NextEra Energy Transmission West and Pacific Gas and Electric Company

Estrella Substation and Paso Robles Reinforcement Project Proponent's Environmental Assessment (A.17-01-023)

Updated Response to Data Request No. 1 as of January 14, 2019

The California Public Utilities Commission (CPUC) requested additional data from NextEra Energy Transmission West, LLC (NEET West) and Pacific Gas and Electric Company's (PG&E) Proponent's Environmental Assessment (PEA) for the Estrella Substation and Paso Robles Reinforcement Project. Below are responses to Data Request No. 1 issued by the CPUC on November 7, 2018. Each data request is numbered according to the list, followed by NEET West's and PG&E's response.

Request #1-1:

In the January 2018 version of Appendix G, the LoadSEER forecast for 2017 for the Paso Robles DPA was 207.6 MW (See Figure 5). In the June 2018 update to Appendix G, the actual load for the Paso Robles DPA was updated to be 195.06 (see Table 2), a difference of 12.34 MW. However, in the June 2018 update to Appendix G, the Load SEER forecast (see Figure 5) has not been adjusted to reflect the lower value for 2017, but instead was unchanged and left at 207.6 MW. This results in a rather large jump of 6.42% between 2017 actuals and 2018 LoadSEER forecast while the annual load growth for the remainder of the forecast (2018 to 2026) averages just 0.55%. Please explain the load increase assumed between 2017 and 2018 and why it is significantly larger than the rest of the forecast. Please provide an updated Figure 5, including both the chart and forecast table shown in Figure 5.

Response:

As background and as discussed in Section III of Appendix G, modeling is used to predict normal electrical demand growth within a DPA. Modeling is based upon many factors, including historic growth patterns, weather, pending business service applications, forecasted system load increases based on the California Energy Commission (CEC) forecast, and distributed energy resources (DER) growth estimates from the CEC.

PG&E utilizes the LoadSEER forecasting tool to predict growth of electrical demand within a DPA for a 10-year period into the future. LoadSEER utilizes the CEC system growth forecast and allocates this growth to feeders based on geospatial analysis, historical energy consumption, economics, demographics, and transportation and environmental factors. In addition, PG&E utilized recent public data on planned new loads in the Paso Robles DPA, as provided in Table 6A of Appendix G (June 2018), to develop the updated LoadSEER forecast for the Paso Robles DPA.

PG&E's goal is to maintain a distribution system that can serve its customers during hot summers without overloads and outages. The Paso Robles DPA is an interior area, sensitive to summer heat with significant residential and commercial air-conditioning load as well as industrial refrigeration load for the wine industry. Consequently, the 1-in-10 forecast for the DPA is used to adequately predict DPA capacity needs. However, forecasts are estimates, not precise predictors of what will happen but rather tools to determine when new facilities are expected to be required.

The 10-year LoadSEER forecast for 2017 to 2026 provided in the January 2018 version of Appendix G was prepared in 2017, incorporating the non-coincident peak loads for each substation bank in the Paso Robles DPA from 2004 to 2016, the 2016 adopted IEPR forecast mid-case, and anticipated large block loads and business service applications.

In the Energy Division's February 27, 2018 Deficiency Letter No. 4, Deficiency Appendix G(2.1(f1)), you requested that we provide the 2017 recorded peak load for the Paso Robles DPA and update Table 2 in Appendix G. In our May 2, 2018 response, we stated that the 2017 recorded peak load for the Paso Robles DPA was 195.06 MW and that we had updated Table 2 in the May 2018 version of Appendix G accordingly.

