Horizon West Transmission and
Pacific Gas and Electric Company
Estrella Substation and Paso Robles Reinforcement Project
Proponent's Environmental Assessment (A.17-01-023)

Response to Data Request No. 4

The California Public Utilities Commission (CPUC) requested additional data from Horizon West Transmission, LLC (Horizon West) and Pacific Gas and Electric Company's (PG&E) Proponent's Environmental Assessment (PEA) for the Estrella Substation and Paso Robles Reinforcement Project (project). Below are responses to Data Request No. 4 issued by the CPUC on June 27, 2019. Each data request is numbered according to the list, followed by Horizon West's and PG&E's response.

This document includes the following attachments, which are described in more detail in the text below under the applicable response:

- Attachment 4-1.4a: Planning Standard TD-3350P-09 (11/17/2017 (Rev.4))
- Attachment 4-1.4b: Guide for Planning Area Distribution Systems Document # 050864, Dated 8/15/18 and Revised 6/1/18
- Attachment 4-1.5a: Planning Standard TD-3350P-09 (07/14/2014 (Rev.3))
- Attachment 4-1.5b: Guide for Planning Area Distribution Systems Document # 050864, Dated 9/15/09 and Revised 3/4/2010

Request #4-1:

1. Provide an updated load forecast for the Paso Robles DPA and update Appendix G to the Proponent's Environmental Assessment (PEA), as appropriate. At minimum, the following Appendix G tables and figures should be updated based on the 2018 recorded peak load and latest available Integrated Energy Policy Report (IEPR) data:

- *Table 2. Historical Paso Robles DPA Capacity and Load*
- *Figure 5. Updated LoadSEER Forecast, Paso Robles DPA*
- *Table 3. Breakdown of Updated LoadSEER Forecast*
- *Table 4. Breakdown of Substation Capacities and Forecasted Loads, Paso Robles DPA*
- *Figure 6. Comparison of LoadSEER Forecasts, Paso Robles DPA*
- *Table 5. Previous 1-in-10 LoadSEER Forecast Incorporating Varying Percentages of the DER Forecast*

2. Refer to the attached slides from a presentation on the Southern California Edison (SCE) Circle City project (in particular, Slide #3). Discuss PG&E's assumptions about photovoltaic (PV) electric generation dependability in the DPA and the types and extent of disaggregated data *that Pacific Gas & Electric Company (PG&E) applied to the updated forecast data provided in response to #1 above.*

3. Discuss the current capabilities of LoadSEER or any alternate software used to provide the forecast update pursuant to #1 above. For example, can LoadSEER incorporate a full 8760 dataset? 15-minute interval data? Provide the full list of LoadSEER capabilities and inputs used for the updated forecast.

4. Please provide the two planning standards referenced in Appendix G to the PEA (Exhibit B and Exhibit C were still being revised at that time) and include all appendices to the two standards. If the standards are still being revised, please let us know when they will be done, and explain why they are still being updated.

5. Please provide the prior versions of the two planning standards referenced in Appendix G to the PEA (Exhibit B 2014 and Exhibit C 2010). Include all appendices to the two prior standards.

Response:

1. See updated figures/tables from Appendix G in Exhibits 4-1.1a through 4-1.1f, which reflect the current 2019 LoadSEER forecast based on 2018 peak data.

   Previous LoadSEER forecasts projected that total load within the Paso Robles Distribution Planning Area (DPA) would exceed available capacity in 2024. The 2017 LoadSEER forecast presented in the May 2017 version of Appendix G projected an overload at the DPA level, and only one overload at the substation bank level. The subsequent 2018 LoadSEER forecast presented in the June 2018 version of Appendix G projected numerous bank and circuit level overloads, influenced by renewed residential and commercial growth within the DPA, coupled with 2017 load data resulting from a 1-in-10 peak temperature heat wave. The current LoadSEER 2019 forecast continues to project overloads at individual substation transformer bank levels, as shown in Exhibit 4-1.1d (New Table 4b). This should be contrasted with the 2017 LoadSEER forecast which only projected the one substation bank overload. Also of note is that all three forecasts have shown the need for a capacity increase in Paso Robles DPA, initially projected in 2024, and now accelerated up to 2020, when assessed at the DPA level.

   While Exhibits 4-1.1a through 4-1.1f are provided as updated figures and tables per Request #4-1, Appendix G will be revised to reflect updated peak loads and growth information for the Paso Robles DPA. A revised version of Appendix G will be provided at a later date.

Exhibit 4-1.1a. Updated 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	164.72	169.33	185.50	195.06	190.30

Note: Paso Robles Bank 1 was replaced in 2010 with a 30 MVA transformer unit, bringing available DPA capacity to 212.55 megawatts (MW).

Exhibit 4-1.1b. Updated 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

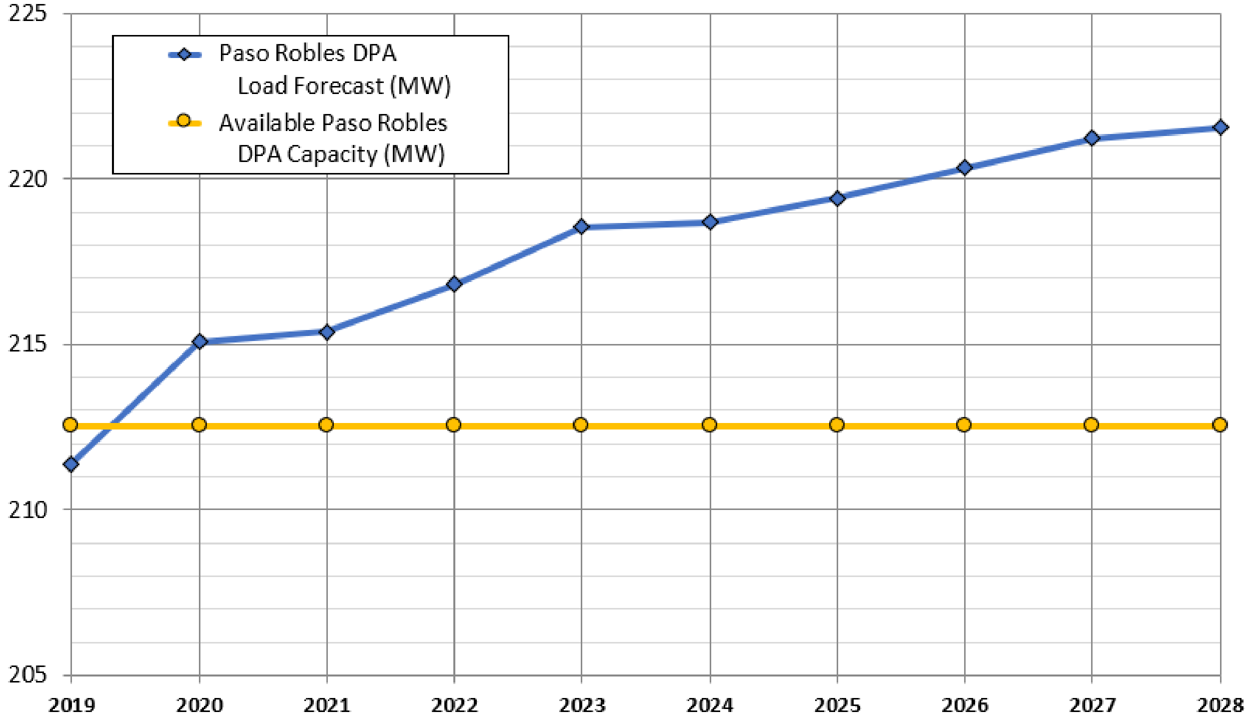


Exhibit 4-1.1c. Updated Table 3: Breakdown of Updated LoadSEER Forecast

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	218.55	218.71	219.43	220.32	221.24	221.57

Exhibit 4-1.1d. Updated Table 4a: 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 Section I.B [in Appendix G to the PEA] and the Guide for Planning Area Distribution Facilities, document 050864, attached as Attachment 4-1.4b.)

[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.

Exhibit 4-1.1d. New Table 4b: Breakdown of Substation Bank Capacities and Forecasted Loads, Paso Robles DPA[1]

Substation Bank	Available	Forecast (MW)									
	Capacity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Atascadero Bank 1	29.70	29.93	30.09	30.16	30.43	30.26	30.05	29.95	29.88	29.92	29.74
Paso Robles Bank 1	29.70	27.56	29.18	29.04	28.89	28.78	28.63	28.59	28.58	28.66	28.56
Paso Robles Bank 2	29.70	26.58	26.99	26.99	27.03	27.06	27.04	27.04	27.08	27.10	27.10
Paso Robles Bank 3	29.70	23.92	24.98	25.15	25.14	25.26	25.24	25.50	25.77	25.96	26.35
San Miguel Bank 1	15.84	18.88	18.90	18.93	18.97	19.10	19.12	19.23	19.35	19.40	19.44
Templeton Bank 2	44.55	41.81	42.22	42.28	42.58	43.43	43.82	44.27	44.75	44.56	44.85
Templeton Bank 3	44.55	42.70	42.71	42.83	43.78	44.67	44.80	44.84	44.92	45.63	45.52
Paso Robles DPA	**212.55**	**211.38**	**215.07**	**215.38**	**216.82**	**218.56**	**218.70**	**219.42**	**220.33**	**221.23**	**221.56**

Exhibit 4-1.1e. Updated Figure 6: Comparison of LoadSEER Forecasts, Paso Robles DPA

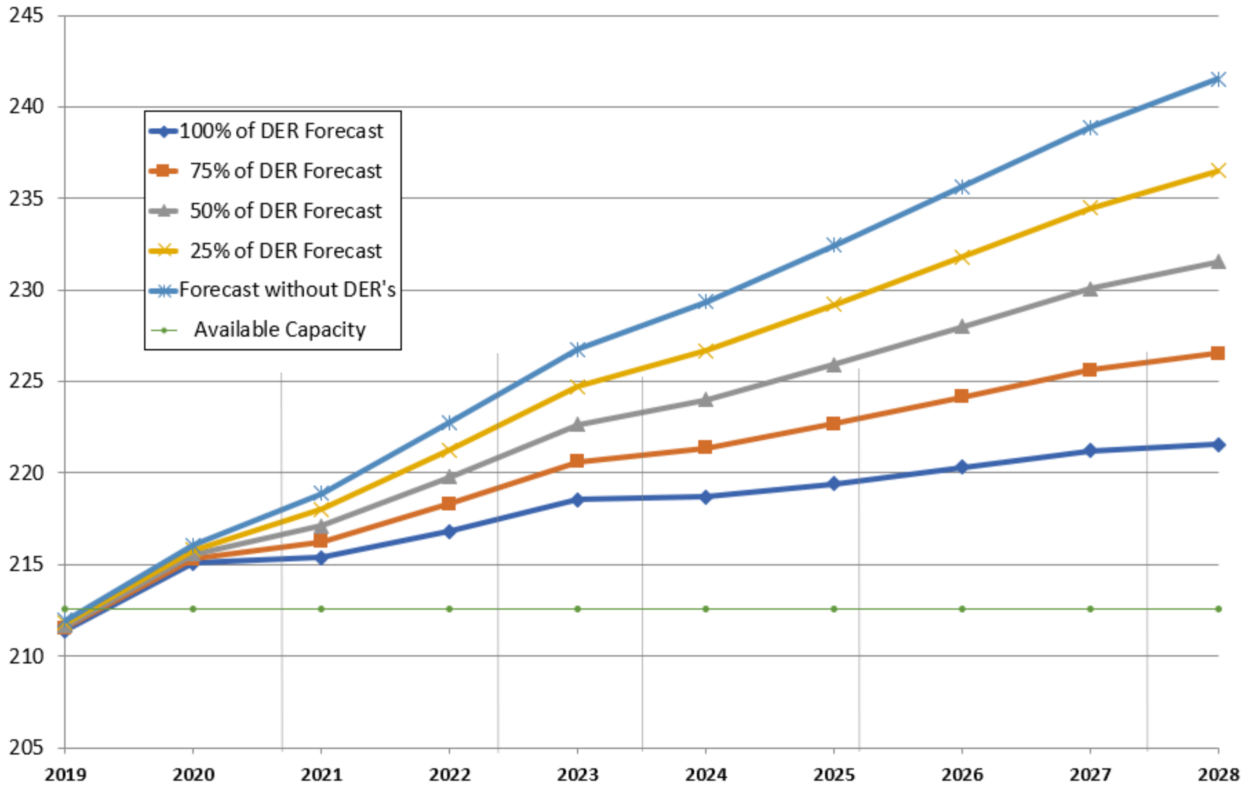


Exhibit 4-1.1f. Updated Table 5: Previous 1-in-10 LoadSEER Forecast Incorporating Varying Percentages of the DER Forecast

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

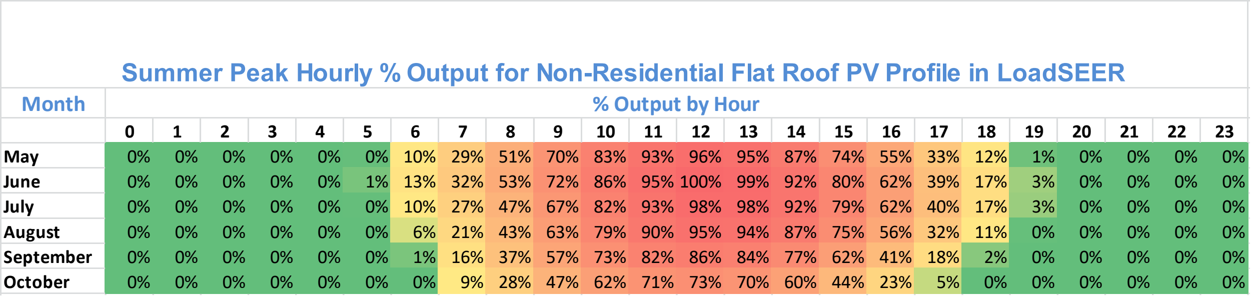
2. PG&E adjusts historical circuit peak demand data to account for the presence of distributed generation (DG) in the manner detailed below.

   Load adjustments are added to the annual bank and feeder peaks to account for the output of the single largest 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-generation units use the same common water source to generate, and the failure of this source could result in multiple generators being offline. 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 PV DG systems, only those locations with a single interconnection point capable of producing an output of 500 kilowatts (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 appropriate adjustment factor. If supervisory control and data acquisition (SCADA) data is not available to determine the peak hour, then the calculated load shapes that reside in LoadSEER (the load forecasting program used by PG&E) can be used. If billing or metering data is not available for the generation output, then the nameplate rating is used to calculate maximum system output using a typical hourly PV output chart.

   Exhibit 4-1.2 provides the summer peak hourly percentage (hour beginning) output for non-residential flat roof PV profile from LoadSEER.

Exhibit 4-1.2. Summer Peak Hourly Percentage for Non-Residential Flat Roof PV Profile in LoadSEER



Summer Peak Hourly % Output for Non-Residential Flat Roof PV Profile in LoadSEER

Month	% 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%

3. LoadSEER produces a 576-hour forecast consisting of a 24-hour forecast for each month for weekdays and a 24-hour forecast for each month for weekends. LoadSEER uses hourly advanced metering infrastructure data to develop base load profiles for each circuit, in conjunction with geo-spatial growth predictions and the approved Integrated Energy Policy Report (IEPR) forecast of load and DER growth. This forecast is reassessed every year to

account for updated peak substation bank and circuit loading, geo-spatial growth analyses, historic temperature data, economic data by county, and IEPR growth and DER forecasts.

4. The two planning standards referenced in Appendix G to the PEA (Exhibits B and C) have been updated and are provided with all the appendices in Attachment 4-1.4a and Attachment 4-1.4b.
5. The prior versions of the two planning standards referenced in Appendix G to the PEA (Exhibit B 2014 and Exhibit C 2010), including all the appendices, are provided in Attachment 4-1.5a and Attachment 4-1.5b.

Request #4-2:

1. The City of Paso Robles plans to construct a 4.3 Megawatt (MW) solar field adjacent to Paso Robles Airport. This solar project is noted in Appendix G to the PEA. Please describe any system upgrades that will be necessary to allow for interconnection of this solar array to PG&E's grid system.

2. If a battery energy storage system (BESS) were installed adjacent to the 4.3 MW solar field, how large could its power output be in MW based on the interconnection upgrades described in response to #2, above?

3. In PEA Appendix G, PG&E suggested that a BESS sited adjacent to a solar generation site should be sized to match the solar output of the arrays unless utility power is used to supplement the charging cycle. In what amounts could utility power be used to supplement the charging cycle?

4. Given the responses to the data requests above, please update the analysis provided in response to No. Deficiency Appendix G (16) of Deficiency Response #4, which indicated that an 8 MW/48 Megawatt-hour (MWh) BESS could defer the proposed substation needed by 5 years.

5. Provide the location of the 3.7 MW storage field (Queue 1529-RD?) described in the response to No. Deficiency Appendix G (16) of Deficiency Response #4, and identify the status of this interconnection. If the interconnection study results indicate failure, explain what system upgrades (at minimum) would be necessary for a successful interconnection.

6. What is the status of the 1MW solar interconnection near Templeton Substation (Queue #1838-RD)? Please also provide the location of the field. If the interconnection study results indicate failure, explain what system upgrades (at minimum) would be necessary for a successful interconnection.

Response:

PG&E is submitting this response confidentially because information about the solar projects in question was obtained by PG&E from third parties with the understanding that PG&E would keep the information confidential.

Request #4-3:

Discuss the potential for installing a flow BESS at or adjacent to Templeton Substation up to the size specified in the Draft ASR (55MW/660MWh).

Response:

A response will be provided at a later date.

Request #4-4:

Provide and underground design for the South River Road Alternative alignment (SE-PLR-2) from the corner of Charolais Road and South River Road north to Paso Robles Substation (approximately 0.63 miles). The design would generally follow the alternative alignment provided on 6/24/19 but should be installed closer to or within the street in some locations to reduce or avoid impacts outside road ROWs. See Figure 1 below. It would transition into Paso Robles Substation overhead across Niblick Road.

Response:

A response will be provided at a later date.

Request #4-5:

1. Please study at least the following two options for undergrounding in this area and provide a design for consideration in the CEQA EIR (see below, Figure 2: Undergrounding Concepts):

- *Purple Line 1 = Wisteria Lane Underground Alignment (about 1.25 miles)*
- *Purple Line 2 = Underground Along the Revised Project Route (about 1.25 miles)*
- *Yellow Line = PG&E Revised Project Route*

Provide the disturbance width and assume the underground alignment could go in the center or on either side of any roadway. We will ensure that the CEQA environmental analysis is adequate for whatever the final undergrounding alignment and length is determined to be in the Formal Proceeding/CPUC Decision (if undergrounding is included in the Decision).

- *NOTE: We plan to re-notice the local parcel owners and the City and County of the design change and undergrounding options as an update notice about the Draft Alternatives Screening Report.*

2. Please clarify the need for facilities at the beginning and end of the underground alignment. Will it be a riser pole or something more? If something more, explain why and provide examples of similar installations that require something akin to a, "small substation," rather than simply an entrance and exit point from the underground conduit (e.g., via the typical riser pole design footprint). Explain the specific conditions under which the additional facilities would be necessary and whether they are for something already planned pursuant to an adopted planning document or for something that might occur in the future.

3. PG&E has referred to the additional facilities as 150-foot x 150-foot transition stations. What physical equipment would be housed inside the transition stations? Who would own the transition stations, if required, and would they be sited by PG&E or by a customer? Are they typically on customer property, for example, and behind the meter? Why would a transition station be required at each end of the underground alignment?

4. Which existing businesses would be served by a 70-kV line direct connection in or near the Gold Hill Park and for what purpose? If none, currently, describe the types of businesses that could be served in the future.

Response:

A response will be provided at a later date.

Request #4-6:

Please provide the following data to support statements made in HWT's comments on the Draft ASR:

- *a. Average daily traffic for El Pomar Road in the vicinity of Templeton Substation.*
- *b. Approximate number of oak trees, including "heritage oaks," that would require removal for construction of the Templeton Substation Expansion (Alternative SE-1).*
- *c. Location of the active golden eagle nest near Templeton Substation referenced in the comments: "The Templeton Substation Expansion would also be located approximately 1 mile closer to an active golden eagle nest than the Proposed Estrella Substation (HWT Comments, page 18)."*

Response:

- a. Average daily traffic (ADT) for El Pomar Drive in the vicinity of Templeton was based on data maintained by the San Luis Obispo County Public Works Department (https://www.slocounty.ca.gov/Departments/Public-Works/Forms-Documents/Transportation/Traffic-Count-Data.aspx). This data shows that the most recent ADT for El Pomar east of Templeton Road (July 11, 2017) was 3,347. The most recent ADT count for Union Road west of Kit Fox Lane (June 30, 2017) was 1,716. The most recent ADT count for Estrella Road north of State Route 46 (April 29, 2018) was 302. Based on this data, Horizon West stated in the Draft ASR comments that ADT is substantially less along Estrella Road (302) than along Union Road (1,716); and ADT on El Pomar Road (3,347) is greater than Union Road (1,716), resulting in greater traffic impacts from Alternative SE-1 than the Proposed Estrella Substation.

- b. GIS data for the location of oak trees that would require removal and/or trimming for Alternative SE-1 was provided to the CPUC on July 31, 2019.

- c. GIS data for the location of the golden eagle nests near Alternatives SE-1, SE-PLR-1, SE-PLR-2, and SE-PLR-3, as well as the golden eagle nests near Alternative PLR-3, will be provided separately. Note that golden eagle nest locations are considered sensitive given that golden eagles are protected under federal law, and in some cases eagles are illegally hunted; therefore, it is best practice not to publicly release precise point locations for eagle nests. PG&E is not claiming confidentiality of this data because this information did not come from a confidential source.

Request #4-7:

See attached figure (pdf). Please discuss the two Minor Route Variations to the Orange line (Alt. PLR-1C) shown on the figure. These were described via phone call in a comment on the Draft Alternatives Screening Report. The pink line (along Estrella Road) is especially interesting as it follows an existing road ROW. The purple line reduces the overland crossing and land access issues associated with the yellow route that we still plan to screen out. One or both Minor Route Variations may be carried forward for further analysis (pink and purple). Please comment on them.

Response:

The pink line route would need to be constructed on the southerly side of Estrella Road (away from Estrella River), and due to the narrow width of Estrella Road in this section, PG&E would construct the double-circuit power line all on private property (approximately 2 to 4 feet on private property). The route has better access than Alternative PLR-1D, but would require significantly more tubular steel poles (TSPs) due to the large number of angles in the proposed route. Installing a TSP is a significantly more labor-intensive and time-intensive process than installing a light duty steel pole. Foundations need to be drilled, framed, and poured, with a 30-day cure time, before TSPs can be set. Being so close to the Estrella River, the soil would likely be very sandy, which could make constructing concrete foundations for these TSPs extremely difficult. This could greatly increase the overall time and cost to construct, and it could result in more truck trips to be able to stabilize and shore the foundations, which would increase air quality and traffic impacts. Also, being so close to the Estrella River, we would assume this route would have a greater impact on cultural and biological resources. The pink line route would also require several oak tree removals and/or trimming, resulting in potentially significant biological resource impacts. For most of the route, construction would need to be from Estrella Road due to poor access from private property, which would require numerous lane/road closures for approximately half the length of the pink line route, increasing traffic impacts.

