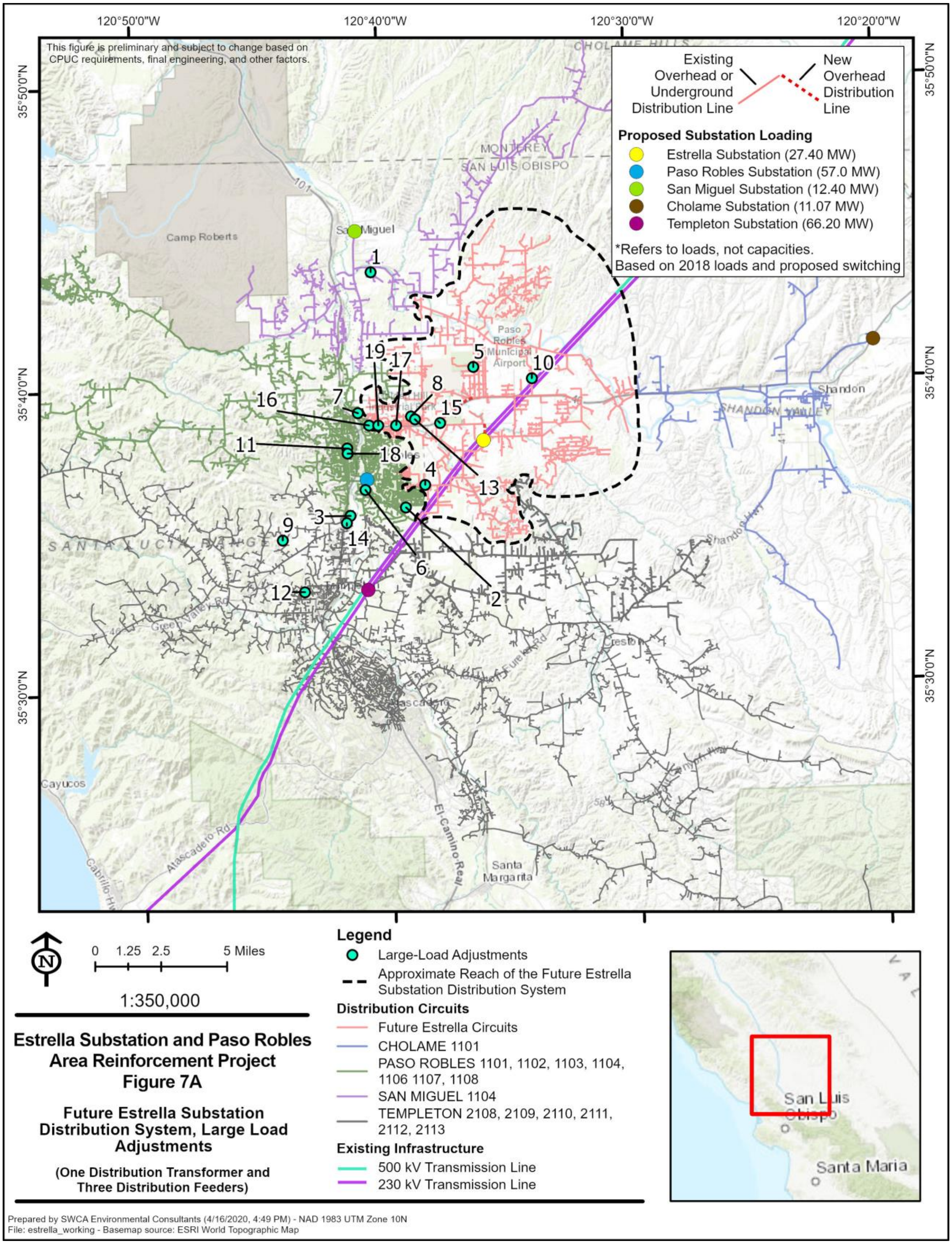


Figure 7B. Future Estrella Substation Distribution System, Other Future Proposed Projects

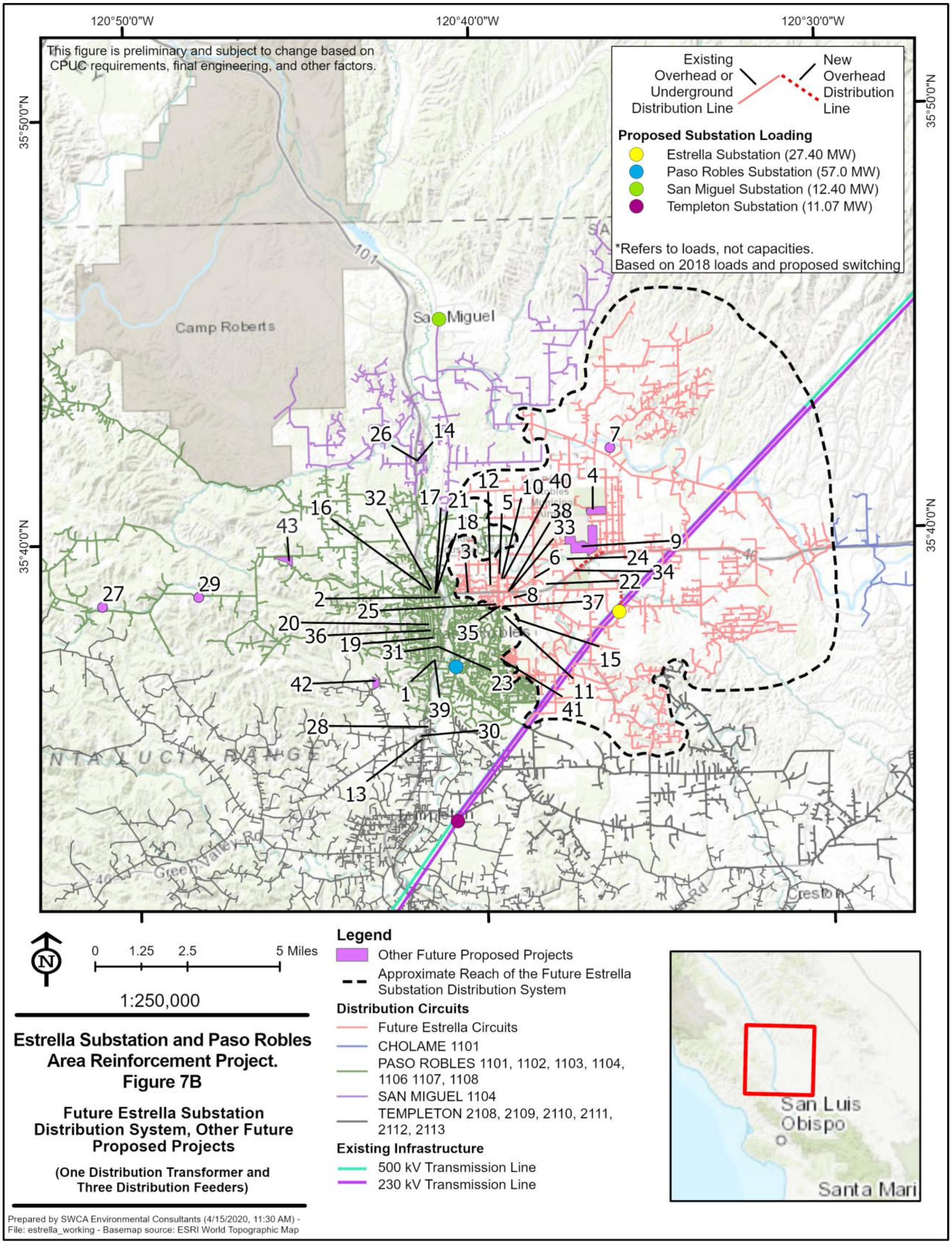


Table 7 below indicates substation capacities and loads for the Paso Robles and Cholame DPAs before and after distribution facilities are added at Estrella Substation. The loads correspond to the proposed circuit configurations indicated in Figure 2, Figure 4A, and Figure 6 are based on 2018 distribution 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	-----	+12.70	+3.30	+1.40	+10.00	27.40
Paso Robles	89.10	69.70	-12.70	-----	-----	-----	57.00
San Miguel	15.84	15.70	-----	-3.30	-----	-----	12.40
Cholame	24.75	12.47	-----	-----	-1.40	-----	11.07
Templeton	89.10	76.20	-----	-----	-----	-10.00	66.20

[1] Substation loads and load transfer amounts are based on 2018 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 2018 peak loads.

While additional capacity at or near Templeton Substation could be utilized to serve existing and planned new loads between Templeton and Paso Robles substations, this would require a new, or reinforced existing, Templeton distribution circuit with which to relieve Paso Robles circuits that currently serve the area south of Paso Robles Substation. Freed-up capacity on Paso Robles Substation could then be used to serve areas of anticipated growth north and east of Paso Robles Substation, but difficulties and complexities of routing new or redirected feeders from Paso Robles Substation to the growth areas do exist, as detailed in Section V.A and B. Additionally, one or more new Templeton feeders would still be required in order to adequately serve known and anticipated growth north and east of the City of Paso Robles, making for more excessively long feeders that would be very expensive to construct and would compound the reliability issues already present in the DPA due to long feeders.

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 with another approximately 4 months of construction and provide approximately 28 MW[18] of additional capacity. This timeline does not include easements, if needed, engineering or ordering of long lead material. 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.

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-load adjustments and DER estimates both inject uncertainty into the planning process, one thing is certain: distribution substation facilities will be needed sometime within 5 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 4B. Future Estrella Main Distribution Feeders and Figure 4C. One-Line Diagram, Future Estrella Substation Distribution Feeders.) 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 enable a reinforced circuit tie 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 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 expensive temporary generation at Cholame Substation during these maintenance periods. 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 proposed project provides a future

[18] Assumes a 95% utilization factor.

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. Alternately, an additional 21 kV distribution circuit from Estrella Substation could be extended into the Cholame DPA to also facilitate planned, or improve restoration of unplanned, outages.[19]

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

A new 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.)

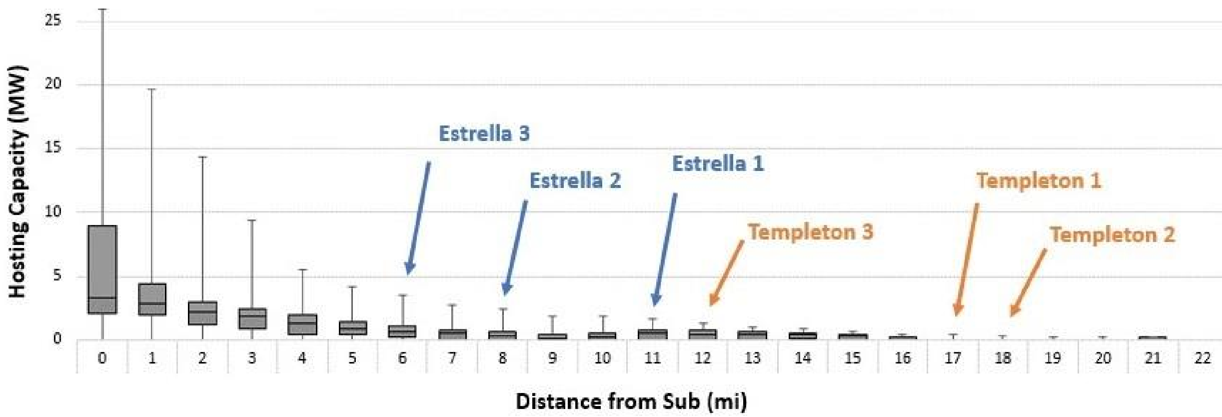
Templeton circuits currently have more than double the average electrical resistance compared to the average circuits for all PG&E substations in the service area. (*See* Figure 8.) The proposed Estrella circuits (average length 9 miles) would average approximately 56% less electrical impedance across all circuits than the proposed Templeton circuits (average length 16 miles). 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

[19] Another solution for the maintenance problem would be to install battery storage at Cholame Substation. While it would not improve operational flexibility on the 70 kV system, it could be a cost-effective answer to the pressing maintenance issue. This option is discussed further in Section V.D.2.

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 90% of its capacity in 2022 and beyond, 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, along Union Road and Mill Road, 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 along Mill Road. 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 4B and Figure 4C.) Based on preliminary design, the first Estrella feeder—"Estrella 1"—will consist of 1.67 circuit miles of reconductored distribution line, primarily along Union Road north and east, 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, primarily along Mill Road, 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 reconductored distribution line, primarily along Union Road south and west, and a total main-line length of 5.96 circuit miles. [20]

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 northeast 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 Templeton 1 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 northeast 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 northeast 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.[21]

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 4A. 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, Estrella 1 along Union Road, is 4.58 circuit miles and the longer route, Estrella 2 along Mill Road, 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

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

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

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 Estrella 1 Union Road feeder from Estrella. The longer route from Templeton to the growth area is 13.83 circuit miles and follows much of the same route as Estrella 2's Mill Road route from Estrella.

Both shorter routes from Estrella and Templeton to the growth area, Estrella 1/Union Road from Estrella and Templeton 1/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, Estrella 2/Mill Road from Estrella and Templeton 2/Mill Road 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.

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, especially for excessively long feeders. . Moreover, our siting principles used to determine optimal substation location target a DPA level analysis of all system components and not just an evaluation of individual feeders (see Table 7).