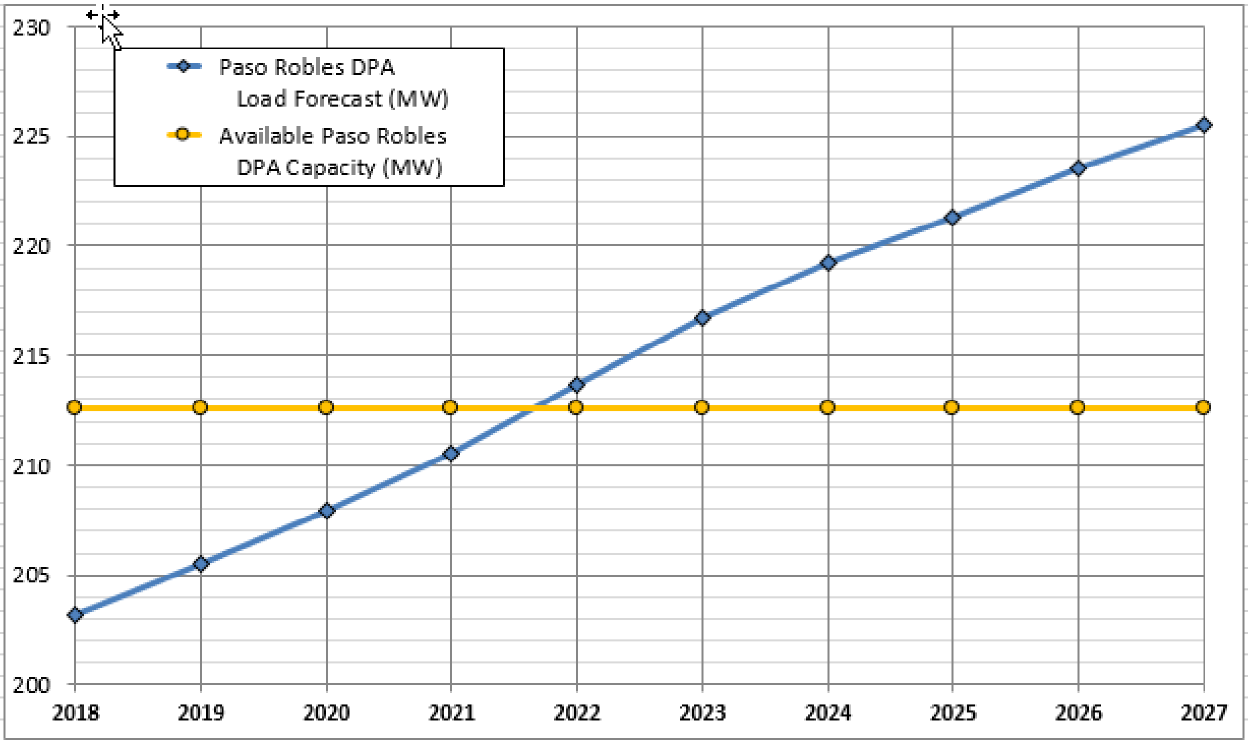
In Deficiency Letter Nos. 4 and 5, you did not request that we update the LoadSEER forecast. The data presented in Figure 5 of the June 2018 version of Appendix G is the same forecast that we presented in the August 2017, January 2018, and May 2018 versions of Appendix G, which forecasted a 2017 peak load of 207.60 MW in the Paso Robles DPA.

As we understand your request, it appears you are replacing the forecasted 2017 peak load of 207.60 MW from Table 5 with the actual 2017 peak load of 195.06 MW in Table 2 and asking why the load increase between the actual peak in 2017 and the forecasted peak in 2018 is significantly larger than the average year-to-year increase forecasted between 2018 and 2026. The difference between the last recorded historic year of load and the first forecasted year is generally higher than subsequent years due to the use of the 1-in-10 forecast for the next 10 years. The 1-in-10 forecast is derived from existing load profiles and accounts for load unpredictability due to temperature, the effect of cloud cover on existing PV systems, and other factors that affect how actual load behaves from day to day. In other words, the 2017 actual peak load in Table 2 is a historical fact; the forecasted peak loads for 2018 to 2026 are just forecasts based on the conservative assumption that each of those years is a 1-in-10 hot year with correspondingly high electricity usage. This is not an "apples to apples" comparison and explains why the jump between the actual peak in 2017and the forecasted peak in 2018 is much larger than the average annual increase between forecasted peaks for 2018 to 2026.

In Exhibit 1-1 below, we have provided an updated Figure 5, including the chart and forecast table, based on the LoadSEER forecast prepared in 2018 and provided to CAISO. This updated LoadSEER forecast incorporates the historical peak loads for 2005 to 2017 in the Paso Robles DPA. The updated Figure 5 is the forecasted peak loads for 2018 through 2027. This new forecast shows that the forecasted peak load could exceed the 212.55 MW of available capacity in the DPA by 2022, which is earlier than 2024 as indicated in the previous LoadSEER forecast.

Exhibit 1-1: Updated Figure 5, Updated LoadSEER Forecast, Paso Robles DPA

Description of Forecast	Forecasted Load (MW)									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Available Capacity	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55	212.55
LoadSEER Forecast	203.21	205.50	207.90	210.52	213.63	216.73	219.21	221.32	223.51	225.52



Request #1-2:

