PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

Pacific Gas & Electric Company
ELC (Corp ID 39)
Status of Advice Letter 6002E
As of December 17, 2020

Subject: Request for Approval to Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities

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CPUC Contact Information:

edtariffunit@cpuc.ca.gov

AL Certificate Contact Information:

Stuart Rubio
415-973-4587
PGETariffs@pge.com

PUBLIC UTILITIES COMMISSION
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San Francisco CA 94102-3298

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From: Energy Division PAL Coordinator

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Pacific Gas and Electric Company®

Erik Jacobson
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

November 16, 2020

Advice 6002-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

<u>Subject:</u> Request for Approval to Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities

Purpose

Pursuant to Ordering Paragraphs (OP) 2.w and 2.x of Decision (D.) 18-02-004 as well as the May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process (May 2019 ALJ Ruling) and the May 11, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing And Process Requirements (May 2020 ALJ Ruling)[1] in Rulemaking (R.) 14-08-013, Pacific Gas and Electric Company (PG&E) submits this Tier 2 advice letter requesting the California Public Utilities Commission's (Commission's or CPUC's) approval to issue competitive solicitations to procure distributed energy resources (DER) solutions for identified electric distribution deferral opportunities as described below.

1. Background

On August 14, 2014, the Commission instituted R.14-08-013 to establish policies, procedures, and rules to guide the California investor-owned utilities (IOUs) in developing their Distribution Resources Plan (DRP) proposals. This rulemaking also established new polices to evaluate the IOUs' existing and future electric distribution infrastructure and planning procedures with respect to incorporating DERs into the planning and operations of their electric distribution systems.

In July 2015, California IOUs each submitted their respective DRP proposals to the Commission. The Commission organized the review of the DRP filing content into three tracks: Track 1 – Tools and Methodologies, Track 2 – Field Demonstration Projects, and

[1] May 11, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing and Process Requirements, Attachment A, pp. 89-98. Attachment A was subsequently revised by the ALJ on June 12, 2020.

Track 3 – Policy Issues. Various DRP working group meetings and workshops were held to inform the Commission and stakeholders, which ultimately led to several decisions in R.14-08-013.

In February 2018 the Commission issued D.18-02-004 on Track 3 Policy Issues, sub-track 1 (Growth Scenarios) and sub-track 3 (Distribution Investment and Deferral Process). This decision directed the IOUs to file a Grid Needs Assessment (GNA) by June 1 of each year, and a Distribution Deferral Opportunity Report (DDOR) by September 1 of each year. Subsequently, the May 2019 ALJ Ruling modified the Distribution Investment Deferral Framework (DIDF). One notable modification was the new August submission date for both the GNA and DDOR reports.

There were two improvement rulings modifying the DIDF process by Administrative Law Judge (ALJ) Mason in 2020. The April 13, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process (April 2020 ALJ Ruling) updated the Independent Professional Engineer (IPE) scope of work for the DIDF process and provided the 2020-2021 DIDF cycle schedule. The May 2019 ALJ Ruling further modifies the DIDF process and filings requirements by focusing on the comments and reforms related to aspects of the DIDF.

PG&E jointly filed its third GNA and DDOR on August 17, 2020 and provided it to its Distribution Planning Advisory Group (DPAG). Also, as required by D.18-02-004, PG&E initiated DPAG meetings by September 16, 2020 to receive advisory input on candidate distribution deferral opportunities that should be issued for competitive solicitation and retained an IPE to attend the meetings and prepare a DPAG Report.

This advice letter is submitted in compliance with D.18-02-004, the November 19, 2018 Administrative Law Judge's Ruling on the Application of the Competitive Solicitation Framework for Distribution Investment Deferrals in the Distribution Resource Planning Proceeding, the May 2019 ALJ Ruling, and the May 2020 ALJ Ruling regarding the application of the competitive solicitation framework (CSF) for distribution investment deferrals in the DRP proceeding.

2. Overview of the Distribution Investment Deferral Framework Process

Pursuant to the DIDF as specified in D.18-02-004, the May 2019 ALJ Ruling, and the May 2020 ALJ Ruling, PG&E has completed the following:

- August 17, 2020: Submitted PG&E's 2020 GNA Report
- August 17, 2020: Submitted PG&E's 2020 DDOR
- September 16, 2020: Hosted PG&E's DPAG Meeting #1 via Webinar
- October 12, 2020: Hosted PG&E's DPAG Follow up meeting via Webinar
- November 13, 2020: Submitted Supplement to PG&E's 2020 DDOR

This advice letter requests approval to solicit DERs to meet the distribution deferral opportunities that were a result of the DPAG's advisory input on the DDOR.

3. Lessons Learned from Prior DER Solicitations for Distribution Deferral

PG&E has gathered valuable learnings from its DRP Demonstrations, its Integrated Distributed Energy Resources (IDER) Incentive Pilot, and prior DIDF cycles. General learnings and insights gathered from progress to-date on IDER Incentive Pilots across all California IOUs are included in the *Energy Division Staff Proposal on a Distribution Investment Deferral Framework (Staff Proposal)* issued on June 30, 2017 and in the *Decision on Track 3 Issues: DER Growth Scenarios and the Distribution Investment Deferral Framework (DIDF)* (D.18-02-004) issued on February 15, 2018. As described in these filings, the adoption of a CSF and establishment of an interim DPAG has provided the IOUs, including PG&E, tangible learnings on the deferral screening criteria and prioritization metrics, which have been incorporated into the DIDF process.

PG&E has incorporated, to the extent possible, the lessons learned from prior solicitations to the 2020-2021 DIDF cycle. For example, PG&E's prioritization metrics are designed to prioritize candidate deferral opportunities with short duration needs. Also, PG&E considered the ability of energy storage to charge from the locations identified for each candidate deferral opportunity. And PG&E has carefully reviewed Supervisory Control and Data Acquisition (SCADA) and Advanced Meter Infrastructure (AMI) data to identify opportunities to limit the duration of the needs required. PG&E may also consider procurement above the minimum performance and operational requirements if it is cost-effective to address forecast uncertainty.

Application of Lessons Learned

- Long duration (i.e., baseload) needs are challenging to source DERs
  - Long duration needs limit feasible technologies and increase costs
  - Long duration needs limit counterparty ability to monetize other revenue streams
- Interconnection within a constrained distribution area is challenging
  - Candidate deferral locations do not indicate that interconnection will be easier
  - Projects are unlikely to qualify for the fast track process and costs may be significant
  - Not all locations will have the capacity to charge storage to meet the grid need
- Grid needs are dynamic
  - Precise grid need determinations are impossible
  - Developers are encouraged to provide options for additional capacity to provide a hedge against changes to forecast
  - New large load applications may make distribution deferral challenging. This has been incorporated into the forecast certainty metric
- Age and condition of substation may impact ability to defer investment

– The forecast certainty metric now reflects an evaluation of candidate deferral opportunities where replacement of failing equipment may be necessary within the deferral period

4. Proposal to Solicit Candidate DER Distribution Deferral Projects

PG&E is requesting approval to solicit candidate DER distribution deferral projects via the CSF RFO for the following candidate distribution deferral opportunities:

- Willow Pass Bank 1 (5.32 MW)
- San Miguel Bank 2 (4.95 MW)
- Calistoga Bank 1 (4.18 MW)
- Ripon 1705 (3.68 MW)
- Blackwell Bank 1 [redacted][2]
- Zamora 1108 (1.05 MW)
- Greenbrae Bank 2 ([redacted])

The following information is provided on the candidate distribution deferral opportunities:

- Prioritization Metrics (cost-effectiveness, market assessment, and forecast certainty) – Attachment A (Confidential)
- Location of Needs (map and description of locations on circuit) – Attachment B
- Unit Cost of Traditional Mitigation – Attachment C
- Metrics to Define Need (Expected Performance and Operational Requirements) – see Section 4.3.1
- Services Required – Seven of the above candidate deferral opportunities are thermal capacity requirements. Six of these are load decreases and one candidate deferral opportunity is to increase the load.

4.1. Prioritization Metrics

In D.18-02-004, three metrics were adopted to characterize and help prioritize projects on the Candidate Deferral Opportunities shortlist. These metrics are: (a) Cost-Effectiveness, (b) Forecast Certainty, and (c) Market Assessment. Each IOU is to apply these metrics using its own approach, provided the metrics support the deferral of any project that can be cost-effectively deferred by DERs.

PG&E has evaluated each of these metrics qualitatively, grouping the Candidate Deferral Opportunities into tiers based on their relative rankings. These qualitative rankings are based on quantitative data as well as engineering judgement by utility distribution planners where noted.

[2] Negative MW value denotes a need to increase load to offset backflow

For ease of summarizing prioritization metric results, PG&E has developed a 4-tier system, where each tier represents PG&E's proposed priority ranking of those candidate deferral projects likelihood of success for DER sourcing. The following table (Table 1) summarizes PG&E's 4-tier system.

Table 1: PG&E's 4-Tier Prioritization System

Tier	Color Designation	Definition
1		Relatively High Ranking
2		Relatively Moderate Ranking
3		Relatively Low Ranking
4[3]		Already Sourced Elsewhere

All ranking of projects is relative. For example, a higher tiered project does not indicate that the project will be cost-effective, have a certain forecast, or have a robust market[4]. It only indicates the ranking of the candidate deferral opportunity relative to other candidate deferral opportunities.

PG&E's preliminary prioritization and ranking of candidate deferral opportunities were published in PG&E's 2020 DDOR. The prioritization metrics and tiering were then thoroughly discussed and updated throughout the DPAG process. The prioritization metrics for each candidate deferral opportunity are included in Attachment A.

[3] No Candidate Deferral Opportunities were under Tier 4

[4] For example, green candidate deferral opportunities are expected to be more cost-effective than red candidate deferral opportunities, but it does not indicate the candidate deferral opportunity will receive conforming and cost-effective bids. Similarly, all the opportunities have some degree of forecast uncertainty.

4.2. Candidate Deferral Opportunities

The following table (Table 2) summarizes the tiering of PG&E's 2020 final candidate deferrals, including the targeted in-service need date and minimum grid capacity needed (i.e., deficiency).

Table 2: PG&E's 2020 DDOR Candidate Deferral Opportunities

Tier	Candidate Deferral[5]	In-Service Date	Deficiency (MW)[6]
1	Willow Pass Bank 1	2023	5.3
	San Miguel Bank 2	2023	5.0
	Calistoga Bank 1	2023	4.2
	Ripon 1705	2024	3.7
	Blackwell Bank 1	2023	[redacted]
	Zamora 1108	2023	1.1
	Greenbrae Bank 2	2023	[redacted]
2	Dunnigan Bank 1	2024	1.6
	Beresford 401 Cut-Over	2023	1.5
	Brentwood 2111 Line Work	2023	0.9
	Hollister 2106 Line Work	2023	5.0
	Rocklin 1104 and Rocklin 1101	2025	0.2
	Caruthers 1104 Regulator	2023	0.7
	Morgan Hill 2103	2023	6.6
	Storey 1103	2023	3.2
	Vasona 1109	2023	3.9
	Peabody 2106 Outlet	2024	[redacted]
	Stelling 1105	2023	4.6
	Mountain View Bank 1	2023	5.7
3	San Luis Obispo 1106	2023	[redacted]
	Woodland 1105 Outlet	2025	1.3
	Lockeford Bank 1	2024	14.8
	Semitropic 1112 Line Work	2024	8.1
	California Ave 1103 & California Ave 1111 Line Work	2023	[redacted]
	Wolfe 1111 & Wolfe 1112	2023	44.1
	FMC 1102	2023	6.7
	Rincon Bank 1	2023	8.0
	Spence Bank 2	2023	[redacted]

[5] Belle Haven Bank 4 candidate deferral project was cancelled due to a large load application after GNA/DDOR publication and the planned investment no longer exists. Distribution planning will need to identify new Planned Investment(s) to meet the need in the area.

[6] Banks and feeders with peak loads listed as "CUSTOMER CONFIDENTIAL" or "CC" or Grey Shaded were redacted due to their peak loads violating the 15-15 customer privacy rule. A 15-15 violation occurs if the load is comprised of less than 15 customers or a single customer contributes to more than 15% of the loading value.

PG&E has identified 28 Candidate Deferral Opportunities totaling approximately 165 megawatts (MW), which are further categorized and prioritized into the following three tiers:

- Tier 1: Identified seven Candidate Deferral Opportunities totaling approximately 25 MW. Tier 1 Candidate Deferral Opportunities are relatively more likely to be deferrable.
- Tier 2: Identified twelve Candidate Deferral Opportunities totaling approximately 35 MW. Tier 2 Candidate Deferral Opportunities have identified some red flags that indicate they are unlikely to be successfully deferred now. PG&E recommends not pursuing these Candidate Deferral Opportunities, but to closely monitor status and project conditions and re-evaluate for a future date.
- Tier 3: Identified nine Candidate Deferral Opportunities totaling approximately 105 MW. Tier 3 Candidate Deferral Opportunities have multiple major red flags that have been identified and indicate it is not likely a DER deferral solution can successfully be sourced.

4.2.1. Tier 1 Candidate Deferral Opportunities

PG&E's recommendation is to pursue competitive solicitations for the Tier 1 Candidate Deferral Opportunities (seven projects totaling ~25 MW). The operational and service requirements are specified in Section 4.3.1 (Expected Performance and Operational Requirements). The Tier 1 candidate deferral opportunities were selected based on their relative ranking using the prioritization metrics (Attachment A). The Tier 1 candidate deferral opportunities had relatively better cost-effectiveness, forecast certainty and market assessment scores.

The Tier 1 candidate deferral opportunities are:

- *Willow Pass Bank 1* – The planned investment consists of replacing the existing 3.5 MVA Willow Pass Bank 1 at Willow Pass substation with a 45 MVA transformer bank, with an expected in-service date of June 1, 2023.

- *San Miguel Bank 2* – The planned investment consists of installing a new substation bank (i.e. Bank 2) at San Miguel with an in-service date of May 1, 2023.

- *Calistoga Bank 1* – The planned investment consists of replacing the existing Calistoga Bank 1 and installing one feeder with an expected in-service date of May 1, 2023.

- *Ripon 1705* – The planned investment consists of installing a new 17 kV feeder, Ripon 1705, at Ripon Bank 1 with an expected in-service date of April 30, 2024.

- *Blackwell Bank 1* – The planned investment consists of replacing Blackwell Bank 1 for generation backflow with an expected in-service date of May 1, 2023

- *Zamora 1108* – The planned investment consists of installing a new 12 kV feeder, Zamora 1108, on Zamora Bank 2 with an expected in-service date of May 1, 2023.

- *Greenbrae Bank 2* – The planned investment consists of replacing the existing Greenbrae Bank 2 with an expected in-service date of April 1, 2023.

4.2.2. Tier 1 Candidate Deferral Opportunity for IOU ownership

Per the May 2020 ALJ Ruling Reform Item 44,[7] PG&E has identified Blackwell Bank 1 as the candidate deferral opportunity to encourage bids for utility ownership.

The selection of Blackwell Bank 1 is based on the solicited DER being relatively well suited as an IOU owned dedicated distribution asset. PG&E intends to solicit for an IOU dedicated distribution DER asset, the frequent use for distribution service (e.g., a high number of calls per year) is most appropriate. Given the current cost recovery rules for the DIDF[8], PG&E does not anticipate using or valuing services other than distribution service. Given the frequent use for distribution service, IOU ownership bids for a dedicated distribution asset can potentially compete cost effectively with 3rd party owned assets that are obtaining other sources of market revenues.

Soliciting utility ownership bids requires significant additional work in terms of defining the specifications for a utility owned asset and potential locations and project configurations. It also requires the development of new form contracts, and a more complex evaluation process. As a result, PG&E is proposing an extended schedule for the Blackwell Bank 1 RFO.

4.2.3. Tier 2 and Tier 3 Candidate Deferral Opportunities

PG&E does not recommend pursuing competitive solicitations for Tier 2 and Tier 3 candidate deferral opportunities at this time, and details are provided in a separate advice letter requesting approval to not pursue competitive solicitations for 2021 DIDF RFO in Advice Letter 6003-E, filed along with this advice letter.

[7] May 2020 ALJ Ruling, Attachment A, Reform Item 44
[8] See PG&E's 2020 DDOR, Proposed DIDF Improvements, for further discussion.