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	Project Status
Projects in Paso Robles DPA – In Service within the Last 7 Years							
877	California Flats[1]	Solar	1/2017	130	Transmission	CalFlats Switching Station	Complete
877	California Flats[1]	Solar	12/2018	150	Transmission	CalFlats Switching Station	Complete
166, 194, 242	California Valley Photovoltaic (First Solar), Carrizo Plain Solar, Desert Topaz PV2[1]	Solar	10/2014	550	Transmission	Solar Switching Station	Complete
239	Carrizo Solar Farm II (California Valley Solar Ranch)[1]	Solar	1/2013	250	Transmission	Caliente Switching Station	Complete
0397-WD	2103 – Hill (Pristine Sun)	Solar	1/2015	0.75	Distribution	Templeton	Complete
0443-WD	2059 – Creston 2 Scherz (Pristine Sun)	Solar	1/2014	0.5	Distribution	Templeton	Complete
0384-WD	Vintner Solar Project	Solar	1/2014	1.5	Distribution	Templeton	Complete
0394-WD	2056 – Jardine	Solar	3/2014	1.0	Distribution	Paso Robles	Complete

Queue	Project	Fuel	Actual In-Service Date	Size (MW)	Distribution/ Transmission	Substation	Project Status
0394-WD	Pristine Sun Fund 7 LLC 996 kW Solar Project	Solar	3/2014	1.0	Distribution	Paso Robles	Complete
114136750	Paso Robles Public Schools 786 kW Solar Project	Solar	10/2017	0.786	Distribution	Paso Robles	Complete
11328998	J Lohr Winery Corporation 642.8 kW Solar Project	Solar	11/2008	0.75	Distribution	Paso Robles/ Future Estrella	Complete
114210798	Templeton Unified School District 636 kW Solar Project	Solar	1/2018	0.636	Distribution	Templeton	Complete
113310042	Meridian Vineyards 620 kW Solar Project	Solar	11/2010	0.620	Distribution	Templeton	Complete
113477076	Niels Udsen 500 kW Solar Project	Solar	12/2015	0.5	Distribution	San Miguel	Complete
113296110	Kohl's Dept Store 100 Niblick Road	Solar	1/2008	0.5	Distribution	Paso Robles	Complete
113306871	San Miguel Winery	Solar	8/2009	1	Distribution	San Miguel	Complete
113310042	Treasury Wine Estate	Solar	11/2010	0.62	Distribution	Templeton	Complete
113310040	Treasury Wine Estate	Solar	11/2010	0.52	Distribution	Templeton	Complete
113305003	Sapphire Wines	Solar	12/2008	0.5	Distribution	Templeton	Complete
0384-WD	Vinter Solar Project	Solar	1/2014	1.5	Distribution	Templeton	Complete
0443-WD	Scherz Renewables Project	Solar	1/2014	0.5	Distribution	Templeton	Complete
0397-WD	2103-Hill (Pristine Sun)	Solar	1/2015	0.75	Distribution	Templeton	Complete
114208786	Paso Robles Vineyard	Solar	12/2018	0.78	Distribution	Templeton	Complete

Queue	Project	Fuel	Actual In-Service Date	Size (MW)	Distribution/ Transmission	Substation	Project Status
Projects in Paso Robles DPA – In Service within the Next 10 Years							
1529-RD	Paso Robles Airport	Solar	TBD	3.2	Distribution	Paso Robles	Implementation
2039-RD	Firestone Walker Inc.	Solar	Proposed 3/2020	1.375	Distribution	Templeton	Implementation
1838-RD	Atascadero State Hospital	Solar	TBD	1.14	Distribution	Templeton	Implementation
114207239	Paris Precision, LLC	Solar	TBD	0.532	Distribution	Templeton	In Process
114207261	Paris Precision, LLC	Solar	TBD	0.504	Distribution	Templeton	In Process

[1]These projects are not in the Paso Robles DPA.

D. Could Battery Storage Solve DPA Distribution Issues?

1. Could Battery Storage Address Distribution Needs More Effectively than a Distribution Substation?

a. Review of Battery Storage Options

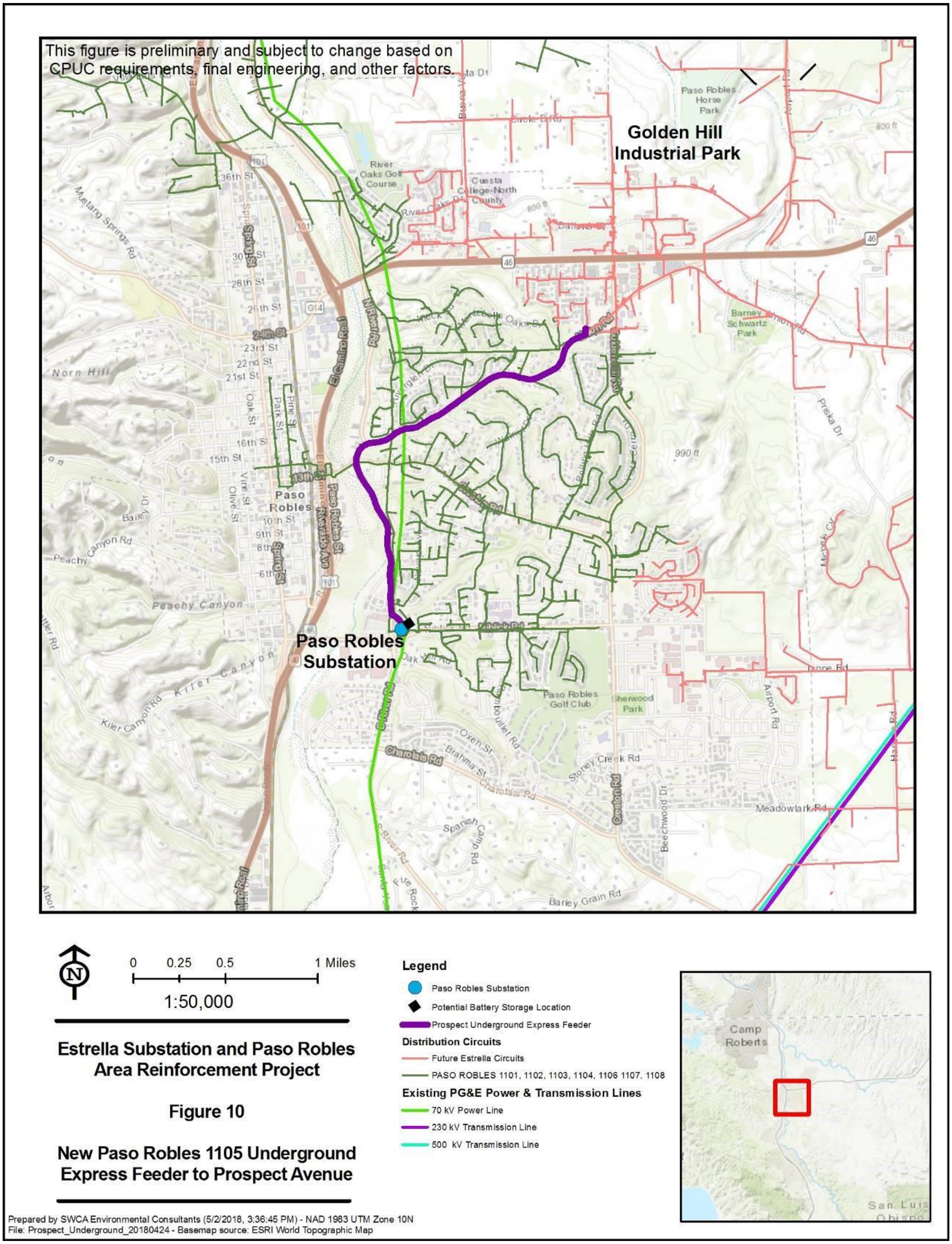
PG&E studied two representative locations for battery storage that could potentially delay the need to add capacity to the Paso Robles distribution system by installing distribution components at Estrella Substation as proposed, or otherwise. First, PG&E studied the option of installing a 4 MW, 24 megawatt hour (MWh) battery bank at Paso Robles Substation, since that is the largest battery that could be installed at the substation (on adjacent land) without taking out neighboring businesses. A 4 MW battery could defer a distribution substation by approximately 3 years. Second, PG&E studied the option of installing a 15 MW, 90 MWh battery bank at the Golden Hill Industrial Park. This battery size is the maximum that could be charged on an express 12 kV distribution feeder, and could delay the need for distribution substation facilities by approximately 10 years. The ability of either potential battery storage option to defer a distribution substation installation assumes adequate distribution circuit ties exist to reconfigure available capacity throughout the Paso Robles DPA, thus mitigating all projected overloads. As detailed below, neither of these battery storage alternatives would eliminate the need for a new distribution substation in the foreseeable future, improve operational flexibility in the local distribution area, or increase Paso Robles DPA's circuit reliability – all benefits that distribution components from Estrella Substation would provide.

The first battery storage location studied was at Paso Robles Substation, where PG&E could install a 4 MW, 24 MWh[22] battery bank to the east of the existing substation. (Note that this study area, a vacant triangular parcel east of the substation, would be the same expansion area targeted to install a ring bus at

[22] A larger battery was not considered feasible at Paso Robles Substation because it would require obtaining additional property currently occupied by local businesses, which would likely involve eminent domain proceedings and result in significant challenges, time delays and substantial costs.

Paso Robles Substation to accommodate a single additional 70 kV line from Templeton Substation. The vacant parcel could not accommodate both options.) A new underground express distribution feeder would be constructed from Paso Robles Substation to connect to the existing distribution system at Prospect Avenue in Paso Robles. (*See* Figure 10.) This battery storage would have the potential to delay the installation of Estrella Substation distribution components, from a capacity perspective, for approximately 3 years. However, as explained further below, it would: (1) provide a solution that is only temporary, (2) limit, rather than improve, operational flexibility, and (3) not increase the circuit reliability of the Paso Robles DPA.

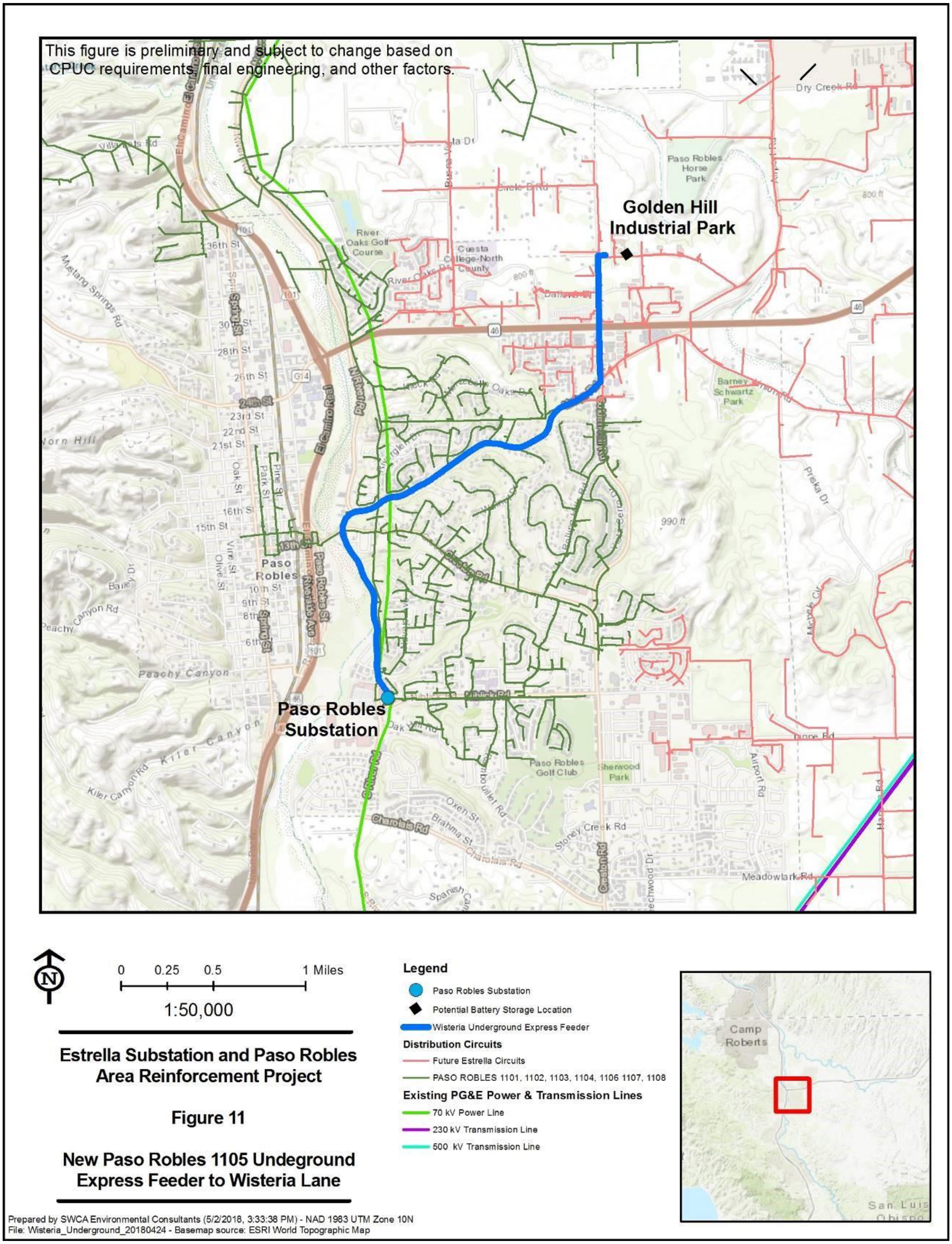
Figure 10. New Paso Robles 1105 Underground Express Feeders to Prospect Avenue



The second study location considered for battery storage was a vacant lot in the Paso Robles Golden Hill Industrial Park, on the east side of Golden Hill Road. This location would require installing a new underground express distribution feeder from Paso Robles Substation to the Golden Hill site to provide off-peak charging of the battery. (*See* Figure 11.) A battery at this location with a connection to Golden Hill Industrial Park would connect directly to the future load center within the Paso Robles DPA, and be located in an area large enough to accommodate the installation (approximately 2 acres) and already zoned for industrial facilities. Moreover, if Paso Robles Substation or San Miguel Substation overloaded, the battery could "off-load" or take over the load being served by either one of these substations because feeder circuits from the battery would connect to circuits extending from these substations. Since it is unknown at this time which substation could overload first, a battery that could connect to either substation seems more prudent than one located at, or tied to, just Paso Robles Substation. The battery would be sized for 15 MW, 90 MWh, to include a 20% reserve capacity above 12 MW, which is the maximum capacity that can be supplied by a new express 12 kV feeder. The reserve capacity would allow the battery to degrade over time while still maintaining the ability to provide 12 MW of output for 6 hours, 72 MWhs.