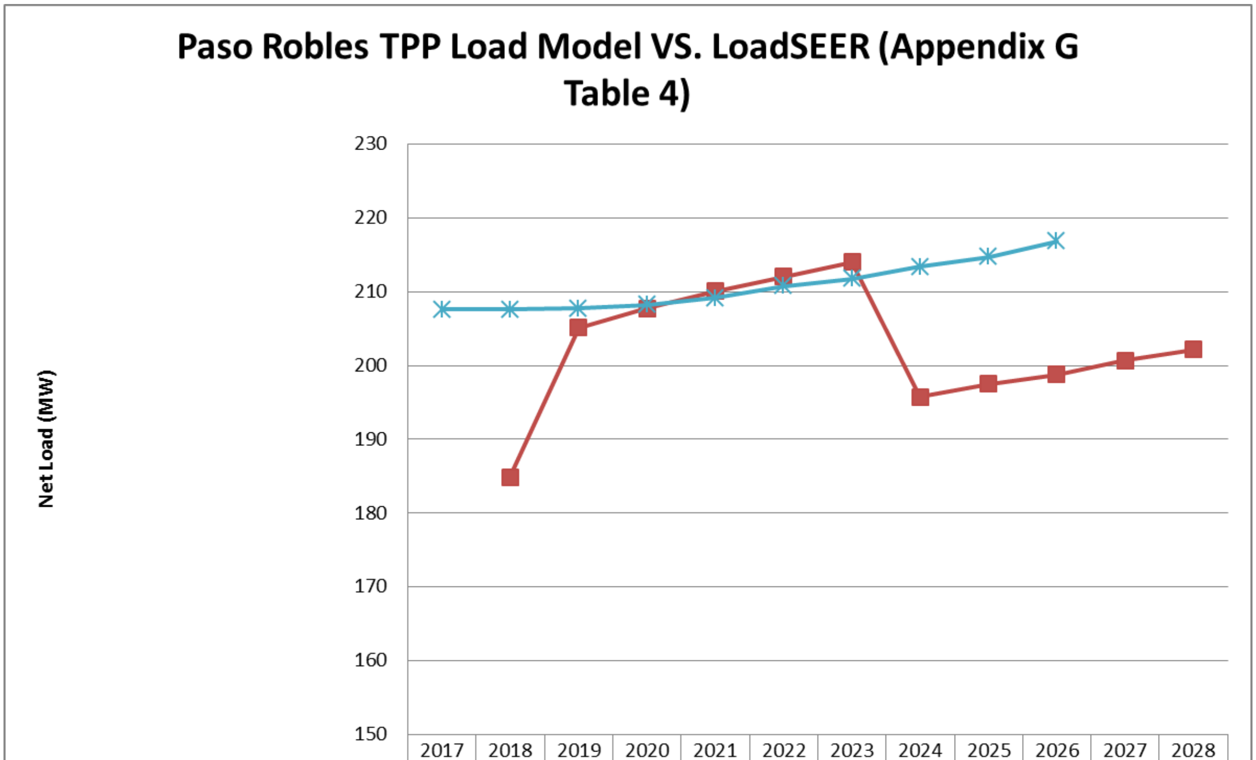
In the CAISO 2018-2019 Transmission Planning Process the CAISO has the 2028 Paso Robles DPA load modeled at 202.17 MW (Cholame = 7.2 MW, San Miguel = 10.95 MW, Estrella = 24.8 MW, Templeton = 68.84 MW, Atascadero = 27.58 MW, and Paso Robles = 62.8 MW). For 2020 and 2023, in the CAISO 2018-2019 TPP cases, the Paso Robles load is 207.74 MW and 213.98 MW respectively. The loadSEER forecast for 2020 (208.24 MW) and 2023 (211.74 MW) are relatively consistent with CAISO assumptions for these years.

However, there seems to be a significant disconnect for years beyond 2023. The loadSEER forecast continues to increase at a rate of roughly 0.7% while the CAISO TPP is showing a decrease of 0.33%. The CAISO attributes the reduction to behind the meter solar and energy efficiency. Please provide an explanation and justification for the loadSEER forecast increasing growth rate with respect to the CAISO TPP decreasing forecast for years beyond 2023.

Response:

The load forecasts mentioned in Request #1-2, e.g., the CAISO 2018-2019 TPP and LoadSEER forecast for 2017 to 2026, are plotted in Exhibit 1-2a. For 2020 and 2023, as identified in the request, the CAISO's 2018-2019 TPP load forecast numbers are similar to the LoadSEER forecast. Then the forecasted values for the years beyond 2023 are different.

Exhibit 1-2a: Paso Robles TPP 2018-2019 Load Model vs. LoadSEER (Appendix G Table 4)