4.3. Technical and Operating Requirements

Since the filing of the DDOR and based on feedback from the DPAG, PG&E has continued to perform detailed engineering analysis to refine the expected performance and operational requirements for the candidate deferral opportunities, including:

- Updated load forecast to reflect any significant changes (e.g., new customer requests)

4.3.1. Expected Performance and Operational Requirements

The expected performance and operational requirements are listed below in Table 3 for the Tier 1 candidate deferral opportunities. For each of the candidate deferral opportunities listed, all the expected performance and operational requirements need to be met in order to defer the planned investment. All requirements are for Day-Ahead Dispatch. Based on DPAG feedback, requirements may be grouped into smaller blocks. Further details on these requirements will be provided during the 2021 DIDF RFO Participants Webinar.

Table 3: Expected Performance and Operational Requirements

Candidate Deferral	GNA Facility Name	Real Time (RT) or Day Ahead (DA)	Grid Need (MW)	Month	Calls/ Year	Hours	Duration (Hours)
Willow Pass Bank 1	WILLOW PASS BANK 1	DA	0.26	6-8	8	2PM-8PM	1
	WILLOW PASS BANK 3	DA	5.06	6-9	101	2PM-10PM	6
San Miguel Bank 2	SAN MIGUEL BANK 1	DA	3.48	6-9	122	6AM-11PM	10
	SAN MIGUEL 1104	DA	0.94	6-9	66	5PM-10PM	4
	PASO ROBLES 1107	DA	0.53	7-9	21	3PM-9PM	3
Calistoga Bank 1[9]	CALISTOGA BANK 1	DA	1.23	6-9	40	2PM-6PM	3
	CALISTOGA 1102	DA	2.95	6-9	122	12PM-9PM	8
Ripon 1705	VIERRA 1707	DA	3.68	6-9	102	3PM-10PM	5
Blackwell Bank 1[10]	BLACKWELL BANK 1	DA	[redacted]				
Zamora 1108	ZAMORA BANK 1	DA	1.05	6-7	45	6AM-10PM	14
Greenbrae Bank 2[11]	GREENBRAE BANK 2	DA	[redacted]				

[9] PG&E has identified potential red flags at this location
[10] Requires additional load due to excess generation
[11] PG&E has identified potential red flags at this location

The expected performance and operational requirements for the Tier 1 candidate are described further below:

- *Willow Pass Bank 1* – Two grid needs, located on Willow Pass Bank 1 and Willow Pass Bank 3. For the solicitation, PG&E has specified performance and operational requirements for each of the independent grid needs. PG&E encourages, but does not require, that Participants submit an offer for all two of the grid needs.

- *San Miguel Bank 2* – Three grid needs, located on San Miguel Bank 1, San Miguel 1104, and Paso Robles 1107. For the solicitation, PG&E has specified performance and operational requirements for each of the independent grid needs. PG&E encourages, but does not require, that Participants submit an offer for all three of the grid needs. Due to capacity constraints on San Miguel Bank 1, DER bids that cause an increase in loading on the bank will not be viable (e.g., energy storage bids would need an alternative source of charging to be eligible.)

- *Calistoga Bank 1* – Two grid needs, located on Calistoga Bank 1 and Calistoga 1103. For the solicitation, PG&E has specified performance and operational requirements for each of the independent grid needs. PG&E encourages, but does not require, that Participants submit an offer for all two of the grid needs. The Rapid Earth Fault Current Limiter (REFCL) project, a new high impedance fault detection system with fire ignition reducing technology, is currently being implemented at this substation. This requires a special protection scheme and coordination with downstream feeder protection from DERs. Interconnection of large generation or energy storage sources could potentially add additional challenge, complexity, and cost to the area.

- *Ripon 1705* – One grid need, located on Vierra 1707. The expected performance and operational requirements include ~5 hour calls for the summer months in the evening hours.

- *Blackwell Bank 1* – One grid need, located on Blackwell Bank 1. Capacity need of a few MW to solve a reverse flow need due to over generation, and day ahead dispatch. The requirement is to increases the load on the bank when solar generation is forecasted to cause a back feed on the bank.

- *Zamora 1108* – One grid need, located on Zamora Bank 1. Zamora Bank 1 has flat, baseload profile with a long duration need of ~14 hours. Due to capacity constraints on Zamora Bank 1, DER bids that cause an increase in loading on the bank will not be viable (e.g., energy storage bids would need an alternative source of charging to be eligible.)
- *Greenbrae Bank 2* – One grid need, located on the Greenbrae Bank 2. Greenbrae has a high number of days per year that DER service is required and will be called on. Despite this requirement, DPAG feedback showed developer interest and

expressed that certain DER technologies may be able to meet this requirement. Therefore, PG&E is requesting to solicit the Greenbrae Bank 2 planned investment based on feedback received from the DPAG meetings and the IPE. The expected performance and operational requirements include long duration need (afternoon to night) and frequent calls needed all year round. Due to capacity constraints on Greenbrae Bank 2, DER bids that cause an increase in loading on the bank will not be viable (e.g., energy storage bids would need an alternative source of charging to be eligible.)

4.3.2. Deferral Term

PG&E determines the term of the deferral to the end of the forecasting period (2030). The terms for the candidate deferral opportunities is based on the expected in-service date as follows:

Candidate Deferral Opportunities	**Deferral Term (Years)**
Willow Pass Bank 1	7
San Miguel Bank 2	7
Calistoga Bank 1	7
Ripon 1705	6
Blackwell Bank1	7
Zamora 1108	7
Greenbrae Bank 2	7

5. Competitive Solicitation Framework

5.1. RFO Schedule

PG&E's RFO schedule is linked to final approval of the Solicitation Process. PG&E plans to conduct the RFO pursuant to the schedule below, assuming CPUC approval has been received. To the extent necessary to ensure a successful RFO and/or successful negotiation and execution of a contract with a DER supplier or suppliers to meet the deferral needs, PG&E reserves the right to request an adjustment to the schedule. PG&E's anticipated RFO schedule is shown in Table 5 below.

Table 5A: PG&E's Anticipated RFO Schedule

(Willow Pass, San Miguel, Calistoga, Ripon~~,~~ Zamora, and Greenbrae)

Date	Activity
Day 0	CPUC Approval of RFO
Day 20	Issue RFO
Day 27	Bidder’s Webinar
Day 50	Offers Due
Day 80	Shortlist
Day 85	Sellers accept shortlist position
Day 165	Complete negotiations and execute transaction
Day 180	File transactions for CPUC approval

Table 5B: PG&E's Anticipated RFO Schedule including IOU Ownership (Blackwell Bank 1[12])

Date	Activity
Day 0	CPUC Approval of RFO
Day 30	Issue RFO
Day 120	Issue detailed specifications and term sheet for IOU ownership
Day 125	Bidder’s Webinar
Day 180	Offers Due
Day 220	Shortlist
Day 225	Sellers accept shortlist position
Day 335	Complete negotiations and execute transaction
Day 365	File transactions for CPUC approval

5.2. Market Outreach

PG&E will conduct market outreach in a similar manner to other recent distribution deferral solicitations (e.g., 2019-20 cycle DIDF RFO). Specifically, PG&E will dedicate a section of its company website to the solicitation, providing a means for interested parties to download the RFO Protocol/Instructions and related materials. PG&E will notify its RFO distribution list, which includes over 2,700 market participants, and will notify the over 240 individuals from the DPAG and CPUC DRP and IDER proceeding service lists that the RFO will be released and invite them to participate.

In addition, PG&E will hold Participants’ webinar to provide an overview of the DIDF solicitations. The webinar will provide potential counterparties an opportunity to learn more about the solicitation, hear presentations, and ask questions. There will be additional opportunities to ask questions via email following the webinar. The Independent Evaluator (IE) will monitor PG&E’s outreach and report on the adequacy of its outreach efforts when the solicitation has been completed.

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[12] Blackwell Bank 1 has been identified as an IOU ownership Candidate Deferral Project

5.3. Project Evaluation Metrics to Select a Bid

PG&E will evaluate individual Offers and/or construct different portfolios of Offers that meet the area need. PG&E's evaluation will apply "least-cost, best-fit" principles, using quantitative and qualitative criteria to evaluate the submitted Offers, which may include, but are not limited to:

Quantitative Attributes:

a) Benefits (Distribution Deferral Value)
b) Fixed and Variable Costs

Qualitative Attributes:

a) Project Viability (experience, technology viability, interconnection, site control)
b) Supply Chain Responsibility
c) Technology, Counterparty Concentration
d) Safety
e) Ability to meet entire need

6. Contingency Plan

PG&E has contingency plans for each of the candidate deferral opportunities recommended for solicitation, based on three different stages of the potential DER deferral:

- *DER Solicitation or Contract Negotiation Stage:* If a contingency such as no cost-effective or combination of cost-effective bids meet the grid need or a change to the forecasted grid need should arise during the solicitation or contract negotiation stage, PG&E will perform a root cause analysis to determine the cause of the failure and the best corrective action. If time and regulatory processes allow, PG&E will consider contracting with alternative bids[13] or administering a revised solicitation. Otherwise, PG&E will move forward with the best alternative wires solution to ensure the safe and reliable provision of distribution services to customers.

- *DER Implementation Stage*: If a contingency such as a failure to meet implementation milestones or achieve operations by the identified grid need date, or a change in the forecasted grid need should arise during the DER implementation stage, PG&E will perform a root cause analysis to determine the cause of the failure and the best corrective action. If time and regulatory processes allow, PG&E will consider administering a revised DER solicitation. Otherwise, PG&E will move forward with the best alternative wires solution to ensure the safe and reliable provision of distribution services to customers.

[13] If third-party DER procurement is unsuccessful, PG&E will consider full or partial IOU-ownership of a DER solution.

- *Commercial Operation Stage:* If a contingency such as a failure of a contracted DER resource to meet the expected performance and operational requirements during the commercial operation stage, PG&E will handle the contingency in the same manner as any other failed equipment. The immediate emergency response may include distribution operations personnel implementing load transfers based on current loading profiles, installation of mobile generation, and/or a plan to interrupt power for local customers as a last resort. The contingency plan beyond the initial 24 hours would consider the area loading, the expected duration of the DER resource failure, any potential transfers that may be available because of recent distribution infrastructure additions or improvements, the installation of temporary facilities such as a mobile transformer bank, and the re-rating of distribution facilities. If a longer-term mitigation is needed, PG&E may move forward with the best alternative wires solution in order to ensure the safe and reliable provision of distribution services to customers.

In order to ensure the safe and reliable provision of distribution services should a contingency arise, the engineering, design and major equipment procurement for the planned investment will continue until contract approval by the Commission of any DER deferral solution. Table 6 below identifies when these activities are expected to start for the planned investments. PG&E will base the contract performance requirements and off ramps on the expected milestones listed below.

Table 6: Expected milestones for planned actives for Planned Investments

Project Name	Project Initiation	Engineering/Design Start Date	Major Equipment Procurement	Construction Start Date	Forecasted In-Service Date
Willow Pass Bank 1	12/1/2020	4/1/2021	8/1/2021	10/1/2022	6/1/2023
San Miguel Bank 2	8/5/2020	4/1/2021	8/1/2021	10/1/2022	5/1/2023
Calistoga Bank 1	5/18/2020	4/1/2021	8/1/2021	10/1/2022	5/1/2023
Ripon 1705	1/1/2020	4/1/2022	8/1/2022	10/1/2023	5/1/2024
Blackwell Bank 1	5/7/2020	4/1/2021	8/1/2021	10/1/2022	5/1/2023
Zamora 1108	9/26/2016	4/1/2021	8/1/2021	10/1/2022	5/1/2023
Greenbrae Bank 1	1/1/2020	4/1/2021	8/1/2021	10/1/2022	4/1/2023

While the DER service requirement would potentially defer the planned investment, it does not provide any margin for load forecast uncertainty. Any increase in the load forecast (e.g., due to new load requests) may result in the solicited DER solution no longer deferring the planned investment. If the grid needs were to increase, the DER service requirement would no longer be sufficient, and the planned investment may no longer be deferred. Additionally, DER resources are procured to meet specific hours and days, and the planned investment may still be required if the timing of the load forecast changes and the grid need is no longer met by the procured resources. Therefore, even if DER resources are procured to meet the specified grid need, the planned “wires” investment may still be required if the load forecast changes and the grid need is no longer met by the procured resources.

PG&E will consider procuring additional DERs if the system needs increases, and if the additional DERs can be procured cost-effectively and still meet the required in-service date. PG&E encourages developers to provide options in their bids for the procurement of DER resources above the minimum performance and/or operational requirements to the extent it is cost effective. PG&E does not plan to change terms of the contract once the contract is executed and approved. PG&E does not plan on cancelling any contracts once the contract is executed and approved by the Commission, even if there is a change in the load forecast and the planned investment is no longer deferred.

7. Recording and Recovery of Procurement Costs

PG&E's preliminary estimate of the cost-effectiveness cap for the Tier 1 candidate deferral opportunities, including the Unit Cost of the Traditional Mitigation, are included in Attachment C. PG&E may revise the initial cost-effectiveness cap shown in the attachment based on additional information, including incremental direct and indirect costs that become available between now and contract execution. Any revisions to the preliminary cost-effectiveness cap calculation shown in the attachment will be included in the Tier 2 advice letter requesting Commission approval of executed contracts for the DIDF.

PG&E requests approval of its incremental administrative costs for its DIDF solicitation, including the solicitation process and other non-procurement costs. The incremental administrative costs approved in this advice letter are considered pre-approved for recording and recovery and will be reviewed by the Commission in PG&E's General Rate Case.[14] Any administrative costs exceeding the forecast approved in this advice letter are subject to a reasonableness review. The annual DER contract costs, having been pre-approved, will be recovered over the life of the contract. For the reasons stated in its comments on the utility regulatory incentive pilot in R.14-10-003 and on D.16-12-036, PG&E is not requesting to apply a four percent (4%) pre-tax incentive to the annual payment for the DER.

PG&E will track all incremental administrative costs of the solicitation, including unavoidable expenditures for commissioning and ongoing testing and verification of the Contract and Contract administrative costs in PG&E's DER Distribution Deferral Account (Electric Preliminary Statement Part GZ). Pursuant to PG&E's contingency plan as specified in Section 6 above and the May 2019 ALJ Ruling, contingency costs, including unavoidable expenditures (e.g., design and engineering) on any planned wires-related investments, will also be tracked and recorded in the DER Distribution Deferral Account.

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[14] The proposed ratemaking treatment for incremental administrative costs associated with PG&E's DIDF Solicitation is consistent with D.16-12-036 and OP 2. aa of D.18-02-004.

8. Commission Action Requested

Pursuant to D.18-02-004, PG&E requests that the Commission approve issuance of a CSF RFO to procure DERs for the seven Tier 1 candidate distribution deferral sites.

Tariff Revisions

The filing would not increase any current rate or charge, cause the withdrawal of service, or conflict with any rate schedule or rule.

Protests

*****Due to the COVID-19 pandemic and the shelter at home orders, PG&E is currently unable to receive protests or comments to this advice letter via U.S. mail or fax. Please submit protests or comments to this advice letter to EDTariffUnit@cpuc.ca.gov and PGETariffs@pge.com*****

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than December 7, 2020, which is 21 days after the date of this submittal.[15] Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000

[15] The 20-day protest period concludes on a weekend; therefore, PG&E is moving this date to the following business day.