This 15 MW battery has the potential to delay the installation of Estrella Substation distribution components, from a capacity stand-point, for approximately 10 years. However, as explained further below, this option would: (1) provide a solution that is only temporary, (2) limit rather than improve operational flexibility, and (3) offer fewer reliability benefits.

Figure 11. New Paso Robles 1105 Underground Express Feeders to Wisteria Lane



b. Comparison of Battery Storage Options with the Proposed Project

Deferral of Capacity Need

Even under the 15 MW/90 MWh battery option, the need for new distribution substation facilities would only be delayed for approximately 10 years. The substantial expenditures that would be necessary to install batteries in any or multiple locations would provide only temporary relief, and substantial additional expenditures would be needed to address the capacity needs in approximately 3 or 10 years. Given the capacity projections for the Paso Robles DPA, Estrella or other distribution facilities would be needed in the foreseeable future under either of the battery storage solutions.

Operational Flexibility

The Estrella distribution substation build-out will provide significant operational flexibility, allowing the substation to off-load several neighboring substations (Paso Robles, San Miguel, Templeton, Atascadero, Cholame) when needed for planned and emergency outages or equipment repairs. Installing a battery at Paso Robles Substation or Golden Hill Industrial Park would actually limit the operational flexibility of some substation equipment at Paso Robles Substation and the associated battery charging feeder, since this equipment must remain in operation during off-peak hours to recharge the battery. Not having this equipment available would limit the time that maintenance or load transfers involving this equipment, or other related equipment, could be accomplished. As a result, a battery at either Paso Robles or Golden Hill Industrial Park would reduce existing operational flexibility rather than providing the significantly-increased operational flexibility of a new distribution substation. Distribution feeders from Estrella Substation will connect to six distribution circuits within the Paso Robles DPA and four separate substations (*see* Figures 4B and 4C), facilitating load transfers between these substations and circuits to support clearances for both planned maintenance and emergency restoration.

Distribution Reliability

Estrella distribution feeders will increase Paso Robles DPA circuit reliability by reducing the length of existing circuits that originate at neighboring substations and feed the growing areas of Paso Robles. For example, the Templeton 2109 circuit is currently 45 miles in length and will be reduced to 18 miles in length once a new distribution connection is built from Estrella Substation. Shortening these existing circuits, like Templeton 2109, will make them much less susceptible to weather, fire, and car pole accidents. When outages do occur, fewer customers will be impacted. Time to patrol lines and return customers to service during outages will also be reduced. By comparison, installing battery storage at Paso Robles Substation or Golden Hill Industrial Park will not reduce existing circuit lengths, so those alternatives would not have any beneficial impact on circuit reliability for the Templeton 2109 circuit or other circuits in the DPA.

Battery storage located in the Golden Hill Industrial Park area could provide some limited reliability benefits to the interconnected Paso Robles or San Miguel circuits it would feed. This could happen during outages to these circuits where the normal distribution supplies are lost. The battery storage could conceivably sustain these circuits for a period of time. This emergency back-feed would last only for as long as the battery storage could supply the circuit loads, or as long as the express charging feeder from

Paso Robles is available to keep charging the battery storage. This would not be the normal operating configuration, and would not provide nearly as much reliability to the overall DPA as a new distribution substation at Estrella.

Since neither of the battery storage options can provide the long-term capacity, operational flexibility or same level of reliability benefits as installing a new distribution substation with three new distribution feeders, battery storage would not address DPA distribution needs more effectively than the proposed Estrella distribution substation.

2. Could Battery Storage at Cholame Substation Replace the Need to Extend the 70 kV Power Line?

PG&E evaluated installing a 15 MW, 90 MWh battery storage bank at Cholame Substation to see whether a battery could defer or eliminate the need to install a second 70 kV transmission line into Cholame Substation from either the future Estrella or existing Templeton substations. A primary need for the second line is to provide service to customers during maintenance of the existing, single transmission line or 70/12 kV transformer bank. A battery would provide a limited, second 70 kV source into Cholame Substation, but it would not be able to sustain the substation over multiple days like an additional 70 kV line would be able to do. The battery could address critical maintenance needs that can be solved within 9 hours, like change-out of transmission poles, installing new transmission line hardware, or conducting limited transformer bank or 70 kV breaker maintenance.

A new line from Estrella Substation would be about 16.5 miles long and a new transmission line from Templeton Substation would be about 24 miles long. Cholame Substation is currently on a radial 70 kV circuit originating from Arco Substation in the San Joaquin Valley. When maintenance is needed on the existing Arco-Cholame 70 kV line or 70 kV portion of the substation, it has been very challenging to schedule it in the past. Expensive stand-by generation has been used more than once to keep the substation's distribution customers energized while transmission line maintenance was completed. The normal daytime load on the substation is approximately 10MW. Designing the battery bank to accommodate a 9-hour clearance window would allow maintenance crews to schedule daily clearances for transmission line work while keeping distribution customers in service during the maintenance period. The battery would be constructed to discharge into the 12 kV bus, and recharge from the Cholame Substation 70 kV bus. When not needed for other purposes, the battery could provide electricity and market-based services to be sold into the wholesale transmission market to offset the cost of the battery bank installation (although this could limit the availability to use the battery as an emergency back-up to the substation if the single 70 kV transmission line is unexpectedly taken out of service). While battery storage could be installed at Cholame Substation to partially address the existing maintenance problem as opposed to adding a new 70 kV power line from Templeton or the new Estrella Substation, it would not provide the same level of back-up support as installing a 70 kV line from Estrella or Templeton substations. Energy storage might be able to provide adequate MW support during load peaking times, but the support is limited due to the charging/discharging time. The challenge would remain to cover the reliability need during all operating normal and emergency conditions. A looped substation (with two transmission feeds capable of holding the substation load) can remain energized indefinitely as long as one transmission line stays energized. This keeps customers in power during single transmission line outages and during periods of extended (multi-day) maintenance activities.

The decision to install a new 70 kV line or battery storage at Cholame Substation would need to be studied by the CAISO before such a project could be determined valid or warranted.

3. Could Battery Storage Connected to Solar Generation Address Distribution Needs More Effectively than a Distribution Substation?

a. What are the benefits of one or more battery storage sites with respect to the solar projects in Table 8 and how would battery storage be ideally sited and sized?

Installing batteries at multiple solar/battery storage sites has the advantage of diversity of supply should problems develop with one of the solar locations or battery storage sites. The largest distribution-level solar installation proposed in Table 8 for the Paso Robles DPA is one for the City of Paso Robles (3.2 MW). This site would be a possible candidate for battery storage depending upon the proximity to the necessary connection point in the DPA that could provide capacity relief to transformer banks at either Paso Robles or San Miguel Substation. (*See* discussion about 15 MW battery storage option and distribution interconnection in Section V.D.1.) The closer these solar/battery storage sites could be located to the distribution connection points, the lower the connection costs and the easier the construction. Sizing of the battery storage sites supplied by solar power would need to be designed to match the solar output of the arrays unless utility power is used to supplement the charging cycle. Ideally, the combination of battery storage sites would be close to the 15 MW, 90 MWh site that was studied for the Golden Hill Industrial Park (*see* Section V.D.1) since, from a capacity perspective, this would delay the need for distribution capacity from Estrella Substation for approximately 10 years. It is difficult to see how this would be possible given the low estimates of peak power for the distribution-level solar projects listed in Table 8. In addition, this battery storage solution would not provide a long-term solution to capacity needs or eliminate the need for a future distribution substation. Furthermore, it would not provide the operational flexibility and improved distribution circuit reliability the Estrella distribution project will bring to the Paso Robles DPA.

b. Discuss the contribution that a battery storage alternative sized to delay construction of the known and full-build-out distribution components of the proposed project would make with respect to the solar projects listed in Table 8

Based on the analysis in Section V.D.1, if a 15 MW, 90 MWh battery storage facility supplied by solar power could be located at or near the Golden Hill Industrial Park and supply consistent power to the electric grid similar to the 15 MW proposal in Section V.D.1, it could provide enough capacity to delay construction of the Estrella distribution components for approximately 10 years. The challenge here would be to collect sufficient solar resources from Table 8 projects to be able to charge a 15 MW battery. Based on the forecasted growth rate in the Paso Robles area of 1.1 MW per year, a smaller 4 MW, 24 MWh solar/battery storage would provide enough capacity to delay construction of Estrella distribution components for approximately 3 years. The solar project planned by the City of Paso Robles in Table 8 offers a total of 3.2 MW of output at full capacity. This site would supplement the charging of co-located batteries with utility power, that could help provide the deferral benefits of a 4 MW battery. Any battery would need to be designed for 20% over capacity to allow for battery degradation over time, so would likely need to be near 5 MW, 30 MWh installed size. Since a 5 MW unit is similar in size to the evaluated Paso Robles Substation battery installation (4 MW, 24 MWh), there would likely be similar benefits for this size of battery, but the battery interconnection costs would be higher due to the longer distance from the needed distribution connection points; the Paso Robles Substation battery was evaluated as being built adjacent to the Paso Robles Substation and not several miles from the distribution connection points.

Disadvantages of Solar/Battery Storage over Distribution Substation Facilities

Using solar/battery storage to defer installation of distribution components from Estrella Substation or another distribution source only temporarily addresses the capacity need within the Paso Robles DPA and does not eliminate the need for future new distribution substation facilities in the foreseeable future. In addition, it does not address the operational flexibility and improved distribution circuit reliability the Estrella project will bring to the Paso Robles DPA. Estrella feeders will be connected electrically to the following circuits and be able to off load those circuits and a portion of the associated substations attached to these circuits: Cholame 1101, San Miguel 1104, Paso Robles 1108, 1107, 1102, and Templeton 2109. The Templeton 2109 feeder is currently 45 miles long; after the Estrella distribution feeder connections are completed it will only be 18 miles long. This will provide an improvement to the reliability of this circuit and, as other circuit connections are completed, to the entire Paso Robles DPA. (*See* Figures 4A and 4B for illustrations of this benefit.)

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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 4A Figure 6
Appendix G (3) and (3.1)	Section II.C Section V.B Section V.D Figure 4A Figure 4B Figure 4C
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 6A Table 6B Figure 7A Figure 7B Footnote 5
Appendix G (8) and (8.1)	Section V.B
Appendix G (9) and (9.1)	Section I.A Section V.B Figure 4A Geographic Information System (GIS) data provided in electronic format.
Appendix G (10) and (10.1)	Figure 2 Figure 4A
Appendix G (11) and (11.1)	GIS data provided in electronic format.
Appendix G (12) and (12.1)	Figure 6 Footnote 6
Appendix G (13) and (13.1)	Section IV.B Section V.D
Appendix G (14)	Section V.D
Appendix G (15)	Section V.D
Appendix G (16)	Section V.D Table 8
Deficiency Letter No. 5, Deficiency 1	Section III.B
Deficiency Letter No. 5, Deficiency 2	Table 4

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Exhibit B. Guide for Planning Area Distribution Systems Document # 050864, Dated 8/15/18 and Revised 6/1/18

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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:**	8/15/18	

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

Rev. #01: The document was updated to include LoadSEER forecasting and DER inclusion

Rev. #02: The document was updated to include GNA and DDOR requirements and timeline.

1.0 PURPOSE AND SCOPE

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. Project recommendations which include deviating from the planning processes described in this guide must be approved by the distribution planning manager.

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.

Application of the procedures described in this guide will result in project proposals to expand distribution system substation and line capacity, or utilization of DERs to reschedule capital investments. 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
EE - energy efficiency
CPCN - Certificate of Convenience and Public Necessity
CYME – Electric distribution load flow analysis program
DER – Distributed Energy Resources
DA – Distribution Automation
DCC – Distribution Control Center
DDOR – Distribution Deferral Opportunity Report
DG - Distributed Generation
DPA - Distribution Planning Area
DPAG – Distribution Planning Advisory Group
DRP – Distribution Resource Plan
DR – Demand Response
DMS – Distribution Management System
EMS – Energy Management System
EASOP - Economic analysis software program
ED-GIS – Electric distribution – Geographical Information System
EDPI – Electric Distribution PI
ESD – Engineering Standard Drawing
ES – Energy Storage (BESS – Energy Storage System)
EV – Electric Vehicles
FLISR – Fault Location, Isolation, Service Restoration
GIS – Geographic Information System
GNA – Grid Needs Assessment
HC – Hosting Capacity
ICA – Integration Capacity Analysis (aka. Hosting Capacity)
IEEE - Institute of Electrical and Electronics Engineers
ILIS – Integrated Logging Information System
IOU – Investor Owned Utilities

KPF - Name of an overhead switch manufacturer

KW - Kilowatt

KVAR – Kilovar

LoadSEER – Program used to produce load forecasts for bank and feeders

LNBA – Locational Net Benefits Analysis

LTC - Load Tap Changer

MW - Megawatt

MVA - Megavolt Amperes

MVAR - Megavolt Amperes Reactive

NEM – Net Energy metering

NPV - Net Present Value

NOC - Notice of Construction

ODS – Operational Data Services

OM&C - Operations, Maintenance and Construction

PF - Power Factor

PTC - Permit to Construct

PVRR - Present Value Revenue Requirement

PV – Photovoltaic

RAM - Renewable Auction Mechanism

RFO – Request for Offer

SCADA - Supervisory Control and Data Acquisition

TDSM- Targeted Demand Side Management

VVO-Volt/VAR Optimization

WAT - Weighted Average Temperature

2.1 Definition of Terms

1- in -10 Temperature: The peak temperature an area should expect to experience once every 10 years. (90th percentile in regression analysis)

1- in -2 Temperature : The peak temperature an area should expect to see once every 2 years (50th percentile in regression analysis)

Load Adjustment: This is load which through customer application or other local knowledge is scheduled to be connected on the distribution system. Adjusted load can also reduce the corporate forecast by applying load reduction, generation or other electric distributed resources.