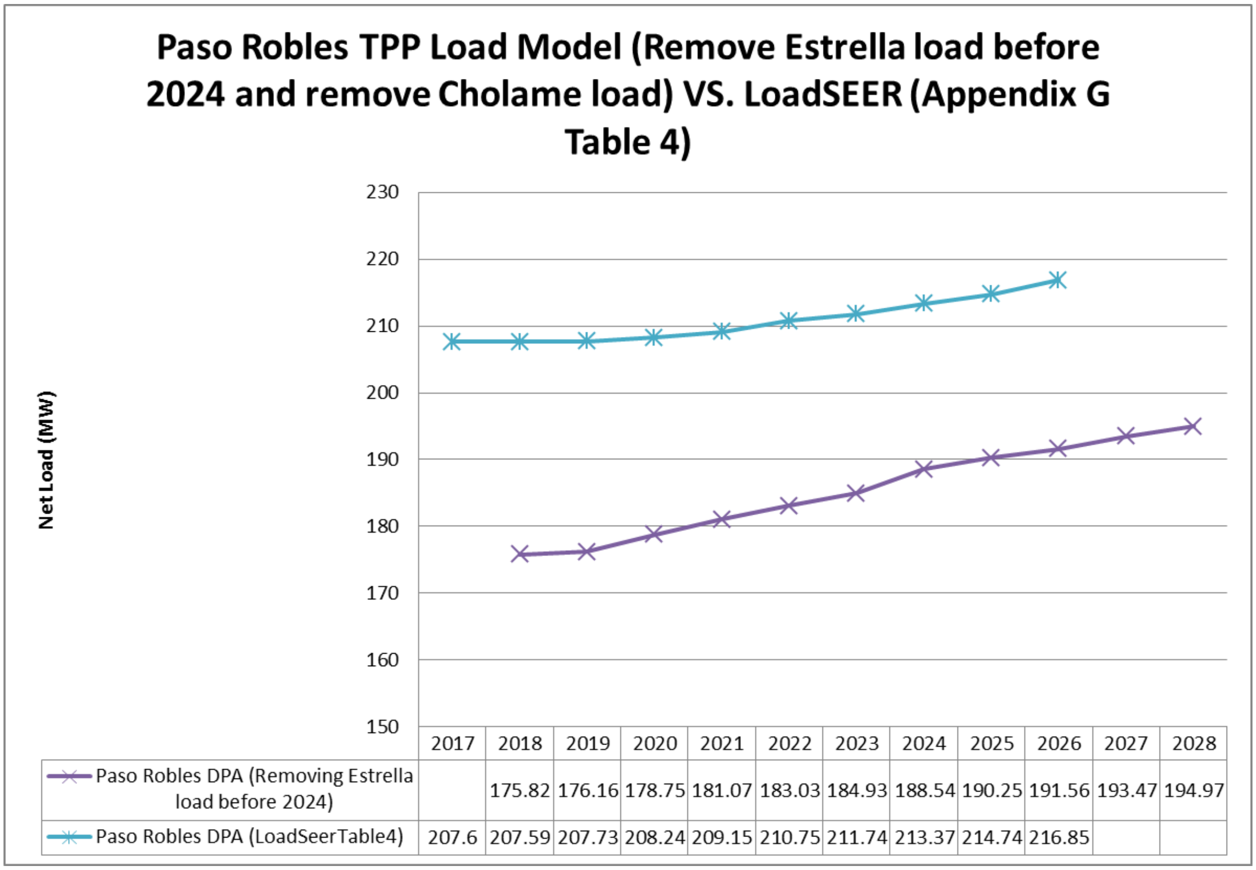


	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Paso Robles DPA (with Cholame)		184.89	205.14	207.74	210.08	212.07	213.98	195.77	197.48	198.78	200.7	202.17
Paso Robles DPA (LoadSeerTable4)	207.6	207.59	207.73	208.24	209.15	210.75	211.74	213.37	214.74	216.85		

There are two corrections that need to be made to the CAISO 2018-2019 load model in order to make a better comparison between the two forecasts. First, Cholame Substation does not belong to the Paso Robles DPA and should be removed before making the comparison. That removes approximately 7 to 8 MW of load per year, depending on the year. Second, approximately 20 MW of load at Estrella Substation, which was accidentally included in the transmission model from 2019 to 2023, needs to be removed. The current assumption is that the load transfer will take place in 2024 when Estrella Substation becomes operational and not before. Furthermore, when the load transfer to Estrella Substation takes place, the load will simply be reallocated among the local area substations; it is not expected to be a new block of load added as the values for 2019-2023 currently and incorrectly indicate.

After removing the 20 MW load at Estrella Substation from 2019 to 2023 and the load at the Cholame Substation, both of the CAISO 2018-2019 TPP load and the LoadSEER load show a similar load growth trend with a consistent gap of 25 to 28 MW between transmission and distribution load forecasts. See Exhibit 1-2b below.

Exhibit 1-2b: Paso Robles TPP 2018-2019 Load Model (Remove Estrella Load Before 2024 and Remove Cholame Load) vs. LoadSEER (Appendix G Table 4)



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Paso Robles DPA (Removing Estrella load before 2024)		175.82	176.16	178.75	181.07	183.03	184.93	188.54	190.25	191.56	193.47	194.97
Paso Robles DPA (LoadSeerTable4)	207.6	207.59	207.73	208.24	209.15	210.75	211.74	213.37	214.74	216.85		

The resulting differences between the two forecasts can be explained primarily by looking at each forecast's purpose and methodology.

The transmission-level load forecast is used for transmission system planning and it mainly focuses on the larger system and wider area load levels. This forecast takes into consideration historical weather, system and division peak load conditions, CEC mid-demand baseline forecast, and distribution-level forecast aggregation.