Starting where the purple line leaves the orange line (Alternative PLR-1C) on the east side of the figure provided, the purple line route would continue along the existing dirt farm road until it intersects with the existing distribution line. Following the existing distribution line from that point, PG&E would be putting structures in the middle of several existing vineyards and at each structure location a row of grapes would need to be removed for access, which would result in significant crop loss over the full length of the line and potentially significant impacts to agricultural resources. Once the purple line intersects Jardine Road, the structures could be placed in an existing dirt farm road heading south on the easterly side of Jardine Road until it intercepts the orange line. A few adjustments could be made instead of following the existing distribution line to try and stay closer to the edge of the vineyard and closer to the existing dirt access roads. Each adjustment would increase the overall length of the line and require the installation of a number of TSPs (at each angle point in the line), increasing construction-related impacts such as air emissions and traffic impacts. Note also that the dirt roads that meander around each individual vineyard do not line up with each other from property to property. This means that no matter how the line is designed, it would be necessary to sever all the properties the new line crosses with a new typically 70-foot-wide transmission easement, which will limit the available use of those properties and diminish their value and usefulness in the future.

Attachment 4-1.4a: Planning Standard TD-3350P-09 (11/17/2017 (Rev.4))

Substation Property – Selling, Acquiring, and Leasing

SUMMARY

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

- Reviewing substation properties for potential sale.
- Reviewing the need to acquire substation properties in the future.
- Reviewing proposals for leasing cellular sites on substation properties.

Level of Use: Informational Use

TARGET AUDIENCE

The target audience includes all PG&E employees involved with maintaining substation properties/facilities and planning for future substation property and facilities, including the purchase, sale, and leasing of substation property.

SAFETY

Performing this procedure does not raise the risk of a specific hazard to personnel, the public, or equipment.

BEFORE YOU START

NA

TABLE OF CONTENTS

PROCEDURE STEPS

1 Substation Asset Management – Role and Responsibilities

1.1 Substation asset management (SAM) personnel MAKE final recommendations for selling, acquiring, and leasing substation properties.

1.2 SAM personnel REQUEST input from the following personnel to review the long-term impacts on properties:

- Transmission planning
- Distribution planning
- Substation maintenance and construction (SM&C)

1.3 SAM personnel REVIEW the 5-year plan and the station's Ultimate Site Plan.

1.4 SAM personnel ENSURE that all proposed improvements, equipment, and facilities meet the following requirements:

1. Safe installation of equipment.
2. Coordination with ongoing and planned work, per the 5-year plan, at the same station.
3. Integration with the existing substation design, including the following elements:
    - Ground grids.
    - Physical clearances.
    - Physical security.
    - Mobile equipment access.
    - Compliance with existing standard designs.
    - Permanent access for inspection, normal station maintenance and operation, and emergency response.
    - Compliance with applicable regulations and local agency requirements.

1.5 When a new request to use or lease PG&E property is received, SAM personnel DIRECT all inquiries, including those from third parties, to the local land management (LM) supervisor.

1.6 The supervisor ASSIGNS a land agent to coordinate with third-party requests to use or lease substation property.

1. The land agent REVIEWS any information by the requesting party including, but not limited to the following issues:

   a. Property availability.

   b. Environmental impacts.

   c. Compatible use.

   d. Probable rents/avoided costs.

   e. California Public Utilities Commission (CPUC), General Order (G.O.) 173 Section 851 Advice Letters review/approval.

      (1) CONSIDER any proposed encumbrances on PG&E real property (currently in the rate base and/or containing facilities used to service customers) as candidates for submission to the CPUC for review under the Section 851 Advice Letters.

   f. Additional factors that determine if PG&E can agree to the requested use.

2. Land personnel FOLLOW the procedures outlined in the *Land Management Manual*.

1.7 Some substation property sales may involve only a portion of a property. This is usually in situations where an agency (Caltrans, county, or city) needs a portion of the property in fee for an improvement project, such as the widening of a road.

1. The majority of partial acquisitions are made under the threat of eminent domain.

1.8 SAM personnel COMMUNICATE the final decision to the appropriate contacts, as described in the following sections.

2 Reviewing Substation Properties for Potential Sale

2.1 In addition to the tasks outlined in Section 1 on Page 2, SAM personnel REVIEW (with appropriate PG&E personnel) any rights that must be retained for existing or planned facilities if the substation property is sold; for example, easements for existing or proposed lines crossing the property.

2.2 The director of asset management APPROVES the surplus via the Electronic Document Routing System (EDRS).

2.3 SAM personnel REPLY to the requestor and the manager of surplus property with a final recommendation to either sell or keep the property.

2.4 Surplus property personnel LEAD the property sale.

3 Acquiring Property for Future Substations

1. There are two types of property acquisition: 1) new substations and 2) expansion of existing substations.
   a. In either of the above two cases, land personnel ACT as the lead for the property acquisition per the *Land Acquisition Manual*.
2. New Substations
   a. Transmission and/or distribution planning personnel IDENTIFY the need for new station properties.
   b. Planning personnel TAKE the lead on site selection, budgeting, and approvals. Planning personnel also WORK with land personnel on property acquisitions.
   c. SAM personnel APPROVE the new station name, per Utility Procedure TD-3350P-20, "Substation Naming Conventions."
3. Expansion of Existing Substations
   a. Substation expansions are usually project driven with a project manager taking the lead.
   b. SAM personnel WORK with planning personnel on the ultimate site plan to determine the amount of additional property needed for the station's future needs.
   c. The responsible engineer, under the direction of SAM, PROVIDES a marked up general arrangement drawing clearly indicating the land to purchase.
   d. The project manager INTIATES the land acquisition by contacting land personnel.

4 Leasing Cellular Sites

4.1 New revenue development (NRD) personnel ACT as the project manager for leasing cellular sites on substation property AND CONTACT SAM personnel for information, as needed.

4.2 Attachment 1, "Standby Generator Requirements and Terms and Conditions," to this procedure describes the technical requirements for leasing substation property for standby generator use.

4.3 NRD personnel must follow the procedures in the *Cellular Antenna Installation Requirements Manual*. In addition, REFER to Utility Standard TD-1005S, "Right-of-Way and Encroachments," Section 4, ""Evaluation of Third-Party Land Uses."

END of Instructions

DEFINITIONS

NA

IMPLEMENTATION RESPONSIBILITIES

NA

GOVERNING DOCUMENT

Utility Standard TD-3350S, “Substation Asset Strategy and Reliability”

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

NA

REFERENCE DOCUMENTS

Developmental References:

CPUC G.O. 173, Section 851 Advice Letters

Cellular Antenna Installation Requirements Manual (LAND-3102M)

Land Acquisition Manual

Land Management Manual (LAND-3001M)

Supplemental References:

Utility Procedure TD-3350P-20, “Substation Naming Conventions”

Utility Standard TD-1005S, “Right-of-Way and Encroachments”

APPENDICES

NA

ATTACHMENTS

Attachment 1, “Standby Generator Requirements and Terms and Conditions”

DOCUMENT RECISION

This utility procedure cancels and supersedes Utility Procedure TD-3350P-09, “Property Review – Coordinating, Leasing, Selling, Acquiring, and Naming,” Rev. 3, dated 07/14/2014.

Substation Property – Selling, Acquiring, and Leasing

DOCUMENT APPROVER

Tom Rak, Manager

DOCUMENT OWNER

Tom Rak, Manager

DOCUMENT CONTACT

Stan Cramer, Senior Consulting Engineer

REVISION NOTES

Where?	What Changed?
Title	Changed title from “Property Review – Coordinating, Leasing, Selling, Acquiring, and Naming” to “Substation Property – Selling, Acquiring, and Leasing.”
Entire document	Made minor revisions to text to meet Guidance Document Management (GDM) writing requirements and to clarify instructions.
Removed Sections 5, 6, and 7	Removed and republished the following sections: • Section 5 – Moved this information to new Utility Procedure TD-3350P-20, “Substation Naming Conventions.” • Section 6 – Moved this information to revised Utility Procedure TD-3350P-06, “4 kV Substation Equipment and Transferring Substation Assets to Distribution.” • Section 7 – Moved this information to new Utility Procedure TD-3350P-21, “Gas Pipelines in Substations.”
Attachment 1	Added new Attachment 1, “Standby Generator Requirements and Terms and Conditions.”

Attachment 4-1.4b: Guide for Planning Area Distribution Systems
Document # 050864, Dated 8/15/18 and Revised 6/1/18

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:

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.

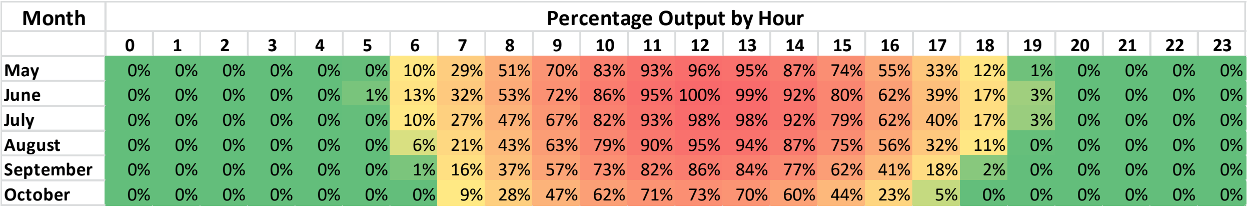
7.3 Validate Transfers

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.

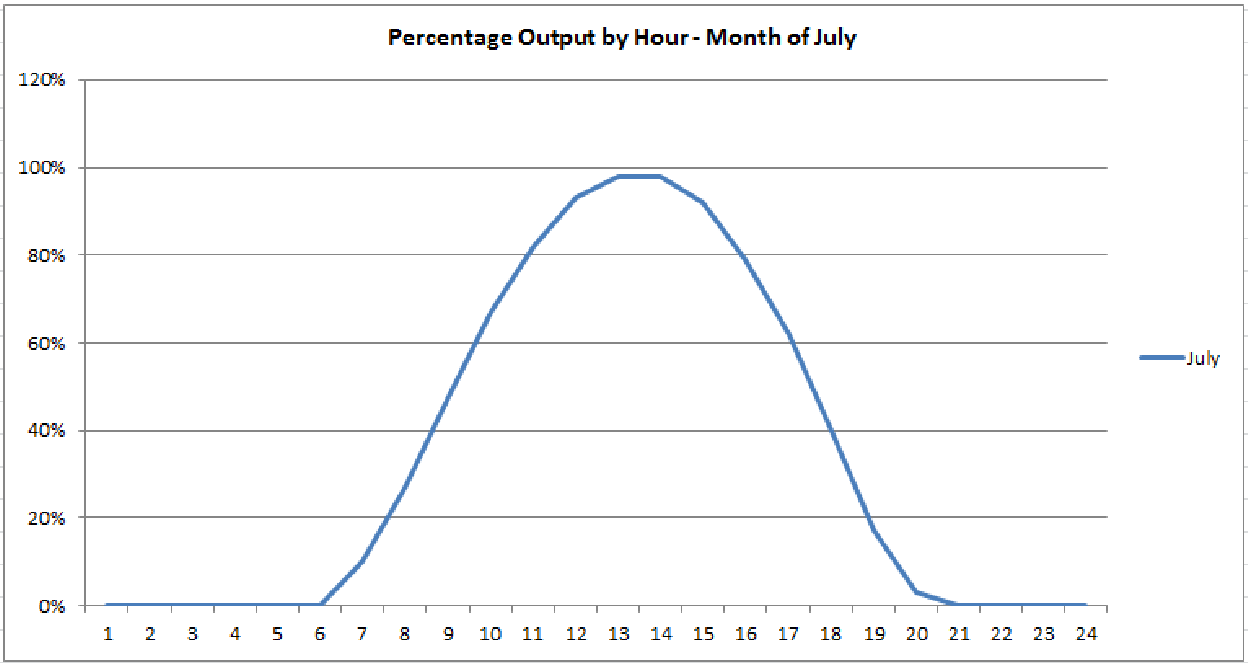
7.4 Add Load Adjustments

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:

1hp x 746W/hp x 0.6 diversity factor or

0.45 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.

8.1.1 Normal Bank Planning

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

DWG. 050864 - Guide for Planning Area Distribution Facilities –

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

DWG. 050864 - Guide for Planning Area Distribution Facilities –

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

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

DWG. 050864 - Guide for Planning Area Distribution Facilities –

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

DWG. 050864 - Guide for Planning Area Distribution Facilities –

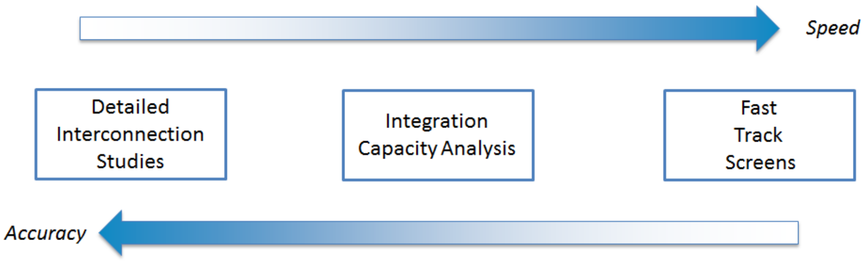
Division	DPA	Designation
Sierra	North Placer	Urban/Suburban
Sierra	Pike	Rural
Sierra	South Placer	Urban/Suburban
Sierra	Yuba City	Urban/Suburban
Stockton	Angles Camp	Rural
Stockton	Clay	Rural
Stockton	Corral	Rural
Stockton	Jackson	Rural
Stockton	Linden 12 kV	Rural
Stockton	Lodi	Rural
Stockton	Manteca 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:

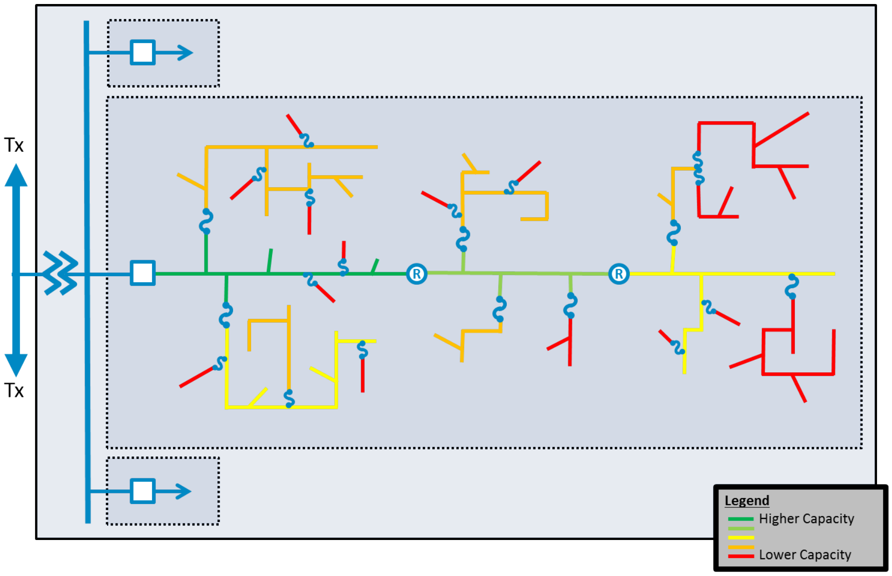
1. Assist in interconnection process for quickly identifying major issues with a new application
2. Compare against DER forecasts to find areas needing further study to determine future planning needs due to DER issues

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.

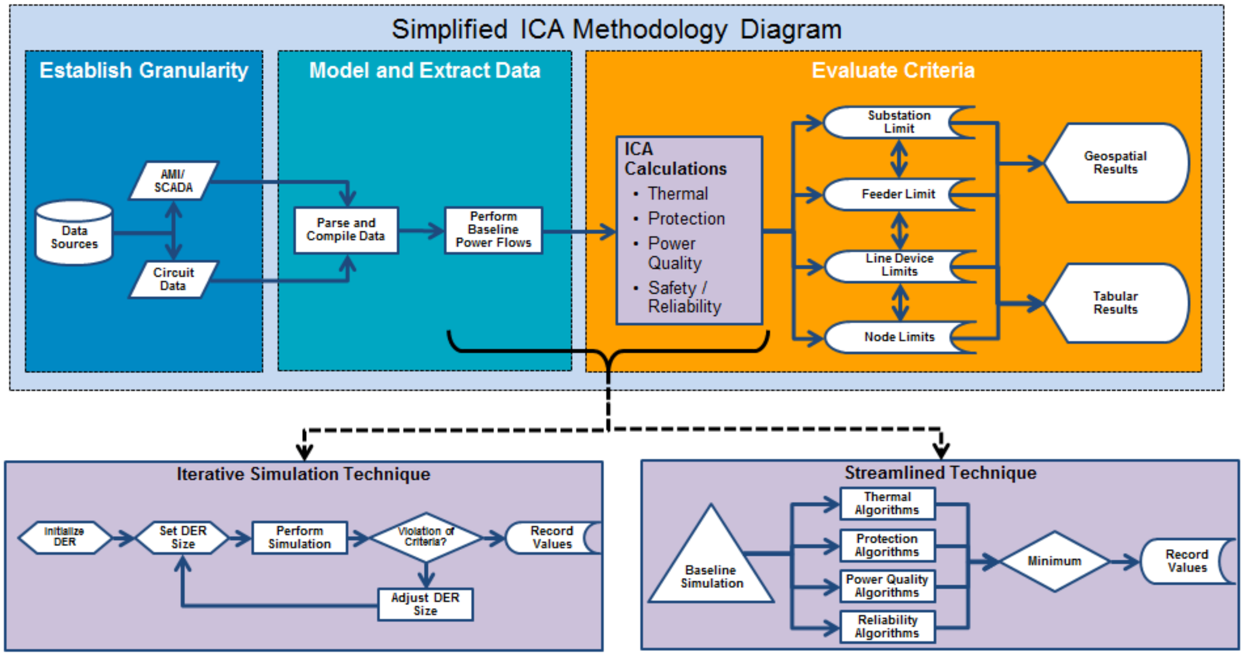


Calculation Techniques

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	$\text{kW Load Limit }[t] = (\text{Thermal Capability } - (\text{Load}[t] - \text{Generation }[t]))$ $\text{kW Generation Limit }[t] = (\text{Thermal Capability } + (\text{Load}[t] - \text{Generation }[t]))$
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	$\text{kW Limit }[t] = \frac{\left(\text{Voltage Headroom }[t]\text{ (per unit) } * V_{LL}{}^{2}\right)}{\left(R * PF_{DER} + X * \sin\left(\cos^{-1}\left(PF_{DER}\right)\right)\right)} * PF_{DER}$ $\mid\ \text{Voltage Headroom }[t] = \frac{\lvert\text{Rule 2 Limit} - \text{Node Voltage}[t]\rvert}{\text{Base Voltage}}$
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	$$\text{kW Limit} = \frac{\left(\text{Deviation Threshold (per unit)} \ * V_{\text{LLnom}}{}^{2}\right)}{\left(R * PF_{\text{DER}} + X * \sin\left(\cos^{-1}\left(PF_{\text{DER}}\right)\right)\right)} * PF_{\text{DER}}$$
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; "$\text{Fault Current}_{\text{DER}}/\text{Rated Current}_{\text{DER}}$" 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.

Attachment 4-1.5a: Planning Standard TD-3350P-09 (07/14/2014 (Rev.3))

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

Summary

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

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

Level of Use: Informational

Target Audience

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

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

Safety

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

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

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

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

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

Table of Contents

Procedure Steps

1 Coordinating Third-Party Projects Involving Substation Property

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

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

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

1.2 (Continued)

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

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

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

2 Reviewing Substation Properties for Potential Sale

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

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

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

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

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

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

3 Leasing Cellular Sites

3.1 General Information

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

3.2 General Requirements

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

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

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

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

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

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

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

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

3.2 (Continued)

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

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

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

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

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

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

3.3 Stand-By Generator Installation Requirements

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

3.3 (Continued)

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

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

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

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

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

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

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

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

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

3.3 (Continued)

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

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

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

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

3.4 Other Terms and Conditions

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

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

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

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

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

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

3.4 (Continued)

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

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

4 Acquiring Property for Future Substations

4.1 General Information

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

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

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

4.2 General Requirements

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

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

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

4.2 (Continued)

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

   a. Engineering Feasibility

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

   b. Land Use

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

   c. Environmental Concerns

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

4.2 (Continued)

d. Acquisition and Construction Costs

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

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

4. If the most economic alternative is a new substation, ensure that the following tasks are completed:

   - All the requirements set forth in this Section 4.2, “General Requirements,” (starting on Page 8) are met.
   - Land use agencies and local jurisdictions are consulted.

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

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

7. Provide the following information in the same format as a standard project analysis, including recommendations, background, and alternatives considered:

   - The load growth projection for the area, including the 5-year plan.
   - The preliminary economic analysis for alternatives to the 5-year plan.

4.2 (Continued)

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

5 Naming Substations

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

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

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

6 Transferring Assets

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

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

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

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

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

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

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

1. Transmission Operations – Substation

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

2. Distribution Operations

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

3. Environmental Services

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

7 Gas Pipelines on Substation Property

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

7.2 New Substations

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

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

7.3 Existing Substations

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

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

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

7.4 Pipeline Study

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

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

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

7.5 Electrical Considerations for Pipeline Study

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

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

7.5 (Continued)

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

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

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

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

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

7.6 Gas Pipeline Considerations for Study

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

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

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

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

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

7.6 (Continued)

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

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

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

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

8 Coordinating Tasks

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

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

8 (Continued)

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

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

END of Instructions

Definitions

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

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

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

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

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

Implementation Responsibilities

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

Governing Document

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

Compliance Requirement/ Regulatory Commitment

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

Reference Documents

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

Code of Safe Practices

Electric Rule 16, "Service Extensions"

"Leases From" Manual for Corporate Real Estate

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

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

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

Electric:

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

Gas:

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

Electric and Gas:

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

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

---

[1] Currently under revision

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

Document Contacts

Stan Cramer (SJC6)
Senior Consulting Engineer
8-323-7016

Rudy Bartley (R3B9)
Supervisor
8-328-5709

Revision Notes

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

Attachment 4-1.5b: Guide for Planning Area Distribution Systems
Document # 050864, Dated 9/15/09 and Revised 3/4/2010

Guide for Planning Area Distribution Facilities 050864

Asset Type:	Electric Distribution	**Function:**	Planning
Issued by:	**Electric Distribution Engineering & Planning**	**Date:**	9/15/09

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

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

1.0 PURPOSE AND SCOPE

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

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

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

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

2.0 ACRONYMS AND TERMS

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

2.1 Acronyms

CAISO - California Independent System Operator

CEE - Customer Energy Efficiency

CPCN - Certificate of Convenience and Public Necessity
DG - Mobile Distributed Generation
DPA - Distribution Planning Area
EASOP - Economic Analysis Software Program
ECCO - Electric Control Center Operations
EDSA - Electric Distribution System Analysis, relational database of system facilities
ESD – Engineering Standard Drawing
FDRCAL - Feeder Calculation Planning Program
IEEE - Institute of Electrical and Electronics Engineers
GIS – Geographic Information System
KPF - Manufacturer name of an overhead switch
KW - Kilowatt
KVAR – Kilovar
LG2004 - Load growth projection program, utilizes Excel software program
LTC - Load Tap Changer
MW - Megawatt
MVA - Megavolt Amperes
MVAR - Megavolt Amperes Reactive
NPV - Net Present Value
NOC - Notice of Construction
OM&C - Operations, Maintenance and Construction
PF - Power Factor
PTC - Permit to Construct
PVRR - Present Value Revenue Requirements
SCADA - Supervisory Control and Data Acquisition
WAT - Weighted Average Temperature

2.2 Definition of Terms

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

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

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

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

CAISO: The California Independent System Operator.