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.

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

Distributed Energy Resources – These are all of the various resources being considered at the distribution level; electric vehicles, stored energy systems, distributed renewable generation resources, energy efficiency and demand response programs.

Design 1- in- 10 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 60 kV.

Distribution Planning Area (DPA): A geographical area which generally operates at the same voltage level with strong electric distribution ties within the area.

Effective Emergency Capability of a Transformer Bank: The capability of a bank to supply load during emergency conditions, considering transmission input and bus connections 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 bus connections, in addition to the normal capability of the bank itself and any other station equipment (such as regulator, LTCs, disconnects, bus, etc.).

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.

Emergent work: Unforeseen condition which requires work to be performed outside of our normal planning timeline to support our customers' connections or changing conditions.

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.

Hosting Capacity (or Integration Capacity) - the calculated amount of power individual distribution circuits, or nodes/line sections on a circuit, to accommodate additional load

[1] CAISO and Industry Standard

and/or generation without requiring significant upgrades in order to ensure system safety and reliability.

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

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 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 Environmental Impact Review (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 60 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). Leading power factor occurs when the current wave leads the voltage and the phasor angle is positive and indicates capacitive loads. Lagging power factor occurs when the current wave lags the voltage and the phasor angle is negative and indicates inductive loads.

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: Capacity reserved for a load 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.

SmartAC: An energy response program that allows for the automatic control of customer owned air conditioning units during certain events to reduce the peak load on equipment.

Standby Capacity: Capacity reserved for generation customers on standby rates.

Summer Peaking: An area that has its annual peak that occur from April 1 through October 31, and when capacity additions typically are required to meet future summer peaks.

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

10% x T_1	T_1 is the maximum temperature of the first hot day
20% x T_2	T_2 is the maximum temperature of the second hot day
+ 70% x 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

Winter Peaking: An area with an annual 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 Underground Distribution Insulated Aluminum Cables	**050166**
Ampacity of Underground Distribution Insulated Copper Cables	**050167**
Ampacity of OH distribution line Conductors	**076251**
Application of Capacitors on Distribution lines	**039586**
Distribution Voltage Regulators and Boosters	**015239**
Ratings for Underground Switching Devices	**072160**
Ratings for Overhead Switching Devices	**072161**
Circuit Breakers, Circuit Switchers and Reclosers (Substation)	**073133**
Switches, Disconnects (Substation)	**073136**
Pad-mounted, Load-break Switches and Fuses	**053318**
Ampacity of Outdoor Bus Conductors	**067909**
Capacitors on Distribution Lines	**028425**
Electric Characteristics of Conductors	**045314**
Distribution System Voltage Regulation	**027653**
Preferred MVA Ratings 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

TD-1004P-02 Circuit Breaker Ratings

TD-1004P-03 Substation Air Switch Rating Details

TD-1004P-05 Generic and Custom Transmission and Distribution Transformer Ratings

TD-2058S Distribution Energy Resource Alternative for Capacity and Reliability Improvements

TD-2306B-002 Distribution Generation Protection Requirements

TD-2306M Distribution Interconnection Handbook

TD-2400B-001 Substation Load Information and Power Factor

TD-2460S Capacity Planning for Electric Distribution Systems

TD-2908B-002 Ratings Information for Overhead and Underground Distribution Switching Equipment

TD-2999B-030 Technical Requirements for Electric Service Interconnection at Primary Distribution Voltages

TD-3340S System Protection Engineering Requirements

TD-068188B-001 Available Pad-Mounted Interrupters

TD-9101S Large Load Connection Standard

Protection Handbook

Guideline D-G0069, "Substation Property Siting and Acquisition"

Reliability Section of the Electric Planning Manual

4.0 PLANNING GUIDELINE AND CRITERIA

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

4.1 Basic Criteria

Distribution system capital investments, including DER deployments will be made so that forecast loads or added generation 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 and circuit interconnections 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) and FLISR 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 Load Power Factor

PG&E generally designs its distribution system to operate at 0.99 lagging power factor at the low side of substation transformer banks during peak load conditions. As described in TD-2400B-001 “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.

All substation transformers and feeders contained within a given DPA are identified as urban, suburban or rural consistent with the DPA designation. The process of designating DPAs as urban, suburban or rural was based upon a combination of population density and engineering judgment. 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. DPAs with distribution feeders that predominantly serve high or medium population areas were designated as urban or suburban DPAs. DPAs with distribution feeders that supply predominantly low density population areas were designated as rural DPA's. Changes to DPA designation or individual banks and feeders within a given DPA will be considered on a case by case basis and must be approved by the distribution planning manager. See Appendix A for a listing of DPAs and their area designations.

In order to prevent or minimize the potential for overloading substation or distribution equipment beyond their applicable capability, PG&E engineers are required to forecast and analyze the distribution system loads at the individual substation bank and feeder level, and down to the feeder component level. These analyses are performed with the system configured for both normal and various emergency operating conditions. The engineers analyze the system to identify voltage or loading deficiencies that cannot be mitigated by modifying equipment settings or by performing 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, placement of 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 to faults as well as customer exposure to the outages that result when making design decisions.

5.1 Distribution System Planning

The forecasting of load growth on the distribution system is performed using the *LoadSEER* program, which produces a 10 year load forecast at the feeder, bank and DPA level. The starting point for the load growth in the forecast is the most recent adopted California Energy Commission mid-baseline load growth forecast for the PG&E service area.

PG&E engineers utilize many factors including historical loading, peak temperatures, certain economic indicators, new load additions, and load transfers to develop their load forecasts. Resultant load forecasts are compared to the applicable equipment's normal and emergency capabilities. The 10 year load forecasts at each feeder, bank, and DPA level are adjusted to account for future capacity projects increases, load transfers, new large load additions, and DER growth as necessary. The organization of a certain number of banks and feeders into a DPA is currently only used to assist in the assignment of work to the engineers. Forecasting load at the DPA area provides some idea of the general growth in the area and alerts the engineer of the potential need of a new substation within the next 10 years, but it doesn't identify the actual facilities that will be impacted by the area's load growth.

In addition to evaluating future loading and the impact to the equipment's normal capacity to serve new growth, studies should be performed to evaluate the impact of this future load during an emergency event, such as the loss of a substation transformer bank or substation circuit breaker. Emergency bank loss studies are performed by assuming the loss of one transformer in a substation which contain 2 or more transformers, or loss of the one transformer in a single transformer bank substation. An emergency capacity deficiency exists when there are customers who are still out-of-service after all available transfers have been completed using emergency capacity ratings.

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 onsite spare transformer or installation of a mobile transformer.

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.

Once the load forecasts have been completed, the engineers evaluate each bank and feeder to determine if loading exceeds normal capability during the next 5 years. The *LoadSEER* program forecasts 10 years into the future and these forecasts are used to identify new substations. The forecast for the first 5 years for each bank or feeder is used to determine the capital investments needed for the 5 year investment plan.

A study to analyze individual bank and feeder loading under normal conditions is performed by comparing forecast bank and feeder loads to their effective normal capacity. A localized normal substation transformer bank deficiency exists when the forecast load is in excess of the normal capacity of the transformer bank. Similarly, a localized normal distribution feeder deficiency exists when the forecast 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 or a normal rating of 600 Amps. The feeder design goal is to limit the total number of customers to no more than 6000. Multiple studies may be required to identify localized emergency transformer capacity deficiencies. The failure of each individual substation transformer bank must be analyzed, one at a time, to determine if a deficiency exists after all possible transfers have been made. 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 may also be 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. 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 and FLISR are 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 use normal substation transformer capability ratings at all times, even 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.

5.2 Feeder component planning

Loads projected for individual distribution feeders are imported into CYME from LoadSEER. Feeder models are developed for subsequent three years to ensure individual components are loaded within normal capacity ratings and voltages remain within allowable limits. Feeder models created for the next peak season will be used primarily for validation of previous assumptions. Models prepared for the second and third peak seasons will be used to identify and mitigate deficiencies.

As noted above, load flow models should also be prepared for the emergency system conditions for the loss of individual substation transformer banks and feeder outlets. Completion of this step will ensure individual components are loaded within their emergency capacity and voltages remain within allowable emergency voltage limits.

5.3 Optimal Circuit Voltage and Conversion

The optimal circuit voltage for new facilities is 12kV (12.0kV) and 21kV (20.78kV). Any new distribution facilities should be preliminarily evaluated for these voltage levels. If surrounding circuits, banks, transformers are predominantly of one voltage level, the new facilities should be added to match the current voltage. However, since there is great benefit to having higher voltages, it is recommended to evaluate benefit-to-cost ratios associated with installing intertie transformers to adapt lower voltage systems with 21kV. Generally, new 21kV systems should be 4-wire type circuits.

When projects are created to convert older 4kV systems to 12kV and 21kV systems, removal of backties should be consider in the planning process and intertie transformers installed as needed to bridge the time between cutover project phases.

6.0 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 substation transformer bank and feeder has a normal and an emergency capability rating. Normal and emergency capability ratings typically are determined by the temperature rise limitations of the transformer and feeder components. Therefore, these capability ratings are higher in winter than in summer. The emergency capability rating is generally higher than the normal capability rating. 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 untenable situations when substation transformer failures occur.

6.1 Substation Bank and Regulator Capability rating update with TD-1004P-05

Significant changes to substation transformer rating policies were implemented through TD-1004P-05. Many substation transformers in the PG&E system have received customized ratings from Substation Asset Strategy in the past that allowed normally planned load levels above nameplate. PG&E has been eliminating all such ratings whenever possible or as a project is needed to correct a normal deficiency within the local area. When the full transition of the system has been completed, all transformers will be rated in accordance with TD-1004P-05. There will no longer be bonus ratings, differentiation based upon pre or post 1998 manufacturing, or differentiation between coastal and interior temperature districts.

The normal capability rating (thermal rating) 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.

Transformer Temperature Alarm Settings and Normal Limits

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

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.

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:

DWG. 050864 - Guide for Planning Area Distribution Facilities –

TOP OIL AND HOT SPOT TEMPERATURE OPERATING GUIDELINES

Level	55C Rise Transformer		60/65C Rise Transformer (3)		Action
	TOP OIL	**HOT SPOT**	**TOP OIL**	**HOT SPOT**	
1	80ºC / 85ºC(2)	105ºC / 110ºC(2)	90ºC / 95ºC(2)	120ºC / 125ºC(2)	Alarm Setting. Plan strategies to transfer load if Level 2 is forecast.
2	95ºC	120 ºC	105ºC	135ºC	Should not exceed for more than 3 hrs. Transfer load if necessary. Notify the maintenance supervisor.
3(1)	100ºC	125ºC	110ºC	140ºC	Do not exceed. Take immediate action to reduce load.

(1) Level 3 limits are considered emergency temperature limits for transformer modeling.
(2) Modified alarm settings. If specific transformers are fully loaded during peak periods and response to the temperature alarms disrupts routine operations, the alarm settings can be raised 5° C to match the normal temperature limits. Asset strategy and maintenance personnel should discuss and agree to this change.
(3) 60° and 65° C rise transformers have the same 65° C raise thermally treated paper insulation; therefore the thermal limits are the same for either transformer. A distribution transformer specification change around 2010 lead to a slight design change that resulted in a very economic method of increasing the cooling capacity. The manufacturers are required to stamp the nameplates showing that they are 60° C-designed transformers. The specification change was trading off a 40° C ambient and 65° C rise with a 45° C ambient and 60° C rise.
Notify the substation asset strategy engineer and substation maintenance personnel for every hot bank alarm, per TD-3350P-12, “Substation Transformer Operation – Summer and Winter Preparations and Hot Bank Reporting.”

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 loading of substation facilities in excess of the normal rating established by TD-1004P-05 on a case by case basis. Increased ratings will only be allowed where there is minimal risk to the equipment. One example where this may be appropriate is in response to a large customer initiated load increase 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. It is the responsibility of the Distribution Planning Manager, or their representative, to notify the Substation Asset Strategy department of any distribution bank forecast above the normal rating of the transformer, and where replacement or transfers aren’t available to correct the deficiency.

6.2 Feeder Outlet Capability

The component that limits the capability of a feeder typically is one of the following: circuit breaker, regulator or associated switches , 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. 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.

Outdoor feeder circuit breakers should not be assigned summer ratings above 100% of nameplate under any conditions. However under emergency conditions, outdoor feeder breakers can be loaded over their nameplate rating if the breaker is in good condition, but the rating must be 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. Note that emergency capability ratings are not available on enclosed circuit breakers (i.e. metalclad switchgear). 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 the summer season and 135% for winter. . 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.

6.3 Conductor and Related Distribution Equipment Capability

The ampacity of overhead conductors and underground cables are provided in Engineering Standard Drawings (ESD) 076251, 050166, and 050167. 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. The ampacity of overhead conductors, overhead switches and single-phase regulators should be de-rated by 5% to allow for phase unbalance.

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 should consider all substation feeder bus components as well as allline equipment ratings. Balance load between the phases of feeders in accordance with Section 2.16, “Phase Balancing” located in the Electric Planning Manual to maintain loading within capabilities. Generally, the imbalance at three-phase, automatic protective devices should be limited to no more than 40 amps deviation from the average.

Switch locations at normal open points should have load break capabilities equal to potential loading during abnormal system configuratins. Typical line equipment rating are discussed below.