Specifically, for a division such as Los Padres in which the Paso Robles DPA is located, the total division summer peak load forecast starts from the load associated with the 1-in-10 high temperature of the division, which helps establish the "starting load" level. Then the CEC forecasted PG&E 1-in-10 system load growth is allocated to the division by calculating the estimated distribution load growth in this division compared to the estimated distribution load growth for the entire PG&E system. To state it another way, the CEC forecasted PG&E 1-in-10 system load growth is allocated to the division according to the ratio of the sum of the distribution load growth forecast in this division (i.e., the sum of the LoadSEER forecasts for all DPAs in the division) to the sum of the distribution load growth forecasted in all DPAs across the entire PG&E system.

At the transmission level, the total forecasted division load is then determined by adding up the "starting load" and the growths from year to year. For transmission planning study and modeling purposes, each year's forecasted division load is further allocated to the transmission bus level in proportion to the distribution forecasted bank load within the division. Such transmission bus level loads do not necessarily represent distribution substation peak loads, but rather when the overall division could be expected to peak.

On the other hand, the distribution load forecasts focus more on peak loads on feeders and substations within relatively small load pockets such as the Paso Robles DPA. Different load pockets tend to peak at different times of day—for example valley zones generally peak at different times than coastal regions. For that reason, whereas the distribution level forecast (i.e., LoadSEER) for a particular DPA assumes that all substations will peak simultaneously, transmission-level forecasting does not assume that all substations in all DPAs will peak at the same time. As a result, when it comes to the division level, LoadSEER forecasted peak loads at distribution substations within the same division typically add up to a higher peak load than the transmission forecasted division peak load.

Detailed steps of PG&E transmission load forecast methodology can be found in CAISO's 2018-2019 TPP Unified Planning Assumptions and Study Plan Section 3.6.2, which can be found at the following link:

http://www.caiso.com/Documents/Final2018-2019StudyPlan.pdf

The map below (Exhibit 1-2c) illustrates the various divisions within the PG&E system, identifying the general location of the Paso Robles DPA within Los Padres Division. Exhibit 1-2d is a closer look at a portion of the Los Padres division outlining the Paso Robles DPA.

Exhibit 1-2c: Paso Robles DPA (red circle, approximate) within Los Padres Planning Division in the PG&E Service Territory