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

Company: Pacific Gas and Electric Company

CPUC: California Public Utilities Commission

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

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

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

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

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

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

---

[1] CAISO and Industry Standard

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Standby Capacity: Capacity reserved for customers on standby rates.

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

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

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

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

3.0 REFERENCES

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

3.1 PG&E Drawings

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

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

3.2 Standards, Guidelines and other documents

Bulletin 2001-PGM-3

Protection Handbook

Reliability Section of the Electric Planning Manual

Standard S2401, "Substation Load Information And Power Factor"

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

Guideline G12058, "Evaluating Mobile Distributed Generation"

Guideline D-G0069, "Substation Siting and Acquisition"

Information Bulletin IB0248, "Distribution Power Transformer Ratings"

Planning Guide for Small Dispersed Generation - 061887

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

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

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

4.0 PLANNING GUIDELINE AND CRITERIA

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

4.1 Basic Criteria

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

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

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

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

4.1.1 Provision for Unplanned Outage of Facilities

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

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

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

4.1.2 Utilization Factor

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

4.1.3 Load Power Factor

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

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

5.0 APPLICATION

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

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

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

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

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

5.1 DPA Planning

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

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

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

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

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

5.2 Individual transformer bank and feeder planning

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

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

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

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

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

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

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

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

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

5.3 Feeder component planning

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

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

6.0 SELECTION OF STUDY AREA

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

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

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

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

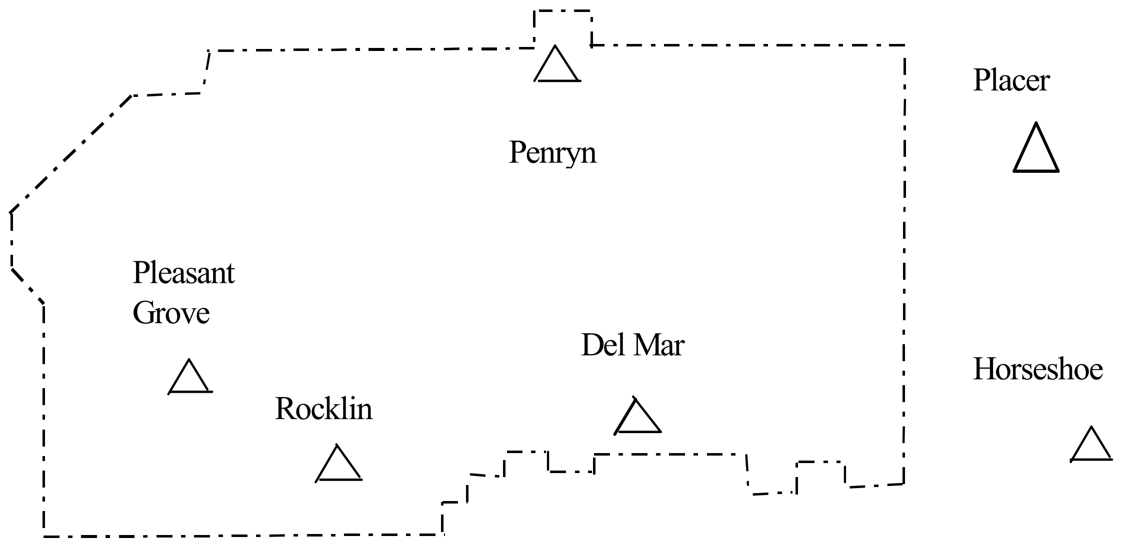
If there are no existing or potential ties to the area distribution system, and no potential load transfers from or to it, substations and the loads they supply should not be considered part of a study area, even though they are surrounded by other substations and loads. For example, single customer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

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

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

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

South Placer Distribution Planning Area



7.0 LOAD FORECASTING

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

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

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

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

i. For weather stations with 50 years of temperature data

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

ii. For weather stations with 10 years of temperature data

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

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

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

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

7.1 Determine load growth rate using historical data

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

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

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

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

10% 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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

7.2 Forecast Future Loads

The following procedure should be used to forecast future loads:

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

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

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

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

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

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

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

8.0 CAPABILITY OF FACILITIES

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

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

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

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

8.1 Substation Bank and Regulator Capability

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

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

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

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

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

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

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

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

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

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

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

TOP OIL AND HOT SPOT TEMPERATURE OPERATING GUIDELINES

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

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

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

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

8.2 Feeder Outlet Capability

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

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

8.3 Conductor and Related Distribution Equipment Capability

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

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

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

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

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

8.4 Air Switches and Disconnects

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

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

8.5 Overhead Line Protective and Voltage Regulation Devices

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

8.6 Padmounted and Sub-Surface Line Devices

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

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

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

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

Padmounted Interrupter (600 amp unit)

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

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

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

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

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

9.0 PLANNED NORMAL LOADING CONSIDERATIONS

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

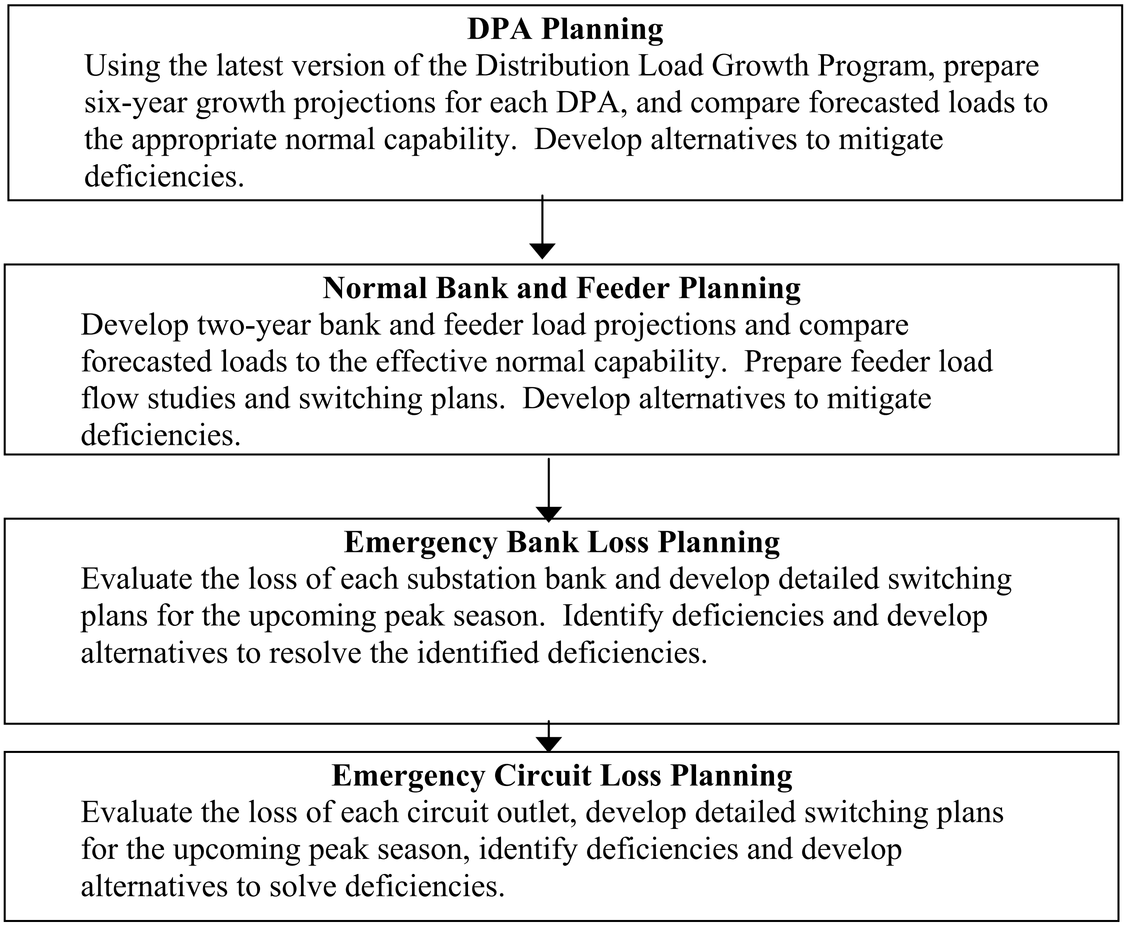
PG&E will continue to limit substation transformer bank size to a maximum of 45 MVA consistent with our maximum mobile transformer size. However, as a last resort, in order to provide adequate emergency substation transformer capacity it may be necessary to install transformers larger than 45 MVA in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

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

9.1 Detailed Procedures

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

Figure 1 - Typical Planning Flowchart



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

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

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

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

9.1.1 DPA Planning

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

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

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

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

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

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

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

9.1.2 Normal Bank and Feeder Planning

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

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

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

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

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

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

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

9.1.3 Emergency Bank Loss Planning

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

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

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

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

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

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

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

9.1.4 Emergency Feeder Loss Planning

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

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

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

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

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

10.0 PROJECT JUSTIFICATION REQUIREMENTS

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

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

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

11.0 CAPACITY PLANNING PROJECT REVIEW DETAIL

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

12.0 REVISION NOTES

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

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

APPENDIX A

List of all Distribution Planning Areas and their Area Designation.

Distribution Planning Area Designation

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

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

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

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

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

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

APPENDIX B

Capacity Planning Project Review Detail

(Required for all capacity projects greater than $300,000)

Note: All instances of text set in italics are instructions for completing this form. Delete them (including this and the following note) from the Capacity Planning Project Review Detail (CPPRD) as information is entered on the form.

Note: The CPPRD assumes the project is for a single Distribution Planning Area (DPA). Some projects involve multiple DPAs. In these cases, edit the form as needed to answer all questions for all DPAs.

Project Description

A) **Project name:** *Enter the name of the project.*

B) **Need for the project:** *Check all that apply.*

___ Normal deficiency.
Describe the deficiency, including percentage, megawatts (MW) or amps, and any equipment that is currently overloaded.

___ Emergency deficiency.
Describe the deficiency, including percentage, MW or amps, and any equipment that is currently overloaded.

C) **Scope of work to be accomplished by the recommended alternative:**

Detail: *Enter a year-by-year detailed listing of the proposed work included in the recommended alternative.*

D) **Scope of other alternatives considered:**

Note: The body of the Project Analysis (PA) normally includes brief descriptions of the recommended alternative and approximately three "real" alternatives. Present here more detail about those alternatives, as well as a discussion of other alternatives, including status quo and mobile distributed generation (DG).

Describe here the other alternatives mentioned in the PA, with year-by-year detail. Also describe any other alternatives considered (with year-by-year detail if applicable), and give the reasons for rejection (if other than simple economics). Use the language from Page 3 of DCS Guideline D-G0058, "Evaluating Mobile Distributed Generation."

Load Forecasting **(Note: Complete sections A, B, C and D for projects proposing additional substation bank capacity or additional feeders. Do not complete these sections for projects involving only distribution line facilities)**

A) Verification of historical load data: *Check one.*

___ The current load-growth data (actual recorded bank peaks, previous load transfers, and historical block loads of the common years) match **exactly** the data used in this DPA's last two annual load-growth studies.

___ The current load-growth data (the actual recorded bank peaks, previous load transfers, and historical block loads) do not match the data used in this DPA's last two annual load-growth studies for the following reasons:

Include an explanation here.

B) Evaluation of last year's block load forecasts: *Check one.*

___ Last year's load growth study did not forecast any block loads to come online before the peak this year.

___ The block loads forecast for the most recent year (indicated in last year's load-growth study) were online this year as forecast. The block load's actual peak load still qualifies as a block load, and this DPA's current load-growth study indicates the actual recorded peaks as historical block loads.

___ The block loads forecast for the most recent year (indicated in last year's load-growth study) were either not online this year or the actual recorded peak loads did not meet the block load criteria for this DPA as summarized below:

Include an explanation here.

C) Verification of load transfers into or out of an adjacent DPA: *Check one.*

___ There were no historical load transfers recorded in the last 7 years, nor are there any planned in the next 5 years.

___ Load transfers indicated in the prior and current area load-growth studies for this DPA match the prior and current load-growth studies of the adjacent DPAs.

___ Load transfers indicated in the prior and current area load-growth studies for this DPA do not match the prior and current growth studies of the adjacent DPAs for the following reasons:

Include an explanation here.

D) *The following load growth items were reviewed:* ***Check each that applies.***

___ The power factor for each bank ranges from 0.99 lagging to 0.99 leading, or notes indicate that capacitors were added or capacity adjustments were made to correct the power factor, or a note explains why the power factor cannot be corrected.

___ All special facility contracts for reserved capacity, if any, are included in the load growth analysis.

___The temperatures shown on the load-growth study were verified by the designated weather station from the Geographic Information System (GIS), and the average 1-in-10-year weather event temperature values are indicated for the future years.

___ The best of the statistically valid forecast methods was applied using either a multivariable or a linear trend method, and a copy of the statistical analysis is attached to this checklist. If a linear trend was used, the need for a trend line adjustment was applied per the capacity planning guideline.

___ The applied forecast method is the same method used in last year's study.

___ All appropriate boxes are checked in the load growth tool to identify whether a linear or multivariable analysis was used.

If any of the above items are not checked, include an explanation here.

If there are no statistically valid load-growth models, explain here that the adopted method used was ORRQ (Operation Revenue Requirement forecasting model).

Methods used to determine block load magnitude:

Use the table below to record the following information for each block load: the name, type of customer, the highest applicable status code, the in service date, the block load size (MW), the estimation method, the representative's name, and the date this information was confirmed. If there are no block loads, enter NA under Name.

Name	Type[1]	Status[2]	Service Date	MW	Method[3]	Rep	Date Checked

[1] **Type:** C = Commercial I = Industrial R = Residential

[2] **Status:**
1 = Permit pending
2 = EIR pending
3 = Planning Board approval on-going
4 = Permit approved
5 = EIR completed
6 = Approved by Planning Board
7 = Site plans complete
8 = Site prepared
9 = Construction started

[3] ***Method used to estimate block load:***
H = Historical demand of similar customers (Type C or I).

D = Demand per square foot by type of occupancy (Type C only).
C = Customer plans and operational needs (Type C or I).
R = Residential demand estimate (Type R only).

For each Type C or I block load that uses Method H, use the table below to list the block's name and square footage, and comparable customers used, including name, location, and watts per square foot (or watts/unit if some other unit of analysis is used) for each similar customer.

Name	Square Feet	Similar Customer	Location	Watts per square foot	Watts per unit

Check one.

___ **All** block loads are estimated using Method H (*Electric Design Manual*, Section 4.2) for commercial and industrial and Method R (*Electric Design Manual*, Chapter 6) for residential.

___ Some of the block load estimates use an other-than-preferred method.

For each block load estimated with an other-than-preferred method, or that deviates from the preferred method, list the block load's name and include the following explanations:

1) *Why the preferred method could not be used or required modification.[Note that for a commercial block estimated from Customer Plans and Operational Needs, you must explain why neither Method H nor Method D can be applied.]*
2) *Details of how the load was estimated.*

Name	Explanation

For each block load, list the block's name, size (MW), the occupancy/usage percentage expected by the peak season in which the overload is projected, the percent of coincidence with the time of peak demand, and the calculated expected coincident demand.

Name	MW	% Occupancy	% Coincidence	Peak MW

___ Future block loads shown in the load growth package are the products of: **each block's peak demand** times **its expected occupancy (or fraction of that block**

expected to be in use at each year's peak) times **the fraction of that block's load which is coincident with the bank (which serves the block) peak**.

Explain here if this item is not checked.

__ Multi-phase, multi-year block loads include only the first 2 future years of development, unless inclusion of more years has been approved by the appropriate Distribution Planning manager and the Capacity Program manager.

Explain here if this item is not checked.

Other Considerations

1. **Substation bank condition evaluation:** *Check each that applies.*
   __ Transformer Capability Analysis Program (TCAP) customized ratings increasing transformer capacity in the substation involved in this project are in effect. Plans are included in this project to provide adequate transformer capacity to remove the TCAP ratings from the other transformers in the substation.

   __ The six year plan for the DPA identifies adequate substation capacity additions which will allow transformer ratings for all substation transformers in the DPA to be reduced to those described in Substation Information Bulletin 0248 (IB 0248) by 2011 summer .

   __ Distribution planning has conferred with Substation Asset Strategy (SAS) to determine whether or not deteriorated substation transformer bank replacement is planned within the next five years in the DPA. The cost impact of any planned deteriorated substation transformer replacement projects are reflected in the economic analysis for this project.

   __ Are there any additional comments or concerns (operational or otherwise) not already included in the PA?

   List them here.

A) Are there any customers in the planning area that may have transmission options in the future? *Check one.*

__ No.

__ Yes.
If yes, describe who and what the potential impact could be.

B) Can the work be deferred with customer energy efficiency (CEE)? *Check one.*
__ No. Significant load reductions from CEE efforts are not feasible in this area.

__ Yes.

Describe the CEE work.

Economic Analysis

Verify that the economic study includes the following items. Check each that applies.

___ The study includes all capacity expansion investments anticipated to at least meet the minimum study period requirements noted in the planning guide (new substation - 10 years; new/upgraded bank - 5 years; new circuit - 2 years).

___ **Either** the study uses present value revenue request (PVRR), since it does not include both distribution and transmission alternatives or other alternatives with differing revenue impacts; **or** the study uses net present value (NPV) and annual revenues for each alternative are included (since the project alternatives result in revenue differences, e.g., transmission E20T versus distribution E20P revenues, or special facilities charges, or other).

___ All alternatives provide equal or near equivalent capacity additions over the study period.

If any of the above items are not checked, include an explanation here.

Project Cost Estimates and Contingency

Complete the project cost table to document the basis for the cost estimate and contingency applied to key project scope components. For application of contingency > 10%, provide supporting information to document the need for contingency > 10%.

The following example is included to illustrate what is required in this section. Please delete the example and enter project specific information for your project.

MWC – Scope	Cost Estimate	Contingency %	Contingency $	Subtotal	Basis for Estimate
MWC 46	$3,750,000	10%	$375,000	$4,125,000	ESE Final Cost Estimate
MWC 61	$1,850,000	10%	$185,000	$2,035,000	ESE Final Cost Estimate
MWC 06 Reconductor 3500' #2 Cu with 715 AL	$3,500,000	25%	$875,000	$4,375,000	Planning Unit Costs and discussion with GC
MWC 06 Install 2 SCADAMATE switches	$100,000	10%	$10,000	$110,000	Planning Unit Costs
MWC 06 install 1,000' new 1100 EPR UG in trench	$2,500,000	25%	$625,000	$3,125,000	Planning Unit Costs and discussion with GC

APPENDIX C

Load Curtailment Process/Rotating Outages

Purpose and Scope

This document is intended to assist electric distribution engineers in calculating bank and circuit peak load following a load curtailment/rotating outage that may have occurred during the peak. It includes a procedure for determining a bank and circuit scaling factor and directions on how to apply this scaling factor to calculate an adjusted peak load. It also includes instructions on how to report load adjustments associated with a load curtailment/rotating outage in the LG2004 program and two-year bank/feeder projection spreadsheets.

Calculating a bank or circuit's adjusted peak following a load curtailment/rotating outage can be a complicated process with many conditions that can affect the final calculation. Engineering judgment should be used when reviewing the quality of the reported and recorded data. Variations from this guide are to be approved by the supervising electric distribution engineer.

This document is intended to provide a consistent system wide approach for calculating and recording peak loads that are affected by load curtailment/rotating outages. These processes should be used in most cases. However, it is understood that these processes may not apply to every situation encountered.

Definition of Terms

Adjusted Bank Peak Load: The calculated peak load that likely would have been recorded had the event not occurred. It is equal to the product of the actual recorded bank load at the beginning of the event and the bank scaling factor.

Bank Scaling Factor: A ratio used to calculate the adjusted peak load of a bank when an event occurs during the bank's peak period. This is a number that is determined from actual recorded peak load data from either the day before or the day after the event. It is used to project what the bank's peak load would likely have been had the event not occurred. It is the ratio of an actual recorded daily peak load to the bank load at a point in time, during the same day, corresponding with the starting time of the event.

Circuit Scaling Factor: The ratio of the adjusted bank peak load and the actual recorded daily peak load used to calculate the bank scaling factor.

Event: a load curtailment/rotating outage.

Load Curtailment/Rotating Outage (LCRO): An outage caused by a lack of generation resources or system disturbance.

Process for Calculating the Bank Scaling Factor and Adjusted Bank Peak Load

Step 1 – Review the bank's recorded KW data on a non-event day to determine when the bank peak occurs. The day before or the day after the event should be used in most cases. In extreme cases, when outages have affected multiple circuits on the same bank over several days, it may be necessary to use recorded load data from another peak load period to determine the time of day the bank normally peaks.

Step 2 – Obtain the starting and ending time of the event outage from the Distribution Operating log or the daily morning report.

Step 3 – Compare the bank daily peak period to the event time frame to determine if load was interrupted during the daily peak period. If the bank was not interrupted during its daily peak period, **stop** – further analysis is not required. If the bank was interrupted during the peak period, however, proceed to Step 4.

Step 4 – Select the most appropriate day (day 1) to use for the purpose of calculating the bank scaling factor. The engineer should select a day when the bank was in normal operation and the temperature or other conditions are similar to the event day. Determine the day 1 peak. Determine the bank load on day 1 at the time corresponding with the beginning of the event. Calculate the bank scaling factor = (day 1 peak)/(day 1 bank load at the time that corresponds to the beginning of the event).

Step 5 – Determine the adjusted bank peak load. The adjusted bank peak load = (Bank load at the beginning of the event) x (the bank scaling factor).

IMPORTANT NOTE: The thermal maximum demand meter is the recommended meter for measuring the bank's peak load. However, the circular recording chart must be used to determine the bank scaling factor. If the maximum load from the thermal demand meter is different than the maximum load on the circular recording chart, an adjustment should be made to the circular chart load before calculating the adjusted bank peak load. This problem should not exist in newer substations equipped with digital recording meters.

Step 6 – Compare the adjusted bank peak load to other daily peak loads to determine if the adjusted peak was the seasonal peak. If the adjusted bank peak load is greater than the other daily peak loads, proceed to Step 7. If it is less than the other daily peak loads, **stop** – further analysis is not required.

If the adjusted peak load is the seasonal peak, it must be recorded in the load growth program (currently LG2004) detailed in Steps 7, 8 and 9.

Step 7 – Enter the maximum recorded peak load (***not*** the adjusted bank peak load) obtained from the weekly substation report into the historical load section of LG2004.

Step 8 – Subtract the maximum recorded peak from the adjusted bank peak load. This will be an adjustment to the historical data.

Step 9 – Enter this difference in the Historical Load Adjustments Section of LG2004 as an "Other" adjustment type with the following description for the load, ***"(LCRO) load adjustment, {date}."***

Note: If several banks in the DPA have load adjustments, these adjustments can be combined into one entry in the historical adjustment section. The individual bank adjustments should be entered in the Notes Section of the LG2004 program.

Process for Calculating and Reporting Adjusted Circuit Loads

Circuit peaks on multiple-circuit banks are typically non-coincident due to load diversity between different types of customers. Distribution engineers with access to recorded (i.e., SCADA) circuit load data should use it to calculate a circuit scaling factor using the process provided to calculate bank scaling factors. If recorded data for the circuit is not available, the distribution engineer needs to calculate a ratio between the bank's adjusted peak load and the actual measured bank peak. This ratio, which will be referred to as the "circuit scaling factor," can then be used to calculate the circuit's peak amperes had the event not occurred.