San Francisco, California 94177

Facsimile: (415) 973-3582
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

PG&E requests that this Tier 2 compliance advice submittal become effective on regular notice, December 16, 2020, which is 30 calendar days after the date of submittal or, if necessary, the date of the Commission Resolution approving the advice letter.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service lists for R.14-08-013 and R.14-10-003. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Erik Jacobson
Director, Regulatory Relations

Attachments
Attachment A – Candidate DER Distribution Deferral Prioritization Metrics (Confidential)
Attachment B – Location of Needs
Attachment C – Unit Cost of Traditional Mitigation and Preliminary Estimate of Cost-Effectiveness Cap
Attachment D – IPE DPAG Report (Confidential)[16]

[16] Attachments to the IPE Report are large in size and will be provided upon request to PG&E and may be subject to a non-disclosure agreement.

cc: Service Lists R.14-08-013 and R.14-10-003
Gabe Petlin – Energy Division
Robert Peterson – Energy Division

ADVICE LETTER SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U 39 E)

Utility type:
- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Stuart Rubio
Phone #: (415)973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: SHR8@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6002-E Tier Designation: 2

Subject of AL: Request for Approval to Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities

Keywords (choose from CPUC listing): Compliance

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.18-02-004

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☑ Yes ☐ No

If yes, specification of confidential information: See Confidentiality Declaration
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information: Quinn Nakayama, (415-973-3732, QJN1@pge.com)

Resolution required? ☐ Yes ☑ No

Requested effective date: 12/16/20 No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Name: Erik Jacobson, c/o Megan Lawson
Title: Director, Regulatory Relations
Utility Name: Pacific Gas and Electric Company
Address: 77 Beale Street, Mail Code B13U
City: San Francisco, CA 94177
State: California Zip: 94177
Telephone (xxx) xxx-xxxx: (415)973-2093
Facsimile (xxx) xxx-xxxx: (415)973-3582
Email: PGETariffs@pge.com

Name:
Title:
Utility Name:
Address:
City:
State: District of Columbia Zip:
Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email:

Clear Form

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECLARATION SUPPORTING CONFIDENTIAL DESIGNATION
ON BEHALF OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

1. I, Quinn Nakayama, am the Director of Integrated Grid Planning & Innovation at Pacific Gas and Electric Company ("PG&E"), a California corporation. Fong Wan, the Senior Vice President of Energy Policy and Procurement at PG&E, delegated authority to me to sign this declaration. My business office is located at:

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105

2. PG&E will produce the information identified in paragraph 3 of this Declaration to the California Public Utilities Commission ("CPUC") or departments within or contractors retained by the CPUC in response to a CPUC audit, data request, proceeding, or other CPUC request.

   Name or Docket No. of CPUC Proceeding (if applicable): R.14-08-013

3. Title and description of document(s): Advice Letter 6002-E; Advice Letter 6002-E: Attachment A, Attachment D.

4. These documents contain confidential information that, based on my information and belief, has not been publicly disclosed. These documents are marked as confidential, and the basis for confidential treatment and where the confidential information is located on the documents are identified on the following chart.

Check	Basis for Confidential Treatment	Where Confidential Information is located on the documents
☒	Customer-specific data, which may include demand, loads, names, addresses, and billing data (Protected under PUC § 8380; Civ. Code §§ 1798 *et seq.*; Govt. Code § 6254; Public Util. Code § 8380; Decisions (D.) 14-05-016, 04-08-055, 06-12-029)	Grey-shaded information in Advice Letter 6002-E; Advice Letter 6002-E: Attachment A, Attachment D
☐	Personal information that identifies or describes an individual (including employees), which may include home address or phone number; SSN, driver's license, or passport numbers; education; financial matters; medical or employment history (not including PG&E job titles); and statements attributed to the individual (Protected under Civ. Code §§ 1798 *et seq.;* Govt. Code § 6254; 42 U.S.C. § 1320d-6; and General Order (G.O.) 77-M)	
☐	Physical facility, cyber-security sensitive, or critical energy infrastructure data, including without limitation critical energy infrastructure information (CEII) as defined by the regulations of the Federal Energy Regulatory Commission at 18 C.F.R. § 388.113 (Protected under Govt. Code § 6254(k), (ab); 6 U.S.C. § 131; 6 CFR § 29.2)	
☐	Proprietary and trade secret information or other intellectual property and protected market sensitive/competitive data (Protected under Civ. Code §§3426 *et seq.*; Govt. Code §§ 6254, *et seq.*, e.g., 6254(e), 6254(k), 6254.15; Govt. Code § 6276.44; Evid. Code §1060; D.11-01-036)	
☐	Corporate financial records (Protected under Govt. Code §§ 6254(k), 6254.15)	

☐	Third-Party information subject to non-disclosure or confidentiality agreements or obligations (Protected under Govt. Code § 6254(k); see, e.g., CPUC D.11-01-036)	
☐	Other categories where disclosure would be against the public interest (Govt. Code § 6255(a))	

5. The importance of maintaining the confidentiality of this information outweighs any public interest in disclosure of this information. This information should be exempt from the public disclosure requirements under the Public Records Act and should be withheld from disclosure.
6. I declare under penalty of perjury that the foregoing is true, correct, and complete to the best of my knowledge.
7. Executed on this 16th day of November, 2020 at San Francisco, California.

/s/

Quinn Nakayama
Director, Integrated Grid Planning & Innovation
Pacific Gas and Electric Company

PACIFIC GAS AND ELECTRIC COMPANY

Attachment A

Attachment A - Candidate DER Distribution Deferral Prioritization Metrics

(Public Version)

Attachment A - Candidate DER Distribution Deferral Prioritization Metrics

Table 1: Candidate Distribution Deferral Prioritization Metrics

Tier	Candidate Deferral[1]	In-Service Date	Deficiency (MW)[2]	Cost Effectiveness	Forecast Certainty	Market Assessment
1	Willow Pass Bank 1	2023	5.3			
	San Miguel Bank 2	2023	5.0			
	Calistoga Bank 1	2023	4.2			
	Ripon 1705	2024	3.7			
	Blackwell Bank 1	2023	CC			
	Zamora 1108	2023	1.1			
	Greenbrae Bank 2	2023	CC			
2	Dunnigan Bank 1	2024	1.6			
	Beresford 401 Cut-Over	2023	1.5			
	Brentwood 2111 Line Work	2023	0.9			
	Hollister 2106 Line Work	2023	5.0			
	Rocklin 1104 and Rocklin 1101	2025	0.2			
	Caruthers 1104 Regulator	2023	0.7			
	Morgan Hill 2103	2023	6.6			
	Storey 1103	2023	3.2			
	Vasona 1109	2023	3.9			
	Peabody 2106 Outlet	2024	CC			
	Stelling 1105	2023	4.6			
	Mountain View Bank 1	2023	5.7			
3	San Luis Obispo 1106	2023	CC			
	Woodland 1105 Outlet	2025	1.3			
	Lockeford Bank 1	2024	14.8			
	Semitropic 1112 Line Work	2024	8.1			
	California Ave 1103 & California Ave 1111 Line Work	2023	CC			
	Wolfe 1111 & Wolfe 1112	2023	44.1			
	FMC 1102	2023	6.7			
	Rincon Bank 1	2023	8.0			
	Spence Bank 2	2023	CC			

[1] Belle Haven Bank 4 candidate deferral project was cancelled due to a large load application after GNA/DDOR publication and the planned investment no longer exists. Distribution planning will need to identify new Planned Investment(s) to meet the need in the area

[2] Banks and feeders with peak loads listed as "CUSTOMER CONFIDENTIAL" or "CC" were redacted due to their peak loads violating the 15-15 customer privacy rule. A 15-15 violation occurs if the load is comprised of less than 15 customers or a single customer contributes to more than 15% of the loading value

Table 2: Detailed Candidate Distribution Deferral Prioritization Metrics

Candidate Deferral	Cost Effectiveness			Forecast Certainty			Market Assessment				
	Unit Cost of Traditional Mitigation ($k)	Estimated LNBA ($/kW-yr)	Estimated LNBA ($/MWh-yr)	Forecasted Need (Year)	SCADA Available (Y/N)	Project Uncertainty Risk Score	Real Time (RA) or Day Ahead (DA)	Number of Grid Needs	Calls/ Year	Hours/Call	Deficiency (%)
Hollister 2106 Line Work	$500	$5.35	$20.75	2023	Y	14	DA	1	43	6	11%
Spence Bank 2	$9,000	$46.91	$53.23	2020	Y	23	DA	4	CC	CC	CC
Wolfe 1111 & Wolfe 1112	$8,600	$21.36	$2.89	2020	Y	14	DA	2	365	24	238%
Vasona 1109	$1,650	$46.20	$13.12	2020	Y	14	DA	3	257	18	25%
Stelling 1105	$3,756	$43.51	$35.45	2020	Y	18	DA	3	236	9	19%
Mountain View Bank 1	$6,000	$55.02	$56.37	2020	Y	24	DA	1	122	8	19%
Brentwood 2111 Line Work	$80	$10.08	$240.03	2023	Y	8	DA	1	21	2	4%
Willow Pass Bank 1	$14,741	$194.62	$337.42	2020	Y	22	DA	2	101	6	17%
Caruthers 1104 Regulator	$110	$8.45	$938.49	2023	Y	13	DA	1	9	1	6%
California Ave 1103 & California Ave 1111 Line Work	$660	$8.08	$7.96	2023	Y	9	DA	4	CC	CC	CC
Semitropic 1112 Line Work	$34	$0.22	$0	2024	Y	14	DA	1	168	6	33%
San Miguel Bank 2	$9,700	$138.09	$151.04	2020	Y	15	DA	3	122	10	22%
San Luis Obispo 1106	$3,130	$60.00	$11.00	2022	Y	14	DA	2	CC	CC	CC
Greenbrae Bank 2	$6,000	$114.67	$52.84	2021	Y	18	DA	1	CC	CC	CC
Beresford 401 Cut-Over	$1,000	$35.83	$64.13	2020	Y	6	DA	2	145	5	17%
Peabody 2106 Outlet	$110	$2.16	$1.37	2022	Y	2	DA	1	CC	CC	CC
Dunnigan Bank 1	$8,000	$257.41	$861.19	2020	Y	26	DA	2	91	5	11%
Woodland 1105 Outlet	$125	$5.11	$13.90	2025	Y	6	DA	1	92	4	10%
Zamora 1108	$1,200	$61.21	$97.15	2020	Y	14	DA	1	45	14	11%
FMC 1102	$1,700	$27.46	$217.91	2020	Y	15	RT	1	9	14	31%
Morgan Hill 2103	$2,100	$34.27	$73.03	2020	Y	17	DA	2	100	6	13%
Rocklin 1104 and Rocklin 1101	$150	$34.87	$335.29	2021	Y	10	DA	1	52	2	2%
Rincon Bank 1	$10,000	$64.89	$14.99	2020	Y	24	DA	2	340	20	29%
Ripon 1705	$2,200	$63.07	$123.68	2023	Y	14	DA	1	102	5	22%
Storey 1103	$2,200	$37.40	$89.35	2020	Y	12	DA	3	105	5	16%
Blackwell Bank 1	$6,000	$106.83	$53.96	2020	Y	16	DA	1	CC	CC	CC
Calistoga Bank 1	$7,340	$91.61	$126.51	2021	Y	16	DA	2	122	8	23%
Lockeford Bank 1	$6,000	$20.67	$35.88	2021	Y	6	RT	1	12	48	50%

PACIFIC GAS AND ELECTRIC COMPANY

Attachment B

Location of Needs

(Public)

Attachment B
Location of Needs

Location of Candidate DIDF Solicitation Sites:

Figure 1: Map of Candidate Deferral Opportunity Locations

DISCLAIMER: Locations shown on these map images are for informational purposes only. This does not guarantee interconnection approval. This does not prevent the need for required upgrades and associated costs for interconnection.

Willow Pass Bank 1 Candidate Deferral Location Map:

Figure 2: Map of grid need locations for Willow Pass Bank 1 and Willow Pass Bank 3

DISCLAIMER: Locations shown on these map images are for informational purposes only. This does not guarantee interconnection approval. This does not prevent the need for required upgrades and associated costs for interconnection.

San Miguel Bank 1 Candidate Deferral Location Map:

Figure 3: Map of grid need locations for San Miguel Bank 1 and Paso Robles 1107

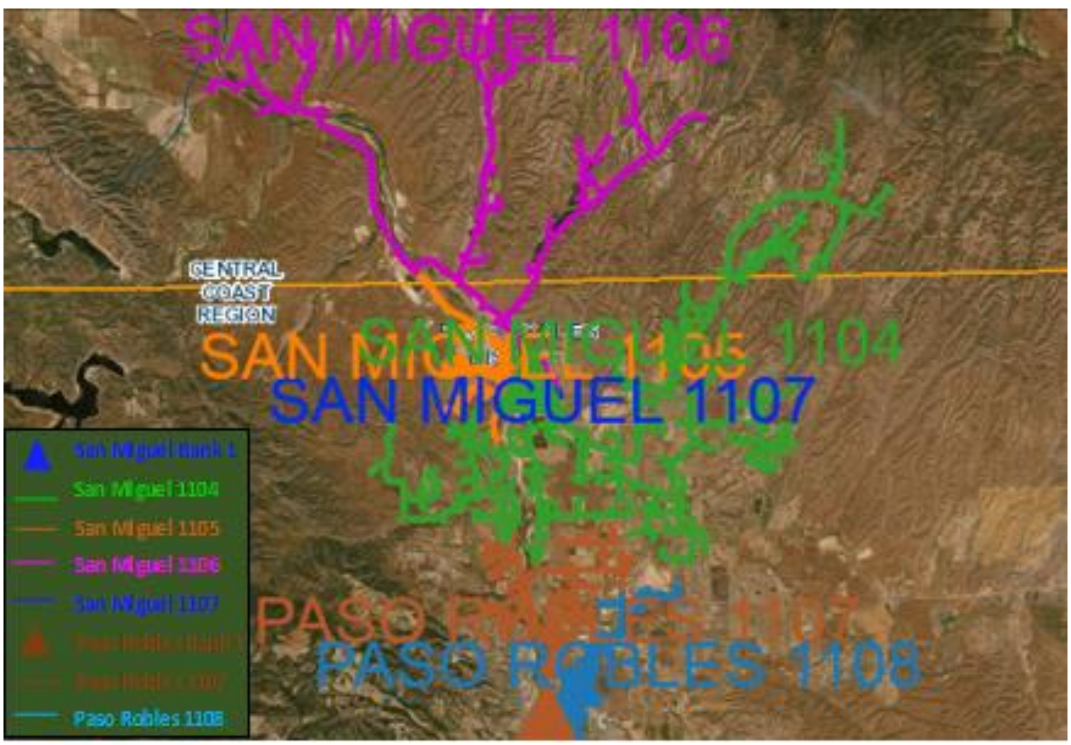

Figure 3a: Map of locations for San Miguel Bank 1 with the associated feeders, and Paso Robles Bank 3 with the associated feeders

DISCLAIMER: Locations shown on these map images are for informational purposes only. This does not guarantee interconnection approval. This does not prevent the need for required upgrades and associated costs for interconnection.

Calistoga Bank 1 Candidate Deferral Location Map:

Figure 4: Map of grid need locations for Calistoga Bank1 and Calistoga 1102

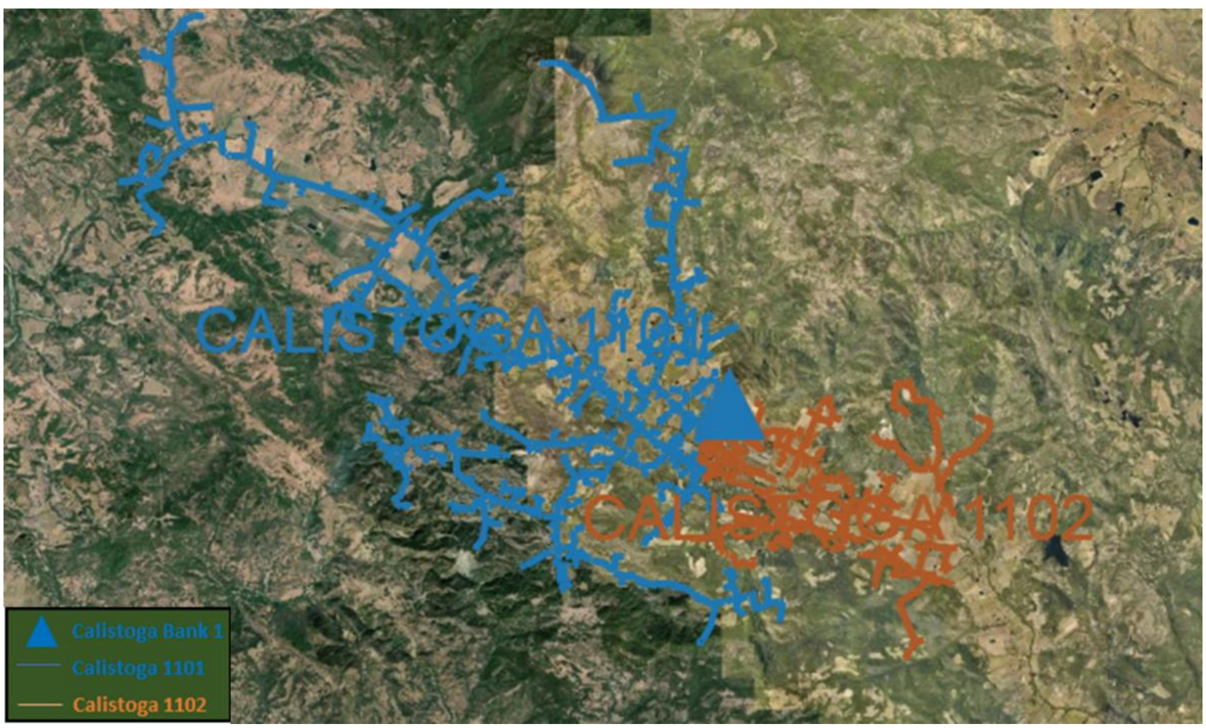

Figure 4a: Map of locations for Calistoga Bank 1 and the associated feeders

DISCLAIMER: Locations shown on these map images are for informational purposes only. This does not guarantee interconnection approval. This does not prevent the need for required upgrades and associated costs for interconnection.