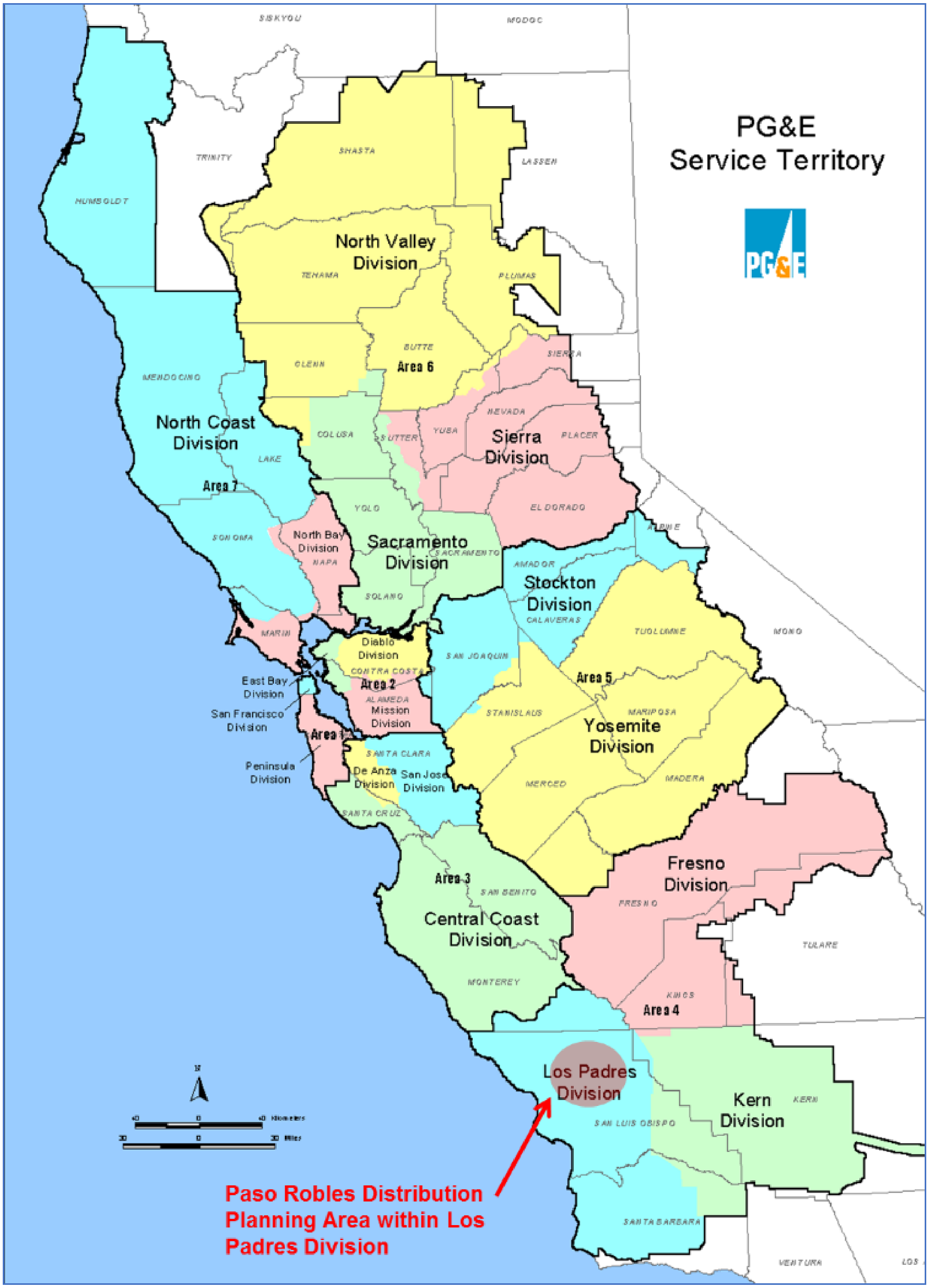


Exhibit 1-2d: Close up of Paso Robles DPA (outlined yellow) within Los Padres Planning Division

Request #1-3:

Outage History for Templeton 21 kV feeders was provided in Table 1 of Appendix G for prior 5 years (Feb 2012 – Feb 2017). For the sustained outages in Table 1, please provide a root cause explanation of the outage, duration of outage, start time for outage, and number of customers affected. For example, outage was caused by a car-pole accident, duration was 2 hours starting on XX/XX/XXXX date and time, and 600 customers were affected.

Response:

The requested information about the sustained outages in Table 1 of Appendix G is provided in Exhibit 1-3 below.

Exhibit 1-3: Sustained Outage History of Templeton 21 kV Feeders (February 2012 to February 2017)

Feeder Name	Outage Report#	Root Cause Explanation of the Sustained Outage	Duration of Sustained Outage	Start Time for Sustained Outage (date and time)	Number of Customers Affected
Templeton 2108	14-0075719	Unknown Cause, Patrol - Not Conducted	39 Minutes	12/11/2014, 17:28	3,115
	15-0035034	Equipment Failure/Involved, Overhead	16 hours and 43 minutes	5/18/2015, 16:22	3,124
	12-0063012	Company Initiated, Personnel, Company	21 minutes	10/5/2012, 15:57	3,146
	14-0011734	Equipment Failure/Involved, Other	21 minutes	3/14/2014, 11:49	3,041
	14-0054112	Unknown Cause, Patrol - Found Nothing	20 minutes	8/29/2014, 13:21	2,307
	14-0062293	Unknown Cause, Patrol - Found Nothing	15 minutes	10/8/2014, 14:06	2,313
	13-0065180	Equipment Failure/Involved, Other	51 minutes	9/27/2013, 7:23	3,011
Templeton 2109	12-0028912	3rd Party Vehicle	2 hours and 3 minutes	5/5/2012, 3:02	4,305
	13-0020379	3rd Party, Vehicle	20 minutes	3/31/2013, 16:58	2,021
	13-0043500	Company Initiated, Coordination Failure	3 hours and 53 minutes	6/28/2013, 16:14	2,023
	17-0022115	Vegetation, Tree - Fell into Line	3 hours and 25 minutes	2/17/2017, 10:10	332
	16-0051688	Equipment Failure/Involved, Other	56 minutes	7/21/2016, 18:19	2,364
Templeton 2110	16-0044879	Equipment Failure/Involved, Substation	3 hours and 45 minutes	6/21/2016, 16:52	2,924
	15-0043205	Equipment Failure/Involved, Other	24 minutes	06/25/15, 07:45	1,247
	16-0044904	Vegetation, Tree - Branch Fell on Line	7 minutes	6/21/2016, 20:49	491
	16-0040382	Equipment Failure/Involved, Underground	24 minutes	6/1/2016, 23:57	1,247
Templeton 2111	15-0049928	Environmental/External, Lightning	10 hours and 15 minutes	7/19/2015, 2:35	1,406
	15-0076522	Equipment Failure/Involved, Overhead	8 hours and 23 minutes	11/9/2015, 1:37	960
	16-0018035	Vegetation, Tree - Fell into Line	10 hours and 40 minutes	3/5/2016, 23:10	959
	16-0029198	Unknown Cause, Patrol - Found Nothing	1 hours and 15 minutes	4/17/2016, 12:53	960
	16-0028599	3rd Party	52 minutes	4/14/2016, 11:34	2,376
	12-0047341	Vegetation, Tree - Fell into Line	51 minutes	7/30/2012, 13:30	2,376
Templeton 2112	16-0086120	3rd Party, Vehicle	12 hours and 16 minutes	12/17/2016, 0:40	937
	12-0043918	Vegetation, Tree - Branch Fell on Line	5 hours and 29 minutes	7/14/2012, 18:51	428
	12-0067873	Company Initiated, Failed Equipment	1 hour and 37 minutes	11/5/2012, 10:27	428