Use caution when reviewing circuit peak load. Circuits that serve primarily residential load may have abnormally large peaks immediately following an event because of load diversity and the thermal heating of homes during the outages. Local knowledge of the circuit should be used to determine if any adjustment is needed to any recorded circuit demand.

Step 10 – Determine the circuit scaling factor by dividing the adjusted bank peak load by the bank maximum demand reading from the same substation load data sheet. In this case, **the bank maximum demand used for this calculation must be from the same load-reporting period.**

Step 11 – Multiply the average maximum ampere load of the circuit by the circuit scaling factor to determine the adjusted circuit load. The average maximum ampere load of the circuit should be obtained from the substation report for the time frame encompassing the event.

Step 12 – Compare the adjusted peak circuit load to other weekly substation reports to determine if the adjusted circuit load is the seasonal peak. If the adjusted circuits load is *not* the seasonal peak, **stop** – further adjustments are not required. If the adjusted circuit load is the seasonal peak, proceed to Step 13.

Step 13 – Enter the actual recorded average amps into the two-year bank and feeder spreadsheet historical load data section. Enter the difference between the adjusted circuit peak and the recorded circuit peak as a line item in the switching section of the two-year bank and feeder projection spreadsheet with the label, ***"LCRO load adjustment, {date}."***

Example for Calculating Adjusted Bank Peak and Circuit Peak

An outage starts at 4:00 p.m. on Thursday afternoon and lasts until 7:30 p.m. Due to the length of the event, multiple rotating outage blocks are affected with individual circuit outages of 90 minutes or less. Station X had two banks with multiple circuits interrupted in the first and second outage block.

Step 1 – A review of the previous day's (Wednesday's) recorded KW demand for Banks #1 and #2 in Station X identified a daily peak on Bank #1 at 5:00 p.m. and on Bank #2 at 6:00 p.m. Wednesday was a non-Stage III day. The load on Wednesday *also* happened to be **maximum summer peak recorded on both banks**.

Bank #1 Recorded Loads on Wednesday

Time	KW	
3:00	29.7 MW	
4:00	31.2 MW	
5:00	**32.6 MW**	🡐daily peak
6:00	31.9 MW	
7:00	31.1 MW	

Bank #2 Recorded Loads on Wednesday

Time	KW	
3:00	27.9 MW	
4:00	28.5 MW	
5:00	29.5 MW	
6:00	**30.3 MW**	🡐daily peak
7:00	29.5 MW	

Step 2 – Obtain the details of the event outage on each bank and circuit from distribution operating log.

Time the System Was Out	Station X
4:00 p.m. – 5:30 p.m.	1101 and 1102 (Bank #1) Block 1
5:30 p.m. – 7:00 p.m.	1105 and 1106 (Bank #2) Block 2

Step 3 – Was either bank interrupted during its normal daily peak? Yes, both banks were interrupted during their daily peak.

Step 4 – Calculate the bank scaling factor.

On Wednesday, Bank #1 peaked at 32.6 MW at 5:00 p.m. and was at 31.2 MW at 4:00 p.m. (The event on Bank #1started at 4:00 p.m. on Thursday.)

Bank #1 Scaling Factor = 32.6 MW/31.2 MW = 1.045

On Wednesday, Bank #2 peaked at 30.3 MW at 6:00 p.m. and was at 29.5 MW at 5:00 p.m. (The event on Bank #2 started at 5:30 p.m. The closest hourly load reading before the interruption should be used to calculate the bank scaling factor.)

Bank #2 Scaling Factor = 30.3MW/29.5 MW = 1.027

Note: If electronic metering is available, and the load is recorded in 15-minute intervals, the reading closest to the actual time of interruption can be used to calculate the bank scaling factor and the adjusted peak.

Step 5 – Calculate the adjusted bank load.

Recorded Load Data on Thursday (event day)

Bank #1 Recorded Loads on Thursday

Time	KW	
3:00	29.9MW	
4:00	**31.7 MW**	peak before event
5:00	10.6 MW	(one circuit on)
6:00	31.9 MW	
7:00	31.1 MW	

Bank #2 Recorded Loads on Thursday

Time	KW	
3:00	28.3 MW	
4:00	29.1 MW	
5:00	**29.9 MW**	peak before
5:30	←	start of event
6:00	6.3 MW	(one circuit on)
7:00	5.9 MW	

Adjusted Bank Peak Load Calculations

Bank #1 adjusted peak ➔ 31.7 MW x 1.045 (bank scaling factor) = 33.13 MW

Bank #2 adjusted peak ➔ 29.9 MW x 1.027 (bank scaling factor) = 30.71 MW

Step 6 – Review all substation reports and load data during the summer loading season to determine if the bank had a higher peak than the adjusted peak calculated in Step 5. If the bank experienced other normal peaks higher than the adjusted peak, then no further analysis is needed. In this example, the adjusted peak load was the highest bank load during the season, so the adjusted peak load must be reported in the load growth (LG2004) program.

Step 7 – In the Historical Bank Loading Section of the LG2004 enter the maximum recorded demand for Bank #1 and Bank #2, 32.6 MW and 30.3 MW, respectively.

Step 8 – Calculate the difference between the adjusted peak and the recorded peak.

Bank #1 33.13 MW (adjusted peak) – 32.6 MW (measured peak) = .53 MW adjustment.

Bank #2 30.71 MW (adjusted peak) – 30.3 MW (measured peak) = .40 MW adjustment.

Total adjusted = .83 MW

Step 9 – Enter 0.83 MW in the historical adjustment section of LG2004 as an "Other" type of adjustment with the description, ***"LCRO load adjustment, {Thursday's date}."*** Include the individual bank adjustments in the Notes Section on Page 3 of the LG2004 report.

Step 10 – Determine the circuit scaling factor. This is a ratio of the adjusted bank peak to the actual recorded peak from the same substation load data sheet.

Scaling Factor for 1101 and 1102	Scaling Factor for 1105 and 1106
33.13MW/32.6 MW = **1.0163**	30.71 MW/30.3 MW = **1.0135**

Step 11 – Determine the adjusted maximum circuit amperes.

Substation load reading data provided for the period when the event outage occurred.

Circuit	Present Amperes	Maximum Amperes	
1101	438/438/455	538/545/552	(545 amps average)
1102	412/430/424	460/480/470	(470 amps average)
1105	484/490/485	585/590/595	(590 amps average)
1106	415/420/415	540/550/540	(545 amps average)

Circuit	Adjusted Amperes
1101	545 x 1.0163 = 554 amperes
1102	470 x 1.0163 = 477 amperes
1105	590 x 1.0135 = 598 amperes
1106	545 x 1.0135 = 552 amperes

Step 12 – Review other weekly substation load readings and compare the adjusted loads to determine if the adjusted loads are the maximum seasonal peak loads.

Step 13 – The adjusted circuit peak loads were determined to be the individual circuit peak loads for the season. The actual measured peaks, as shown above for each circuit, were entered into the two-year bank and feeder projections in the Historical Load Section of the spreadsheet. In addition, the differences between the adjusted circuit peaks and the maximum recorded load was entered into the Switching Section with the label ***"LCRO load adjustment, {date}."***

Circuit	Two-Year Bank and Feeder	Switching Section
1101	545 amps	9 amps
1102	470 amps	7 amps
1105	590 amps	8 amps
1106	545 amps	7 amps

APPENDIX D

Instructions for preparing load Growth Studies (previously covered in Electric Planning Guideline G-12009)

1. Introduction

This attachment replaces the Electric Distribution Guideline G-12009 which contained the procedures and instructions for forecasting distribution load growth using LG2004. LG2004 is an MS Excel spreadsheet application that calculates load-growth forecasts. Examples of the LG2004 are shown in Appendix D of this document. LG2004 includes the following features:

- The default forecast is load versus year; alternative models are available when additional variables are entered.
- Forecasts load growth up to 6 years out.
- Distributed under the filename LG2004_.xls

See the guide "Analysis of Distribution Forecasts," located at \\Fairfield07\EDD\LG2000 (filename LG_method.doc), for instructions on interpreting regression results. Using Excel's regression tool is discussed at the end of this guide as an alternative to LG2004 for developing a forecasting model.

1.1. Features in LG2004

The following features are included in this version:

- Peak Date and Weather Station fields added to the LoadData sheet.
- Adjusted R^2 values for each model are now listed on the Anova sheet.
- "Load vs. Temp" model is available on the LoadData sheet.
- "Adjusted F" is calculated for models that include a Domestic Customers (Dcusts) variable. (Adjusted F equals F times the adjusted correlation co-efficient for Dcusts versus Year.)
- Bold, underlined font indicates an "outaged" bank for emergency capacity.
- Load adjustments are now entered on the Adjustments sheet. Additional lines are available for entering historical and future adjustments
- Block loads less than the 1.5% criteria are flagged (after running regression).
- Rejected models are flagged as "Do Not Use!" on the Anova sheet.
- Historical and future domestic customer adjustments for load transfers (customers transferred in and out of the distribution planning area [DPA]) are now addressed on the Adjustments worksheet.

1.2. Organization of LG2004

The LG2004 spreadsheet includes the following six worksheets:

- LoadData: Enter data, such as voltage and capacity, for each bank or circuit in the study area. The historical bank loading, 3 day weighted temperature, historical regression model used to forecast and peak day/date information is also entered on this sheet.
- Adjustments: Enter historical and future block loads, transfers, etc.
- Anova (analysis of variance): Reports the statistics for all models.
- Chart: Plots historical and projected load (with prediction intervals), and area normal and emergency capacity.
- Normal Capacity 2 yr. Base: Displays normal capacity load projections for transformer banks and circuits in the study area.
- Emergency Capacity 2 yr. Base: Displays emergency capacity load projections for transformer banks and circuits in the study area.

2. Using LG2004

At a minimum, LG2004 requires historical load data and starting year to create a forecast. The spreadsheet can use additional variables, such as temperature and the number of domestic customers, to generate other forecast models.

After entering data on the LG2004 worksheets and making any changes to the data, select the ***Run Regression*** button on the LoadData sheet. The regression button runs all models and determines the most statistically valid regression model.

LG2004 generates the following forecasts (given the necessary data) on the Anova sheet:

1) Load vs. Year
2) Load vs. DCust
3) Load vs. Temp
4) Load vs. Temp*DCust
5) DCust vs. Year
6) Load vs. Other1
7) Load vs. Other2
8) Load vs. Temp and Year
9) Load vs. Temp and Cust
10) Load vs. Other1 and Other2

When temperature or domestic customers data is entered, LG2004 generates a regression analysis for both variables versus year. LG2004 expects thirteen temperature entries for temperature sensitive DPAs (7 historical and 6 future 1-in-10 temperatures).

Enter only historical data for domestic customers (e.g., from the Centralized Electric Distribution System Analysis [CEDSA] database) on the Adjustments worksheet. The program forecasts future domestic customers. Account for customers transferred in and out of the DPA due to switching on the Adjustments worksheet. Select ***Forecast DOM*** on the Adjustments worksheet and this will calculate net domestic customers (Net DCust) and post it on the LoadData worksheet for the historical 7 years. LG2004 also generates a forecast for future domestic customers and automatically post domestic customers for future 6 years on the LoadData worksheet. **Do not** enter domestic customers directly on the LoadData worksheet.

Verify regression statistics associated with the customer forecast (i.e., verify that the F statistic is significant). (Classical linear regression analysis assumes that the independent variables are known precisely.) An unreliable domestic customer forecast **cannot** be used as an independent variable for other forecasts.

2.1. Load variability Due to Temperature

Following are two methods to account for load variability due to temperature:

1. **Normalize load to a constant temperature**. Eliminate temperature as a factor by increasing or decreasing the peak load based on the load-temperature curve for the DPA being forecast. Adjust the peak load to the DPA's 1-in-10 peak temperature, before calculating the yearly load growth. This method has two significant problems:

    - Developing the necessary load-temperature curves for the DPA may not be possible if the weather is mild.
    - Studies by the Company's Energy Research group have shown that not all load is temperature sensitive.

2. **Multi-linear regression, using temperature as a variable**. Minor variations in peak temperatures from summer to summer, and limited data points (taking only the peak) may not generate a statistically valid variable. The inability of the regression model to account for temperature may be due to temperature-load saturation (e.g., all load is on at 110°F, and no additional load is seen at 112°F, 114°F, 115°F, etc.) On the other hand, temperature can be a statistically useful variable where there is more variation in temperature between summers (e.g., in semi-coastal areas).

2.2. Temperature Data

The Meteorology department has populated the Geographical Information System (GIS) on the Company intranet with temperature data for each of the DPAs.

Note: Listed temperatures are a 3-day weighted average (WAT), where the first day is weighted 10%, the second day 20%, and the third day 70%. Use the WAT for the day on which the peak demands occurred.

Enter the 1-in-10 temperature for projections in climate zones R, X, and S. See Table 6-1, in Chapter 6, "Residential Demand" of the Electric Design Manual for a description of climate zones. The 1-in-10 temperature is calculated from historical weather data recorded from the weather station which is assigned to the DPA. The 1-in-10 temperature is the average of the 4th, 5th and 6th highest recorded temperatures during the past 50 years. The 1-in-10 temperatures are reviewed periodically to determine if adjustments are required.

Enter the 3-day weighted average temperature on the LoadData worksheet next to the label for temperature. The 3-day weighted temperature which is selected for entry into the LoadData worksheet should coincide with the date when the majority of all banks experienced their seasonal peak load.

2.3. Domestic Customers

Population projections from several sources were reviewed, including the Association of Bay Area Governments (ABAG) and Wharton Econometric Forecasting Associates (WEFA). These data sources were either inaccurate or their projections could not easily be overlaid to specific DPAs.

Using CEDSA data avoids the above problems. In temperature-sensitive areas, the number of domestic customers correlates with peak load. Customer data is stored on the server and directory; \\Fairfield07\edd\LG2000\CCT_DATA.

Enter 7 years of domestic customer data on the Adjustments worksheet. For accuracy, account for transfers of domestic customers into and out of the DPA. Enter historical and future customer transfers into and out of the DPA on the Adjustments worksheet. Select ***Forecast DOM*** on the Adjustment worksheet. The spreadsheet automatically forecasts future customers (the program regress the domestic customers versus year). The adjusted future customers forecast is automatically entered as net domestic customers on the LoadData worksheet.

Note: Do not input a numerical domestic customer future adjustment in the "*Future Adjustments for Customer (Domestic) Transfers*" table, if using any regression model based on Dcust. However, the adjustment should still be noted in the appropriate year including the number of customers in description cell. This information still needs to be captured and moved over to historical adjustments in the "Historical Adjustments for Customers (Domestic) Transfers" table as required in future years.

2.4. Other1 and Other2 Variables

Use the Other1 and Other2 rows on the LoadData worksheet to enter data for variables such as available land for development, housing starts, business development, yearly rainfall, local economic indicators, etc. See the directory \\Fairfield07\edd\LG2000\Metro for a list of additional economic indicators by metro area. (Metro data is a commercial database and is forwarded to Electric T&D by the Rates and Services department.)
For areas that have experienced regular economic expansion over the historical study period, Year can substitute as an economic indicator.

Note: The Other1 and Other2 variables do not project for future years (based on 7 years of entered data). If the variables Other1 or Other2 are used, data must be entered for all 13 years.

The use of Other1 or Other2 variables is currently limited in use and the selection of a regression model which utilizes these variables should only be considered in rare situations.

3. Report Data Entries

This section describes the information required to generate load-growth forecasts with the LG2004 spreadsheet.

3.1. LoadData Worksheet

Enter the following information on the LoadData worksheet:

Title Block: Enter the season and name of the DPA in the title block (in the upper left-hand corner of the spreadsheet). For example: *Summer Study - Morgan Hill DPA*. If the forecast is only one alternative in a project analysis, include the alternative number this particular forecast reflects,e.g., *Summer Study - Morgan Hill DPA Alternative 2.*

Substation Bank or Circuit: Enter the substation bank/circuit names. Certain DPAs may include both banks and feeders. Include firm generation sources here also.

Firm Bank: Enter Y (yes) or N (no) to indicate if the bank is firm or not. LG2004 uses this entry to calculate the area emergency capacity.

Limit Code: Use the drop-down box to select the appropriate (Bank, Feeder, Other, Reg., or Trans.) capacity limit code. This information is useful in studying how to increase area capacity.

Voltage (kV): Enter the transmission and distribution voltage associated with the bank or the feeder voltage in the form: 115/12 for banks and 12 for feeders. Omit the tertiary voltage unless appropriate for the DPA.

Capacity: The Substation Asset Strategy (SAS) group provides bank capabilities stated as megavolt-amps (MVA). Enter the supplied values under the Normal and Emergency Capacities section. Per instructions in Section 8 – Capacity of Facilities, the MVA of all equipment can be calculated. The MVA is then converted to MW by utilizing a .99 Power Factor (P.F.) adjustment.

Year T-Capped: Enter the year of the transformer’s most recent capacity re-rating. Leave the entry blank if no TCAP has been performed, of if the TCAP rating has been removed and substation bulletin - IB0248 has been applied.

Year: Enter the initial year of the historical period in the first box. The spreadsheet will calculate the remaining years. Do not enter a dual-year format (xx/yy) to represent 2 years reflected in a winter study. Note the winter season elsewhere on the study, such as in the title, e.g. Livermore Winter 00/01.

Variable Description: When using the variables Other1 and Other2, include descriptions for them in the Comments section.

Load Data Section: Enter the peak demand for each bank/feeder within a 4-week rolling window as described on page 17 of 78 of this document, under section 7.1.B. Also include in this section any load served by non-firm local generation.

Utilization Factor: The default value is 0.95 (1.00 for single bank DPAs.) Consult the area senior engineer before changing the utilization factor (UF).

Years Used / Not Used: The default is to include all years. To exclude a year, enter “0” in the appropriate box.

Note: Discounting a year affects only the “Load versus Year” model. All other models use all years by default. Reducing the number of data points (years) reduces the degrees of freedom and weakens the statistical validity of the model.

Peak Date: Enter the date when the DPA’s peak demand occurred. If some banks peaked on different dates, then selected the date when the majority of the banks peaked.

Day of Week: Enter the corresponding day for the date when the peak demand occurred.

Weather Station: Enter the name of the weather station used to obtain temperature data for the DPA.

Regression Model Used: Enter the regression model selected for the load forecast.

Comments: Enter additional notes on the forecast model used here. Explain any unusual UF, capability or power factor (PF) conditions here as well. Comment on any other current or future conditions not documented by the framework.

3.2. Adjustments Worksheet Data

Enter the following information on the Adjustments worksheet.

Historical Adjustments: Enter the year and click on the gray button to select the appropriate Type from the drop-down list for each adjustment entered here. The choices are as follows.

1. Load Transfers—Loads transferred into or out of the DPA.

Note: Enter each load transfer into or out of the DPA. Load transfers out of DPA should be assigned a negative value and transfers into the DPA should be assigned a positive value.

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

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

Include any supporting data to show that the block load was in place at the time of the peak in the year indicated (i.e., verified via the 300 kW report).

3. Other—One time adjustments made to the area for unique conditions that occurred in a particular year.

Future Adjustments: Adjust future area peak loads for load transfers, block loads, or any other adjustments. For block loads, include supporting data to show they will be on line at the time of peak in the year indicated and with the loads stated. (Use loads from an existing customer with comparable watts per square foot, etc.)

Six Year Plan: Enter the future normal and emergency capacity additions or deletions for the study area, and any work necessary to achieve a .99 lagging power factor for each distribution bank in the area.

For new bank additions, use IB0248, dated 10/2/08, to determine the appropriate normal and emergency capacity values.

Use feeder equipment limitations to determine actual rating increases for feeder changes or additions.

Note: Enter any information relevant to the DPA to support or supplement the data included in the spreadsheet. This may include information relevant to block loads, load transfers, capacitor status and additions, significant changes within the DPA, etc.

- **Printing the Spreadsheet**

Format the spreadsheet via Print Preview. Select the Print button on the Excel toolbar to print the spreadsheet.

- **Saving and Closing the Spreadsheet**

Save the file with an .xls extension. The name of the file should reflect the DPA name and first year forecasted in the study. If the file has substation load data through year 2008 the file name would be *Morgan Hill DPA 2009.xls*

- **Chart Worksheet**

The Chart worksheet displays a plot of historical and forecast load, and the area's normal and emergency capacity. The prediction interval is set to 95%. To change the prediction interval, edit cell AB1 on the Anova worksheet (function = TINV[0.05,5]) for single regression. Edit cell AF45 (function = TINV[0.05,4]) for multiple regression.

- **Anova Worksheet**

LG2004 automatically calculates a least squares regression of load versus year. Statistical results from this analysis appear on the Anova worksheet. When using additional data variables, such as temperature or domestic customers, Anova calculates a least squares regression of load versus the additional variables. See "Analysis of Distribution Forecasts" for instructions on interpreting regression results.

2. Steps for Identifying the Most Statistically Valid Forecast Model

The Anova worksheet provides statistics for the following load projection methods:

Single variable regression models

- Load vs. Year
- Load vs. Domestic Customers
- Load vs. Temperature
- Load vs. (Temperature * Domestic Customers)
- Load vs. Other1, or Other2 (where Other can be any relevant variable that the planner has data for, such as kilowatt-hour usage, yearly rainfall, acres of developable land, etc.)

Multiple variable regression models

- Load vs. Year and Temperature
- Load vs. Domestic Customers and Temperature
- Load vs. Other1 and Other2

The Anova worksheet shows the best statistical model. LG2004 automatically calculates the most valid statistical model as follows:

Step 1

LG2004 reviews the coefficients for each independent variable, such as Year, Temp, DCust, etc. If any forecast model includes a negative coefficient, LG2004 rejects that model. For example, a negative coefficient for Year corresponds to negative load growth. A negative intercept does not reject that model.

Step 2

If any model has an "F-significance" value greater than 0.05, the LG2004 program rejects that model. A lower "F-significance" value normally suggests a better regression correlation between the variables.

Step 3

The spreadsheet checks the "p-value" for each independent variable. Where the independent variable's p-value is greater than 0.05, the LG2004 program rejects that model. Note: This step does not apply to an intercept "p-value" greater than 0.05.

Step 4

From the remaining models, LG2004 selects the model with the lowest "F-significance" value as the most statistically valid forecast model.

If all models (which is not likely) are rejected based on the outcome of Steps 1 through 3, an alternate method for forecasting the area load is used. In cases where a statistically valid projection can not be achieved, excluding agricultural areas, utilize the Operation Revenue Requirements forecasting model (ORRQ model) for the Bay or Non-Bay Area as recommended. For agricultural areas the Load vs. Year model is the recommended model, if another model is used the reason should be documented in the comment section. Consult with your area senior engineer before selection of a different model.

3. Engineering Judgment and Consistent Data

Usually, the model selected is the most statistically valid model. However, engineering judgment still applies: if two models are statistically similar (i.e., "F-significance" are close in value) choosing the less statistically valid model may be acceptable. (Reasons could be an inability to continue collecting data to support the better model in future years or the continued selection of a temperature and domestic customer model in a DPA which historically is sensitive to these variables, etc.). If a valid model with a higher "F-significance" value is selected, include the reasons in the Comments section on the LoadData worksheet.