6.4 Air Switches and Disconnects

Type	Manufacturer	Manufacture Dates	Continuous Current Rating	Load Break Rating[2]	Emergency Rating
All	KPF [1]	All	400 amp 600 amp 800 amp	See Note 2	None None None
Under Arm Side Break	Cooper/Kearny	Pre-Nov 2003 After Nov 2003	720 amp 900 amp	600 amp	900 amp (24 hr) 1233 amp (24 hr)
Under Arm Side Break	S&C	All	900 amp	900 amp	1233 amp (24 hr)
PT 57 HSB[3]	All	All	600 amp	600 amp	828 amps (24 hr)

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

2 – Load Break capabilities of KPF switch are dependent on the type of attachements it has. Refer to TD-2908B-002 for more information.

3 - Solid-blade disconnects operated with an S&C Loadbuster tool may be used to interrupt load currents up to the continuous current rating of the disconnect or the tool, whichever is less.

6.5 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 Drawing 015239 for capabilities of line regulators and boosters.

6.6 Padmount and Sub-Surface Line Devices

Trayer and ISG 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, 4, 5, 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 (PMI 600 amp unit)

- 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**	**17200**	**20780**
Multiply by	7.57	8.73	21.82	31.28	37.80

The multiplying factors above 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.

7.0 LOAD FORECASTING

To plan for sufficient resources to supply the load in an area, it is necessary to forecast future magnitude and location of load as accurately as possible. The need to forecast future loads and assign load to specific facilities is intended to allow adequate time to address capacity deficiencies 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 and system load flow model inaccuracies or during weather conditions which exceed PG&E's design weather event.

PG&E utilizes a commercially available load forecasting program called LoadSEER. This program consists of two separate forecasting applications, LoadSEER FIT and LoadSEER GIS, in which each application uses different methodologies to develop a 10 year forecast.

There are several steps that each engineer must consider when completing their LoadSEER forecasts. The engineer must review their available capacity, historical loading, load transfers, adjustments to future forecasts, and generation or firm capacity agreements before forecasting future loads.

For additional information about the use of the LoadSEER program refer to the developers' User Guide and the LoadSEER Forecasting Guideline which are located at the following sharepoint locations.

LoadSEER User Guide

LoadSEER Forecasting Guideline

7.1 Validate normal and emergency capabilities for banks and feeders

Correct capability ratings are critical to the identification of capacity deficiencies. The system of record for these capabilities is stored within EDPI. Ratings documented in EDPI are then imported and synchronized with LoadSEER, which contains the normal and emergency capability ratings of each distribution bank and feeder in the system. These capabilities should be validated as part of the load forecasting process. This is especially critical for banks and feeders where facilities have been recently modified.

7.2 Determine bank and feeder peaks for the Planning Area

Accurate substation load reporting and power factor monitoring are extremely important for operating purposes and for planning future capacity additions. LoadSEER requires accurate data on which to base regression forecasts. A single year's peak entered incorrectly can significantly hinder LoadSEER's forecasting process. Compliance with the following items improves system efficiency and optimizes the use of existing substation assets.

- Peak bank and feeder load data should be obtained through either the Condition Based Maintenance (CBM) sharepoint or the EDPI System. Peak MW and power factor for banks as well as peak amps and power factor for feeders should be recorded including the peak date and time (if available.)
- The Distribution Capacity Planner should compare these peak loads with adjacent days' peaks as well as previous month's peaks to assess whether the peak is a switching peak (an unusually high or low load read caused by either planned or unplanned switching).
- If a switching peak is suspected, the daily ILIS report for unplanned switching and the DCC Monthly Calendar for scheduled switching should be reviewed. DMS temporary states reports are also available to evaluate suspect data.
- If large generation is present on the feeder and has SCADA visibility, its output should also be recorded at the time of feeder and bank peak.
- Distribution Capacity Planning and Distribution Operations Engineering are both accountable for notifying the Substation Maintenance Group when load reads are inaccurate or missing.
- Distribution Capacity Planning and Distribution Operations Engineering are both accountable for notifying the ODS Group when SCADA data is of poor quality or missing.

7.3 Validate Transfers

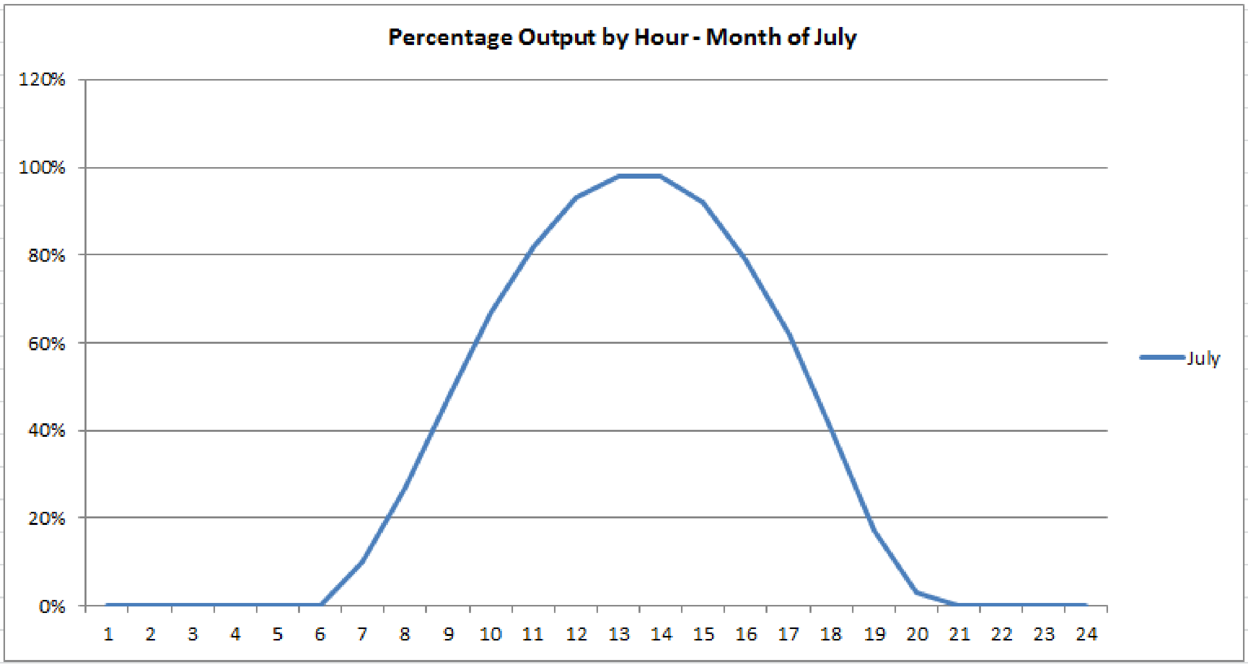
Load transfers are used within LoadSEER to automatically adjust the load history for improved regression forecasting. Only permanent load transfers should be recorded. Temporary transfers are not relevant for forecasting annual peaks unless they occurred during peak loading conditions, then the peak load should be adjusted to account for the temporary load transfer.

7.4 Add Load Adjustments

Load adjustments are added to the annual bank and feeder peaks to account for the output of the single largest distributed generation (DG) connected to the feeder or bank during the time of the feeder or bank's peak hour. The loss of the largest DG system is considered as a N-1 scenario on the distribution system. Multiple generation units can be considered as a N-1 scenario if the units have a common facility. For example, two or more circuits each serving large scale PV systems reside on the same wood pole line and that pole line is susceptible to a single car pole event. A second example is where multiple hydro-generations units use the same common water source to generate and the failure of this source could result in mutliple generators being off-line. In both these situations the total output of all hydro-generation units connected to the one water source and all the PV units served by the same pole line should be utilized to determine the amount of load adjustment added to the annual peak demand.

For photovoltaic (PV) DG systems, only those locations with a single interconnection point capable of producing an output of 500 kW or greater should be considered for an adjustment to the historical peak load. When adding a load adjustment for PV systems of this size, the hour of the feeder and banks peaks (these may be different hours) must be compared with the PV output at the time of the facility peak to determine the approprate adjustment factor. If SCADA data is not available to determine the peak hour, then the calculated load shapes that reside in LoadSEER can be used. If billing or metering data is not available for the generation output, then the nameplate rating should be used to calculate maximum system output using a typical hourly PV output chart. The table below is the summer peak hourly percentage (hour beginning) output for non-residential flat roof PV profile from LoadSEER.

Month	Percentage Output by Hour																							
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
May	0%	0%	0%	0%	0%	0%	10%	29%	51%	70%	83%	93%	96%	95%	87%	74%	55%	33%	12%	1%	0%	0%	0%	0%
June	0%	0%	0%	0%	0%	1%	13%	32%	53%	72%	86%	95%	100%	99%	92%	80%	62%	39%	17%	3%	0%	0%	0%	0%
July	0%	0%	0%	0%	0%	0%	10%	27%	47%	67%	82%	93%	98%	98%	92%	79%	62%	40%	17%	3%	0%	0%	0%	0%
August	0%	0%	0%	0%	0%	0%	6%	21%	43%	63%	79%	90%	95%	94%	87%	75%	56%	32%	11%	0%	0%	0%	0%	0%
September	0%	0%	0%	0%	0%	0%	1%	16%	37%	57%	73%	82%	86%	84%	77%	62%	41%	18%	2%	0%	0%	0%	0%	0%
October	0%	0%	0%	0%	0%	0%	0%	9%	28%	47%	62%	71%	73%	70%	60%	44%	23%	5%	0%	0%	0%	0%	0%	0%



7.5 Add Customer Adjustments

Customer class adjustments can be added to the feeder or bank forecasts to take into account future new business projects which will add load to the feeder. If the current forecast has adequate load growth in the year the project is planned, then the project load should not be applied in the forecast as an adjustment. By not applying a load adjustment we are considering this project is part of the normal growth. If the amount of load being added exceeds the growth forecast in the year planned, but does not exceed the 10 year total growth forecast then the adjustment should be identified as "shifting the horizon load" when entering the adjustment and it should be applied when preparing the forecast. Shifting the horizon load does not increase the total load growth forecast over the 10 years, but only moves the forecast growth forward in time to the year when the new business load will happen and then adjusts the remaining year's forecast growth to meet the original 10 year forecast. If a new business load is larger than the forecast 10-year growth, then the load forecast is increased to accommodate the new peak load.

For transmission customers, self-generating customers or other third-party customers who have entered into contracts with PG&E to provide service during an unexpected interruption of their normal source, these contract amounts should be added as a fixed MW adjustment to the forecast on the feeder and bank to which they are connected, with appropriate documentation in the comment field. If a self-generating or other third party customer's normal source of power is interrupted such that PG&E serves all or part of their load during the recorded peak demand, then the observed peak must be adjusted to account for this additional abnormal load.

7.6 Calculation of New Customer loads

An important part of the planning process is the validation of new loads provided by customers on new applications for service. Customers often provide connected loads rather than maximum demand loads. It is important to distinguish between the two.

Connected load is defined as the sum of the continuous power ratings of all load-consuming apparatus connected to the utility.

Maximum demand load is defined as the sum of the continuous power ratings of all load-consuming apparatus that could be expected to be on simultaneously. For example, maximum demand load excludes the lesser of items when only one would be on at a time, such as heating and cooling. Maximum demand load accounts for load diversity whereas connected load does not. Considersations should also be made for season and time of day of maximum demand.

Maximum demand loads should be used when looking at distribution system impacts. A new customer's maximum demand load is best obtained from similar size and type customers. Examples include Target, Costco, and Safeway stores, hospitals, sporting goods stores, residential high-rise buildings, distribution centers, warehouses and office buildings.

If no similar customers can be found, Table 4-3 from the Electric Design Manual can be used to obtain watts per square foot for certain customer types such as offices, refrigerated warehouses, colleges, and shopping malls.

For new pumping load, maximum demand can be calculated from horsepower using the following conversion factor:

$$1\text{hp} \times 746\text{W/hp} \times 0.6 \text{ diversity factor or}$$

$$0.45 \text{ kW/hp}$$

When new customer loads meet the criteria for being included as adjustments to a bank or feeder in LoadSEER, the following information should be determined:

1. Does the time of customer's maximum demand coincide with the time of bank and feeder peak? If not, then LoadSEER will determine the appropriate scaling factor by applying the adjustement shape to the feeder shape. Therefore, it is essential that new load be included in LoadSEER with the most appropriate adjustment shape to ensure the correct adjustment magnitude is applied to the feeder peak based on the feeder shape.
2. Is the customer's maximum demand greater in the summer or in the spring/fall/winter? Examples include colleges that have reduced usage during June-August and wastewater treatment facilities that run additional pumps to keep up with storm water volume only in the winter.
3. Will the customer shift loads, utilize batteries or DG to maximize time of use rates shifting maximum demands to off peak hours?

LoadSEER includes different types of load profiles (load shapes) or generation profiles that are used to determine the impact of known new loads to the forecast at time of peak. The program also calculates the feeder's future load shape based on the type of new customer and forecast adjustment projected on the circuit over the next 10 years.

The Large Load Connection Standard (TD-9101S-01) and the Large Load Connection Procedure (TD-9101P-01) generally should be followed when dealing with new customer demand in excess of 2 MW. TD-9101P establishes a uniform process to respond to customers' service requests and defines the roles and responsibilities of various team members. Additionally, it provides guidelines for the engineering advance and sets timelines for PG&E's response to the customer.

7.7 Determine load growth rate using both regression and geospatial methods

The LoadSEER program is designed to forecast 10 years of future non-simultaneous load at the circuit, bank, and DPA level by using two different forecasting methodologies: LoadSEER FIT and LoadSEER GIS.

The LoadSEER FIT methodology uses a traditional regression forecast based on historical load peaks for the past 12 years, normalized for both weather and economy. The program performs a standard 1, 2 or 3 variable regression model analysis using 12 years of historical load data, temperature data and various economic variables. The economic variables provided by Moody's Economic & Consumer Credit Analytics, are compared with the historic kWH consumption load history from the various customer classes throughout PG&E's service territory and only the 8 variables with the highest regression fit are used in the forecast. Some economic variables are only available based on local relevance. For example, a water allocation variable is available in agricultural areas South of the Sacramento Delta where peak loads are driven by agricultural pumping when low State and Federal water storage cause a severe reduction in water allocations to agricultural contracts. If there are no variables that have a reasonable fit, then a flat or no growth regression is applied.