Feeder Name	Outage Report#	Root Cause Explanation of the Sustained Outage	Duration of Sustained Outage	Start Time for Sustained Outage (date and time)	Number of Customers Affected
Templeton 2113	16-0021105	Equipment Failure/Involved, Overhead	14 hours and 15 minutes	3/13/2016, 22:46	5,444
	16-0036852	Equipment Failure/Involved, Fire, Pole	5 hours and 21 minutes	5/18/2016, 15:45	5,446
	17-0012780	Vegetation, Tree - Branch Fell on Line	1 hours and 45 minutes	1/22/2017, 4:57	4,999
	13-0037206	Animal, Bird Found	4 hours and 50 minutes	6/6/2013, 14:50	908
	13-0079501	3rd Party, Vehicle	12 hours and 2 minutes	11/26/2013, 17:03	1,837
	13-0057921	Company Initiated, Equipment Upgrade	8 hours and 46 minutes	9/10/2013, 7:02	7
	12-0019257	Company Initiated	1 hour and 39 minutes	4/17/2012, 9:24	1

Request #1-4:

For the Paso Robles DPA please provide the SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), MAIFI (Momentary Average Interruption Frequency Index), and CAIDI (Customer Average Interruption Duration Index) associated with the Outage History for Templeton 21 kV feeders in Table 1 of Appendix G. For the same period please provide the PG&E system wide outage indices (SAIDI, SAIFI, CAIDI, and MAIFI).

Response:

The outage indices associated with the Templeton 21 kV feeder outage history in Table 1 of Appendix G (February 2012 to February 2017) are provided in Exhibit 1-4a. For additional comparison, we provided in Exhibit 1-4b the outage indices for the other mainline outages occurring on distribution feeders in the Paso Robles DPA for the same time period. The outage indices for all distribution feeder mainline outages in the entire PG&E system for the same time period are provided in Exhibit 1-4c.

Exhibit 1-4a: Templeton 21 kV Feeder Outage Indices

Sample	Year	AIDI	AIFI	MAIFI	CAIDI	SO	MO
Selected Templeton Feeder Outages	2012	28.8	0.590	1.687	48.8	6	13
Selected Templeton Feeder Outages	2013	52.5	0.570	0.907	92.1	6	9
Selected Templeton Feeder Outages	2014	14.8	0.598	1.234	24.7	5	12
Selected Templeton Feeder Outages	2015	64.0	0.490	2.337	130.8	5	25
Selected Templeton Feeder Outages	2016	112.2	1.463	2.532	76.7	12	21
Selected Templeton Feeder Outages	2017	24.5	0.290	1.011	84.5	2	7
	Average	**49.48**	**0.67**	**1.62**	**76.27**		

Notes:
AIDI = average outage duration
AIFI = average frequency of sustained outages
MAIFI = average frequency of momentary interruptions
CAIDI = average service restoration times
SO = sustained outages
MO = momentary outages

Exhibit 1-4b: Paso Robles DPA Distribution Feeder Mainline Outage Indices

Sample	Year	AIDI	AIFI	MAIFI	CAIDI	SO	MO
Other Feeder Outages in Paso DPA	2012	34.1	0.329	0.835	103.4	12	33
Other Feeder Outages in Paso DPA	2013	49.6	0.504	1.611	98.5	16	40
Other Feeder Outages in Paso DPA	2014	110.9	0.659	1.144	168.3	25	23
Other Feeder Outages in Paso DPA	2015	136.5	0.617	1.021	221.1	22	61
Other Feeder Outages in Paso DPA	2016	38.2	0.454	1.440	84.2	22	47
Other Feeder Outages in Paso DPA	2017	109.0	0.430	1.017	253.7	19	17
	Average	**79.70**	**0.50**	**1.18**	**154.87**		

Exhibit 1-4c: System-wide Distribution Feeder Mainline Outage Indices

Sample	Year	AIDI	AIFI	MAIFI	CAIDI	SO	MO
System-wide Feeder Outages	2012	70.8	0.609	1.467	116.1	3,191	7,706
System-wide Feeder Outages	2013	61.3	0.584	1.350	105.0	2,933	7,521
System-wide Feeder Outages	2014	73.8	0.643	1.265	114.8	3,419	6,870
System-wide Feeder Outages	2015	59.5	0.546	1.538	108.8	3,281	8,816
System-wide Feeder Outages	2016	56.2	0.620	1.311	90.5	3,486	8,154
System-wide Feeder Outages	2017	82.9	0.312	0.667	266.0	1,893	4,247
	Average	**67.41**	**0.55**	**1.27**	**133.53**		

Although the outage indices provided in Exhibit 1-4a are calculated based on the outage history in Table 1 of Appendix G, some clarification is needed. PG&E assigns an outage identification number for each outage that occurs. Sometimes, a single outage affects more than one circuit, in which case the related outages on different circuits are still assigned the same outage number. This is the case with some of the outages listed in Table 1. As a result, the number of outages that were used to calculate the outage indices in Exhibit 1-4a is higher than the number of outages listed in Table 1. Specifically, Table 1 lists 32 sustained outages, whereas the outage indices in Exhibit 1-4a are based on 36 sustained outages. Similarly, Table 1 lists 84 momentary outages, whereas the outage indices in Exhibit 1-4a are based on 87 momentary outages.