A reliable forecast requires consistent data. **Failure to account for switching, block loads, generation, etc., will create an inconsistent forecast**. The data should include the same DPA bounds from year to year. Include load transfers into and out of the DPA in the Historical and Future Adjustments sections. Switching transfers within the DPA should balance.

Non-firm generation is any generation for which there is no guarantee of availability during the peak demand period. If any generation within a DPA is serving load during the peak load period, add that load to the data to ensure that the spreadsheet accounts for it consistently and includes it in the calculations. Include this generation below the banks and feeders in the capacity section. Show the non-firm portion of the generation as a 0.0 normal and emergency capacity.

Remember that there must be a logical correlation between regression variables and the corresponding load data. For example, temperature and demand must coincide. It would be inconsistent to use the (peak) demand on August 7 and the (highest) temperature for the area on June 20.

4. Trend Adjustment

Trend line adjustments account for changes in the area growth that are unexplained by the linear regression model. Instead of ignoring this unexplained variation, a trend line adjustment is one way of recognizing the under-forecast.

After selecting a forecast model, compare the year’s current peak with the forecast peak. Adjust the trend line if the following conditions are true:

- The forecast peak is significantly below the current peak.
- The megawatt (MW) difference meets the block load criteria definition.
- The latest peak does not exceed the extreme weather event criteria.

The load adjustment should equal the difference between the actual peak and the trend line peak. Trend line adjustments only apply to the current year and for Load vs. Year model. Enter trend line adjustments on the Adjustments or Anova worksheet.

- **Normal and Emergency Capacity 2yr.Base Worksheets**

LG2004’s primary purpose is to forecast area load; the Normal Capacity 2yr. Base worksheet and the Emergency Capacity 2yr. Base worksheet are included to promote consistent tracking of bank/feeder projections. (Copy additional emergency worksheets as necessary for each bank.)

When preparing the transformer bank and feeder projections, it is important that the sum of the bank projections match those projected on the LoadData worksheet. To ensure consistency, LG2004 performs the following process:

1. The spreadsheet subtracts the current year’s summer area load from the following year’s projected load (as identified on LoadData). This accounts for external factors (i.e., temperature)that may affect loads and, thereby, projections.

2. From the result of the previous step, the spreadsheet subtracts the following items:

   - Block loads
   - Out-of-area transfers
   - Non-firm generation
   - Known new business loads (non block loads)

3. The spreadsheet allocates the remaining “growth” to each transformer.

Note: The worksheet allocates this amount to each transformer proportionally. Planners can change the allocations based on their experience with the DPA and where the growth is occurring.

8.1. Automated Features

The spreadsheet performs the following functions automatically:

Note: Cells containing formulas are shown in blue.

- Shows the current year.*
- Shows the DPA name.*
- Shows the area’s growth rate.*
- Shows the substation name.*
- Shows the transformers’ normal and emergency ratings as shown on LoadData. *

  Note: Since these ratings could be associated with the sum of the feeder capabilities (i.e., effective capacity of a feeder limited bank), the true transformer rating must be entered manually.

- Shows the current year’s load for each transformer.*
- Shows the current year area capacity.*
- Shows the projected area load for the following 2 years.*
- Spreads the area growth proportionally to each bank and feeder. As noted earlier, the planner can change the area growth distribution based on their knowledge of new area loads.

  Note: Planners must use the drop-down list adjacent to each bank to identify the voltage on each transformer so the MWs convert properly to amps.

- Sum all the load transfers, capacity work, etc.
- Converts the sum of the amps to MW for reserve capacity, block loads, load transfers, new business loads (non-block loads), and capacity.

  Note: If planners prefer going from MW to amps, they can do so by writing over the existing formulas.

* Indicates a cell reference to the LoadData worksheet.

8.2. Data to Be Entered Manually:

Manually enter the following data onto the spreadsheet:

- Transformer numbers.
- Feeder numbers.
- Normal and emergency feeder capabilities (in amps).
- Current year's peak load for each feeder (average the three phase amps readings)
- Reserved capacity on feeders (in amps and as a positive number).**
- Projected block loads in amps (the MW must match the entries on LoadData).**
- Known new business loads on feeders (non-block loads).**
- Out-of-area load transfers by feeder (must match entries on LoadData).**
- Within DPA load transfers (in amps).
- Future capacity work (must match entries on LoadData).

** LG2004 converts amps to MW for these entries.

Note: For bank capacity increases, the worksheet sums the bank capabilities and multiplies it by the area's UF to provide a total area increase. For feeder only projects, this area capacity must be entered manually.

- **Error Messages and Flags**

The spreadsheet compares projections from the LoadData worksheet with the sum of the bank projections. If the projections do not match, an "Error" message appears just below the Total Area projection. If the data matches, "Ok" is displayed.

The spreadsheet also provides flags that identify banks and feeders that are at 90% or more of capacity.

- **Alternatives to using LG2004**

Because LG2004 uses no more than seven data points to generate a forecast, generating statistically reliable variables becomes somewhat problematic. Nevertheless, because load growth typically follows an S-curve (see "Analysis of Distribution Forecasts" for a discussion of the S-curve), as few as four or five data points may be sufficient to generate a usable engineering forecast.

Excel includes a regression analysis tool that can be used instead of LG2004's framework for forecasting future load. Make the following menu selections in Excel to access the regression analysis function:

1. Select the "Tools" menu.
2. Select "Data Analysis."
2. Select "Regression."

If “Data Analysis” does not appear on the Tools menu, use the following instructions to install the“Analysis ToolPak”:

1. Select the “Tools” menu.
2. Select “Add Ins.”
3. Select “Analysis ToolPak” for installation.

For DPAs with access to Supervisory Control and Data Acquisition (SCADA) data (substation or reclosers), Excel’s regression analysis tool can be used to analyze the data. See “Analysis of Distribution Forecasts” for instructions on running and interpreting Excel’s regression results. Excel Help gives a good example of regression. Search help for the LINEST function to see the example.

Various regression studies suggest themselves for determining how temperature affects load, and how load varies by number of domestic customers. Here is an example:

1. For a temperature-dependent DPA, keep the area, types of customers, and day of the week constant, while regressing load on temperature. Then determine the following information:

    - If the load saturates and at what temperature.
    - The amount of load variation with temperature.

2. Regress load versus feeders with varying numbers of domestic customers, keeping the time of day and temperature constant.

3. Determine the regression co-efficient for domestic customers, and compare this regression coefficient with the regression co-efficient calculated in LG2004.

Reference:

Analysis of Distribution Forecasts,” located at \\Fairfield 07\EDD\LG2000
(filename LG_method.doc),

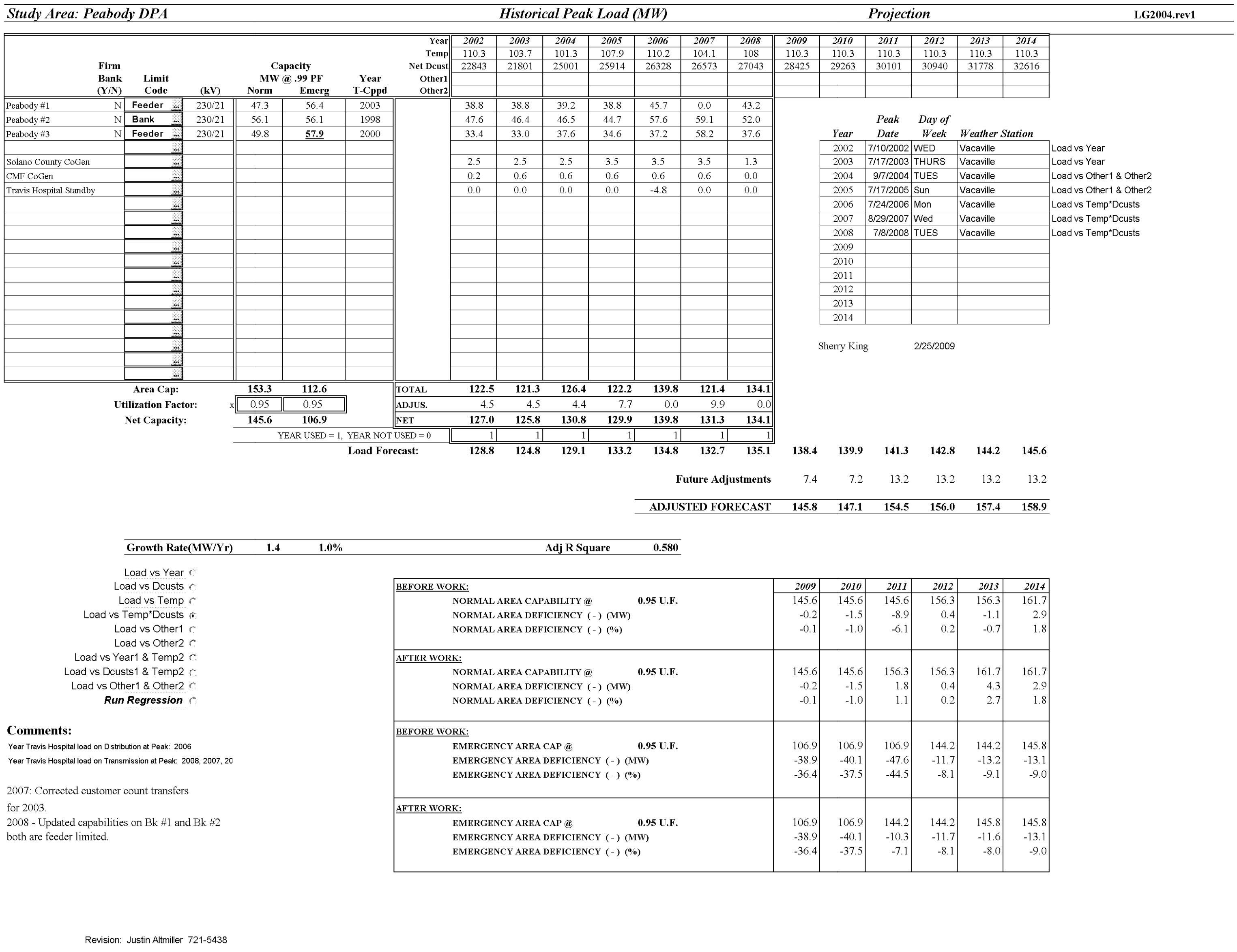
Electric Design Manual, Chapter 6, “Residential Demand”

APPENDIX E

Typical examples of Load Growth, Capacity Sheets and Bank Loss documents.

EXAMPLE FILES

- Sample Load Growth #1: Includes standby contract, customer parallel generation, Adjustment sheets, Chart and Two Year Bank and Feeder Projection
- Sample Load Growth #2: Two distribution voltages, Adjustment sheet and Two Year Bank and Feeder Projection
- Bank Loss Example
- Bank Capability Example
- Feeder Capability Example



Study Area: Peabody DPA *Historical Peak Load (MW)* *Projection* **LG2004.rev1**

	Firm Bank (Y/N)	Limit Code	(kV)	Capacity MW @ .99 PF Norm	Capacity MW @ .99 PF Emerg	Year T-Cppd	Year	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
							Temp	110.3	103.7	101.3	107.9	110.2	104.1	108	110.3	110.3	110.3	110.3	110.3	110.3
							Net Dcust	22843	21801	25001	25914	26328	26573	27043	28425	29263	30101	30940	31778	32616
							Other1													
							Other2													
Peabody #1	N	Feeder	230/21	47.3	56.4	2003		38.8	38.8	39.2	38.8	45.7	0.0	43.2						
Peabody #2	N	Bank	230/21	56.1	56.1	1998		47.6	46.4	46.5	44.7	57.6	59.1	52.0						
Peabody #3	N	Feeder	230/21	49.8	**57.9**	2000		33.4	33.0	37.6	34.6	37.2	58.2	37.6						
Solano County CoGen								2.5	2.5	2.5	3.5	3.5	3.5	1.3						
CMF CoGen								0.2	0.6	0.6	0.6	0.6	0.6	0.0						
Travis Hospital Standby								0.0	0.0	0.0	0.0	-4.8	0.0	0.0						
Area Cap:				**153.3**	**112.6**		TOTAL	**122.5**	**121.3**	**126.4**	**122.2**	**139.8**	**121.4**	**134.1**						
Utilization Factor:			x	0.95	0.95		ADJUS.	4.5	4.5	4.4	7.7	0.0	9.9	0.0						
Net Capacity:				**145.6**	**106.9**		NET	**127.0**	**125.8**	**130.8**	**129.9**	**139.8**	**131.3**	**134.1**						
				YEAR USED = 1, YEAR NOT USED = 0				1	1	1	1	1	1	1						
							Load Forecast:	**128.8**	**124.8**	**129.1**	**133.2**	**134.8**	**132.7**	**135.1**	**138.4**	**139.9**	**141.3**	**142.8**	**144.2**	**145.6**
														Future Adjustments	7.4	7.2	13.2	13.2	13.2	13.2
														ADJUSTED FORECAST	**145.8**	**147.1**	**154.5**	**156.0**	**157.4**	**158.9**

Year	*Peak Date*	*Day of Week*	*Weather Station*	
2002	7/10/2002	WED	Vacaville	Load vs Year
2003	7/17/2003	THURS	Vacaville	Load vs Year
2004	9/7/2004	TUES	Vacaville	Load vs Other1 & Other2
2005	7/17/2005	Sun	Vacaville	Load vs Other1 & Other2
2006	7/24/2006	Mon	Vacaville	Load vs Temp*Dcusts
2007	8/29/2007	Wed	Vacaville	Load vs Temp*Dcusts
2008	7/8/2008	TUES	Vacaville	Load vs Temp*Dcusts
2009				
2010				
2011				
2012				
2013				
2014				

Sherry King 2/25/2009

Growth Rate(MW/Yr) **1.4** **1.0%** **Adj R Square** **0.580**

Load vs Year ○
Load vs Dcusts ○
Load vs Temp ○
Load vs Temp*Dcusts ●
Load vs Other1 ○
Load vs Other2 ○
Load vs Year1 & Temp2 ○
Load vs Dcusts1 & Temp2 ○
Load vs Other1 & Other2 ○
Run Regression ○

		2009	*2010*	*2011*	*2012*	*2013*	*2014*
BEFORE WORK:							
NORMAL AREA CAPABILITY @	**0.95 U.F.**	145.6	145.6	145.6	156.3	156.3	161.7
NORMAL AREA DEFICIENCY (-) (MW)		-0.2	-1.5	-8.9	0.4	-1.1	2.9
NORMAL AREA DEFICIENCY (-) (%)		-0.1	-1.0	-6.1	0.2	-0.7	1.8
AFTER WORK:							
NORMAL AREA CAPABILITY @	**0.95 U.F.**	145.6	145.6	156.3	156.3	161.7	161.7
NORMAL AREA DEFICIENCY (-) (MW)		-0.2	-1.5	1.8	0.4	4.3	2.9
NORMAL AREA DEFICIENCY (-) (%)		-0.1	-1.0	1.1	0.2	2.7	1.8
BEFORE WORK:							
EMERGENCY AREA CAP @	**0.95 U.F.**	106.9	106.9	106.9	144.2	144.2	145.8
EMERGENCY AREA DEFICIENCY (-) (MW)		-38.9	-40.1	-47.6	-11.7	-13.2	-13.1
EMERGENCY AREA DEFICIENCY (-) (%)		-36.4	-37.5	-44.5	-8.1	-9.1	-9.0
AFTER WORK:							
EMERGENCY AREA CAP @	**0.95 U.F.**	106.9	106.9	144.2	144.2	145.8	145.8
EMERGENCY AREA DEFICIENCY (-) (MW)		-38.9	-40.1	-10.3	-11.7	-11.6	-13.1
EMERGENCY AREA DEFICIENCY (-) (%)		-36.4	-37.5	-7.1	-8.1	-8.0	-9.0

Comments:

Year Travis Hospital load on Distribution at Peak: 2006

Year Travis Hospital load on Transmission at Peak: 2008, 2007, 20

2007: Corrected customer count transfers
for 2003.
2008 - Updated capabilities on Bk #1 and Bk #2
both are feeder limited.

Revision: Justin Altmiller 721-5438

Example # 1 – LoadData sheet

HISTORICAL ADJUSTMENTS (LOAD TRANSFERS, BLOCK LOADS, AND OTHER)

YEAR	TYPE	DESCRIPTION OF ADJUSTMENTS	MW
2004	Load Transfers	Transfer from VV 1107	+1.30
2004	Load Transfers	Transfer From Suisun 1104	+1.37
2004	Load Transfers	Transfer from Suisun 1109	+0.59
2004	Load Transfers	Bk#3 adjustment for emergency transfer thru auto T11212 during peak	-1.80
2004	Load Transfers	Transfer to GI2221 for Voltage	-0.50
2004	Load Transfers	Bk#2 adjustment for transfer to GI2221 (Creed/113 Line Outage)	-0.80
2005	Load Transfers	Santa Fe Pipeline Decommissioning	-2.50
2005	Load Transfers	Transfer from Suisun 1105 to P2107 (clo 2684, open 19918)	-0.80
2006	Block Loads	Transfer Elmira sewage plant to P2105 from VD1106 no domestic customers	+2.20
2006	Load Transfers	T11212 Outage during peak on 7/23/06 Peabody Bk3 P2113	+5.60
2007	Other	Peabody Bank 1 Failure Load transfer to Vacaville-Dixon DPA at peak	+6.00
2007	Other	Peabody Bank 1 Failure Load transfer to Suisun DPA (This will be a perm. Load trasfer)	+3.90

HISTORICAL ADJUSTMENTS

	2002	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	1.3	1.3	0.0	0.0	0.0	0.0	0.0
	1.3	1.4	0.0	0.0	0.0	0.0	0.0
	0.6	0.6	0.0	0.0	0.0	0.0	0.0
	-1.7	-1.8	0.0	0.0	0.0	0.0	0.0
	-0.5	-0.5	0.0	0.0	0.0	0.0	0.0
	-0.8	-0.8	0.0	0.0	0.0	0.0	0.0
	-2.4	-2.4	-2.5	0.0	0.0	0.0	0.0
	-0.8	-0.8	-0.8	0.0	0.0	0.0	0.0
	2.2	2.2	2.2	2.2	0.0	0.0	0.0
	5.3	5.4	5.4	5.5	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	6.0	0.0
	0.0	0.0	0.0	0.0	0.0	3.9	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**4.5**	**4.5**	**4.4**	**7.7**	**0.0**	**9.9**	**0.0**

FUTURE ADJUSTMENTS (LOAD TRANSFERS, BLOCK LOADS, AND OTHER)

YEAR	TYPE	DESCRIPTION OF ADJUSTMENTS	MW
2009	Block Loads	David Grant Medical Center (TAFB) Reserve Capacity (Autotransfer 60kV to 21kV)	4.80
2009	Load Transfers	CLOSE 6473, OPEN 8511 (SUISUN 1105 TO PEABODY 2113)	1.20
2009	Load Transfers	CLOSE 2880, OPEN 10063 (Vacaville 1109 to Peabody 2112)	0.49
2009	Block Loads	California Medical Facility (CMF)--Peabody 2106--Projected Peak Load of 4MW	0.90
2010	Load Transfers	CLOSE 8511, OPEN 6473 (PEABODY 2113 TO SUISUN 1105)	-1.20
2010	Block Loads	California Medical Facility (CMF)--Peabody 2106--Projected Peak Load of 5MW	1.00
2011	Block Loads	California Medical Facility (CMF)--Peabody 2106--Projected Peak Load of 6MW	1.00
2011	Block Loads	California Healthcare Facility (CHCF)--Peabody 2106 or Peabody 2112	5.00

FUTURE ADJUSTMENTS

	2009	*2010*	*2011*	*2012*	*2013*	*2014*
	4.8	4.8	4.8	4.8	4.8	4.8
	1.2	1.2	1.2	1.2	1.2	1.3
	0.5	0.5	0.5	0.5	0.5	0.5
	0.0	0.0	0.0	0.0	0.0	0.0
	0.9	0.9	0.9	0.9	0.9	0.9
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	-1.2	-1.2	-1.2	-1.2	-1.2
	0.0	1.0	1.0	1.0	1.0	1.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	1.0	1.0	1.0	1.0
	0.0	0.0	5.0	5.0	5.0	5.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**7.4**	**7.2**	**13.2**	**13.2**	**13.2**	**13.2**

Revision: Justin Altmiller 721-5438
Date: 12/17/08

Example #1 – Adjustment sheet – page 1 of 3

SIX YEAR PLAN

	CAPACITY INCREASE (in MW)		
YEAR	NORM	EMERG	DESCRIPTION OF WORK
2011	+15.5	+23.2	New project to offset loss of TCAP ratings. Replace BK# 1 with New 75MVA, add 1 circuit.
2011	+15.5	+12.8	New project to offset loss of TCAP ratings. Replace BK# 2 with New 75MVA (Limit to 60MW)
2011	-2.8	+1.5	PEABODY BK # 1 - IB0248
2011	-11.6	+1.8	PEABODY BK # 2 - IB0248
2011	-5.3	0.0	PEABODY BK # 3 _ IB0248
2013	+5.7	+1.7	Replace Peabody Bk # 3 with New 75MVA.