Ripon 1705 Candidate Deferral Location Map:

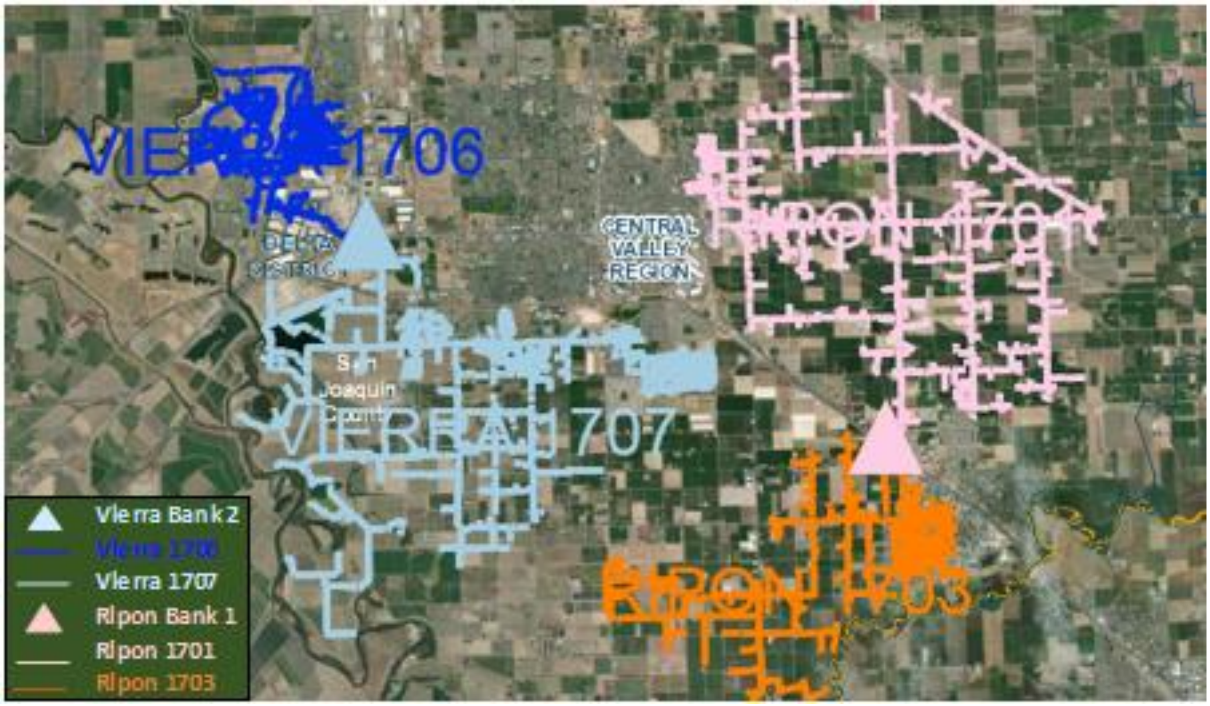

Figure 5: Map of grid need location (Vierra 1707) for Ripon 1705 (new feeder)

Blackwell Bank 1 Candidate Deferral Location Map:

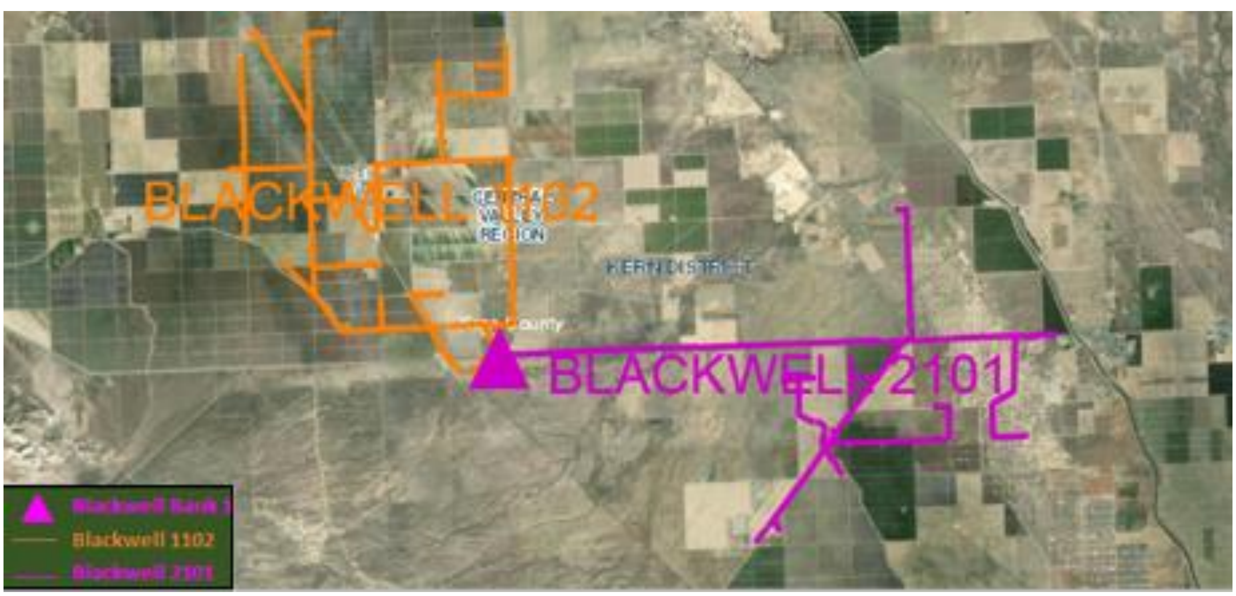

Figure 6: Map of grid need location for Blackwell Bank 1 and associated feeders

DISCLAIMER: Locations shown on these map images are for informational purposes only. This does not guarantee interconnection approval. This does not prevent the need for required upgrades and associated costs for interconnection.

Zamora Candidate Deferral Location Map:

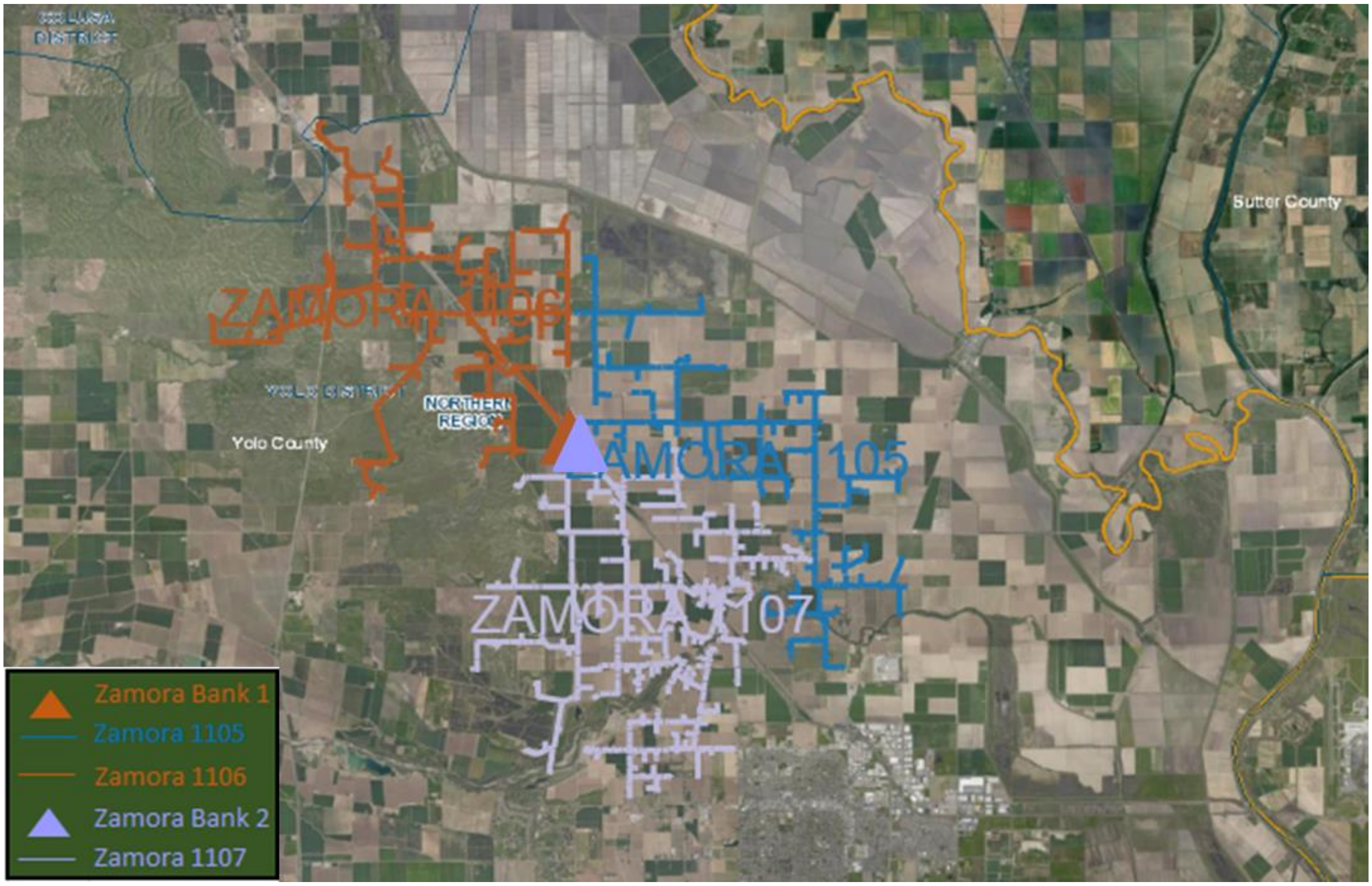

Figure 7: Map of grid need location (Zamora Bank1) for Zamora 1108 (new feeder)

DISCLAIMER: Locations shown on these map images are for informational purposes only. This does not guarantee interconnection approval. This does not prevent the need for required upgrades and associated costs for interconnection.

Greenbrae Bank 2 Candidate Deferral Location Map:

Figure 7: Map of grid need location for Greenbrae Bank 2 and associated feeders

DISCLAIMER: Locations shown on these map images are for informational purposes only. This does not guarantee interconnection approval. This does not prevent the need for required upgrades and associated costs for interconnection.

PACIFIC GAS AND ELECTRIC COMPANY

Attachment C

Unit Cost of Traditional Mitigation and Preliminary Estimate of Cost-Effectiveness Cap

(Public)

Attachment C - Unit Cost of Traditional Mitigation and Preliminary Estimate of Cost-Effectiveness Cap

The preliminary cost effectiveness cap is based on the indicative deferral value calculated using the Real Economic Carrying Charge (RECC) methodology as described in PG&E's Demo B final report, section 8.2,[1] using the following inputs:

- Capital upgrade unit cost: See table below
- Revenue Requirement Multiplier (Fixed Costs):
  - 134.8% for substation equipment
  - 138.38% for primary feeders
- Revenue Requirement Multiplier with Operation and Maintenance (O&M):
  - 182.17% for substation equipment
  - 278.98% for primary feeders
- Discount Rate (After Tax Weighted Cost of Capital (ATWACC))[2]: 6.79%
- Equipment inflation: 2.5%
- O&M Inflation Rate: 2.5%
- Annual O&M of deferred upgrade as a % of upgrade cost:
  - 2.52% for new substation equipment
  - 7.48% for new primary feeder
  - 0% for replacing existing equipment
- Book life of capital asset: 46 years
- Deferral time frame: Based on deferring projects until the end of the planning window

Table 1: Preliminary Deferral Value for Candidate Deferral Opportunities

Project	Project Cost ($000s)	Deferral Time Frame	Deferral Value in 2020 ($000s)
Willow Pass Bank 1	$14,741	7 years	$7,032
San Miguel Bank 2	$9,700	7 years	$4,644
Calistoga Bank 1	$7,340	7 years	$2,600
Ripon 1705	$2,200	6 years	$1,353
Blackwell Bank 1	$6,000	7 years	$2,125
Zamora 1108	$1,200	7 years	$436
Greenbrae Bank 2	$6,000	7 years	$2,133

PG&E proposes to set the initial cost-effectiveness cap at the deferral value for each candidate deferral opportunity shown in Table 1 above. PG&E may revise the initial cost-effectiveness cap shown in the attachment based on additional information, including regarding incremental direct and indirect costs, that becomes available between now and contract execution.

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[1] http://drpwg.org/wp-content/uploads/2016/07/R1408013-PGE-Demo-Projects-A-B-Final-Reports.pdf

[2] As a result of emerging from bankruptcy, PG&E's long-term debt rate declined from 5.16 to 4.17%. As a result, the new ATWACC is 6.79%

PG&E will continue planning and designing the planned investment until CPUC approval of any executed DER deferral contracts. Charges for these activities will be subtracted from the deferral value and will be recorded appropriately for future recovery. Any revisions to the preliminary cost-effectiveness cap calculation shown in the attachment will be included in the Tier 2 advice letter requesting Commission approval of executed contracts for the DIDF.

Preliminary Estimate of Administrative Costs Associated with the DIDF Solicitations

PG&E's preliminary estimate of administrative costs associated with the DIDF are based on the estimate of administrative costs for the IDER Incentive pilot approved in Resolution E-4956.[3] The actual administrative costs will be recovered via the memorandum account in PG&E's General Rate Case. The table below provides PG&E's preliminary estimate of administrative costs per candidate deferral opportunity.

Table 2: Preliminary estimate of administrative costs.

Milestone No.	Work Scope/Activity	Category	Schedule* (months are additive)	Preliminary Budget
1	CPUC Approval		December 2020 (if decision is later, project viability and schedule may change)	
2	Develop/Administer Competitive Solicitation	Solicitation	+4 months from milestone No. 1	$1,250,000
3	CPUC Approval of Contract(s)	Solicitation Approval	+8 months from milestone 2	
4	Commissioning and Ongoing Testing and Verification of Deployed DERs	Commissioning + Ongoing Testing and Verification	+18 months from milestone 3	$500,000
5	Ongoing Project and Contract Management Costs ($100,000 per year)			$700,000*
Total				**$2,450,000[4]**

[3] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M235/K815/235815737.PDF

[4] Assumes seven-year contract term. A contract with a six-year term would have an estimate $100,000 less.

PACIFIC GAS AND ELECTRIC COMPANY

Attachment D

Independent Professional Engineer PG&E 2020 DPAG Report

(Public Version)

REPORT

Independent Professional Engineer PG&E 2020 DPAG Report

PUBLIC VERSION

Submitted to California Public Utilities Commission Energy Division and PG&E

November 16, 2020

Statement of Confidentiality

The CPUC made provision for the Investor Owned Utilities to request confidentiality treatment for certain data submitted in their GNA/DDOR reports or other material provided to the IPE that is contained in this report. PG&E has designated certain data in this report to be confidential. Thus, this PUBLIC VERSION of the report can be distributed to any interested party. Note there is some data that is cited in this report that is confidential as a result of the application of the 15/15 rule and some that is confidential because it is business confidential. All such confidential data is redacted in the Public Version of the report.

In summary, this PUBLIC VERSION of the report can be distributed to anyone.

Contents

1 Introduction and Background

Summary of CPUC April 13, 2020 Rulemaking 14-08-013

The paragraphs that follow summarize the parts of the April 13, 2020 CPUC ruling that directly impact the role of the IPE and/or this report.