Comparing the average AIFI and MAIFI values for all 6 years of data presented in Exhibits 1-4a and 1-4b shows that the outage history in Table 1 of Appendix G resulted in a higher average frequency of sustained outages per customer and momentary outages per customer than resulted from the other outages occurring on distribution feeders in the Paso Robles DPA.

Similarly, comparing the average AIFI and MAIFI values for all 6 years of data presented in Exhibits 1-4a and 1-4c shows that the outage history in Table 1 of Appendix G resulted in a higher average frequency of sustained outages per customer and momentary outages per customer than resulted from outages occurring on distribution feeders throughout the entire PG&E system.

The data presented above is consistent with the statement in Appendix G (p. UG-3) that “[t]he number of outages is relatively high for typical distribution main lines, but not unexpected in these areas due to the long express nature of the 21 kV feeders.” Shortening the length of these lines would reduce their exposure to potential outages and result in a lower frequency of sustained and momentary outages. For this reason, adding distribution capacity at the proposed Estrella Substation site will result in greater service reliability (including less frequent sustained and momentary outages) in the future load center by allowing feeders from Templeton, Paso Robles, San Miguel, and Cholame substations to be significantly reduced in their reach and correspondingly less susceptible to outages. In contrast, constructing new express distribution feeders from Templeton Substation to serve the future load center would be less reliable because they would be several miles longer than lines constructed from Estrella Substation and have a correspondingly higher susceptibility to outages.

Request #1-5

Please provide the location of known circuit protection equipment on the distribution system across the DPA, in GIS readable format. This should include the following:

- *Length of circuit*
- *Maximum 3-phase resistance*
- *Voltage regulator count and location*
- *Capacitor count and location*
- *Protective recloser count and location*

Response:

PG&E has designated the information responsive to this request as confidential pursuant to the CPUC's requirements for confidentiality as set forth in Decision 16-08-024. PG&E has prepared a declaration of confidentiality to support this designation. The requested GIS information and confidentiality declaration are being provided separately through PG&E's Enterprise Secure File Transfer (ESFT) site. PG&E will provide you with access to the ESFT site.

Request #1-6

Please provide the results of CYME power flow analysis (e.g., criteria limit violations across the 576 hour time series dataset) for each circuit at the line segment level.

Response:

PG&E uses CYME power flow analysis software to model steady state power flow on each of its distribution feeders. This model is created for the most recently observed peak loading scenario on each distribution feeder, and for the projected loading on each feeder for the coming 3 years. PG&E does not perform a 576 hour time series power flow analysis on its distribution feeders. While PG&E models its distribution feeders for peak loading conditions to identify and resolve localized deficiencies, the Distribution Needs Analysis for the proposed Estrella Substation presented in PEA Appendix G (based on the 2017 LoadSEER forecast) is based on a DPA-level capacity deficiency; no other deficiencies were identified. The subsequent 2018 LoadSEER forecast (provided above in the response to Request #1-1) identified both bank- and feeder-level deficiencies (see the response to Request #1-7 below), via the LoadSEER load forecasting tool, but the projected deficiencies are only at the bank- or feeder-source level, and do not indicate localized deficiencies (e.g.,, overloaded facilities or voltage outside of Rule 2 limits) on any of the distribution feeders.

Additional capacity at Estrella Substation would enable load transfers from adjacent distribution feeders, thereby reducing loading on substation facilities. Estrella Substation is not proposed to resolve localized deficiencies on distribution feeders.

Request #1-7

In Deficiency Letter 5, CPUC asked why PG&E did not include a list of feeders and banks projected to be loaded over their normal thermal ratings in 2024 based on the 2017 forecasting *cycle in SCE. This list was provided to CAISO for purposes of transmission planning. PG&E provided an answer in their response to Deficiency Letter 5. We believe this information informs where and how block load increases are forecasted at the circuit level.*

Please provide information for individual distribution bank or feeder loads and overloads projected over normal thermal ratings, based on the latest forecasting cycle.

Response:

The PG&E 2018 distribution forecast (based on 2017 peak loads) shows the following bank and feeders to be loaded at or over 100% of their respective summer normal thermal ratings in 2024:

- Atascadero 1103: 102% loaded
- Paso Robles 1107: 101% loaded
- Paso Robles 1108: 100% loaded
- San Miguel 1104: 102% loaded
- Templeton Bank 2: 102% loaded
- Templeton 2113: 101% loaded

The above list agrees with the information CAISO provided to CPUC on February 23, 2018.