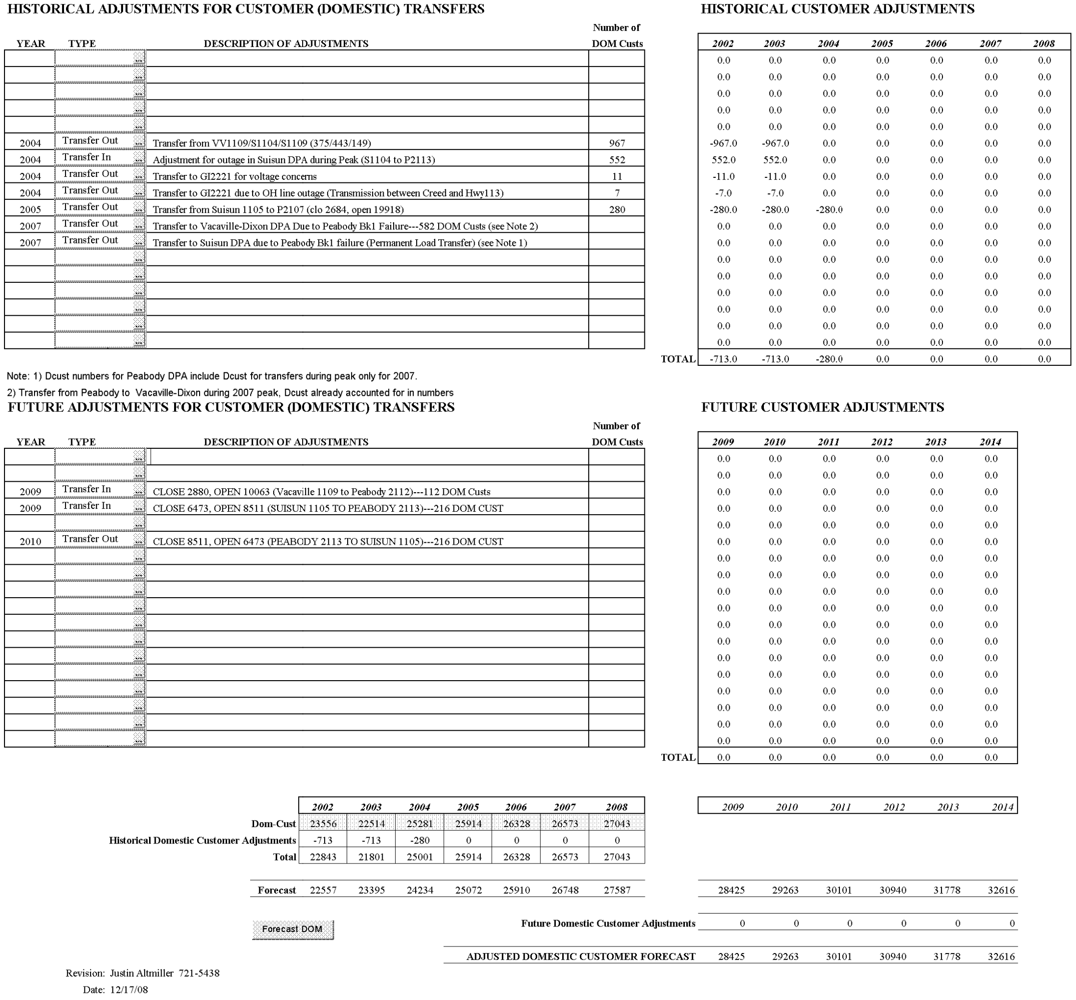
Notes:

CAPACITY INCREASES

NORMAL							EMERGENCY					
2009	*2010*	*2011*	*2012*	*2013*	*2014*		*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
0.0	0.0	15.5	15.5	15.5	15.5		0.0	0.0	23.2	23.2	23.2	23.2
0.0	0.0	15.5	15.5	15.5	15.5		0.0	0.0	12.8	12.8	12.8	12.8
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	-2.8	-2.8	-2.8	-2.8		0.0	0.0	1.5	1.5	1.5	1.5
0.0	0.0	-11.6	-11.6	-11.6	-11.6		0.0	0.0	1.8	1.8	1.8	1.8
0.0	0.0	-5.3	-5.3	-5.3	-5.3		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	5.7	5.7		0.0	0.0	0.0	0.0	1.7	1.7
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**11.27**	**11.27**	**16.97**	**16.97**		**0.00**	**0.00**	**39.26**	**39.26**	**40.92**	**40.92**
CAPACITY INCREASES @			**0.95**	**U.F.**			CAPACITY INCREASES @			**0.95**	**U.F.**	
0.00	**0.00**	**10.70**	**10.70**	**16.12**	**16.12**		**0.00**	**0.00**	**37.29**	**37.29**	**38.87**	**38.87**

Revision: Justin Altmiller 721-5438
Date: 12/17/08

Example #1 – Adjustment Sheet page 2 of 3



HISTORICAL ADJUSTMENTS FOR CUSTOMER (DOMESTIC) TRANSFERS

YEAR	TYPE	DESCRIPTION OF ADJUSTMENTS	Number of DOM Custs
2004	Transfer Out	Transfer from VV1109/S1104/S1109 (375/443/149)	967
2004	Transfer In	Adjustment for outage in Suisun DPA during Peak (S1104 to P2113)	552
2004	Transfer Out	Transfer to GI2221 for voltage concerns	11
2004	Transfer Out	Transfer to GI2221 due to OH line outage (Transmission between Creed and Hwy113)	7
2005	Transfer Out	Transfer from Suisun 1105 to P2107 (clo 2684, open 19918)	280
2007	Transfer Out	Transfer to Vacaville-Dixon DPA Due to Peabody Bk1 Failure---582 DOM Custs (see Note 2)	
2007	Transfer Out	Transfer to Suisun DPA due to Peabody Bk1 failure (Permanent Load Transfer) (see Note 1)	

HISTORICAL CUSTOMER ADJUSTMENTS

	2002	2003	2004	2005	2006	2007	2008
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	-967.0	-967.0	0.0	0.0	0.0	0.0	0.0
	552.0	552.0	0.0	0.0	0.0	0.0	0.0
	-11.0	-11.0	0.0	0.0	0.0	0.0	0.0
	-7.0	-7.0	0.0	0.0	0.0	0.0	0.0
	-280.0	-280.0	-280.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	-713.0	-713.0	-280.0	0.0	0.0	0.0	0.0

Note: 1) Dcust numbers for Peabody DPA include Dcust for transfers during peak only for 2007.

2) Transfer from Peabody to Vacaville-Dixon during 2007 peak, Dcust already accounted for in numbers

FUTURE ADJUSTMENTS FOR CUSTOMER (DOMESTIC) TRANSFERS

YEAR	TYPE	DESCRIPTION OF ADJUSTMENTS	Number of DOM Custs
2009	Transfer In	CLOSE 2880, OPEN 10063 (Vacaville 1109 to Peabody 2112)---112 DOM Custs	
2009	Transfer In	CLOSE 6473, OPEN 8511 (SUISUN 1105 TO PEABODY 2113)---216 DOM CUST	
2010	Transfer Out	CLOSE 8511, OPEN 6473 (PEABODY 2113 TO SUISUN 1105)---216 DOM CUST	

FUTURE CUSTOMER ADJUSTMENTS

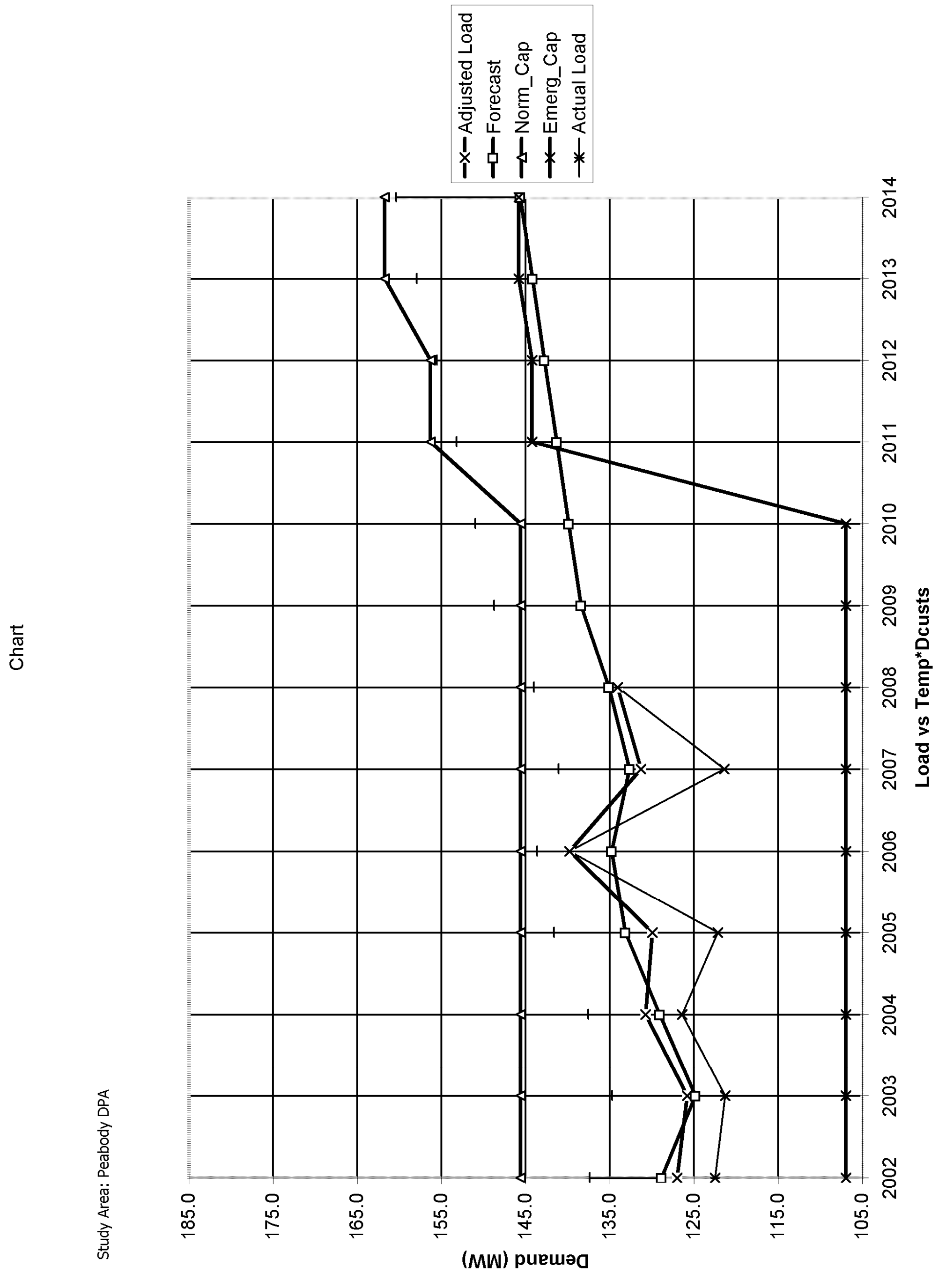
	2009	2010	2011	2012	2013	2014
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Dom-Cust	23556	22514	25281	25914	26328	26573	27043						
Historical Domestic Customer Adjustments	-713	-713	-280	0	0	0	0						
Total	22843	21801	25001	25914	26328	26573	27043						
Forecast	22557	23395	24234	25072	25910	26748	27587	28425	29263	30101	30940	31778	32616
Future Domestic Customer Adjustments								0	0	0	0	0	0
ADJUSTED DOMESTIC CUSTOMER FORECAST								28425	29263	30101	30940	31778	32616

Revision: Justin Altmiller 721-5438

Date: 12/17/08

Example #1 – Adjustment Sheet page 3 of 3



Example #1 – Chart of forecast

Normal Capacity 2yr. Base

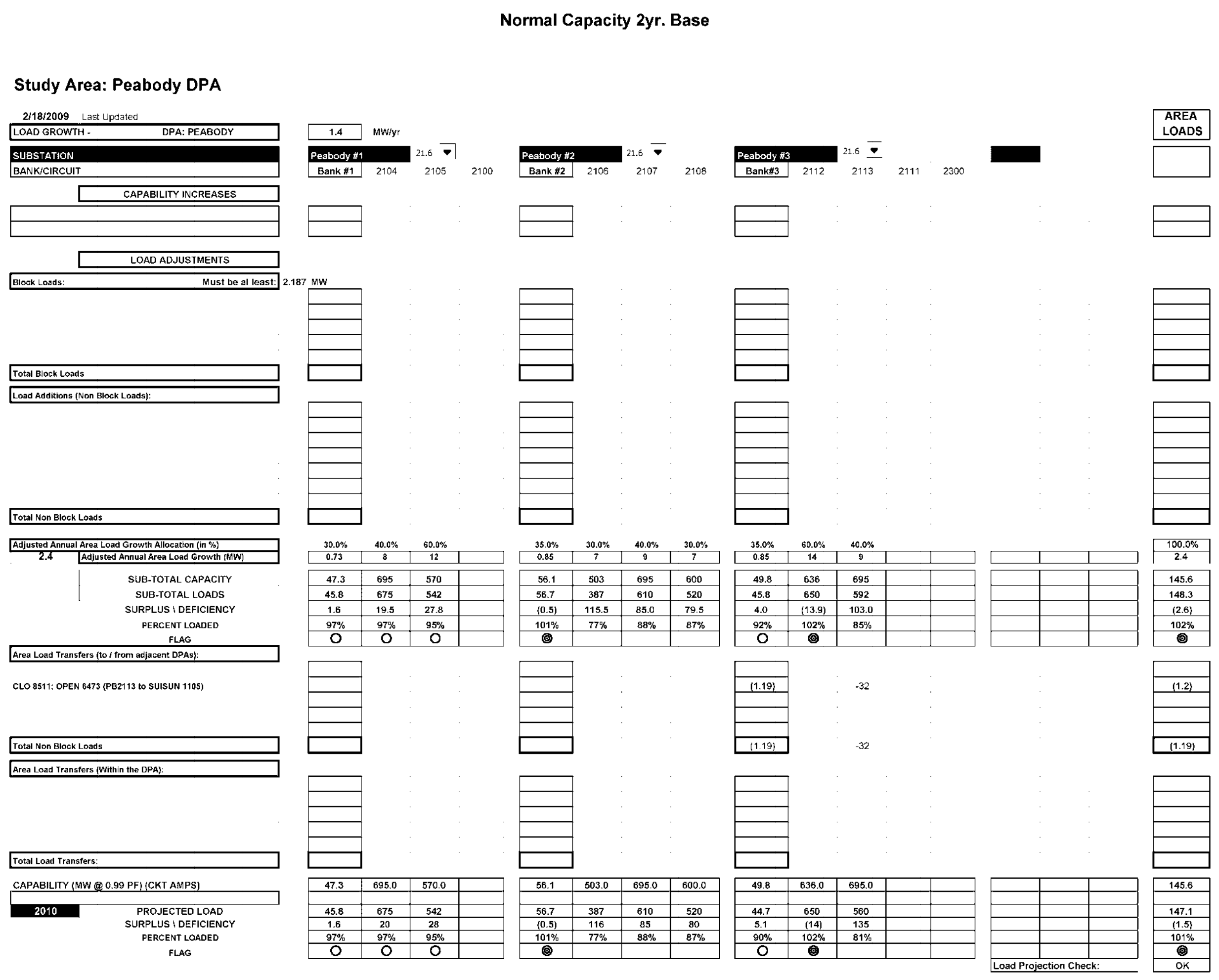
Study Area: Peabody DPA

2/18/2009 Last Updated

LOAD GROWTH - DPA: PEABODY	1.4	MW/yr															AREA LOADS
SUBSTATION	Peabody #1		21.6 ▼		Peabody #2		21.6 ▼		Peabody #3		21.6 ▼						
BANK/CIRCUIT	Bank #1	2104	2105	2100	Bank #2	2106	2107	2108	Bank#3	2112	2113	2111	2300				
NOR. CAPABILITY (MW @ 0.99 PF) (AMPS)	47.3	695	570		56.1	503	695	600	49.8	636	695						145.6
EM. CAPABILITY (MW @ 0.99 PF) (AMPS)	56.4	832	700		56.1	570	700	620	57.9	792	752						106.9
2008 ACTUAL PK LOAD	43.2	648	501		52.0	404	461	528	37.6	555	465						132.8
DATE OF PEAK: 7/8/2008														2009 Area Projection			145.8
LOAD ADJUSTMENTS																	
Reserved Capacity																	
Total Reserved Capacity																	
CAPABILITY INCREASES / DECREASES																	
Co-Generation																	
Solano County CoGen									1.30		35						1.3
CMF CoGen																	
Total Co-generation									1.30		35						1.30
Block Loads: Must be at least:	1.992 MW																
Travis Standby Capacity					4.81		130										4.8
Total Block Loads					4.81		130										4.81
Load Additions (Non Block Loads):																	
Total Non Block Loads																	
Adjusted Annual Area Load Growth Allocation (in %)	35.0%	40.0%	60.0%		35.0%	40.0%	20.0%	40.0%	30.0%	60.0%	40.0%						100.0%
5.2 Adjusted Annual Area Load Growth (MW)	1.84	20	29		1.84	20	10	20	1.57	25	17						5.2
SUB-TOTAL CAPACITY	47.3	695	570		56.1	503	695	600	49.8	636	695						145.6
SUB-TOTAL LOADS	45.0	668	530		58.7	424	600.8	547.6	40.5	580	517						144.2
SURPLUS \ DEFICIENCY	2.3	27	40		(2.5)	79	94	52	9.3	56	178						1.5
PERCENT LOADED	95%	96%	93%		104%	84%	86%	91%	81%	91%	74%						99%
FLAG	○	○	○		◎			○		○							○
Area Load Transfers (to / from adjacent DPAs):																	
CLO 2880; OPEN 10063 (Vacaville 1109 to PB 2112)									0.48	13							0.5
CLO 6473; OPEN 8511 (SUISUN 1105 TO PB2113)									1.19		32						1.2
Total Load Transfers:									1.67	13	32						1.67
Area Load Transfers (Within the DPA):																	
CLO 48261; OPEN 17400 (PB2108 TO PB2113)					(1.26)			-34	1.26		34						
CLO 19188; OPEN 17084 (PB2106 TO PB2112)					(1.59)	-43			1.59	43							
Total Load Transfers:					(2.85)	(43)		(34)	2.85	43	34						
CAPABILITY (MW @ 0.99 PF) (CKT AMPS)	47.3	695	570		56.1	503	695	600	49.8	636	695						145.6
2009 PROJECTED LOAD	45.0	668	530		55.8	381	601	514	45.0	636	583						145.8
SURPLUS \ DEFICIENCY	2.3	27	40		0.3	122	94	86	4.8	(0)	112						(0.2)
PERCENT LOADED	95%	96%	93%		99%	76%	86%	86%	90%	100%	84%						100%
FLAG	○	○	○		○				○	◎							◎
PROJECTED LOAD MW (Circuit Peak)		**25.236**	**20.051**			**14.388**	**22.711**	**19.415**		**24.050**	**22.031**			Load Projection Check:			OK
PROJECTED LOAD MW (Bank Peak)		25.096	19.939			14.206	22.423	19.169		23.4796	21.5085						
														2010 Area Projection			147.1

P

Example #1 – Normal Capacity 2 yr Base – page 1 of 2



Normal Capacity 2yr. Base

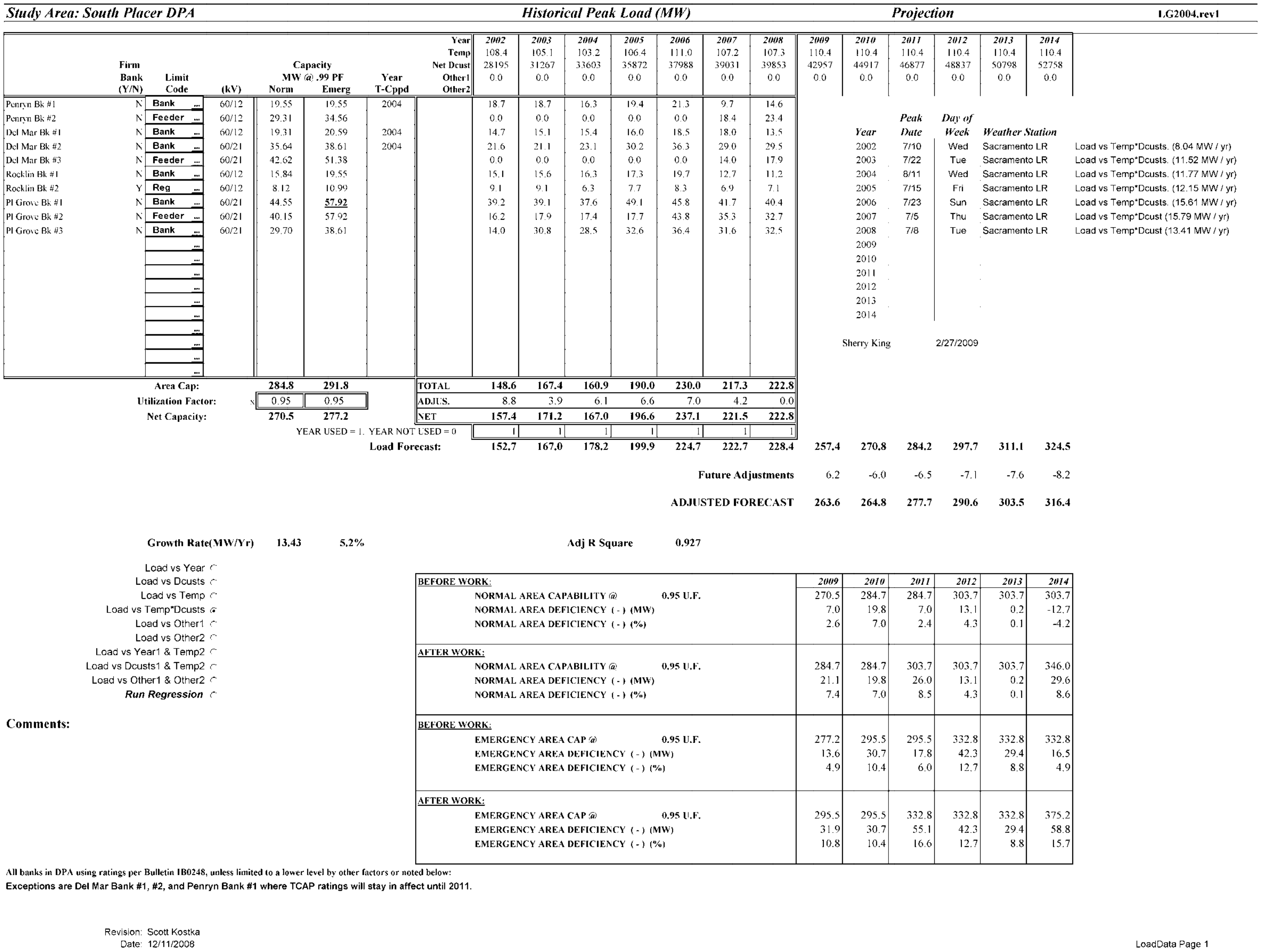
Study Area: Peabody DPA

2/18/2009 Last Updated

LOAD GROWTH - DPA: PEABODY	1.4	MW/yr															AREA LOADS
SUBSTATION	Peabody #1		21.6 ▼		Peabody #2		21.6 ▼		Peabody #3		21.6 ▼						
BANK/CIRCUIT	Bank #1	2104	2105	2100	Bank #2	2106	2107	2108	Bank#3	2112	2113	2111	2300				
CAPABILITY INCREASES																	
LOAD ADJUSTMENTS																	
Block Loads: Must be al least: 2.187 MW																	
Total Block Loads																	
Load Additions (Non Block Loads):																	
Total Non Block Loads																	
Adjusted Annual Area Load Growth Allocation (in %)	30.0%	40.0%	60.0%		35.0%	30.0%	40.0%	30.0%	35.0%	60.0%	40.0%						100.0%
2.4 Adjusted Annual Area Load Growth (MW)	0.73	8	12		0.85	7	9	7	0.85	14	9						2.4
SUB-TOTAL CAPACITY	47.3	695	570		56.1	503	695	600	49.8	636	695						145.6
SUB-TOTAL LOADS	45.8	675	542		56.7	387	610	520	45.8	650	592						148.3
SURPLUS \ DEFICIENCY	1.6	19.5	27.8		(0.5)	115.5	85.0	79.5	4.0	(13.9)	103.0						(2.6)
PERCENT LOADED	97%	97%	95%		101%	77%	88%	87%	92%	102%	85%						102%
FLAG	○	○	○		◎				○	◎							◎
Area Load Transfers (to / from adjacent DPAs):																	
CLO 8511; OPEN 6473 (PB2113 to SUISUN 1105)									(1.19)		-32						(1.2)
Total Non Block Loads									(1.19)		-32						(1.19)
Area Load Transfers (Within the DPA):																	
Total Load Transfers:																	
CAPABILITY (MW @ 0.99 PF) (CKT AMPS)	47.3	695.0	570.0		56.1	503.0	695.0	600.0	49.8	636.0	695.0						145.6
2010 PROJECTED LOAD	45.8	675	542		56.7	387	610	520	44.7	650	560						147.1
SURPLUS \ DEFICIENCY	1.6	20	28		(0.5)	116	85	80	5.1	(14)	135						(1.5)
PERCENT LOADED	97%	97%	95%		101%	77%	88%	87%	90%	102%	81%						101%
FLAG	○	○	○		◎				○	◎							◎
														Load Projection Check:			OK

P

Example #1 – Normal capacity 2yr Base – page 2 of 2



Study Area: South Placer DPA — ***Historical Peak Load (MW)*** — ***Projection*** — LG2004.rev1

Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Temp	108.4	105.1	103.2	106.4	111.0	107.2	107.3	110.4	110.4	110.4	110.4	110.4	110.4
Net Dcust	28195	31267	33603	35872	37988	39031	39853	42957	44917	46877	48837	50798	52758
Other1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other2													

	Firm Bank (Y/N)	Limit Code	(kV)	Capacity MW @ .99 PF Norm	Capacity MW @ .99 PF Emerg	Year T-Cppd	2002	2003	2004	2005	2006	2007	2008
Penryn Bk #1	N	Bank ...	60/12	19.55	19.55	2004	18.7	18.7	16.3	19.4	21.3	9.7	14.6
Penryn Bk #2	N	Feeder ...	60/12	29.31	34.56		0.0	0.0	0.0	0.0	0.0	18.4	23.4
Del Mar Bk #1	N	Bank ...	60/12	19.31	20.59	2004	14.7	15.1	15.4	16.0	18.5	18.0	13.5
Del Mar Bk #2	N	Bank ...	60/21	35.64	38.61	2004	21.6	21.1	23.1	30.2	36.3	29.0	29.5
Del Mar Bk #3	N	Feeder ...	60/21	42.62	51.38		0.0	0.0	0.0	0.0	0.0	14.0	17.9
Rocklin Bk #1	N	Bank ...	60/12	15.84	19.55		15.1	15.6	16.3	17.3	19.7	12.7	11.2
Rocklin Bk #2	Y	Reg ...	60/12	8.12	10.99		9.1	9.1	6.3	7.7	8.3	6.9	7.1
Pl Grove Bk #1	N	Bank ...	60/21	44.55	57.92		39.2	39.1	37.6	49.1	45.8	41.7	40.4
Pl Grove Bk #2	N	Feeder ...	60/21	40.15	57.92		16.2	17.9	17.4	17.7	43.8	35.3	32.7
Pl Grove Bk #3	N	Bank ...	60/21	29.70	38.61		14.0	30.8	28.5	32.6	36.4	31.6	32.5
		...											
		...											
		...											
		...											
		...											
		...											
		...											
		...											
		...											
		...											