The Ruling modified the Distribution Investment Deferral Framework (DIDF) process and filings with respect to the Independent Professional Engineer (IPE) scope of work and provided the updated 2020-2021 DIDF cycle schedule. In its Attachments A and B are included a listing of the IPE-specific reforms discussed in the Ruling and the updated IPE scope of work. These attachments of the ruling are attached as Appendices A of this report.

In Decision 18-02-004, the Commission adopted the DIDF. Building upon the Competitive Solicitation Framework developed in the companion Integration of Distributed Energy Resources proceeding, the DIDF established an ongoing annual process to identify, review, and select opportunities for third party-owned distributed energy resources (DERs) to defer or avoid traditional capital investments by the investor-owned utilities (IOUs) on their electric distribution systems. Decision 18-02-004 ordered the IOUs to implement the DIDF as an annual planning cycle that would result in the selection of distribution upgrades for deferral through the competitive solicitation of DERs.

The DIDF was implemented in 2018 and 2019 with the expectation that it would be evaluated and revised after each cycle to improve the process. To that end, the assigned Administrative Law Judge (ALJ) issued a Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process on February 25, 2019 (February 25, 2019 Ruling). Based on these comments, the ALJ issued a Ruling Modifying the Distribution Investment Deferral Framework Process on May 7, 2019 (May 7, 2019 Ruling). The parties have proposed additional recommendations for DIDF reform throughout the 2019 DIDF cycle. A Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process was subsequently issued on November 8, 2019 (November 8, 2019 Ruling), and the contents of this Ruling further modify the DIDF. A Ruling on May 11. 2020 modified the DIDF filing and process requirements including proposing a number of possible reforms to the DIDF.

The IPE scope of work outlined in Appendix A provides for improvement to the IPE review process based on comments received and clarifies that the development of IPE review plans for each IOU will be overseen and approved by Energy Division. According to the Ruling, it is important the IPE has sufficient time to prepare the IPE Plans in advance of the GNA/DDOR filings and that after the filings, the IPE has the cooperation and coordination of the IOUs necessary to collect the data needed for review in time to prepare the IPE Preliminary Analysis of GNA/DDOR Data Adequacy and IPE DPAG Report.

The revised IPE scope reflected in Ruling 14-08-013 includes the requirement to develop an IPE Plan that will cover most if not all of the IPE activities. A copy of the Final IPE Plan for PG&E is included in Appendix C.

According to the Ruling, planning standards that lead to the identification of reliability needs need not be reviewed at this time. Instead, the IOUs should provide the IPE with planning documentation that supports the identification of all reliability needs. At this time, a formal review of IOU planning standards is not required as it could be a significant undertaking. However, the Ruling states that the Energy Division should discuss the 2020 GNA/DDOR filings with the IPE to determine if inconsistencies and shortcomings in the IOU planning standards exist and whether further review should be prioritized for future DIDF cycles.

The Ruling goes on to state to further assist the IPE with DPAG Report completion, a new IPE Post-DPAG Report deliverable is included within the IPE scope of work. The IPE Post-DPAG Report should review and compare overall IOU DIDF compliance and make recommendations for process improvements and DIDF reform.

As stated in the May 7, 2019 Ruling, the IPE shall report directly to Energy Division to prepare its deliverables and conduct its analyses for DIDF implementation. The term of the IPE scope of work shall be the entire DIDF cycle, which starts on January 1 each year to plan for Pre-DPAG and DPAG implementation and concludes on July 31 the following year after all RFOs are concluded and all DIDF reforms are implemented. As a result, IPE scopes of work for each DIDF cycle will overlap.

The schedule and milestones established by the April 13, 2020 Ruling are shown below.

DPAG Schedule for 2020-2021 DIDF Cycle

Activity	Date
Pre-DPAG 2020	
Pre-DPAG meetings and workshops, including Draft IPE Plans review	May 2020
DPAG 2020	
IOU GNA / DDOR filings, Final IPE Plans circulated	August 15, 2020
IOUs update DRP Data Portals with GNA / DDOR data	August 30, 2020
IPE Preliminary Analysis of GNA / DDOR data adequacy circulated	September 5, 2020
DPAG meetings with each IOU	September 15, 2020 (week of)
Participants provide questions and comments to IOUs and IPE	September 25, 2020

IOU responses to questions	October 5, 2020
Follow-up IOU meetings via webinar	October 10, 2020 (week of)
IPE DPAG Reports	October 25, 2020
DIDF Advice Letters submitted	November 15, 2020
Post-DPAG 2020 and 2021	
Provide draft RFO launch materials to Energy Division for approval in consultation with IPE and IE	December 10, 2020
Launch RFOs for DERs	January 15, 2021 (or within 30 days of DIDF Advice Letter approval if approval is after December 15, 2020)

Independent Professional Engineer

The California Public Utilities Commission (Commission) rulings direct Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities or IOUs) to enter into a contract with an Independent Professional Engineer (IPE). The role of the IPE is as previously described.

Through a contract with Nexant, Inc., PG&E engaged Mr. Barney Speckman[1], PE, to serve as the advisory engineer (referred to as the Independent Professional Engineer (IPE)) for the scope described in the April 23, 2020 CPUC Ruling.

This report which meets the requirements included in the CPUC ruling was provided to PG&E in sufficient time to be included in their DIDF Advice Letter.

1.1 IPE Plan

As required by the April 23, 2020 Ruling, the IPE developed an IPE Plan that served to guide the IPE's steps to implement its 2020 IDIF work scope. The plan was developed using a three step process:

1. In step 1 the IPE developed a draft IPE Plan working with the Energy Division and PG&E by mid-May 2020.

[1] Consistent with the CPUC decision, the contract with Nexant Inc. the firm where Mr. Speckman is employed provides for other individuals within Nexant to assist Mr. Speckman to perform the work in the IPE contract provided that these other individuals are also bound by the same confidentiality and conflict of interest requirements that Mr. Speckman is required to meet.

2. The Plan was distributed to the service list and also discussed at the CPUC Distribution Forecasting Working Group meeting - both in an attempt to obtain stakeholder feedback on the plan.

3. Based upon stakeholder feedback received and under the direction of the Energy Division, the IPE revised the plan and made its IPE Final Plan available on August 15, 2020.

A copy of the Final IPE Plan is included as Appendix C.

The IPE Plan covers the business processes that the IOUs use to identify which distribution or subtransmission projects are recommended to proceed to an RFO seeking DER bids to determine if there is a cost effective non-wires alternative. One of the core purposes of the plan is to answer the question - Are the IOUs identifying every project that could feasibly and cost effectively be deferred by DERs?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2019, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level adjusted for known loads then used to determine if there is an overload or other issue during the planning period. For circuits that have a need, a planned investment is selected, capital costs developed for that project and the planned investments are screened to develop a list of candidate deferral projects. These candidate deferral projects are then prioritized into tiers using several metrics with the projects in the first tier normally recommended for a DER RFO.

1.2 Definitions of Verification and Validation

As part of the development of the IPE Plan, detailed definitions were developed to clarify the meaning of Verification and Validation as applied to the IPE scope of work. These definitions which are used and applied in all IPE deliverables, are listed below:

Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words “Did the IOU follow their own processes correctly as defined by the IOU?”

Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics and business perspective. In other words “Are the processes implemented by the IOU the best way to identify all planned investments that could feasibly be deferred by DERs cost effectively? And to what extent were the IOU methodologies appropriate and effective?”

1.3 Services Considered within the DDOR Framework

The CPUC, in a previous decision[2], approved the four services proposed by the Competitive Solicitation Framework Working Group (CSFWG) and directed the utilities to consider these services in the GNA/DDOR process. The four services as described in the decision are listed below in an excerpt from the decision:

> "The following definitions for the key distribution services that distributed energy resources can provide are adopted for the Competitive Solicitation Framework:
>
> Distribution Capacity services are load-modifying or supply services 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 net loading on desired distribution infrastructure;
>
> Voltage Support services are substation and/or feeder level dynamic voltage management services 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;
>
> 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; and
>
> Resiliency (micro-grid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations."

1.4 Approach to Information Collection

The information reflected in this report was obtained through a number of methods including:

- Participation by the IPE in the CPUC sponsored 2020 Distribution Forecasting Working Group held on May 21, 2020.
- Special conference calls with PG&E were held to perform Verification and/or Validation Demonstration walk-throughs as described in the IPE Plan and whose results are described later in the report.
- Written data requests sent to PG&E regarding their planning process that led to the needs identified in their GNA Report and the projects included in their DDOR Report.

[2] Decision 16-12-036; definitions can be found on Page 8. Link to document below: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF

Responses from PG&E were made during follow up conference calls or in writing. A copy of written requests and written responses are included as Appendix D.

- Participation in PG&E's DPAG meeting (September 16) and its follow up DPAG Webinar (October 12).
- A review of publicly available materials referred to in the discussions with PG&E or materials previously filed with the CPUC.

1.5 Report Contents

The remainder of this report includes the following sections:

- **Section 2** – Review of GNA Report which briefly discusses the contents of the PG&E GNA Report and any significant differences noted in PG&E's reports between the 2020 and 2019 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the GNA Report are included in this section.
- **Section 3** – Review of DDOR Report which briefly discusses the contents of the PG&E DDOR Report and any significant differences noted in PG&E's reports between the 2020 and 2019 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the DDOR Report are included in this section.
- **Section 4** – Review of Screening and Prioritization which discusses the screening and prioritization process and results. Observations, comments, and recommendations that result from the Validation review with respect to the screening and prioritization are included in this section.
- **Section 5** – Review of Candidate Deferral Projects which includes the review of projects that have been placed into the Tiers defined by PG&E. Observations, comments, and recommendations that result from the Validation review with respect to the placement of projects in the PG&E defined Tiers are included in this section.
- **Section 6** – Discussion of Other Topics of Interest. Observations, comments, and recommendations that result from the Validation review with respect to these topics are included in this section.
- **Section 7** – Verification completed which reviews the approach and results of the verification performed by the IPE.
- **Appendix A** – IPE Scope - Excerpt from April 23, 2020 CPUC Rulemaking 14-08-013.
- **Appendix B** - Comments Received from the DPAG Members and IOU and IPE responses.
- **Appendix C** – IPE Final IPE Plan - PG&E
- **Appendix D** - PG&E Data Requests and Responses

Confidential Information

There are a number of instances where information is confidential and such information is highlighted in the confidential version of the Report and blacked out (redacted) in the Public Version of the Report. These are data elements that are considered confidential by PG&E because they are entries for projects that meet the 15/15 Rule. They include, but are not limited to, such things as GNA and DDOR report appendices, PV and LMDR profiles, Distribution Engineer questionnaires, charging and discharging, and disaggregation information, etc.

2 Review of GNA Report

The GNA Report submitted by PG&E is summarized at a high level below.

2.1 Scope of PG&E's GNA/DDOR Reports

The PG&E Grid Needs Assessment (GNA) Report is a written report including an Excel data base of potential grid needs on its distribution system. A corresponding DDOR Distribution Deferral Opportunity Report (DDOR) was completed summarizing the mitigation efforts required to meet the needs identified in the GNA. PG&E filed its GNA and DDOR Reports on August 17, 2020 as required by the CPUC. A supplemental filing to the DDOR report is being filed due to the extension granted on reform items 16, 47, and 50 of the May 2020 DIDF Improvements Ruling.

2.2 Summary of PG&E's 2020 GNA Report

The GNA covers all substations, distribution circuits and includes circuit/segment level information for which needs have been identified after no-cost load transfers have been reflected in load forecasts. The GNA Excel spreadsheet for PG&E includes 582 separate grid needs. The needs listed included the following information:

- Service Required – Capacity, Voltage Support, Reliability (back-tie), Resiliency (Microgrid);
- Primary Driver of Grid Need – driven by Demand Growth, Voltage or Reliability/other;
- Rating – Element, Rating and Units; and
- Deficiencies – in MW, MVAR, or Vpu and %.

2.3 Changes to GNA for 2020

The 2019 GNA included an evaluation of the needs for all substation, distribution feeders, and feeder segments after the application of planned load transfers. In the 2020 GNA, rather than identifying all line segments, only the circuit line segments which have needs during the planning period after the application of planned no-cost load transfers are identified.

2.4 Discussion Related to Needs

2.4.1 Needs and In-service or Operational Dates

A summary of needs and associated in-service or operational dates can be seen in Table 2-1 and Table 2-2, which are tables included in PG&E's GNA Report and duplicated here for convenience.

Table 2-1: Summary of Grid Needs by Distribution Service and Project Type

Facility Type	Distribution Service				Total
	Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency (Microgrid)	
Substation /Bank	109	0	7	1	**117**
Feeder	187	0	25	0	**212**
Distribution Line	142	100	11	0	**253**
Totals	**438**	**100**	**43**	**1**	**582**

Table 2-2: Summary of All Grid Needs by Anticipated Need Date

Anticipated Need Date					Total
2020	2021	2022	2023	2024	
409	92	40	28	13	**582**

2.4.2 Line Segment Needs

The 2019 GNA had 6,994 needs, of which 6,795 were Distribution Line needs. The 2020 GNA implemented the new line segment methodology per Reform 14 of Attachment A of the May 2020 DIDF Reforms Ruling. PG&E's 2020 GNA includes only the circuit segments for which the peak needs are listed, rather than all line segments as in 2019. The line segment with the worst need solved by an individual project is the one shown, rather than the hundreds of line sections with voltage issues resolved by the same project.

2.4.3 Specific Reliability Criteria Projects

Per the PG&E Guide for Planning Distribution Facilities, once the load forecasts are complete, the Distribution Engineer reviews the banks and feeders for adherence to company standards and goals. Bank capacities are provided in PG&E document TD-1004P- 05. Per that document, normal bank capacity is 100% of nameplate for summer months and 120% for winter months. Emergency ratings are 130% of nameplate for summer months and 150% in winter months. In urban and suburban areas, normal 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 6,000. In the past PG&E had identified projects to reduce the circuit loading to less than 6,000 amps and to reduce the number of customers on a circuit or lateral by creating a back-tie. In the 2020 DDOR, PG&E identified 39 reliability projects but only one, FMC1102, meet the screening requirements for further consideration. It was ranked a Tier 3 opportunity and not reviewed as part of this report. Reliability projects are often short term and/or discretionary and do not pass the timing screen.

2.4.4 Planned Investments for DER-Driven Needs

PG&E has two planned investments for a DER driven capacity need - Blackwell Bank 1 (DDOR178) and Huron Bank 1 (DDOR036). The Blackwell Bank 1 Planned Investment is a replacement/upgrade of the Blackwell Bank 1 at the Blackwell Substation and the Huron Bank 1 Planned Investment is a replacement/upgrade of Huron Bank 1 with a 30 MVA transformer. Both of these needs are due to backflow caused by PV generation on the distribution grid. The Blackwell Bank 1 Planned Investments is a traditional solution and is identified as a Tier 1 Candidate Deferral Opportunity in PG&E's 2020 DDOR. For Huron Bank 1 Planned Investment, PG&E has solicited, contracted, and received approval for a non-DER solution to address the DER-driven needs.[3] The approved contingency plan for Huron Bank 1 includes both DER and non-DER solutions.

2.5 GNA - Observations, Conclusions and Recommendations

We observe that the number of total needs declined from 6,994 in 2019, to 582 in 2020 with all of the decline in the Distribution Capacity and Voltage Support service categories. This was a result of a change in the reporting for line segment needs and has improved the GNA reporting without degrading the information provided to the reader.

As done in the 2019 GNA, the 2020 GNA only includes segment needs that were not addressed by a no cost transfer. Providing the needs for only circuit line sections that have needs after no-cost load transfers appears to be a more manageable approach to providing this information in the GNA/DDOR reports and we recommend this approach be continued.

We observe that there may be another category of need that could potentially be mitigated with a DER solution. This involves situations where an asset could be replaced or its life could be extended via a DER solution. For example, single customers served from long radial lines in remote areas, such as fire watch stations, camping grounds or other small remote loads. Some of these locations are served by older direct buried primary cable that will need to be repair or replaced. A DER solution could be a viable alternative. Another example is a transformer bank that is approaching the end of life. In this example reducing the load could potentially extend the asset life. We observe that this DER application does not belong under the definition of reliability as used in DIDF. It is recommended that this type of DER application be considered in future DIDF cycles. There may be not a lot of these situations, but this could be an opportunity to expand the types of deferrable projects to be considered.