Historical peak loads are weather normalized during the regression analysis and the final forecast shows the load normalized to a 1 in 2 year (50th percentile) and 1 in 10 year (90th percentile) weather event. Each bank and feeder is assigned to a weather station to be used for this function. If the weather variable is selected in the regression forecast, then the current year's load is adjusted up or down to reflect a 1 in 2 weather event, prior to adding the future load forecast.

PG&E's geospatial load growth forecast (LoadSEER GIS) begins with the most recent approved California Energy Commission (CEC) PGE TAC Peak and Energy Forecast: Mid Baseline growth forecast. Transmission-level growth and known new distribution loads are removed from the CEC load growth forecast. The resultant growth is broken out by customer class (residential, industrial, commercial, and agricultural). This growth is then allocated to the distribution feeders of the PG&E system using geospatial analysis and the LoadSEER GIS tool as described below.

The LoadSEER GIS methodology involves a spatial forecasting program that utilizes proprietary algorithms and satellite imagery to score each acre of PG&E's service territory for the likelihood of increased load. The LoadSEER GIS model also includes 20 years of historical aerial imagery of land use to determine the historical type of expansion that has occurred in an area and to facilitate the scoring of each acre. The LoadSEER GIS spatial model is further enhanced by utilizing a mega-watt-hour (MWh) model that is weather normalized and also includes economic variables. The algorithm used by LoadSEER GIS evaluates and scores each acre based on the likelihood of increased load by customer class (domestic, commercial, industrial, or agricultural) The program then allocates the California Energy Commission's (CEC) annual simultaneous distribution system peak load growth projections for each customer class to each parcel and feeder by identifying which feeder is in the closest proximity to the acre. Because the CEC forecast assumes very little new agricultural load as being online during the July/August summer peak day, local engineers should identify all planned new agricultural load, including new cannabis growing facilities as a load adjustment in their load forecast.

LoadSEER GIS utilizes PG&E's distribution transformers' longitude and latitude coordinates and distribution circuit connections to produce a weather adjusted kWH consumption forecast by customer class for each feeder. It also uses the customer class connected to each transformer to determine the attraction of future loads of similar types in a geo-spatial model. The geo-spatial model within LoadSEER GIS establishes attractors or detractors for new growth by customer class based on specific criteria which results in each 50 acre parcel being scored for reception of new load. The proximity to certain known geo-spatial features modifies the scoring each 50 acres parcel receives for the attraction of future new load by customer class. An example of this is the attraction of new residential customers to existing residential customers, but the detraction of new residential customers to existing industrial load (in plain words, most people don't normally want to live next to industrial regions). There are also attractors for certain customer classes based on proximity to certain types of roadways. Example of this is the increased attraction of new commercial customers to major surface intersections that are unoccupied or are in areas where new major surface streets have been added in a city. Industrial customers are attracted to major highways, railroads and shipping lanes; while residential customers generally prefer to live within 7 miles of major highways but not closer than 0.5 miles. Residential customers also have attraction to hospitals, schools and commercial centers/malls and normally locate in those areas with minor surface streets. There are detractors in the scoring for such things as wetlands, waterways, steep sloped property or other known "no build" areas.

LoadSEER uses customer class load shapes to produce a peak 576-hour growth load shape that is applied to the simultaneous peak forecast allocations and converts it to a non-simultaneous customer class peak values. This process is completed for all circuits within PG&E's service territory, for each of the future 10 years.

The output of this spatial forecast is imported into the LoadSEER FIT program and provides the distribution engineer with two forecasts to consider during the annual forecasting process. One regression forecast based on historic load and a second spatial forecast based on the geo-spatial simulation of future load derived from CEC system growth. Having two different forecasts provides the engineers with valuable information to help them finalize and select an accurate forecast. By comparing the forecast to each other, considering their general slopes, their adjusted R-Square regression values, and quality of the historical data or temperature adjustment values, engineers have the capability to analyze and compare the two forecasts. Having two forecasts that appear similar in values and slopes with good adjusted R-Square values, produced by different programs that use statistically valid methodologies and algorithms, provide the engineers with a greater confidence in the quality of the forecast. LoadSEER also provides the capability of blending the two forecasts by utilizing adjustable percentages of the regression and spatial forecasts to develop a resultant. Currently, engineers are instructed to use the LoadSEER

GIS forecasts as the default since it has a direct link to the CEC/Corporate forecast values, unless there is specific data (new applications, customer discussions, or local ordinance changes) that does not support the spatial forecast. In this case, blending or adjustments made by the local engineer are used to modify the spatial forecast for the following year to account for this local knowledge. Justification for blended forecasts are recorded in LoadSEER and should be approved by the assigned Senior Engineer.

7.7.1 Distributed Energy Resource Capacity

Load impacts from existing interconnected small distributed generation (DG), solar (PV), demand response (DR) and energy efficiency (EE) measures are embedded in the annual historic observed peak loads. For all DER systems (machine based as well as other types of DERs) greater than 500 kW, load adjustment are added to the annual bank and feeders peaks to account for the output of the single largest unit (Section 7.4). This adjustment is necessary to ensure system distribution facilities are adequately sized to serve all customer load during any long-term (more than 24 hours) unavailability, absence or failure of these DERs systems.

LoadSEER also allocates the DER forecast using a similar geo-spatial approach as described above for load growth allocation. The starting point for each DER scenario is the adopted California Energy Commission's (CEC) California Energy Demand (CED) forecast. For each of the individual DERs (residential PV, non-residential PV, energy efficiency, electric vehicles, and demand response) methodology has been developed to allocate projections consistent with the CED's PG&E system level projections to each of the approximately 3,200 feeders. Demographic variables used for DER allocation include various indicators such as consumption for each customer class, generation by feeder, historical PV adoption by zip code, s-curve trending model, observed penetration levels, daily peak diversity factors, weather zones, and many other factors specific for each type of DER.

An adjustment for each type of DER including the appropriate shape file is available for application at the feeder level through the Adjustment tab. When applied in the Adjustment tab, the DER forecast for PV, DR, and EE are included in the final corporate GIS forecast as a "Before Projects" adjustment.

In addition to performing load and DER forecasting, the LoadSEER program includes planning functionality. LoadSEER retains the rated capacity of each bank and circuit and can identify when the forecast exceeds the normal capabilities of the load limiting component. It also allows the engineers to adjust future capacity based on planned or proposed projects. LoadSEER tracks load transfers between circuits and banks, both past and future, and uses these load changes to generate the correct regression forecast that reflects the increase or decrease of forecast due to the net transfers. Growth rates and current year peak load data can be exported into PG&E's circuit modeling software (CYME) to allow the engineers to do circuit level planning for 3 years into the future.

8.0 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 substation 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, but 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.

8.1 Detailed Procedures

The decision to expand distribution facilities in an area is determined by following the steps listed below. Each year these steps shall be completed for all banks and feeders for the summer peaking season. Banks and feeders with winter peak loads that exceed the summer peak loads will be analyzed for both winter and summer critical capacity deficiencies. The steps are summarized below.

<u>8.1.1 Normal Bank Planning</u>

NOTE: It is expected that all major substation projects necessary to increase normal capacity will be identified, planned, and have advanced authorization at least 36 months before the project needs to be operational. Exceptions for emergent projects will be reviewed on a case by case basis.

Step 1- For each future year to be studied, forecast the magnitude of the load using the latest version of the LoadSEER distribution load growth program. (Refer to the Load Forecasting Section)

Step 2- Determine the projected bank and feeder deficiencies using the appropriate facility capability compared to the forecast demand. Determine whether any of these deficiencies can be corrected by load transfers in lieu of increasing the capability of any facilities. Each proposed load transfers should be reviewed to determine if any of the following issues are created:

a) Feeders with customer counts greater than 6000

b) Feeder loads greater than 600 Amps

c) Feeder loads greater than 75% of emergency capacity

d) A large DG unit is included in the proposed transfer

If any of these issues are created by a potential load transfer to eliminate a normal deficiency, then a capacity increase should be evaluated in lieu of the transfer. In addition if a FLISR scheme or end of line protection settings are disrupted by a load transfer to eliminate a forecast deficiency, then the scheme must be reconfigured and/or protection device settings adjusted to account for the load transfer and placed back into service by a capacity project.

Step 3- Formulate alternative plans to correct the capacity deficiencies indicated by Step 2 that cannot be corrected by cost-effective load transfers. Include in the plans minor work necessary for feeder ties, reinforcements, and/or switches necessary to enable the transfers. Review load break capabilities of new proposed normal open points and include work to upgrade as necessary.

Step 4- Evaluate alternative plans, including DERs and select an overall preferred plan to correct any remaining future bank or feeder deficiencies.

Include required substation level capacity additions or DER related projects in the project section of the LoadSEER forecasting program. It is expected that transformer bank and feeder additions or replacements necessary to increase normal capacity are identified 5 years before the project needs to be operational. New bank or feeder additions that were not identified in the current 5 year planning window will be considered emergent work.

Advance Authorization for all new capacity projects are required to initiate a new project. New substations usually require a 10 year lead time to allow for permitting, property acquisition and site development.

8.1.2 Normal Feeder Component Planning

NOTE: It is expected that all major reconductoring or other significant reconstruction projects necessary to increase normal capacity on the distribution system outside of the substation will be identified, planned, and approved 24 months before the project needs to be operational. Exceptions for emergent projects will be reviewed on a case by case basis.

Step 5- Use CYME to develop load flow models to verify switching needed to correct bank or feeder deficiencies identified in step 2. 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 6- Use CYME to analyze distribution line deficiencies that cannot be corrected by load transfers. Consider new switches, power factor improvement, new feeder ties, conductor replacement, converting load to a higher voltage, swapping feeders between transformer banks, and distributed generation. Adopt the preferred plans to correct the deficiencies.

Step 7- Repeat Steps 6 for the second and third year of the feeder planning process.

8.1.3 Emergency Bank Loss Planning

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

Step 8- Assume an individual bank outage for the upcoming peak load period. For each bank 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 necessary in (1) above in excess 10 manual transfers.

Step 9- If customers are projected 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 8.

Step 10- 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 11- Provide Substation Asset Strategy with a list of all emergency bank deficiencies for preparation of mobile/transportable transformer installation plans.

Step 12- Formulate alternative plans to correct the deficiencies indicated in Steps 8 and 10. Submit a division wide emergency bank deficiency summary to the appropriate distribution planning manager for system wide prioritization purposes.

8.1.4 Emergency Feeder Loss Planning

NOTE: After all emergency bank loss studies are completed as outlined in Steps 8 through 10, the electric distribution engineers shall proceed with emergency feeder loss planning, as described in Step 13.

Step 13- Assume an individual feeder outlet outage during the upcoming peak load period. For each feeder 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 MWs of load left out of service after exhausting all transfers, (2) the number of transfers required in (1) above in excess of 3.

Step 14- 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 a failed outlet can be replaced within 24 hours.

Step 15- Formulate alternative plans to correct the deficiencies indicated by Step 13. Submit a division wide feeder emergency deficiency summary to the appropriate distribution planning manager for system wide prioritization purposes.

8.2 DER – Identification of Candidate Deferral Projects

Beginning in 2018, PG&E will file annual GNA and DDOR reports that will be used in developing DER alternatives for Candidate Defferal Projects.

8.2.1 GNA and DDOR Requirements

a) Develop the annual GNA by June 1 using the most recent forecasting and planning cycle data, include all forecast grid needs within the 5 Year Investment Planning window. The GNA report includes the following data points:

    i. By substation, circuit, and/or facility identification, identify the location and the grid need.

    ii. The distribution service required

    iii. Forecasted need date

    iv. Existing equipment rating

    v. Forecast percentage deficiency above the existing equipment rating.

b) The GNA filing will also include planning asssumptions in the form of demand and DER forecast used to develop the grid needs. This report includes the following data points:

    i. By substation, circuit, and/or facility indentification

    ii. Peak load by year

    iii. DER growth by category by year

    iv. ICA planning values based on forecasting assumptions

c) Develop the list of planned investments to be included in the DDOR filing on September 1. This report includes the following data points:

i. By substation, circuit, and/or facility indentification

ii. Project desciptions

iii. Type of equipment to be installed or replaced

iv. Additional information relavent to the project

v. In Service date

vi. Deficiency (MW, %)

vii. Distribution service

viii. Estimated LNBA range for the most likely traditional wires alterantive to correct identified deficiency

d) Between June 1 and September 1 of the current year's planning cycle screen each capacity deficiency identified for an equipment upgrade for potential DER deployment.

i. The first screen is a project timing screen to ensure that cost-effective DER solutions procured have sufficient time to fully deploy and begin commercial operation prior to the projected need for the distribution service provided by the DER.Anticipated timeline includes approximately 12 months for contract solicitation and another 18-24 monts to deploy and begin commercial operations once the contracts are effective. Therefore, projects with required in service dates within a 36 month window are screened out as potential DER candidate projects.

ii. The second screen is the distribution service screen that consists of the four distribution services listed below:

a) Distribution Capacity – Services are load-modifying or supply service that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing new loading on the desired distribution infrastructure.

b) Voltage Support – Service are substation and/or feeder level dynamic voltage management service provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems.

c) Reliability (Back-Tie) – Services are load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations.

d) Resiliency (Microgrid) – Services are load-modifying or supply services capable of improving local distribution reliability or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations.

e) Projects that pass both screens will be included in the Candidate Deferreal Projects list for DDOR filed annually on September 1. Each planned investment included in the DDOR shall be characterized by the following attributes:

   i. Project Description
   ii. Substation
   iii. Circuit
   iv. Deficiency (MW, %)
   v. Type of equipment to be replaced or installed
   vi. Need timing and duration
   vii. Need events per year
   viii. Distribution service required
   ix. In service date
   x. Unit cost of traditional mitigation
   xi. Estimated LNBA range for the most likely traditional wires alterantive to correct identified deficiency

f) Each project included on the Candidate Deferral Projects list presented to the DPAG will be prioritized using a Deferral Criteria metric of: Cost Effectiveness, Market Assessment, and Forecast Certainty.

g) Between September 1 and December 1, the DPAG will review the annual GNA and DDOR and provide advisory input.

h) RFOs for projects that are considered for DER deferral will be finalized by December 1.