	Norm	Emerg
Area Cap:	**284.8**	**291.8**
Utilization Factor:	0.95	0.95
Net Capacity:	**270.5**	**277.2**

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
TOTAL	**148.6**	**167.4**	**160.9**	**190.0**	**230.0**	**217.3**	**222.8**						
ADJUS.	8.8	3.9	6.1	6.6	7.0	4.2	0.0						
NET	**157.4**	**171.2**	**167.0**	**196.6**	**237.1**	**221.5**	**222.8**						
YEAR USED = 1. YEAR NOT USED = 0	1	1	1	1	1	1	1						
Load Forecast:	**152.7**	**167.0**	**178.2**	**199.9**	**224.7**	**222.7**	**228.4**	**257.4**	**270.8**	**284.2**	**297.7**	**311.1**	**324.5**
Future Adjustments								6.2	-6.0	-6.5	-7.1	-7.6	-8.2
ADJUSTED FORECAST								**263.6**	**264.8**	**277.7**	**290.6**	**303.5**	**316.4**

Year	*Peak Date*	*Day of Week*	*Weather Station*	
2002	7/10	Wed	Sacramento LR	Load vs Temp*Dcusts. (8.04 MW / yr)
2003	7/22	Tue	Sacramento LR	Load vs Temp*Dcusts. (11.52 MW / yr)
2004	8/11	Wed	Sacramento LR	Load vs Temp*Dcusts. (11.77 MW / yr)
2005	7/15	Fri	Sacramento LR	Load vs Temp*Dcusts. (12.15 MW / yr)
2006	7/23	Sun	Sacramento LR	Load vs Temp*Dcusts. (15.61 MW / yr)
2007	7/5	Thu	Sacramento LR	Load vs Temp*Dcust (15.79 MW / yr)
2008	7/8	Tue	Sacramento LR	Load vs Temp*Dcust (13.41 MW / yr)
2009				
2010				
2011				
2012				
2013				
2014				

Sherry King 2/27/2009

Growth Rate(MW/Yr) **13.43** **5.2%**

Adj R Square **0.927**

Load vs Year ○
Load vs Dcusts ○
Load vs Temp ○
Load vs Temp*Dcusts ●
Load vs Other1 ○
Load vs Other2 ○
Load vs Year1 & Temp2 ○
Load vs Dcusts1 & Temp2 ○
Load vs Other1 & Other2 ○
Run Regression ○

		2009	2010	2011	2012	2013	2014
BEFORE WORK:							
NORMAL AREA CAPABILITY @	**0.95 U.F.**	270.5	284.7	284.7	303.7	303.7	303.7
NORMAL AREA DEFICIENCY (-) (MW)		7.0	19.8	7.0	13.1	0.2	-12.7
NORMAL AREA DEFICIENCY (-) (%)		2.6	7.0	2.4	4.3	0.1	-4.2
AFTER WORK:							
NORMAL AREA CAPABILITY @	**0.95 U.F.**	284.7	284.7	303.7	303.7	303.7	346.0
NORMAL AREA DEFICIENCY (-) (MW)		21.1	19.8	26.0	13.1	0.2	29.6
NORMAL AREA DEFICIENCY (-) (%)		7.4	7.0	8.5	4.3	0.1	8.6
BEFORE WORK:							
EMERGENCY AREA CAP @	**0.95 U.F.**	277.2	295.5	295.5	332.8	332.8	332.8
EMERGENCY AREA DEFICIENCY (-) (MW)		13.6	30.7	17.8	42.3	29.4	16.5
EMERGENCY AREA DEFICIENCY (-) (%)		4.9	10.4	6.0	12.7	8.8	4.9
AFTER WORK:							
EMERGENCY AREA CAP @	**0.95 U.F.**	295.5	295.5	332.8	332.8	332.8	375.2
EMERGENCY AREA DEFICIENCY (-) (MW)		31.9	30.7	55.1	42.3	29.4	58.8
EMERGENCY AREA DEFICIENCY (-) (%)		10.8	10.4	16.6	12.7	8.8	15.7

Comments:

All banks in DPA using ratings per Bulletin IB0248, unless limited to a lower level by other factors or noted below:
Exceptions are Del Mar Bank #1, #2, and Penryn Bank #1 where TCAP ratings will stay in affect until 2011.

Revision: Scott Kostka
Date: 12/11/2008

LoadData Page 1

Example #2 – LoadData Sheet

HISTORICAL ADJUSTMENTS (LOAD TRANSFERS, BLOCK LOADS, AND OTHER)

YEAR	TYPE	DESCRIPTION OF ADJUSTMENTS	MW
2003	Load Transfers	From Lincoln 1103 to Pleasant Grove 2103	+1.85
2003	Block Loads	Thunder Valley Indian Casino - Opened on 5/1/03.	+3.60
2004	Load Transfers	From Pleasant Grove 2103 to Lincoln 1101	-1.93
2007	Load Transfers	To Horseshoe 1106 - Close SW 767, Open SW 667	-1.18
2007	Load Transfers	From Wise 1101 - Close 2033, Open 2229	4.43
2008	Load Transfers	From Wise 1101 - Close 633, Open 677	4.52

HISTORICAL ADJUSTMENTS

	2002	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*
	1.7	0.0	0.0	0.0	0.0	0.0	0.0
	3.6	0.0	0.0	0.0	0.0	0.0	0.0
	-1.6	-1.8	0.0	0.0	0.0	0.0	0.0
	-0.8	-0.8	-0.9	-1.0	-1.1	0.0	0.0
	3.0	3.3	3.6	3.9	4.1	0.0	0.0
	2.9	3.2	3.4	3.7	4.0	4.2	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**8.8**	**3.9**	**6.1**	**6.6**	**7.0**	**4.2**	**0.0**

FUTURE ADJUSTMENTS (LOAD TRANSFERS, BLOCK LOADS, AND OTHER)

YEAR	TYPE	DESCRIPTION OF ADJUSTMENTS	MW
2009	Load Transfers	From Lincoln - Close 51877, Open SW 50689 and Close SW 50687, Open SW 50685	1.22
2010	Load Transfers	To Lincoln DPA (see 2 year sheet for various transfers)	-12.26
2009	Block Loads	Thunder Valley Casino - Phase 2 (23 story hotel, event center, casino expansion)	5.00

FUTURE ADJUSTMENTS

	2009	*2010*	*2011*	*2012*	*2013*	*2014*
	1.2	1.3	1.3	1.4	1.5	1.5
	0.0	-12.3	-12.9	-13.5	-14.1	-14.7
	0.0	0.0	0.0	0.0	0.0	0.0
	5.0	5.0	5.0	5.0	5.0	5.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**6.2**	**-6.0**	**-6.5**	**-7.1**	**-7.6**	**-8.2**

Revision: Scott Kostka
Date: 12/11/08

Example #2 – Adjustment Sheet – page 1 of 3

SIX YEAR PLAN

YEAR	CAPACITY INCREASE (in MW) NORM	EMERG	DESCRIPTION OF WORK
2009	-29.70 MW	-38.6 MW	Remove 30 MVA at Pleasant Grove Bank #3
2009	+44.55 MW	+57.9 MW	Install 45 MVA at Pleasant Grove Bank #3
2011	-8.12 MW	-10.99 MW	Remove 60/12kv bank at Rocklin Bank #2
2011	+41.24 MW	+50.3 MW	Install new 115x60/21kv, 45MVA and 2-21kv circuits at Rocklin Bank #2 (feeder limited to 1103 amps)
2011	-13.11 MW	0.0 MW	Remove Bank TCAP ratings at Del Mar #1, #2, and Penryn #1
2014	+44.55 MW	+44.6 MW	Install Athens Substation (115kv/21kv, 45 MVA with 2-21kv feeders)

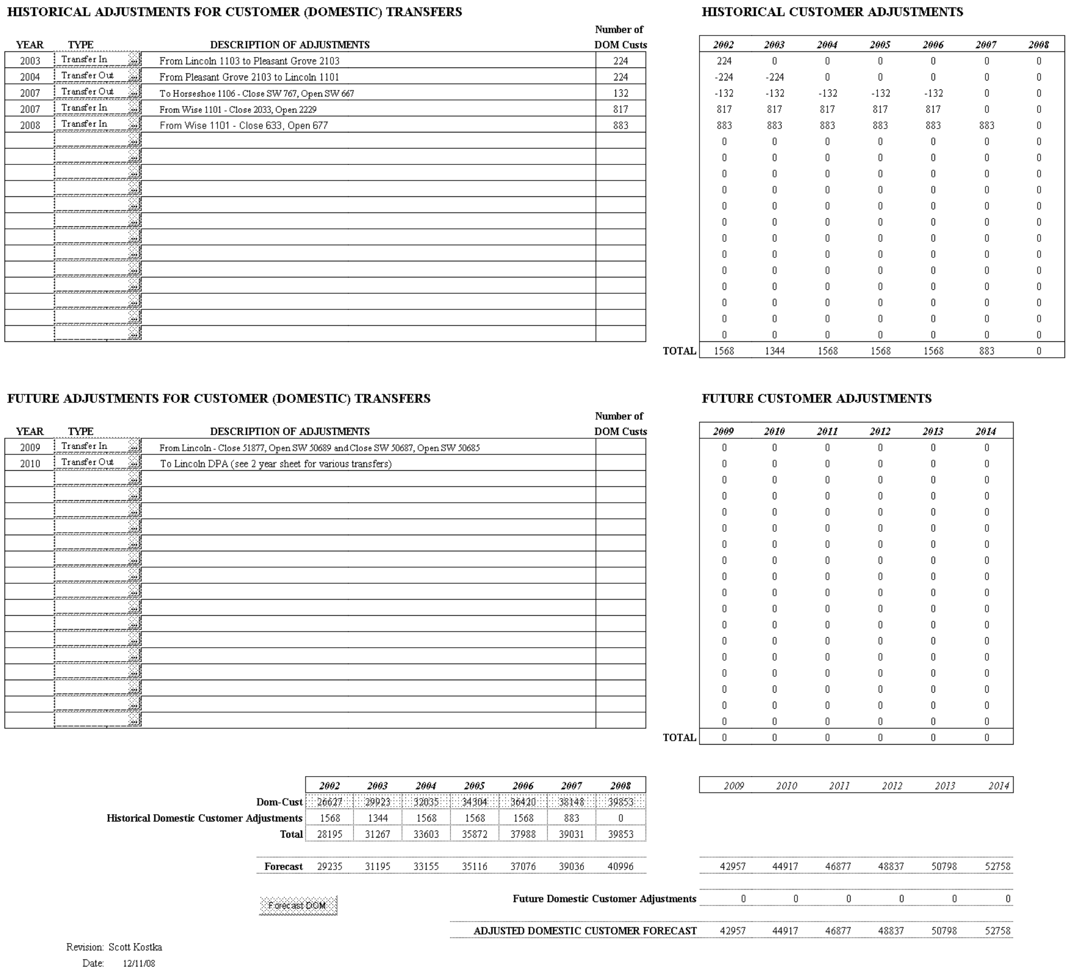
Notes:

Revision: Scott Kostka
Date: 12/11/08

CAPACITY INCREASES

NORMAL						EMERGENCY					
2009	*2010*	*2011*	*2012*	*2013*	*2014*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
-29.7	-29.7	-29.7	-29.7	-29.7	-29.7	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6
44.6	44.6	44.6	44.6	44.6	44.6	57.9	57.9	57.9	57.9	57.9	57.9
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	-8.1	-8.1	-8.1	-8.1	0.0	0.0	-11.0	-11.0	-11.0	-11.0
0.0	0.0	41.2	41.2	41.2	41.2	0.0	0.0	50.3	50.3	50.3	50.3
0.0	0.0	-13.1	-13.1	-13.1	-13.1	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	44.6	0.0	0.0	0.0	0.0	0.0	44.6
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14.85	**14.85**	**34.86**	**34.86**	**34.86**	**79.41**	**19.31**	**19.31**	**58.61**	**58.61**	**58.61**	**103.16**
CAPACITY INCREASES @			**0.95**	**U.F.**		CAPACITY INCREASES @			**0.95**	**U.F.**	
14.11	**14.11**	**33.12**	**33.12**	**33.12**	**75.44**	**18.34**	**18.34**	**55.68**	**55.68**	**55.68**	**98.00**

Example #2 – Adjustment Sheet – page 2 of 3



HISTORICAL ADJUSTMENTS FOR CUSTOMER (DOMESTIC) TRANSFERS

YEAR	TYPE	DESCRIPTION OF ADJUSTMENTS	Number of DOM Custs
2003	Transfer In	From Lincoln 1103 to Pleasant Grove 2103	224
2004	Transfer Out	From Pleasant Grove 2103 to Lincoln 1101	224
2007	Transfer Out	To Horseshoe 1106 - Close SW 767, Open SW 667	132
2007	Transfer In	From Wise 1101 - Close 2033, Open 2229	817
2008	Transfer In	From Wise 1101 - Close 633, Open 677	883

HISTORICAL CUSTOMER ADJUSTMENTS

	2002	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*
	224	0	0	0	0	0	0
	-224	-224	0	0	0	0	0
	-132	-132	-132	-132	-132	0	0
	817	817	817	817	817	0	0
	883	883	883	883	883	883	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
TOTAL	1568	1344	1568	1568	1568	883	0

FUTURE ADJUSTMENTS FOR CUSTOMER (DOMESTIC) TRANSFERS

YEAR	TYPE	DESCRIPTION OF ADJUSTMENTS	Number of DOM Custs
2009	Transfer In	From Lincoln - Close 51877, Open SW 50689 and Close SW 50687, Open SW 50685	
2010	Transfer Out	To Lincoln DPA (see 2 year sheet for various transfers)	

FUTURE CUSTOMER ADJUSTMENTS

	2009	*2010*	*2011*	*2012*	*2013*	*2014*
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0

	2002	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
Dom-Cust	26627	29923	32035	34304	36420	38148	39853						
Historical Domestic Customer Adjustments	1568	1344	1568	1568	1568	883	0						
Total	28195	31267	33603	35872	37988	39031	39853						
Forecast	29235	31195	33155	35116	37076	39036	40996	42957	44917	46877	48837	50798	52758
Future Domestic Customer Adjustments								0	0	0	0	0	0
ADJUSTED DOMESTIC CUSTOMER FORECAST								42957	44917	46877	48837	50798	52758

Revision: Scott Kostka
Date: 12/11/08

Example #2 – Adjustment Sheet – page 3 of 3

Normal Capacity 2 yr - Base

Study Area: South Placer DPA

12/11/2008 Last Updated

LOAD GROWTH - South Placer DPA: 13.4 MW/yr

SUBSTATION	Penryn Bk #1	12.47 ▼		Penryn Bk #2	12.47 ▼			Del Mar Bk #1	12.47 ▼		Del Mar Bk #2	21.6 ▼		Del Mar Bk #3	21.6 ▼		
BANK/CIRCUIT	Bank #1	1103	1104	Bank #2	1105	1106	1200	Bank #1	1103	1104	Bank #2	2105	2106	Bank#3	2109	2110	2300
CAPABILITY INCREASES																	
LOAD ADJUSTMENTS																	
Block Loads: Must be at least: 4.0 MW																	
Total Block Loads																	
Load Additions (Non Block Loads):																	
Twelve Bridges														0.85	23		
Whitney Ranch																	
Bickford Ranch														0.85	23		
Sorrento Village																	
Total Non Block Loads														1.70	46		
Adjusted Annual Area Load Growth Allocation (in %)	6.3%	46.2%	53.8%	9.2%	56.0%	44.0%		6.4%	29.8%	70.2%	13.2%	71.5%	28.5%	12.0%	38.9%	61.1%	
9.3 Adjusted Annual Area Load Growth (MW)	0.58	12	14	0.86	22	17		0.59	8	19	1.22	23	9	1.11	12	18	
SUB-TOTAL CAPACITY	19.5	570	570	29.3	721	636	570	19.3	502	573	35.6	721	573	42.6	503	636	573
SUB-TOTAL LOADS	17.1	358	417	26.2	675	531		17.3	243	570	35.9	723	288	34.3	394	547	
SURPLUS \ DEFICIENCY	2.5	212	153	4.1	46	105	570.0	2.0	259	3	(0.2)	(2)	285	8.3	109	89	573
PERCENT LOADED	87%	63%	73%	86%	94%	83%		90%	48%	99%	101%	100%	50%	81%	78%	86%	
FLAG					○			○		○	◎	◎					
Peak MW		7 650	8 914		14 433	11 344			5 187	12 191		26 766	10 675		14 503	20 251	
Simultaneous MW	17 08	7 687	9 191	25 19	14 102	11 083		17 33	5 174	12 160	35 82	25 655	10 161	34 34	14 389	19 965	
Area Load Transfers (to / from adjacent DPAs):																	
To Lincoln Area																	
Total Load Transfers																	
Area Load Transfers (Within the DPA):																	
Close SW 385, Open New SW (Bankhead s/o King)				0.64		30		(0.64)	-30								
Close SW 1534, Open SW 586																	
Close SW 910, Open SW 50434											2.22	60					
Close SW 2350, Open SW 2348											(3.52)	-95					
Close SW 50422, Open SW 51169																	
Close 50038, Open 50543														(2.30)	-62		
Close SW 431, Open LR 2716				0.43		20		(0.43)	-20								
Close SB 4921, Open SW 1744								(0.38)	-18								
Total Load Transfers:				1.07		50		(1.45)	(68)		(1.30)	(35)		(2.30)	(62)		
CAPABILITY (MW @ 0.99 PF) (CKT AMPS)	19.5	570	570	29.3	721	636	570	19.3	502	573	35.6	721	573	42.6	503	636	573
2010 PROJECTED LOAD	17.1	358	417	26.3	675	581		15.9	175	570	34.6	688	288	32.0	332	547	
SURPLUS \ DEFICIENCY	2.5	212	153	3.1	46	55	570	3.4	327	3	1.0	33	285	10.6	171	89	573
PERCENT LOADED	87%	63%	73%	90%	94%	91%		82%	35%	99%	97%	95%	50%	75%	66%	86%	
FLAG				○	○	○				○	○	○					
Peak MW		7 650	8 914		14 433	12 413			3 733	12 191		25 472	10 675		12 306	20 251	
Simultaneous Amps		359	430		650	568			174	569		658	276		327	538	
Simultaneous MW	17 08	7 887	9 191	26 25	14 115	12 139		15 88	3 723	12 158	34 59	24 375	10 216	32 05	12 114	19 935	

SUBSTATION	Rocklin Bk #1	12.47 ▼		Rocklin Bk #2	12.47 ▼		Pl Grove Bk #1	21.6 ▼		Pl Grove Bk #2	21.6 ▼		Pl Grove Bk #3	21.6 ▼		AREA LOADS
BANK/CIRCUIT	Bank#1	1101	1102	Bank#2	1103	1104	Bank#1	2103	2104	Bank #2	2107	2108	Bank #3	2109	2110	
CAPABILITY INCREASES																
LOAD ADJUSTMENTS																
Block Loads: Must be at least: 4.0 MW																
Total Block Loads																
Load Additions (Non Block Loads):																
Twelve Bridges																0.9
Whitney Ranch													1.67	45		1.7
Bickford Ranch																0.9
Sorrento Village													0.85		23	0.9
Total Non Block Loads													2.52	45	23	4.22
Adjusted Annual Area Load Growth Allocation (in %)	5.3%	35.5%	64.5%	3.1%	100.0%	0.0%	17.1%	47.2%	52.8%	13.1%	49.2%	50.8%	14.4%	43.5%	56.5%	100.0%
9.3 Adjusted Annual Area Load Growth (MW)	0.49	8	15	0.29	13	0	1.58	20	22	1.22	16	17	1.34	16	20	9.3
SUB-TOTAL CAPACITY	15.8	503	566	8.1	503	418	44.6	636	666	42.6	503	636	44.6	503	948	287.0
SUB-TOTAL LOADS	14.5	214	388	8.4	391	0	46.6	616	689	35.8	468	474	41.9	512	629	277.1
SURPLUS \ DEFICIENCY	1.4	289	178	(0.3)	112	418	(2.1)	21	(23)	6.8	45	162	2.7	(9)	319	9.9
PERCENT LOADED	91%	42%	69%	104%	78%	0%	105%	97%	103%	84%	91%	75%	94%	102%	66%	97%
FLAG	○			◎			◎	○	◎		○		○	◎		○
Peak MW		4 566	8 296		8 354	0 000		22 767	25 516		15 974	17 561		18 979	23 292	
Simultaneous MW	14 47	5 138	9 334	8 44	8 439	0 000	46 62	21 992	24 627	35 83	17 611	18 220	41 88	18 805	23 075	
Area Load Transfers (to / from adjacent DPAs):																
To Lincoln Area							(10.89)	-294					(1.37)		-37	(12.26)
Total Load Transfers							(10.89)	-294					(1.37)		-37	(12.26)
Area Load Transfers (Within the DPA):																
Close SW 385, Open New SW (Bankhead s/o King)																
Close SW 1534, Open SW 586	0.51		24	(0.51)	-24											
Close SW 910, Open SW 50434							(2.22)		-60							
Close SW 2350, Open SW 2348													3.52	95		
Close SW 50422, Open SW 51169										4.41		119	(4.41)	-119		
Close 50038, Open 50543							2.30	62								
Close SW 431, Open LR 2716																
Close SB 4921, Open SW 1744	0.38	18														
Total Load Transfers:	0.90	18	24	(0.51)	(24)		0.07	62	(60)	4.41		119	(0.89)	(24)		
CAPABILITY (MW @ 0.99 PF) (CKT AMPS)	15.8	503	566	8.1	503	418	44.6	636	666	42.6	503	636	44.6	503	948	287.0
2010 PROJECTED LOAD	15.4	232	412	7.9	367	0	35.8	383	629	40.2	458	593	39.6	488	592	264.8
SURPLUS \ DEFICIENCY	0.5	271	154	0.2	136	418	8.7	253	37	2.4	45	43	4.9	15	356	22.2
PERCENT LOADED	97%	46%	73%	98%	73%	0%	80%	60%	94%	94%	91%	93%	89%	97%	62%	92%
FLAG	○			○					○	○	○	○		○		○
Peak MW		4 951	8 609		7 840	0 000		14 194	23 294		15 974	21 969		18 089	21 922	Load Projection Check: OK
Simultaneous Amps		259	460		371	0		366	601		474	613		484	586	
Simultaneous MW	15 57	5 530	9 639	7 93	7 926	0 000	35 80	13 557	22 248	40 24	17 539	22 699	39 63	17 915	21 710	