We observe there was little analysis provided for Planned Investments for DER Driven Needs. We expect DER driven needs will increase in the future as more DER is used as alternatives to traditional wires solutions. We also expect the analysis for these needs may be different from

[3] PG&E AL 5707-E

the other needs and should be reviewed. In the future, we recommend the IOU provide analysis that can be reviewed by the IPE for Planned Investments resulting from DER driven needs. This analysis would include a review of approach, assumptions, processes used, and recommended solutions.

Stakeholders have observed for all three utilities that there are many needs in the first three years of the planning period which are currently screened out as a result of the timing screen which raises the question whether these needs existed in the 2019 GNA or previous GNAs..

The IPE recommends that in future GNA/DDORs the three utilities identify the needs in the current cycle that were also identified in a prior cycle and provide the year(s) that these needs were forecasted to occur in the prior cycle(s).

3 Review of DDOR Report – Planned Investments

Using the GNA as the foundation, the DDOR identifies candidate distribution deferral opportunities for potential competitive solicitation for cost-effective Distributed Energy Resource (DER) solutions to mitigate the identified distribution system needs. It also includes a description of the methodology used to prioritize candidate deferral projects for potential solicitation and procurement.

The PG&E DDOR report covers all needs identified in the GNA and includes an Appendix with four Excel-based workbooks each containing several tabs: Appendix A and Appendix B, with tabs for “Planned Investments” and “Candidate Deferral Opportunities”; Appendix C with tabs for “Planned Opportunities (Tiers)”, “Planned Opportunities (Prioritization Metrics)”, and “Planned Opportunities (Prioritization Metrics Ranking)”; Appendix D, with tabs “LNBA – Candidate Deferral Opportunities”, “LNBA – Planned investments - Bank and Feeder”, and “LNBA – Planned Investments Line Section”, and Appendices 6.4 - 6.7, with four tabs for “GNA Results - DER Growth”, “GNA Results - Demand Forecast and Bank/Feeder Capacity Needs”, “GNA Results - Reliability/Resiliency Needs”, and “GNA Results –Line Section Capacity and Voltage Needs”.

The data reflected in these workbooks represents a portion of PG&E’s traditional infrastructure projects that contribute to the safe and reliable operation of the distribution system and serves as the baseline for evaluating opportunities for DERs to potentially defer or avoid traditional distribution system investments.

The Planned Investment-Final tab identifies 582 grid needs and since projects often fulfill multiple needs the DDOR identifies 348 associated projects that are potential DDOR opportunities. The Candidate Deferral tab identifies the 29 candidate deferral projects proposed by PG&E for further consideration. The Prioritization Metrics Summary tab summarizes the individual deferral candidates and their respective metric component relative evaluations. The Tier tab provides a prioritized listing of the 29 candidate projects. The use of the Prioritization Metrics to prioritize candidate deferral projects is described in more detail later in this report.

A summary of the 348 identified 2020 DDOR Planned Investments can be seen in the tables below from PG&E’s DDOR Report.

Table 3-1 summarizes the number of project types by PG&E Distribution Planning Region.

Table 3-1: Summary of Planned Investments by Distribution Planning Region and by Project Type

Distribution Planning Region	Project Type			Total
	Substation/Bank	Feeder	Distribution Line	
Bay Area	4	36	18	**58**
Central Coast	11	31	50	**92**
Central Valley	7	44	86	**137**
Northern	4	20	37	**61**
Totals	26	131	191	**348**

Of the project types, Distribution Line (referred to as segment level projects) projects make up 55% of the projects while feeders and substation project make up 37.5% and 7.5% respectively.

Distribution capacity service needs make up 79% of the service requirements as can be seen in Table 3-2.

Table 3-2: Summary of Planned Investments by Distribution Service

Distribution Service				Total
Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency	
275	43	29	1	348

Table 3-3 shows 91.5% of the needs or 319 projects have an in-service or operational date earlier than 2023.

Table 3-3: Summary of Planned Investments by In-Service Date

In-Service Date						Total
2020	2021	2022	2023	2024	2025	
74	168	77	22	5	2	348

3.1 DDOR Report Planned Investments- Observations, Conclusions and Recommendations

The total number of needs for 2020 increased by 113 or 62% compared to 2019. In 2020 the percentage of Distribution Line (segments) projects declined from 72% in 2019 to 55%, the percentage of feeders increased from 18% in 2019 to 37.5%, and the percentage of substation projects decreased from 10% in 2019 to 7.5%.

As observed in prior reports, the majority of the projects required to mitigate the GNA needs are capacity related for distribution lines with an in-service date earlier than 2023. This is an expected outcome because when compared to banks and feeders, 1) there are a more distribution lines than banks and feeders, 2) they normally have less load carrying capacity and smaller load increases can result in overload or voltage conditions more quickly and, 3) smaller load increases impacting distribution lines occur with less lead time than the larger loads that impact banks and feeders, so these needs are not identified as early as other needs.

No conclusions or insights can be reached on either observation above based on this limited set of data

It is observed the information for Planned Investments is not provided in a comprehensive manner that can easily be followed by stakeholders. Much of the information is provided in various Excel workbooks and in the Appendices. We recommend that each Planned Investment in each Tier be summarized providing a description of the project including such things as, but not limited to, the need, assets involved, loading, and general scope of work.

4 DDOR Report - Review of Screening and Prioritization

This section contains a discussion of the two screens used by PG&E used to develop its candidate deferral project list. The screens, required by D.18-02-004, are a technical screen and a timing screen

4.1 Project Screens

The first screen used is the Technical Screen which is intended to identify all grid needs that could be potentially mitigated by DERs with one of the four distribution services adopted by D.16-12-036, specifically Distribution Capacity, Voltage Support, Reliability (Back-Tie) and Resiliency (Microgrids).

The second screen is the Timing Screen which is intended to ensure cost-effective DER solutions can be procured and implemented with sufficient time to fully deploy and begin commercial operation in advance of the forecast need date. For this DDOR, a 2023 or later in-service date is considered as adequate lead time. Since the GNA needs analysis covers the years 2020 to 2024, the timing screen eliminates all projects other than those with in-service dates starting in 2023, 2024, and 2025. The required in-service dates are developed as part of the distribution planning process that includes load and DER forecasting at the system level and then disaggregation to the circuit level followed by a needs determination. This process is described in detail in the GNA/DDOR reports and discussed in Section7 – Verification Approach and Results.

The technical screening is implemented as part of the development of the GNA list. If a capital project, such as a pole replacement or road widening project, does not provide one of the four services mentioned it is not included in the GNA. The technical screen can be considered as a continuous process as opposed to being performed at a single point in time. Therefore, the number of projects screened out because of technical concerns is not available from the GNA data. Of the 348 projects that meet the technical requirements as a potential candidate deferral opportunity, only 29 projects have in-service or operational dates of 2022, 2023, or later.

4.2 Project Prioritization

This section contains a discussion of the prioritization process used by PG&E to prioritize its candidate deferral projects and a discussion of the various metrics PG&E used in that process.

PG&E used three prioritization metrics – Cost-effectiveness, Forecast Certainty, and Market Assessment. These metrics are consistent with the guidance provided by the CPUC including the use of an LNBA/kWh-yr metric as a component of the Cost Effectiveness metric. The application of these three metrics is demonstrated in the final PG&E project prioritization was presented to the DPAG at PG&E's DPAG Webinar which and is shown in Table 4-1 below.

It should be noted as in previous years, PG&E does not use a quantitative assessment but rather uses a qualitative evaluation/prioritization methodology for comparing projects to each other.

Table 4-1: DDOR Candidate Deferral Summary

Note: This table has confidential information which has been redacted in the gray cells

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
	Willow Pass Bank 1	2023	5.3			
	San Miguel Bank 2	2023	5.0			
	Calistoga Bank 1	2023	4.2			
1	Ripon 1705	2024	3.7			
	Blackwell Bank 1	2023				
	Belle Haven Bank 4	2023	5.0			
	San Luis Obispo 1106	2023				
	Zamora 1108	2023	1.1			
	Dunnigan Bank 1	2024	1.6			
	Beresford 401 Cut-Over	2023	1.5			
	Brentwood 2111 Line Work	2023	0.9			
	Hollister 2106 Line Work	2023	5.0			
	Rocklin 1104 and Rocklin 1101	2025	0.2			
	Caruthers 1104 Regulator	2023	0.7			
2	Morgan Hill 2103	2023	6.6			
	Storey 1103	2023	3.2			
	Vasona 1109	2023	3.9			
	Peabody 2106 Outlet	2024				
	Stelling 1105	2023	4.6			
	Mountain View Bank 1	2023	5.7			
	Greenbrae Bank 2	2023				
	Woodland 1105 Outlet	2025	1.3			
	Lockeford Bank 1	2024	14.8			
	Semitropic 1112 Line Work	2024	8.1			
	California 1103 & California 1111	2023				
3	Wolfe 1111 & Wolfe 1112	2023	44.1			
	FMC 1102	2023	6.7			
	Rincon Bank 1	2023	8.0			
	Spence Bank 2	2023				

The evaluation of the metrics is used qualitatively by PG&E to place Candidate Deferral Opportunities into tiers based upon their relative rankings using the three metrics. The qualitative rankings also include the local engineering judgement of distribution planners obtained from a Forecast Uncertainty Questionnaire completed by them. The questionnaire provides local engineering judgement potentially   the certainty of the forecast, such as the health and condition of the asset, and other activity in the area which may impact the forecast loading for each potential candidate deferral opportunity.

The relative ranking of each candidate opportunity is identified with a color code as shown in Table 4-2. Note there are no projects in Tier 4, labelled "Considered Already Sourced Elsewhere".

Opportunities with a relatively low ranking (red) are not considered as Tier 1 opportunities.

Table 4-2: 4-Tier Prioritization System

Tier	Color Designation	Definition
1		Relatively High Ranking
2		Relatively Moderate Ranking
3		Relatively Low Ranking
4		Already Sourced Elsewhere

The development of the three-prioritization metrics is based on the evaluation of components of each of the three metrics as discussed below.

Table 4-3 identifies the metric components and basis for the metric evaluations.

Table 4-3: Basis for Prioritization Metrics

Note: This table has confidential information which is identified by C.C.

Candidate Deferral	Cost Effectiveness			Forecast Certainty			Market Assessment				
	Unit Cost of Traditional Mitigation ($k)	Estimated LNBA ($/kW-yr)	Estimated LNBA ($/MWh-yr)	Forecasted Need (Year)	SCADA Available (Y/N)	Project Uncertainty Risk Score	Real Time (RA) or Day Ahead (DA)	Number of Grid Needs	Calls/ Year	Hours/Call	Deficiency (%)
Hollister 2106 Line Work	$500	$5.35	$20.75	2023	Y	14	DA	1	43	6	11%
Spence Bank 2	$9,000	$46.91	$53.23	2020	Y	23	DA	4	CC	CC	CC
Wolfe 1111 & Wolfe 1112	$8,600	$21.36	$2.89	2020	Y	14	DA	2	365	24	238%
Vasona 1109	$1,650	$46.20	$13.12	2020	Y	14	DA	3	257	18	25%
Stelling 1105	$3,756	$43.51	$35.45	2020	Y	18	DA	3	236	9	19%
Mountain View Bank 1	$6,000	$55.02	$56.37	2020	Y	24	DA	1	122	8	19%
Brentwood 2111 Line Work	$80	$10.08	$240.03	2023	Y	8	DA	1	21	2	4%
Willow Pass Bank 1	$14,741	$194.62	$337.42	2020	Y	22	DA	2	101	6	17%
Caruthers 1104 Regulator	$110	$8.45	$938.49	2023	Y	13	DA	1	9	1	6%
California 1103 & California 1111	$660	$8.08	$7.96	2023	Y	9	DA	4	CC	CC	CC
Semitropic 1112 Line Work	$34	$0.22	$0.22	2024	Y	14	DA	1	168	6	33%
San Miguel Bank 2	$9,700	$138.09	$151.04	2020	Y	15	DA	3	122	10	22%
San Luis Obispo 1106	$3,130	$94.21	$57.41	2022	Y	14	DA	2	CC	CC	CC
Greenbrae Bank 2	$6,000	$114.67	$52.84	2021	Y	18	DA	1	CC	CC	CC
Beresford 401 Cut-Over	$1,000	$35.83	$64.13	2020	Y	6	DA	2	145	5	17%
Belle Haven Bank 4	$8,500	$89.07	$52.92	2020	Y	16	DA	1	153	11	31%
Peabody 2106 Outlet	$110	$2.16	$1.37	2022	Y	2	DA	1	CC	CC	CC
Dunnigan Bank 1	$8,000	$257.41	$861.19	2020	Y	26	DA	2	91	5	11%
Woodland 1105 Outlet	$125	$5.11	$13.90	2025	Y	6	DA	1	92	4	10%
Zamora 1108	$1,200	$61.21	$97.15	2020	Y	14	DA	1	45	14	11%
FMC 1102	$1,700	$27.46	$217.91	2020	Y	15	RT	1	9	14	31%
Morgan Hill 2103	$2,100	$34.27	$73.03	2020	Y	17	DA	2	100	6	13%
Rocklin 1104 and Rocklin 1101	$150	$34.87	$335.29	2021	Y	10	DA	1	52	2	2%
Rincon Bank 1	$10,000	$64.89	$14.99	2020	Y	24	DA	2	340	20	29%
Ripon 1705	$2,200	$63.07	$123.68	2023	Y	14	DA	1	102	5	22%
Storey 1103	$2,200	$37.40	$89.35	2020	Y	12	DA	3	105	5	16%
Blackwell Bank 1	$6,000	$106.83	$53.96	2020	Y	16	DA	1	CC	CC	CC
Calistoga Bank 1	$7,340	$91.61	$126.51	2021	Y	16	DA	2	122	8	23%
Lockeford Bank 1	$6,000	$20.67	$35.88	2021	Y	6	RT	1	12	48	50%

The Cost Effectiveness metric is intended to provide a relative indication of how likely DER resources can cost effectively defer a planned investment. This metric has three components, Unit Costs of Traditional Mitigation, Estimated LNBA $/KW-yr and Estimated LNBA $/MWh-yr. The Unit Costs are the estimated project capital costs at the time of the report. This topic is discussed further in Section 7.3. The projects with larger unit or project costs for traditional solutions are ranked higher than those with lower costs. The LNBA-related metrics are developed by taking the LNBA value for this project and dividing that value by the maximum kW need during the deferral period and the maximum kWh-yr need during any one year of need. The overall evaluation is tempered with engineering judgement based on experience with lessons learned from PG&E's DRP Demonstration Projects C and D RFOs.

High tiered projects under the Cost Effectiveness Metric are characterized by:

- High Unit Cost of Traditional solution;
- High LNBA ($/kW-year);
- High LNBA per MWh of deferral ($/Megawatt-hour (MWH)-year); and
- Judgement based on experience with previous pilots.

The Forecast Certainty Metric is intended to give a relative indication of the certainty of the forecast grid need. This metric also contains three components, Forecasted Need (year), SCADA Available, and a Project Uncertainty Risk Score. The Forecasted Need identifies the year the need is required which is developed in the distribution planning process (utilizing a number of tools including LoadSEER and CYME). PG&E considers needs in later years as having more uncertainty. PG&E places high importance on the ability to the use SCADA to validate the existing load and therefore a strong foundation for the forecast. This component is given the most weight in the Forecast Certainty Metric but since all the Candidate Deferral Opportunities have SCADA data available, this component did not impact the prioritization process results.

Starting this year, PG&E gathered feedback from the local distribution engineers by way of a Forecast Uncertainty Questionnaire. This questionnaire provides local engineering judgement potentially impacting the certainty of the forecast, such as the health and condition of the asset and other activity in the area which may impact the forecast loading. As discussed in the DPAG meeting the questionnaire asks the likelihood that the area served by the asset will connect to new EV charging stations, new cannabis cultivation, new agricultural pumps or new high tech growth, including campuses and data centers. The questionnaire also asks how strongly load is inversely proportional to State and Federal water allocation, how strongly load correlates to temperature and how much the project impacts area capacity. This Load Uncertainty Questionnaire is a good attempt to standardize local input for these major projects, however the scoring mechanism needs to be explained. A sample questionnaire is included in Appendix D.