Projects with DER RFOs will remain in the 5 Year Investment Plan as identified for the traditional wire alterantive until the RFO has been submitted and approved.

9.0 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 or more of capacity upgrades are required to be used in the capacity equivalency and cost comparison. For banks (new or upgrades) a minimum of five years of capacity upgrades is required. For new substations a minimum of ten years of capacity upgrades 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.

10.0 REVISION NOTES

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

Rev. 01 – 8/1/2016 Update criteria with new load forecast information, DER planning and removal of CPPRD document.

Rev. 02 – 6/1/2018 Update criteria with 1) new DER load forecasting methodology 2) feeder loading maximum criteria, and 3) switch emergency ratings. Included new Appendix C, Integrated Capacity Analysis section.

APPENDIX A

List of all Distribution Planning Areas and their Area Designation.

Distribution Planning Area Designation

Division	DPA	Designation
Central Coast	Carmel Valley	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	Urban/Suburban
Central Coast	Santa Cruz Area	Urban/Suburban
Central Coast	Seaside-Marina	Urban/Suburban
Central Coast	Soledad/Greenfield	Rural
Central Coast	Watsonvlle (12/21kV)	Urban/Suburban
Central Coast	Watsonvlle (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	Delta	Urban/Suburban
Diablo	Pittsburg	Urban/Suburban
Diablo	Walnut Creek 12 kV	Urban/Suburban
Diablo	Walnut Creek 21 kV	Urban/Suburban
East Bay	Oakland Edes / Station "J"	Urban/Suburban
East Bay	Oakland K-X	Urban/Suburban
East Bay	Richmond North	Urban/Suburban

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Division	DPA	Designation
East Bay	Richmond South	Urban/Suburban
East Bay	Oakland "C / D / L"	Urban/Suburban
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	Urban/Suburban
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

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Division	DPA	Designation
Los Padres	Sisquoc	Rural
Mission	Fremont 12 kV	Urban/Suburban
Mission	Fremont 21 kV	Urban/Suburban
Mission	Hayward	Urban/Suburban
Mission	Livermore	Urban/Suburban
Mission	San Ramon - Vineyard	Urban/Suburban
Mission	Tri-Valley	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 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	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	Rural
North Coast	Big Lagoon	Rural
North Coast	Petaluma 12 kV	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

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Division	DPA	Designation
North Coast	Ukiah Valley	Rural
North Coast	Willits	Rural
North Coast	Willow Creek	Rural
North Valley	Antler	Rural
North Valley	Bucks Creek	Rural
North Valley	Burney	Rural
North Valley	Cedar Creek	Rural
North Valley	Chester	Rural
North Valley	Chico	Urban/Suburban
North Valley	Clark Road	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	Urban/Suburban
North Valley	Rising River	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 Peninsula 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

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Division	DPA	Designation
Sacramento	Peabody	Urban/Suburban
Sacramento	South Colusa	Rural
Sacramento	Suisun / Cordelia	Urban/Suburban
Sacramento	Vacaville	Urban/Suburban
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	Urban/Suburban
San Francisco	Potrero	Urban/Suburban
San Francisco	HuntersPt	Urban/Suburban
San Francisco	Martin	Urban/Suburban
San Francisco	Mission	Urban/Suburban
San Francisco	Larkin	Urban/Suburban
San Jose	Evergreen	Urban/Suburban
San Jose	Morgan Hill/Gilroy	Urban/Suburban
San Jose	Milpitas 12 kV	Urban/Surburban
San Jose	Milpitas 21 kV	Urban/Suburban
San Jose	Downtown San Jose 12kV	Urban/Suburban
San Jose	South San Jose 21KV	Urban/Suburban
San Jose	West San Jose	Urban/Suburban
San Jose	Downtown San Jose 4KV	Urban/Suburban
San Jose	East San Jose	Urban/Suburban
San Jose	North San Jose 21 kV	Urban/Suburban
San Jose	North San Jose 12 kV	Urban/Suburban
San Jose	South San Jose12KV	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	Yuba Foothills	Rural

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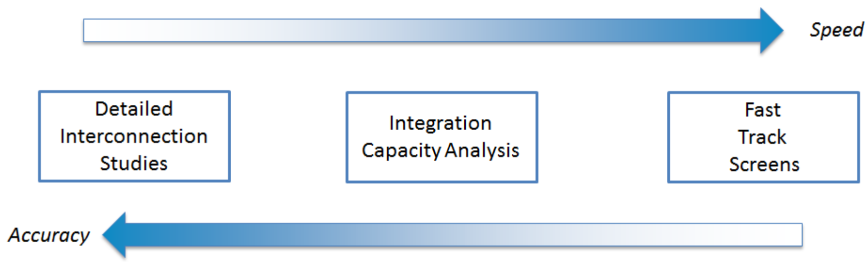
Division	DPA	Designation
Sierra	North Placer	Urban/Suburban
Sierra	Pike	Rural
Sierra	South Placer	Urban/Suburban
Sierra	Yuba City	Urban/Suburban
Stockton	Angles Camp	Rural
Stockton	Clay	Rural
Stockton	Corral	Rural
Stockton	Jackson	Rural
Stockton	Linden 12 kV	Rural
Stockton	Lodi	Rural
Stockton	Manteca 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	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	Rio Mesa	Rural
Yosemite	Sonora	Rural
Yosemite	Spring Gap	Rural
Yosemite	Storey	Urban/Suburban
Yosemite	Westley	Rural

APPENDIX B

Hosting Capacity

Introduction

At a high level, PG&E's Hosting Capacity (a.k.a. Integration Capacity Analysis, ICA) methodology takes the components of an interconnection study process to develop a streamlined approach to identifying available capacity. PG&E's streamlined Integration Capacity Analysis provides faster results than a detailed interconnection study along with a higher level of accuracy than a Fast Track screen.[2] PG&E's approach is similar to the Electric Power and Research Institute (EPRI) streamlined hosting capacity for PV Interconnection. Like EPRI, PG&E's framework provides a methodology that can be regularly applied to analyze its entire service territory.[3]



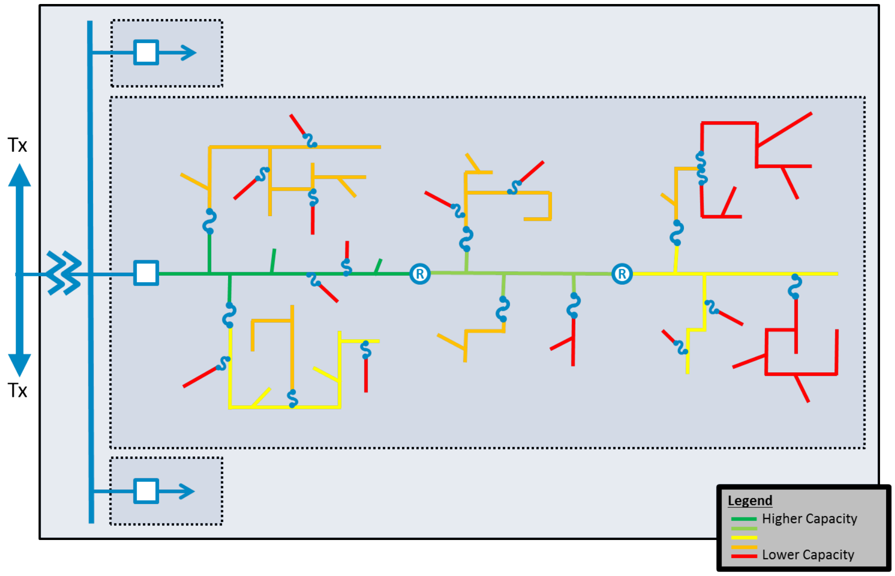
The following are uses for this data:

1. Assist in interconnection process for quickly identifying major issues with a new application
2. Compare against DER forecasts to find areas needing further study to determine future planning needs due to DER issues

The figure below is a illustration showing how ICA could be expressed across a circuit. The intent is to express the amount of capacity a resource has at different parts of the circuit.

[2] Fast Track Screens are a set of technical screening questions in the California Rule 21 Interconnection Tariff and FERC Wholesale Distribution Tariff that are meant to determine if detailed study is needed using a basic set of engineering data.

[3] See EPRI published report "A New Method for Characterizing Distribution System Hosting Capacity for Distributed Energy Resources: A Streamlined Approach for Solar Photovoltaics." http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?productId=000000003002003278.

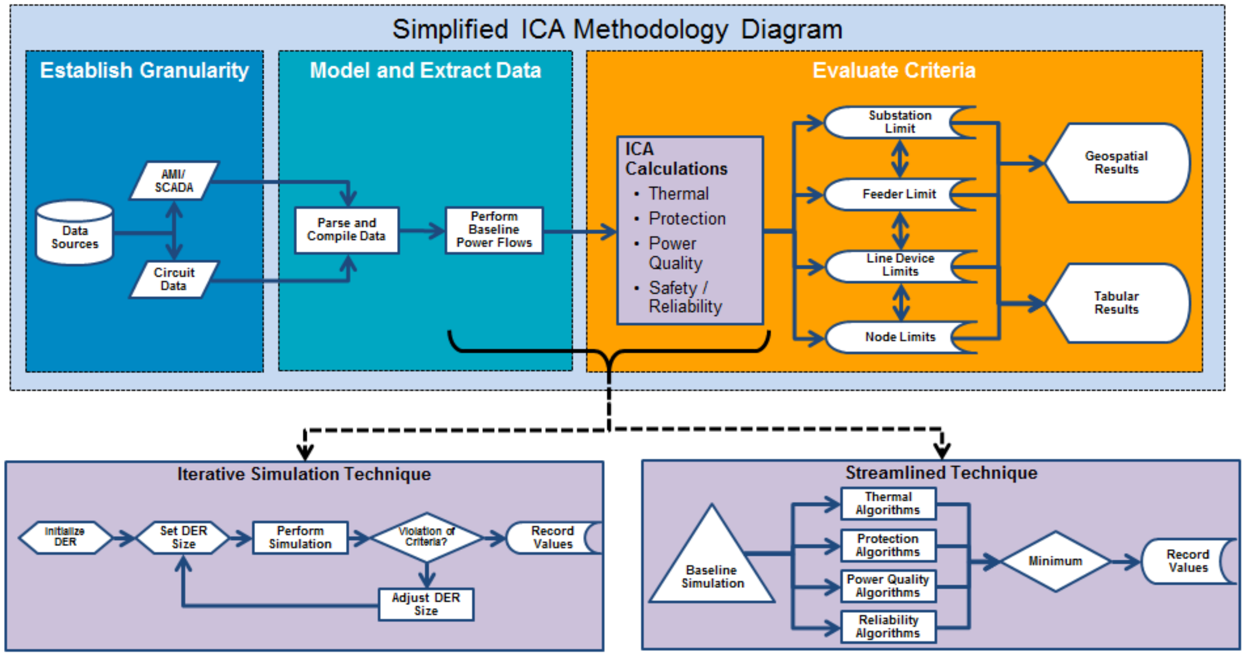


Calculation Techniques

The ICA calculation techniques provide approaches towards evaluating distribution system limits to host DER across the entirety of a utility's service territory. The specific technique to the methodology has two main goals to ensure a successful and scalable analysis for the DRP which are (1) streamlined efficiency and (2) improved detail and granularity. These two objectives in general can lead to diverging paths for a methodology, but the goal of the demonstration project is to determine if there is a best path forward to strike a balance between the two. There are two calculation techniques being explored within Demo A. These are:

1. **Streamlined Abstract Calculation**
   - Promotes streamlined efficiency through reduced simulation and principles of abstraction and using engineering formulas
   - Simplified or abstracted evaluation based on algorithms with input from a baseline power flow
   - Requires less processing resources. Enables more batch output insights (e.g., for DER planning where multiple scenarios are needed)
   - May prove less precision in accuracy since resource is not directly modeled

2. **Iterative DER Modeling Simulation**
   - Promotes detail and accuracy through direct modeling and observing simulated conditions
   - Increased confidence in accuracy due to direct modeling of resource
   - Better for more accurate representation of DER impact to electrical conditions of circuit.
   - Requires powerful computing through simulation of iterative placement/upsizing of DER in model to simulate very precise conditions with many power flows



Criteria Analyzed

PG&E's Integration Capacity Analysis methodology uses the Load Forecasting and Power Analysis tools to evaluate certain power system criteria within the selected nodes and line sections to determine DER capacity limits on each distribution feeder. Integration Capacity Analysis results depend on the most limiting power system criteria. That is, whatever power system criterion has the most limiting capacity result, will establish the overall Integration Capacity result for that line section. Ideally, each criterion should be analyzed independently, to better understand the impact of each power system criteria. Table 2-8 summarizes the evaluation criteria for Integration Capacity. This section outlines the Power System criteria and sub-criteria to comprehensively evaluate capacity limits, including the criteria analyzed by PG&E for its Initial Integration Capacity Analysis.