Example #2 – Normal Capacity 2 yr Base – page 1 of 2

Normal Capacity 2 yr - Base

Study Area: South Placer DPA

12/11/2008 Last Updated

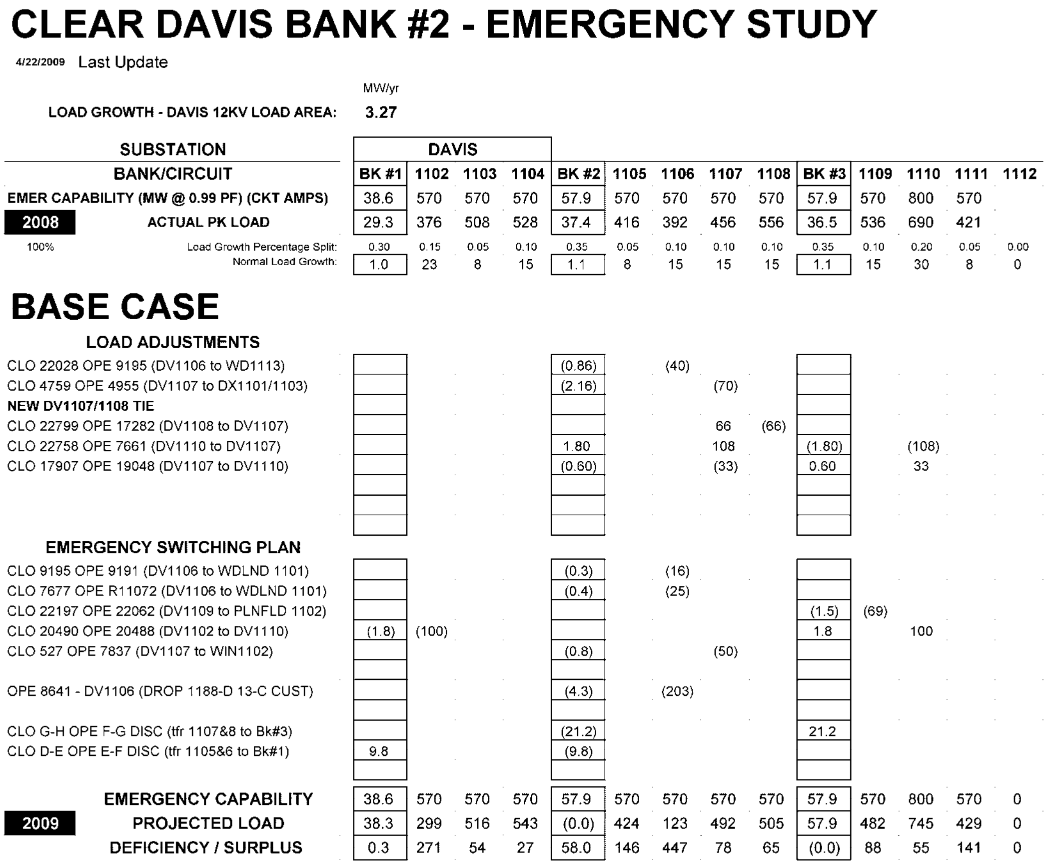
LOAD GROWTH - South Placer DPA: 13.4 MW/yr

SUBSTATION	Penryn Bk #1		12.47 ▼	Penryn Bk #2		12.47 ▼		Del Mar Bk #1		12.47 ▼	Del Mar Bk #2		21.6 ▼
BANK/CIRCUIT	Bank #1	1103	1104	Bank #2	1105	1106	1200	Bank #1	1103	1104	Bank #2	2105	2106
NOR. CAPABILITY (MW @ 0.99 PF) (AMPS)	19.5	570	570	29.3	721	636	570	19.3	502	573	35.6	721	573
EM. CAPABILITY (MW @ 0.99 PF) (AMPS)	19.5	570	570	34.6	800	800	570	20.6	580	720	38.6	760	700
2008 ACTUAL PK LOAD	14.6	300	360	23.4	547	577		13.5	636		29.5	695	245
DATE OF PEAK:	7/9/08			7/8/08				7/8/08			7/8/08		
LOAD ADJUSTMENTS													
Reserved Capacity													
Total Reserved Capacity													
CAPABILITY INCREASES / DECREASES													
Replace Pl Grove Bank #3													
Co-Generation													
Total Co-generation													
Block Loads: Must be at least: 3.3 MW													
Thunder Valley Casino (Phase 2)													
Total Block Loads													
Load Additions (Non Block Loads):													
Whitney Ranch													
Total Non Block Loads													
Adjusted Annual Area Load Growth Allocation (in %)	6.6%	45.5%	54.5%	10.5%	48.7%	51.3%		6.1%	100.0%		13.2%	70.8%	29.2%
32.9 Adjusted Annual Area Load Growth (MW)	2.15	45	54	3.45	78	82		2.00	92		4.35	82	34
SUB-TOTAL CAPACITY	19.5	570	570	29.3	721	636	570	19.3	502	573	35.6	721	573
SUB-TOTAL LOADS	16.8	345	414	26.9	625	659		15.5	728		33.9	677	279
SURPLUS \ DEFICIENCY	2.8	225	156	2.5	96	(23)	570	3.8	(226)	573	1.8	44	294
PERCENT LOADED	86%	61%	73%	92%	87%	104%		80%	145%		95%	94%	49%
FLAG				○		◎			◎		○	○	
Peak MW		7.384	8.861		13.380	14.093			15.576			25.090	10.331
Simultaneous MW	16.75	7.616	9.139	26.85	13.068	13.785		15.53	15.526		33.85	23.979	9.874
Area Load Transfers (to / from adjacent DPAs):													
From Lincoln 1102 - Close SW 51877, Open SW 50689 X													
From Lincoln 1102 - Close SW 50687, Open SW 50685 X													
Total Load Transfers:													
Area Load Transfers (Within the DPA):													
Close SW 51772, Open SW 2293 - putting Del Mar 1104 back into service on 7/25/08 X									-602	602			
Close SW 635, Open SW 431 - place circuits back normal (Completed 7/25/08) X				(3.12)		-146		3.12	146				
Close SW 4923, Open SW 9689 - place circuits back normal X								(1.09)		-51			
Completion of Del Mar circuit work X	(0.26)		-12					(0.21)	-10				
Close new Ties, Open SW 50427 and SW 50420 X													
Close 50416, Open 50038 X													
Close SW 50581, Open SW 50442 X													
Close 50253, Open 50263 & Close 50309, Open 50311 X													
Close SW 50442, Open SW 50422 X													
Close new tie, Open SB 34893 X													
Install new tie along Industrial, Open SW 51049 and Close SW 574, Open SW 576 X													
Close SW 1763, Open SW 910 and Close SW 639, Open SW 50231 X				0.60	28			(0.60)	-28		0.81	22	
Total Load Transfers:	(0.26)		(12)	(2.52)	28	(146)		1.22	(494)	551	0.81	22	
CAPABILITY (MW @ 0.99 PF) (CKT AMPS)	19.5	570	570	29.3	721	636	570	19.3	502	573	35.6	721	573
2009 PROJECTED LOAD	16.5	345	402	24.3	663	513		16.7	234	551	34.7	699	279
SURPLUS \ DEFICIENCY	3.1	225	168	5.0	68	123	570	2.6	268	22	1.0	22	294
PERCENT LOADED	84%	61%	71%	83%	91%	81%		87%	47%	96%	97%	97%	49%
FLAG					○					○	○	○	
Peak MW		7.384	8.605		13.959	10.971			5.013	11.782		25.905	10.331
Simultaneous Amps		356	415		537	501			234	549		689	267
Simultaneous MW	16.50	7.619	8.878	24.33	13.623	10.707		16.75	4.996	11.747	34.67	24.784	9.884

SUBSTATION	Del Mar Bk #3		21.6 ▼		Rocklin Bk #1		12.47 ▼	Rocklin Bk #2		12.47 ▼
BANK/CIRCUIT	Bank#3	2109	2110	2300	Bank#1	1101	1102	Bank#2	1103	1104
NOR. CAPABILITY (MW @ 0.99 PF) (AMPS)	42.6	503	636	573	15.8	503	566	8.1	503	418
EM. CAPABILITY (MW @ 0.99 PF) (AMPS)	51.4	639	734	700	19.5	570	570	11.0	570	488
2008 ACTUAL PK LOAD	17.9	35	463		11.2	132	319	7.1	329	0
DATE OF PEAK:	7/8/08				7/8/08			7/8/08		
LOAD ADJUSTMENTS										
Reserved Capacity										
Total Reserved Capacity										
CAPABILITY INCREASES / DECREASES										
Replace Pl Grove Bank #3										
Co-Generation										
Total Co-generation										
Block Loads: Must be at least: 3.3 MW										
Thunder Valley Casino (Phase 2)										
Total Block Loads										
Load Additions (Non Block Loads):										
Whitney Ranch										
Total Non Block Loads										
Adjusted Annual Area Load Growth Allocation (in %)	8.0%	7.0%	93.0%		5.0%	29.3%	70.7%	3.2%	100.0%	0.0%
32.9 Adjusted Annual Area Load Growth (MW)	2.64	5	66		1.66	22	54	1.05	49	0
SUB-TOTAL CAPACITY	42.6	503	636	573	15.8	503	566	8.1	503	418
SUB-TOTAL LOADS	20.5	40	529		12.9	154	373	8.2	377	0
SURPLUS \ DEFICIENCY	22.1	463	107	573	3.0	349	193	(0.0)	126	418
PERCENT LOADED	48%	8%	83%		81%	31%	66%	100%	75%	0%
FLAG								◎		
Peak MW		1.480	19.580			3.503	7.982		8.070	0.000
Simultaneous MW	20.54	1.444	19.098		12.89	3.777	9.117	8.15	8.152	0.000
Area Load Transfers (to / from adjacent DPAs):										
From Lincoln 1102 - Close SW 51877, Open SW 50689 X										
From Lincoln 1102 - Close SW 50687, Open SW 50685 X										
Total Load Transfers:										
Area Load Transfers (Within the DPA):										
Close SW 51772, Open SW 2293 - putting Del Mar 1104 back into service on 7/25/08 X										
Close SW 635, Open SW 431 - place circuits back normal (Completed 7/25/08) X										
Close SW 4923, Open SW 9689 - place circuits back normal X					1.09	51				
Completion of Del Mar circuit work X	0.47	13								
Close new Ties, Open SW 50427 and SW 50420 X	8.89	240								
Close 50416, Open 50038 X	1.63	44								
Close SW 50581, Open SW 50442 X										
Close 50253, Open 50263 & Close 50309, Open 50311 X										
Close SW 50442, Open SW 50422 X										
Close new tie, Open SB 34893 X										
Install new tie along Industrial, Open SW 51049 and Close SW 574, Open SW 576 X										
Close SW 1763, Open SW 910 and Close SW 639, Open SW 50231 X										
Total Load Transfers:	10.99	297			1.09	51				
CAPABILITY (MW @ 0.99 PF) (CKT AMPS)	42.6	503	636	573	15.8	503	566	8.1	503	418
2009 PROJECTED LOAD	31.5	337	529		14.0	205	373	8.2	377	0
SURPLUS \ DEFICIENCY	11.1	166	107	573	1.9	298	193	(0.0)	126	418
PERCENT LOADED	74%	67%	83%		88%	41%	66%	100%	75%	0%
FLAG								◎		
Peak MW		12.471	19.560			4.393	7.987		8.070	0.000
Simultaneous Amps		331	520			232	422		381	0
Simultaneous MW	31.53	12.269	19.263		13.98	4.963	9.017	8.15	8.152	0.000

SUBSTATION	Pl Grove Bk #1		21.6 ▼	Pl Grove Bk #2		21.6 ▼	Pl Grove Bk #3		21.6 ▼	AREA LOADS
BANK/CIRCUIT	Bank#1	2103	2104	Bank #2	2107	2108	Bank #3	2109	2110	
NOR. CAPABILITY (MW @ 0.99 PF) (AMPS)	44.6	570	666	40.2	503	570	29.7	503	700	270.5
EM. CAPABILITY (MW @ 0.99 PF) (AMPS)	57.9	689	700	57.9	639	689	38.6	639	700	277.2
2008 ACTUAL PK LOAD	40.4	534	604	32.7	384	465	32.5	318	571	222.8
DATE OF PEAK:	7/8/08			7/8/08			7/8/08		2009 Area Projection	263.6
LOAD ADJUSTMENTS										
Reserved Capacity										
Total Reserved Capacity										
CAPABILITY INCREASES / DECREASES										
Replace Pl Grove Bank #3		66		2.44		66	14.85		248	16.4
Co-Generation										
Total Co-generation										
Block Loads: Must be at least: 3.3 MW										
Thunder Valley Casino (Phase 2)							5.00		135	5.0
Total Block Loads							5.00		135	5.00
Load Additions (Non Block Loads):										
Whitney Ranch				0.85		23	0.81	22		1.7
Total Non Block Loads				0.85		23	0.81	22		1.67
Adjusted Annual Area Load Growth Allocation (in %)	18.1%	46.9%	53.1%	14.7%	45.2%	54.8%	14.6%	35.8%	64.2%	100.0%
32.9 Adjusted Annual Area Load Growth (MW)	5.96	75	85	4.82	58	71	4.79	46	82	32.9
SUB-TOTAL CAPACITY	44.6	636	666	42.6	503	636	44.6	503	948	287.0
SUB-TOTAL LOADS	46.3	609	689	38.4	442	559	43.1	386	788	262.4
SURPLUS \ DEFICIENCY	(1.8)	27	(23)	4.2	61	77	1.5	117	160	24.6
PERCENT LOADED	104%	96%	103%	90%	88%	88%	97%	77%	83%	91%
FLAG	◎	○	◎	○			○			○
Peak MW		22.547	25.503		16.382	20.669		14.290	29.197	
Simultaneous MW	46.35	21.749	24.600	38.35	16.949	21.405	43.09	14.159	28.978	
Area Load Transfers (to / from adjacent DPAs):										
From Lincoln 1102 - Close SW 51877, Open SW 50689 X	0.76	21								0.8
From Lincoln 1102 - Close SW 50687, Open SW 50685 X							0.46		12	0.5
Total Load Transfers:	0.76	21					0.46		12	1.22
Area Load Transfers (Within the DPA):										
Close SW 51772, Open SW 2293 - putting Del Mar 1104 back into service on 7/25/08 X										
Close SW 635, Open SW 431 - place circuits back normal (Completed 7/25/08) X										
Close SW 4923, Open SW 9689 - place circuits back normal X										
Completion of Del Mar circuit work X										0.0
Close new Ties, Open SW 50427 and SW 50420 X				(8.89)		-240				
Close 50416, Open 50038 X	(1.63)	-44								
Close SW 50581, Open SW 50442 X				4.00		108	(4.00)	-108		
Close 50253, Open 50263 & Close 50309, Open 50311 X	(2.07)	-56		2.07		56				
Close SW 50442, Open SW 50422 X				(6.44)		-174	6.44	174		
Close new tie, Open SB 34893 X	2.44	66					(2.44)		-66	
Install new tie along Industrial, Open SW 51049 and Close SW 574, Open SW 576 X				5.52		149	(5.52)		-149	
Close SW 1763, Open SW 910 and Close SW 639, Open SW 50231 X	(0.81)		-22							
Total Load Transfers:	(2.07)	(34)	(22)	(3.74)		(101)	(5.52)	66	(215)	0.0
CAPABILITY (MW @ 0.99 PF) (CKT AMPS)	44.6	636	666	42.6	503	636	44.6	503	948	287.0
2009 PROJECTED LOAD	45.0	595	667	34.6	442	458	38.0	452	586	263.6
SURPLUS \ DEFICIENCY	(0.5)	41	(1)	8.0	61	178	6.5	51	362	23.4
PERCENT LOADED	101%	94%	100%	81%	88%	72%	85%	90%	62%	92%
FLAG	◎	○	◎					○		○
Peak MW		22.047	24.558		15.382	16.949		16.735	21.693 Load Projection Check:	OK
Simultaneous Amps		574	642		459	475		447	580	
Simultaneous MW	45.03	21.245	23.790	34.61	17.012	17.601	38.03	16.561	21.467 2010 Area Projection	264.8

Example #2 – Normal Capacity 2 yr Base – page 2 of 2



CLEAR DAVIS BANK #2 - EMERGENCY STUDY

4/22/2009 Last Update

	MW/yr
LOAD GROWTH - DAVIS 12KV LOAD AREA:	**3.27**

SUBSTATION	**DAVIS**														
BANK/CIRCUIT	**BK #1**	**1102**	**1103**	**1104**	**BK #2**	**1105**	**1106**	**1107**	**1108**	**BK #3**	**1109**	**1110**	**1111**	**1112**
EMER CAPABILITY (MW @ 0.99 PF) (CKT AMPS)	38.6	570	570	570	57.9	570	570	570	570	57.9	570	800	570	
2008 **ACTUAL PK LOAD**	29.3	376	508	528	37.4	416	392	456	556	36.5	536	690	421	
100% Load Growth Percentage Split:	0.30	0.15	0.05	0.10	0.35	0.05	0.10	0.10	0.10	0.35	0.10	0.20	0.05	0.00
Normal Load Growth:	1.0	23	8	15	1.1	8	15	15	15	1.1	15	30	8	0

BASE CASE

LOAD ADJUSTMENTS

	BK #1	1102	1103	1104	BK #2	1105	1106	1107	1108	BK #3	1109	1110	1111	1112
CLO 22028 OPE 9195 (DV1106 to WD1113)					(0.86)		(40)							
CLO 4759 OPE 4955 (DV1107 to DX1101/1103)					(2.16)			(70)						
NEW DV1107/1108 TIE														
CLO 22799 OPE 17282 (DV1108 to DV1107)								66	(66)					
CLO 22758 OPE 7661 (DV1110 to DV1107)					1.80			108		(1.80)		(108)		
CLO 17907 OPE 19048 (DV1107 to DV1110)					(0.60)			(33)		0.60		33		

EMERGENCY SWITCHING PLAN

	BK #1	1102	1103	1104	BK #2	1105	1106	1107	1108	BK #3	1109	1110	1111	1112
CLO 9195 OPE 9191 (DV1106 to WDLND 1101)					(0.3)		(16)							
CLO 7677 OPE R11072 (DV1106 to WDLND 1101)					(0.4)		(25)							
CLO 22197 OPE 22062 (DV1109 to PLNFLD 1102)										(1.5)	(69)			
CLO 20490 OPE 20488 (DV1102 to DV1110)	(1.8)	(100)								1.8		100		
CLO 527 OPE 7837 (DV1107 to WIN1102)					(0.8)			(50)						
OPE 8641 - DV1106 (DROP 1188-D 13-C CUST)					(4.3)		(203)							
CLO G-H OPE F-G DISC (tfr 1107&8 to Bk#3)					(21.2)					21.2				
CLO D-E OPE E-F DISC (tfr 1105&6 to Bk#1)	9.8				(9.8)									
EMERGENCY CAPABILITY	38.6	570	570	570	57.9	570	570	570	570	57.9	570	800	570	0
2009 **PROJECTED LOAD**	38.3	299	516	543	(0.0)	424	123	492	505	57.9	482	745	429	0
DEFICIENCY / SURPLUS	0.3	271	54	27	58.0	146	447	78	65	(0.0)	88	55	141	0

Bank Loss – Example

DISTRIBUTION
SUBSTATION
BANK CAPABILITY

SUBSTATION: PLEASANT GROVE
BANK: #2
LAST UPDATED: Div. Engrg. 4/22/2009

	NAMEPLATE RATING	VOLTAGE HIGH/LOW	RATING	UNBALANCE FACTOR	CAPABILITIES								
					SUMMER NOR		SUMMER EMER		WINTER NOR		WINTER EMER		
TRANSFORMERS	1-12/16 MVA	115X60/21KV	16000	1	16800	*	20800		20000		24000		
REGULATORS	LTC	+/-10%											
	ASSOCIATED EQUIP	SIZE/TYPE											
	BANK HIGH SIDE	200E FUSE	20785	0.95	19745		19745	*	19745	*	19745	*	
	BUS CONDUCTOR	N/A											
	REGULATOR BUS	N/A											
	BUS DISC'S	N/A											
	OTHER	METERING C.T. -800/5	30240	0.95	28728		28728		28728		28728		
	NET BANK CAPABILITY	(IN KVA)			16800		19745		19745		19745		
	NET BANK CAPABILITY	(IN MW) @ 0.99PF		0.99	16632		19548		19548		19548		
		(AMPS)			444		522		522		522		

BOLD Text denotes TCAP rerate values

Bank Capability Sheet - Example

Division :	**Sierra**	Substation :	**PLEASANT GROVE**
District :	**Drum**	Bank # :	**2**
Updated :	**Apr 22, 2009**	Circuit :	**2107**
By :	**Div. Engineering**	Blk Map # :	**W-3**

Equipment	Size	Derate Factor	Summer		Winter		Remarks
			Normal	Emerg	Normal	Emerg	
Bank / LTC / HS Fuse / CT	16000		444 *	522 *	522 *	522 *	200E FUSE
Circuit Breaker	1200	1.00	1200	1200	1200	1320	GE PVD
OCB Drops	1150	0.95	1093	1093	1093	1093	
Disconnects	1200	0.95	1140	1368	1140	1368	
Current Transformers	600	0.95	570	570	570	570	2000/5 CT W/TAPS
Phase Relay (83.3% or -50a)	720		600	600	600	600	CO-9
Backup Phase Relay							
Grd Relay - No Limits	240		NA	NA	NA	NA	CO-9
Regulator	LTC						LTC
UG Cable @ 75 % LF (1W)	N/A	1.00					
UG Cable @ 75 % LF (2W)	1000AL	1.00	503	639	557	674	
PVC Riser	1000AL	1.00	530	748	666	845	
Metal Riser	N/A	1.00					
OH Conductor at 2 FPS	N/A	0.95					
OH Conductor at 2 FPS	N/A	0.95					
OH Conductor at 4 FPS	N/A	0.95					
OH Conductor at 4 FPS	N/A	0.95					
OH Switch #	N/A	0.95					
Special Limiting Factor	N/A						
Circuit Capability (Amps)			444	522	522	522	
MVA Capability			16.783	19.732	19.732	19.732	
MW Capability at 99% PF			16.615	19.534	19.534	19.534	

Notes: MVA Capability = (Amps * 1.73 * 1.05 * KV) / 1000
* Denotes limiting factor(s).

Bank & Circuit Capability Sheet - Example