High tiered projects under the Forecast Certainty Metric are characterized by:

- Nearer term need (2023 vs. 2024);
- Availability of Supervisory Control and Data Acquisition (SCADA) data recordings;
- A lower forecast uncertainty rating from the Forecast Uncertainty Questionnaire completed by the distribution engineers; and
- Judgement based on engineering knowledge of the area.

The third metric Market Assessment is intended to give a relative indication of how likely DER resources can be sourced to successfully meet the DER distribution service requirements. This metric has five components, Real Time or Day Ahead Notification, Days/Year, Number of Grid Needs, Calls/Year Hours/ Per Call, and Deficiency (%).

Real Time projects are identified as either just Real Time, where capacity is required in support of PG&E service, and as Real-Time-Islanding, where the capacity is required and must be maintained independent of PG&E service. It should be noted only two Distribution Deferral

Opportunities in 2020 have Real Time requirements and they are both in Tier 3. In the 2019 DDOR, PG&E had 14 Real Time or Real Time/Islanding opportunities in Tiers 2 and 3.

Projects with Day Ahead requirements are given a higher ranking than projects with Real Time requirements, because it is believed some developers may view a Real Time five-minute dispatch notice and potential islanding requirements to be more difficult and costly to achieve in practice and likely to impact potential revenue streams.

The Calls/Year component is listed as one component. Unlike 2019, the Calls/Year are compared directly between Real Time and Day Ahead projects in PG&E's 2020 DDOR. A separate metric was included to distinguish between Real Time and Day Ahead projects.

For the Number of Grid Needs component, a project with fewer needs (i.e. a project that has fewer circuits with needs) is given a higher evaluation rating than a project with many circuits that have needs. The reason for this is implementing DER solutions for few locations will be easier (and less costly) than implementing DER for many locations.

The Hours/Per Call component addresses the duration of the DER service requirement. For a project with one element this value would be the project's DER duration need as determined in the planning process. For projects with multiple needs the value would be the maximum duration of any of the elements included in the project. Projects with a shorter duration are weighted higher (better) than those with longer durations.

Finally, the Deficiency component is calculated over a ten-year planning horizon (2020-2029) and is intended to evaluate the penetration of DER required to meet the need. This value is calculated as the percent (%) deficiency of the need over the ten-year planning period. If there are multiple needs, the maximum need, not the sum of the needs, is used for this calculation. According to PG&E, the lower the overcapacity deficiency the more likely a DER solution would be successful. As with the other metrics, engineering judgement and lessons learned from the previous pilots are also considered.

High tiered projects under the Market Assessment Metric are characterized by:

- Only Day Ahead, rather than Real Time, operational requirements;
- Low number of electric facilities experiencing grid needs in a project;
- Fewer number of days needed per year;
- Lower deficiency; and
- Judgement based on experience with pilots.

As mentioned above, numerical values are not used in the individual metric component evaluation; instead PG&E segregates the values into relatively high/medium/low groups which are then identified by the associated color previously described.

The final metric prioritization decision is a qualitative evaluation of the individual metric components. Under PG&E's methodology, if all components are identified as green (relatively high ranking), the overall prioritization for that metric is green. However, in practice the worst individual component ranking is used for the overall ranking. So, two green and one yellow component evaluation is generally ranked as yellow overall for that metric. The purpose of is process is to primarily highlight potential problems or red flags.

4.2.1 Project Prioritization - Observations Conclusions and Recommendations

Prioritization Metrics

We observe that PG&E has changed two of the metric components. Previously the Forecast Uncertainty Metric had as one of its components the Number of Customers component. They have removed that component and replaced it with a Project Uncertainty Risk Score derived from a Forecast Uncertainty Questionnaire completed by the Distribution Planning Engineers. We believe that the use of a standard questionnaire to gather forecast certainty information regarding new customer projects that are drivers for load growth is a very good approach to gathering comparable information for each project. It adds structure to the review and a form of transparency in that the IPE can request copies of the questionnaire. We observe, however, that the scoring methodology which uses the questionnaire information is not explained and thus cannot be replicated or verified. We recommend that additional information be added to the process/questionnaire to clarify how the questionnaire data is used to develop a final score/rating.

The Market Assessment component, Over Capacity, has been replaced with the component, Deficiency. This is basically a name change to better describe the evaluation.

As part of their new Forecast Uncertainty, PG&E is now looking at several new uncertainty drivers. The first is the consideration for the potential for new customer load above and beyond the CEC forecast that is used in the top down load forecasting process. These new loads being considered in the forecast uncertainty metric for projects reviewed are new commercial EV fast charging sites and new cultivation customers. These are new customer loads that were not previously identified in the forecasting process as local known loads and thus can be considered as "incremental" local known loads (incremental to the CEC Forecast and not embedded in the forecast). The Forecast Uncertainty Questionnaire mentions other loads that should be also be considered. They are agricultural pumps and high tech company development, including campuses and data centers. For example, for the Dunnigan Bank project discussed below, the relatively low Forecast Uncertainty score is based upon the assumption that there is a high likelihood that there will be additional commercial EV fast charging stations that apply for service on the circuit within the planning period. Introducing this additional load in the prioritization process is somewhat similar to adding incremental load to the CEC forecast although this added load is not added at the load forecasting step in the process. PG&E indicated that they believe that these additional loads have a high probability of developing. We recommend that PG&E should consider reviewing/revising how it introduces these uncertainties in load growth including the potential to treating these loads as known loads in the forecasting process (either embedded or incremental) in future DIDF cycles and consider the implications to the needs and projects developed as a result.

PG&E has been challenged with forecasting load that can be directly impacted by Federal and State water allocation for years. They are working with State and Federal agencies developing tools to help forecast the water allocation and improve PG&E's load forecasts for areas subject to agricultural pumping load. This issue is addressed in the Forecast Uncertainty Questionnaire.

We also observe in the review of PG&E's load forecasting business processes that the load on many circuits are not temperature sensitive but sensitive to other factors including, as previously mentioned, Federal and State water policy, and new EV charging stations, cannabis cultivation and high tech loads. We conclude, that as a result, there are other business processed needed and involved with load forecasting at the circuit level for a number of PG&E distribution circuits. We recommend that those other business processes be considered for review in future DIDF cycles.

Tier Ranking

PG&E uses a qualitative as opposed to quantitative process to determine the projects included in each tier. PG&E states these are relative evaluations and when all the values for a given metric are reviewed, there are normally natural breaks or gaps between high, medium, and low values. That implies a given score for this year could be high and the same score next year could be low, depending upon the other projects being compared against. For example, in 2019 the Camp Evers 2107 and FMC 1102 projects had unit costs of $1.7M and this year the FMC 1102 project has that same unit cost. Last year these unit cost components were is ranked relatively high, while this year this unit cost component is ranked relatively moderate

It is recommended PG&E consider moving toward more transparency in the development of the metric scores and develop a more quantitative prioritization process. SCE has developed a detailed scoring approach and it is recommended PG&E consider that approach for ranking its opportunities as the three IOUs consider a standardized approach as directed by the May CPUC Ruling.

5 Review of PG&E Prioritization of Candidate Deferral Projects

In this section we review the projects PG&E initially recommended for inclusion in Tier 2. It is noted that PG&E recommended 4 tiers however there are no projects recommended for Tier 4 (Already Sourced Elsewhere).

We believe that the Cost Effectiveness category, in general, is very important to the overall ranking process. If there is not sufficient funds/budget to develop and operate a DER solution that is cost effective (one that results in a bid that is below the cost cap) then the other two categories become less important. For this reason, we examined candidate projects with strong Cost Effectiveness metric values that were not in Tier 1.

It must be noted however, if a project looks favorable on a cost-effectiveness basis, it does not mean it should automatically receive an overall high ranking because there may be significant issues/red flags in the other two prioritization categories that could result in a lower overall ranking.

5.1.1 Candidate Deferral Projects – Observations, Conclusions and Recommendations

Project Related Comments

The Tier 2 opportunities were reviewed to identify what changes would be required to move one or more of them to Tier 1. The focus was on opportunities with medium or high cost effectiveness rankings. Because the opportunities in Tier 3 are all red in the Cost Effectiveness metric and in one other metric they were not reviewed for potentially moving to Tier 1. Note that some of these projects are also discussed in subsequent sections following The DPAG Follow UP meeting and an additional meeting to discuss three projects.

Dunnigan Bank 1

The Dunnigan Bank 1 (8.09 MW) opportunity is capacity project driven by a deficiency of 1.6 MW. It is ranked relatively high for Cost Effectiveness, relatively low for Forecast Certainty and relatively moderate for Market Assessment. The bank is being proposed for upgrade because of new load applications for two new electric vehicle charging stations which will overload the bank. The upgraded bank will be three single phase 7 MW banks for a total rating of 21 MVA (20.8MW). According to PG&E, the reason for the relatively low ranking is the Project Uncertainty Risk Score. It is PG&E's experience that electric vehicle charging stations tend to congregate in an area. Once an application is received it is not unusual for other electric vehicle charging stations to apply for service in the same area. Therefore the total load that can be expected is uncertain. In addition, the bank is 78 years old and well beyond the expected life of a substation transformer, which PG&E indicates is 68 years. The concern is if the bank fails it is extremely unlikely it can be cost-effectively repaired and will need to be replaced. If PG&E procures DER capability it is reasonable to expect this bank to fail during the duration of the contract and need to be replaced anyway. The size of the Dunnigan bank (8.09MW) is non-standard and its upgrade will be to a standard larger size (20.8 MW) and capable of handling the additional electric vehicle charging load.

While the specific bank test results and maintenance records were not reviewed, the likelihood of a bank failure appears to be high given the age and description of the conditions of the bank. Therefore it is our recommendation this bank upgrade not be considered as a deferral opportunity and be scheduled to be replaced and upgraded as planned replacement work rather than waiting for this aged asset to fail.

Mountain View Bank 1

The Mountain View Bank 1 opportunity is ranked relatively moderate for Cost Effectiveness and Market Assessment and relatively low for Forecast Certainty. As with the Dunnigan Bank, the added load is a result of an electric vehicle charging station application. PG&E has some experience with the growth pattern of this type of new load. Their experience is once an EV charging station has identified a location other EV charging competitors consider the same general location. PG&E states these EV charging stations can have an average load of 3 MW each. Hence the ultimate load in the area will be larger. It is just not known how much larger.

While PG&E has some experience with the growth pattern of this type of new load, it may not be enough to warrant deferring this opportunity at this time. PG&E has received two EV charging applications which will be served from Mountain View substation. Both applications are smaller than the 3 MW mentioned above. They expect additional EV charging loads beyond these two applications in the area. Since these expected loads have not applied for service, we recommend this opportunity be considered as a Tier 1 and review the load again just before making a solicitation. It is also recommended PG&E study the growth pattern of electric vehicle charging stations including the experience of other utilities to gather more knowledge on this subject and to refine their approach to dealing with the uncertainty associated with new charging stations. (See updated recommendation in Section 5.3 below.)

Greenbrae Bank 2

The Greenbrae Bank 2 opportunity is ranked relatively moderate for Cost Effectiveness and Forecast Certainty and relatively low for Market Assessment. The relatively low ranking for Market Assessment is a result of a large number of calls per year requirement. Because of the location, there may be some difficulty being able to charge any storage devices and the solution would have to include a separate power source. It is our recommendation this opportunity be moved to Tier 1 and that both of these obstacles be identified in the solicitation for potential bidders to evaluate. It is our understanding PG&E is reconsidering this opportunity as a Tier 1. We support this re-evaluation.

General Comments

We have two general observations/recommendations.

- The first concerns the likelihood of equipment failure and how it is considered in the DIDF process. The health of assets, such as the case with Dunnigan Bank 1, should be considered as part of the need development and the solution development. As it stands, the Dunnigan Bank 1 need is developed without the consideration of the bank health while a DER solution is not considered because of the bank's poor health. If done as part of DDIF, as we recommend, this would require changes to the DIDF process.

- The second observation concerns the expectation of future load on specific feeders without customer applications. As discussed earlier, consideration of this expected load (i.e. fast EV charger stations as part of the Mountain View Bank 1 project) without adjusting load allocation to other circuits effectively increases the CEC system level load forecast. There is no reason to doubt the expectation of the added load but we recommend that adjustment to the disaggregation of the CEC system level load to the circuits needs to be considered as well.

5.2 DPAG Follow-up Meeting Comments

On October 12, 2020, a PG&E DPAG follow up Webinar was held to discuss additional information PG&E had gathered since the September 16, 2020 DPAG meeting and DDOR changes being contemplated by PG&E as a result of the DPAG meeting and associated IPE comments.

Additional information was provided for the Calistoga Bank 1 and Blackwell Bank 1 opportunities regarding protection or overvoltage schemes which would be required if these moved forward. It was informational only and did not change the ranking of these two projects. They remained in Tier 1.

The Greenbrae Bank 2 opportunity was initially ranked a Tier 2 opportunity because the calls per year component of the Market Assessment Metric was large and therefore resulting in a relatively low Market Assessment Metric ranking. As a result of questions and feedback received and the interest displayed by developers, PG&E reassessed the calls per year component of the Market Assessment Metric and re-ranked it as relatively moderate. The Greenbrae Bank Opportunity is now recommended to be moved to Tier 1. This is consistent with our comments on this opportunity described earlier and we agree with the movement of this project into Tier 1.

The Belle Haven Bank 4 opportunity was initially ranked a Tier 1 opportunity. Since the DDOR report has been issued, a new large load application has been received that could impact the scope of the work. Per PG&E, this changes the Forecast Uncertainty from relatively moderate to relatively low and moves this opportunity from a Tier 1 to Tier 2 while the impact of this new load application is analyzed. We agree the analysis needs to be completed, but believe it is too early to change the Tier ranking. If the load analysis determines the full customer load does not appear until much later, there may no reason to make a tier ranking change. The IPE is planning to discuss with PG&E after the customer load analysis is complete. (See updated recommendation in Section 5.3 below.)

The San Luis Obispo 1106 opportunity was initially ranked a Tier 1 opportunity. Since the DDOR was issued, additional information regarding the health of the Foothill Bank 1 (the driver for the San Luis Obispo 1106 work) has been discovered. The bank is described as at the end of its life. To extend the life of the bank, PG&E is anticipating the bank will be de-rated and the DER Service Requirements will need to be revised. These changes are expected to result in multiple red flags and hence the change from Tier 1 to Tier 2. We agree the bank data needs to be reviewed and the health of the transformer determined. But as with Belle Haven Bank 4, we do not believe the tier level should change at this time. Once the health of the bank is determined, the decision to change the tier could be made. The IPE is planning to work with PG&E on this analysis. (See updated recommendation in Section 5.3 below.)

Dunnigan Bank 1 is a Tier 2 opportunity which remains unchanged in PG&E's update. Specific data has not been provided but from the PG&E narrative, the bank could fail at any time. We agree this should not move forward as part of the DDIF procurement process.

Mountain View Bank 1 is a Tier 2 opportunity which remains unchanged in PG&E's update. As discussed earlier, we recommend this be moved to Tier 1.

5.3 Project Detail Review Meeting

On November 5, there was a conference call between PG&E, ED and the IPE to discuss three DDOR Candidate Deferral Opportunities – Belle Haven Bank 4, Mountain View Bank 1 and San Luis Obispo 1106.

Belle Haven Bank 4

Following the issuance of the DDOR report, discussions with a high tech company resulted in an application for a 49 MW load to be located in the area served by Belle Haven Substation. This application will require 1.6 MW of construction power starting in 2021 with initial permanent load starting in 2024 (of tens of MWs) and continuing to increase until 2026. The initial load requirement which generated the Belle Haven Bank 4 project still exists but the 2023 load requirements are likely to change because of the construction power required for the new high tech application.

Based on this new information, the Belle Haven Bank 4 may not be the correct solution for the combination of forecast needs. PG&E will perform a large load study which is expected to take approximately three months to complete. Until that study is completed, the Belle Haven Bank 4 project will not proceed. The project may ultimately be cancelled or re-scoped depending upon the results of the large load study. The study will examine the combined needs (new customer and previous needs) and developed a proposed solution to all needs which may end up having a nearer term solution component and a longer term solution component.

PG&E and the Energy Division agreed that if needed a new special RFO cycle would be available for this project to be initiated in January, 2021, after the study is completed.

The IPE agrees with this approach and is planning to work with PG&E during the large load study.