Thermal	**Exceeding thermal limits of specified equipment**
Voltage / Power Quality	**Creating power quality conditions outside acceptable ranges**
– Transient Voltage	Short time period relative voltage variation outside acceptable limits
– Steady State Voltage	Exceeding voltage outside ANSI voltage range
– Voltage Regulator Impact	Creating conditions for regulator to improperly manage voltage
– Substation Load Tap Changer Impact	Creating conditions for LTC to improperly manage voltage
Protection	**Creating issues that impact protection schemes**
– Protective Relay Reduction of Reach	Reducing bulk system fault contribution to protection devices
Safety/Reliability	**Creating conditions that diminish operating reliability and safety**
– Transmission Penetration	Limiting reverse flow into the transmission system

– Operational Flexibility	Reducing possible reverse flow in abnormal switching conditions

Thermal Criteria

Thermal criteria determine whether the addition of DER to the distribution feeder causes the power flow to exceed any equipment thermal ratings. These limits are the rated capacity of the conductor, transformer, cable, and line devices established by IOUs' engineering standards or equipment manufactures. Exceeding these limits would cause equipment to potentially be damaged or fail, therefore mitigation measures must be performed to alleviate the thermal overload.

An hour-by-hour calculation is performed to compare the equipment thermal limits given a certain amount of DERs. The Integration Capacity value is the highest value of DER which can be connected at a node which does not exceed the thermal rating of any piece of upstream equipment on the distribution circuit or substation.

The table below shows the equations and flags used to evaluate thermal limitations in the streamlined method and the iterative method, respectively.

Streamlined	kW Load Limit [t] = (Thermal Capability − (Load[t] − Generation [t])) kW Generation Limit [t] = (Thermal Capability + (Load[t] − Generation [t]))
Iterative	• CYMDIST ICA Module: "Thermal Loading" • Power flow tool flags when abnormal loading conditions occur on the circuit.

In the equations, "kW Load Limit [t]" refers to the integration capacity value for energy consuming DERs at hour t; "kW Generation Limit [t]" refers to the integration capacity value for energy producing DERs at hour t; "Thermal Capability" refers to the 100% of the most limiting equipment's loading limit from the substation to the node being analyzed; "Load[t]" refers to gross load at hour t; "Generation[t]" refers to gross generation at hour t for the node being analyzed. The "Load [t] – Generation [t]" could be thought of or replaced by net load. Load and Generation may be stored and evaluated separately to help evaluate contingency scenarios which are not assessed at this time.

The iterative technique evaluates the loading conditions of all the assets on the feeder for each iteration of evaluation. When equipment thermal ratings are exceeded by their respective power throughput then the tool flags this condition. This condition then informs the ICA module that a thermal limit has been exceeded.

Power Quality / Voltage Criteria

Power Quality / Voltage Criteria determine whether the addition of DER to the distribution feeder causes the distribution primary feeder to operate outside of allowable power quality and voltage limits which can lead to customer facilities and equipment damaged. DER planning must include power quality analysis so that new resources are evaluated for sufficient voltage and quality of service.

There are both steady state voltage limits and voltage fluctuation limits established by IOUs' Rule 2 and Engineering Standards, which are drawn from American National Standard (ANSI) C84.1 - 2011 Range A.

Steady State Voltage

The table below shows the equation and flag used to evaluate steady state voltage limitations in the streamlined method and the iterative method, respectively.

Streamlined	$\text{kW Limit [t]} = \frac{\left(\text{Voltage Headroom [t] (per unit)} * V_{LL}^{2}\right)}{\left(R * PF_{DER} + X * \sin\left(\cos^{-1}\left(PF_{DER}\right)\right)\right)} * PF_{DER}$ $\mid \text{Voltage Headroom [t]} = \frac{\lvert\text{Rule 2 Limit} - \text{Node Voltage[t]}\rvert}{\text{Base Voltage}}$
Iterative	• CYMDIST ICA Module: "Abnormal Voltage" • Power flow tool flags for steady state over-voltage and under-voltage abnormal conditions

Steady state voltage changes can be generally estimated using the Ohm's Law principles. This limit is determined by the headroom of voltage from the simulated voltage at the node to the Rule 2 steady state voltage limits (i.e., the voltage shall remain in the range between 0.95pu and 1.05pu).

In the equation, "V_{LL}" refers to the actual circuit voltage at hour "t"; "R" and "X" refer to the line impedance to the node under study, "PF_{DER}" refers to the power factor of DERs, which is assumed at 1 in the study. Section **Error! Reference source not found.** evaluates smart inverters and DER operating at other power factors.

The iterative technique evaluates the voltage conditions of all the assets on the feeder for each iteration of evaluation. When abnormal voltage is observed outside of the prescribed ranges then the tool flags this condition. This condition then informs the ICA module that a thermal limit has been exceeded.

Voltage Variation

Voltage fluctuation is evaluated to ensure deviations from loads and resources on the grid do not cause harm or affect power quality to nearby customers. The voltage fluctuation limit used in Demo A is 3%[4], which is prescribed by engineering standard practices. This criterion is used in order to minimize the impact of fluctuations caused by DERs on other customers. The table below shows the equation used to evaluate voltage fluctuation limitations in the streamlined method.

[4] The 3% limit can be found in IEEE Std 1453-2015 "IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems" in Table 3 for medium voltage systems.

Streamlined	$\text{kW Limit} = \dfrac{\left(\text{Deviation Threshold (per unit)} * V_{\text{LLnom}}{}^{2}\right)}{\left(R * PF_{DER} + X * \sin\left(\cos^{-1}\left(PF_{DER}\right)\right)\right)} * PF_{DER}$
Iterative	• CYMDIST ICA Module: "Voltage Variation" • Compare node voltages with DER on and off • Highest value recorded before deviation threshold is surpassed

The equation used for voltage fluctuations is fundamentally derived from Ohm's law. In the equation, "Deviation Threshold" refers to the voltage fluctuation limit; "V_{LLnom}" refers to the nominal circuit voltage; "R" and "X" refer to the Thévenin impedance to the node under study, "PF_{DER}" refers to the power factor of DERs, which is assumed at 1 in the study. Section **Error! Reference source not found.** evaluates smart inverters and DER operating at other power factors.

Iterative methods perform a power flow with the DER on and off and compare the node voltages before and after. All voltage devices on the feeder are locked in order to understand the true voltage variation before the voltage devices correct for such changes. When any node voltage deviation surpasses the set threshold then the DER size is recorded for that node.

Voltage Regulator Impact

Voltage regulators monitor specific conditions of the grid and dynamically adjust voltage based on changes to the system loading conditions. One of these conditions is monitoring current flows in order to estimate what the lowest voltage downstream would be. Historically the assumption was that current flow was always in the forward direction which assumes a voltage drop downstream. When DER is connected downstream from the regulator, with the current flow at the voltage regulator will reverse and the voltage rise due to the DER. If the regulator does not have the proper settings to understand this it will regulate the voltage improperly. Regulators now have options to consider the reverse flow conditions properly and manage the voltage while generation is downstream. When regulators do not have these settings and see reverse flow the analysis will flag for issues.

Streamlined	$\text{kW Limit [t]} = (\text{Load[t]} - \text{Generation [t]}) \mid \text{where limit} > 0$
Iterative	• CYMDIST ICA Module: "Reverse Flow" • Flag for reverse current through voltage regulator • Applied only to devices without distributed generation mode settings

The iterative method might not specifically need this screen if it models the regulating equipment operations. Currently the CYMDIST ICA module locks all regulating equipment in place. This means that the current form of iterative would not capture the full effect of reverse flow through voltage regulators. The ICA module also does not specifically separate reverse flow through different devices. Because of this, the regulator reverse flow was evaluated within the Operational Flexibility criteria for Demo A.

Protection Criteria

Protection Criteria determine whether the addition of DER to the distribution feeder reduces the ability of existing protection schemes to monitor the grid to promptly disconnect areas during abnormal system conditions (reduction of reach).

If a fault occurs electrically downstream of a distribution protection device, the device is designed to detect and interrupt high magnitude fault current as to isolate the affected portions of the circuit from the rest of the system. Typically, these devices are programed with defined Minimum Trip current settings so that the device does not open during normal peak loading conditions but can still detect the lowest fault current possible within its defined protection zone and trip quickly enough to safely isolate the affected system.

If a power producing DER is placed electrically downstream of the protection device, it is a source of power that can contribute to a fault and lower the fault contribution detected by upstream protection devices. The reduction of ability to detect a faulted condition is referred to as "reduction of reach." When DER causes significant reduction of reach the distribution protection device may not operate as designed when sufficient DER is connected beyond a protection device. DER planning must account for its impacts to protection schemes to keep employees, public, and assets safe from potential electrical disturbances on the distribution system.

The table below shows the equation and flag used to evaluate the reduction of reach limitations in the streamlined method and the iterative method, respectively.

Streamlined	$\text{kW Limit} = \dfrac{\text{Reduction Threshold Factor} * I_{\text{Fault Duty}} * \text{kV}_{\text{LL}} * \sqrt{3}}{\left(\dfrac{\text{Fault Current}_{\text{DER}}}{\text{Rated Current}_{\text{DER}}}\right)} * \text{PF}_{\text{DER}}$
Iterative	• CYMDIST ICA Module: "Protective Reduction of Reach" • Power flow tool flags for fault current lower than prescribed limits

The streamlined equation follows the screening concept that possible issues may arise when DER fault current reaches a certain percentage of fault duty. In this equation, "Reduction Threshold" refers to the threshold of DER contribution, which is 10% in the study, as specified in Rule 21; "$I_{\text{Fault Duty}}$" refers to the maximum fault duty current seen at each node; "kV_{LL}" refers to the circuit nominal voltage; "Fault $\text{Current}_{\text{DER}}$/Rated $\text{Current}_{\text{DER}}$" refer to DER fault current per unit contribution, which is assumed as 1.2 in the study for inverter based DERs[5].

The iterative method performs a fault flow analysis to the protection limitation. This determines the specific fault contribution that would occur based on the impedance between the fault and the

[5] National Renewable Energy Laboratory, "Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources", p.p.33

generator and to ensure that the end of line fault current can still be seen. The device fault current must exceed the minimum trip value by a specific threshold as prescribed by protection engineering practices. A generator is placed at the end of line fault location for each protective zone and then simulates a fault at that node. When protection device currents do not meet set thresholds then the DER value is recorded.

Safety / Reliability Criteria

Safety and Reliability must also be analyzed as part of Integration Capacity. High penetration scenarios of DER have the potential to cause excess back flow that can result in congestion and affect reliability during system events. Safety and reliability is assessed to ensure that all customers are served reliably and safe under the abnormal operating conditions and high penetration scenarios that can occur on the electric grid.

Currently the Safety/Reliability Criteria is mainly assessed based on reverse flow at specific points on the system. There are some valid reasons when general reverse flow limitations are needed while some components of this criteria may be used in more heuristic senses. Two major instances of when reverse flow can directly trigger an issue is with voltage regulators protection devices. Voltage regulators may not be able to properly control the voltage given reverse flow conditions. There are even special controls that enable the handling of reverse power conditions. Protection devices can begin to provide false tripping if power flow is allowed to exceed the minimum trip settings of these devices. This would lead to false tripping and reduce reliability. PG&E strongly recommends to not discount reverse flow as a simple heuristic all together, but to understand when it should be appropriately applied.

One of the major components of these criteria is determining the ability to reliably serve portions of circuits in abnormal configurations. High DER penetration can potentially cause excess back flow and load masking which can result in poor reliability conditions during abnormal system configurations, circuit transfers and emergency restoration. When certain line sections are electrically isolated from the grid for repair or maintenance, other line sections are transferred to other grid source paths for continuous services to customers, the distribution system could be rearranged in a manner that unexpected power flows in a manner which would create safety and reliability concerns.

Operational Flexibility Limits

To ensure proper reliability during these abnormal system configurations, the Operational Flexibility Criteria aim to limit the amount of back feed through switching points which are generally SCADA controlled switching devices, so that when a line section is switched to a new configuration, the amount of generation on that section will only serve the local load and does not generate power through the tie point towards the alternative source. Similar to switching devices, backflow would also be limited to the amount of load beyond voltage regulating devices.

The Operational Flexibility Criteria ensures that the amount of energy producing DERs does not exceed the load beyond SCADA controlled switching devices; in other words, the criteria will match the generation to the load between an automated circuit tie and the adjacent SCADA controlled switching device on the feeder.

The table below shows the equation and flag used to evaluate the operational flexibility criteria in the streamlined method and the iterative method, respectively.

Streamlined	$\text{kW Limit }[t] = (\text{Load}[t] - \text{Generation }[t]) \mid \text{where limit} > 0$ $\mid \text{where device has SCADA capabilities}$
Iterative	• CYMDIST ICA Module: "Reverse Flow" • Power flow tool flags the reverse flow through selected devices such as switching devices, circuit breakers, remote automated reclosers, voltage regulators and remote controlled switches

While heuristic approaches were not encouraged, the IOUs have established that non-heuristic approaches to analyzing this issue are quite process intensive and will significantly hinder the ability to achieve efficient results. In essence, this will not necessarily limit the amount of generation that can be placed on each substation, but disperse the allowable generation across all line sections connected to the substation. This can be an important aspect of reliability that needs to be addressed for high penetration scenarios of DER. Limitations in the iterative ICA module did not allow for the isolation and filtering of devices based on SCADA availability.

Transmission Penetration Limits

This limit is similar to operational flexibility, but specifically focused on the reverse flow through the substation transformers. This is mainly due to the fact that transmission limitations and conditions are not considered in the analysis. Similarly a good method to reduce possible unknown issues when conditions are unknown is to limit the back flow.

Streamlined	$\text{kW Limit }[t] = (\text{Load}[t] - \text{Generation }[t]) \mid \text{where limit} > 0$
Iterative	• CYMDIST ICA Module: "Reverse Flow" • Power flow tool flags the negative current through SCADA controlled switching devices such as remote automated reclosers and remote controlled switches • NOTE: This was not applied directly in ICA module and only applied in post process as substation simulation was not used.