Mountain View Bank 1

There are currently two EV charging applications for Mountain View. One is an EV fast charging facility and the other is for a series of EV chargers at a hospital. PG&E's experience indicates other EV charging applications will soon follow and they need additional capacity to quickly respond to these requests. They do not believe they can tell a new EV application they will need to wait 2-3 years for system reinforcement before the EV chargers can be served especially since PG&E is considering a system reinforcement now. PG&E states this would not be supportive of the State's transportation electrification strategy. They believe they should be adding the additional capacity now as they reinforce the local distribution system. This would be achieved by the replacement of the Mountain View Bank. This replacement would add a total of 15 MW of capacity. Therefore they propose to continue to consider this project as a Tier 2 opportunity. It was suggested the additional load that PG&E expects to appear be added to the load forecast and the prioritization metrics be re-evaluated for the new larger project. The results of this re-evaluation are expected to yield relatively low prioritization scores and not move the project to a higher level.

After this discussion, the IPE agrees with the re-evaluation of the Mountain View Bank 1 project with this new anticipated EV charger loads and that the project remain in Tier 2.

San Luis Obispo 1106

In the DPAG Follow-up Meeting, PG&E indicated they had received some indication that the Foothill bank was potentially at the end of its life but they did not have any details or test results. Since that meeting, PG&E has confirmed the bank is at the end of its life and plans to de-rate the bank to operate at less than 80% in the interim. PG&E has updated its distribution planning to reflect the de-rate and has recalculated the DER Service Requirements. PG&E plans to provide the updated DER requirements and rankings which were not received at the time this report was finalized.

PG&E recommends the project should be moved from a Tier 1 to Tier 3. While the actual bank data was not provided, the IPE supports the recommended approach subject to confirmation after reviewing the data PG&E promised to provide to the IPE,

6 Other Items of Interest

6.1 Miscellaneous – Observations, Conclusions and Recommendations

Forecast and Disaggregation Review

- We observe that PG&E accepts the CEC system forecast and does not add incremental local growth projects (also referred to as known loads) in their most recent system forecasting process. Known loads are removed from the system forecast and added to specific feeders after the system forecast has been disaggregated. We were unable to verify the 2020 loading and believe the amount of known load for some customer classes maybe larger than the load forecast by the CEC. We also observed some projects are being impacted and ranked based on large new loads that may not be accounted for in the system forecast. The specific examples discussed included large EV charging loads, but PG&E also appears to be considering cannabis cultivation, large agricultural pumping, and high tech, including campuses and call centers. Based upon our review this year, new commercial fast charging loads are a challenge for SCE and PG&E and there is the potential for such impacts to grow as the State takes steps to increase transportation electrification to achieve its GHG targets. We recommend that the Energy Division working with the utilities and CEC take steps to ensure that future IEPR forecasts reflect not only new cultivation but also new commercial fast charger local load growth projects.

Load Forecasting Comparison

- In the 2019 IPE Report we recommended that a comparison be made (which eventually became Step 19 of the IPE Plan) of 2019 forecasts (included in the 2019 DIDF) and 2019 actuals (both on a 1 in 10 year basis) at the circuit level for 2019 candidate deferral projects. The verification of that comparison for PG&E is included in Section 7.4.7. We believe that insight was gained through this review for all of three utilities and we recommend that it be included future IPE validation and verification processes with improvements aimed at obtaining circuit data for circuits that represents an appropriate sample size.

Data Provided to DPAG

- As part of the development of the IPE Report that dealt with data adequacy that was completed the week prior to the DPAG meetings, the Energy Division asked the IPE to consider if the data was adequate not only for the IPE but the DPAG members. In general, we concluded that the data provided was adequate for the scope set out for the IPE. We observed that all of the information that was provided to the IPE was included with the IPE's report completed after the DPAG and therefore stakeholders would receive copies (public versions) of the data provided to the IPE. The IPE did note that

DPAG members would not have that data prior to the DPAG. To allow DPAG members to get the most out of the DPAG meeting, we recommend that the Public version of the prioritization metrics spreadsheet (a fully functional version with all calculations active) be provided to the DPAG prior to the DPAG meeting.

Outstanding Data Requests

- There are a few outstanding data requests. These requests are not expected to change this report but would help provide clarity. The IPE will continue to work with PG&E to gather these data and reflect any updates in the Post DPAG Report.

Redaction of Data in Public Version of the IPE DPAG Report

- We observe that as a result of the request by PG&E to treat some data in this report as confidential, the Public version of this report will contain some figures and tables that are redacted. We recognize that this impacts the information that the public receives from the IPE report. Using the approved process to get feedback upon what is confidential in the IPE report results in the IPE learning about this relatively late in the process. In many cases the need for redacting cannot be avoided. In some cases, it may be possible for the IPE to use different example circuits to analyze or for the utility to use different circuits for their verification demonstrations. We recommend that the IPE include in future IPE Plans a discussion with the utility to avoid the use of confidential data when possible (i.e. data that is confidential due to 15/15 rule) when non confidential data would serve the same verification or validation purpose.

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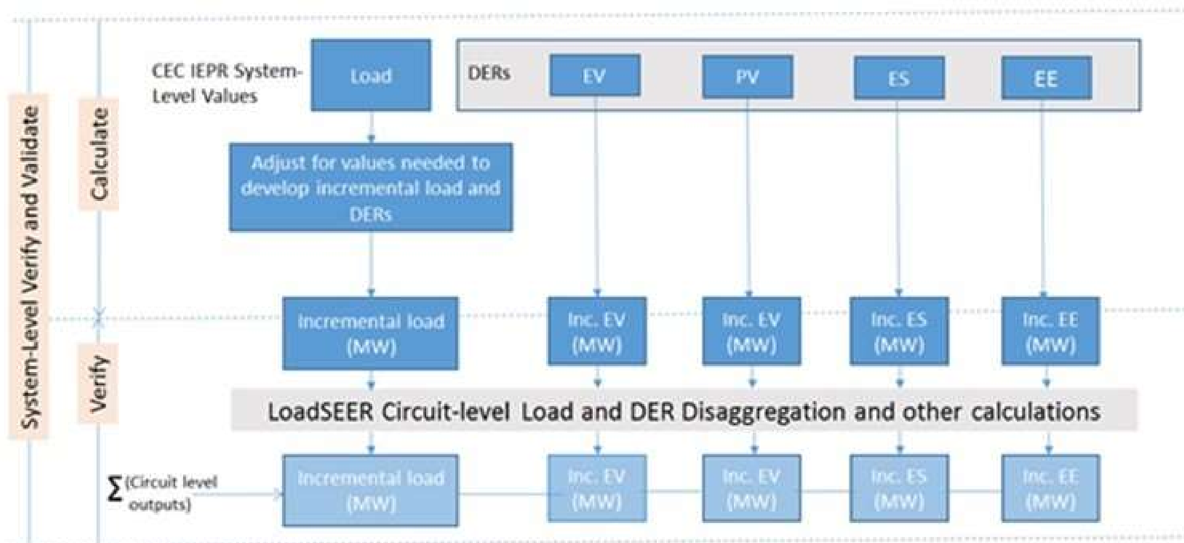
7 Verification Approach and Results

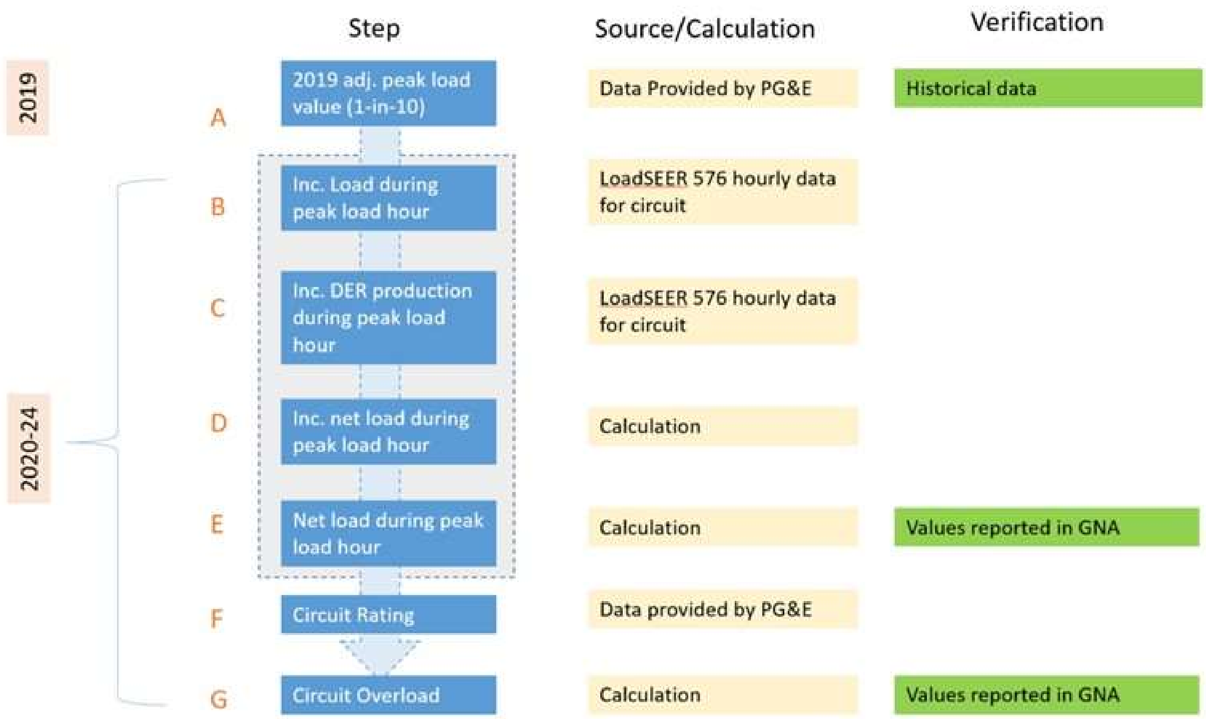
The approach used to verify steps related to load forecasting and checking for circuit overloads is shown in Figure 7-1 and Figure 7-2.

Figure 7-1: System Verification



Prior to allocating the CEC IEPR System-Level forecast to distribution circuits, the system load forecast is reduced to account for transmission load served from the distribution system and for new known distribution loads (which are added later in the process directly to the circuits where the new known loads will be served). This adjusted system load is then distributed by customer class and allocated to the circuits in LoadSEER using geospatial analysis. The transmission load is a not included in this allocated since it is not delivered over the distribution system. The new known distribution loads that were removed are added to the circuit to which they will be connected after the adjusted system load has been allocated to the distribution circuits.

Figure 7-2: Circuit Level Verification



The review includes both a system level review and a circuit level review. The system level review includes:

- The review of the use of the CEC IEPR data to develop top-down load and DER growth forecasts for the planning period.
- This review of CED IEPR data adjustments for such items as transmission customer loads and known new distribution customer loads.
- It also includes a check of the output results of the disaggregation of load and DERs to confirm the aggregate of the outputs at the circuit level (summation of all circuit values) match the input values developed from the CEC IEPR.
- The review performs a number of checks at the individual circuit level for selected circuits. The review checks to see whether the disaggregated load and DERs when integrated, results in the values that are included in the GNA/DDOR reports.

7.1 PROCESSES TO DEVELOP SYSTEM LEVEL AND CIRCUIT LEVEL FORECASTS

7.1.1 Collect 2019 Actual Circuit Loading, Normalize and Adjust for Extreme Weather – Steps 1 and 8

Monthly peak loads are obtained from SCADA or manual reads and entered into LoadSEER. To determine peak loads for the load forecast, peak load values are obtained from LoadSEER for the months of June through September. The peak load value for the summer months is checked by the Distribution Planning Engineer to ensure it was not associated with a system operating abnormality and is entered into LoadSEER for load forecasting purposes. If a circuit is identified as subject to temperature variations, LoadSEER adjusts the actual load according to the temperature and generates a 1-in-2 and a 1-in10 load forecast. If the circuit is not identified as temperature sensitive, the starting load is not adjusted the forecast starting point for the 1-in-2 forecast in LoadSEER is the most recent historic peak load. LoadSEER then produces a 1-in-10 forecast based on this historic starting point. Seven circuits were selected for verification. Table 7-1 presents the data collected and reviewed. Only three circuits were treated as temperature sensitive in the LoadSEER load forecasting software system. During a demonstration we observed LoadSEER provide both 1-in-2 and a 1-in10 load forecasts for the temperature sensitive circuits. For the other circuits, only a 1-in-2 forecast was developed by LoadSEER.

Load Forecast Comparison Across IOUs

The Energy Division approved the use of Mid-Mid IEPR scenarios by each IOU for the 2020 GNA/DDOR filings pursuant to the May 11, 2020 Administrative Law Judge Ruling (Reform No. 3). There was one exception, the Mid-Low scenario was approved for energy efficiency (Figure 7-3, below). Energy Division also seeks to ensure IOU processes align for distribution load forecasting based on 1-in-10 extreme weather events (i.e., heat storms that occur every 1-in-10 years).

The IOUs each generate a 1-in-10 load forecast, but the approach to generating the forecast differs. PG&E and SDG&E use LoadSEER to complete the calculations, but SCE uses internally developed processes and SAS data analytics software.

As a first step, Each IOU normalizes historical load data to a 1-in-2 (in general) prior to generating the 1-in-10 load forecast. This is done to ensure that if the prior year was an outlier weather year, the load data is normalized to what it would have been in an average year. This provides an average year as the starting point for generating the 1-in-10 forecast

The IPE Post-DPAG Report (February 2021) will further review the approaches used by each IOU with the goal of ensuring each IOU's approach to 1-in-10 load forecasting is reasonably equivalent. The minimum, maximum, and average load increases (percentages) that result from each IOU's approach will be compared with due consideration given to the different climates experienced throughout each service territory.

Figure 7-3: CEC IEPR Scenarios for 2020 GNA/DDOR Filings as Approved by Energy Division

The Joint Utilities request approval of the IEPR scenarios for their 2020 GNA/DDORs. The Joint Utilities met and conferred to establish which IEPR datasets would be used for forecasting and disaggregation. On May 21, 2020, the scenarios were shared at the DFWG.[3] A similar table is included below for reference.

		Calendar Year 2019-2020		
		2020 GNA/DDOR		
		SCE	PG&E	SDG&E
	IEPR Vintage	2018 IEPR Update	2018 IEPR Update	2018 IEPR Update
Scenario[4]	Solar PV	Mid - Mid	Mid – Mid	Mid – Mid
	Energy Storage	Mid – Mid	Mid - Mid	Mid – Mid
	Electric Vehicles[5]	Mid – Mid	Mid – Mid	Mid – Mid
	Energy Efficiency	Mid – Low	Mid – Low	Mid – Low
	Load Modifying Demand Response	Mid – Mid	Mid – Mid	Mid – Mid
	Load	Mid - Mid	Mid – Mid	Mid - Mid

2 Decision on Track 3 Policy Issues, Sub-track 1 (Growth Scenarios) and Sub-track 3 (Distribution Investment and Deferral Process) issued February 8, 2018, OP 1a and OP 1c.

3 2020 DFWG Joint Utilities Presentation, presented at Distribution Forecasting Working Group Meeting on May 21, 2020 at p. 46.

4 SCE separately disaggregates Time of Use ("TOU") impacts utilizing data obtained from CEC IEPR. SCE used the TOU impacts from the CEC 2018 IEPR Update Mid-Mid scenario for calendar year 2019-2020.

5 For SCE's calendar year 2019-2020, SCE separately disaggregated Non-Light Duty Vehicles ("Non-LDV") Electric Vehicles ("EV") (includes Medium & Heavy duty, Bus, and Forklift) from the load Mid-Mid scenario for that calendar year.

Table 7-1: Data for Circuit Net Load Verification

Note: This table has confidential information which has been redacted in gray

Feeder Name/ID	2019 Peak Date/Time from EDPI	2019 Peak Average Amps from EDPI	2019 Peak Date/Time in LoadSEER	2019 Peak Amps in Load SEER	If EDPI is different from Load SEER, why?	Temp Used as a Variable in Forecast ?	2019 Starting Point (Amps) - Corp 1-in-2	2019 starting point Adjustmnt ?	3-day Weighted Avg: 1-in-2 Temp: 3-day WAT	3-day Weighted Avg: 1-in-10 Temp: 3-day WAT	3-day Weighted Avg: Actual 3-day WAT on day of 2019 Peak
Llagas 2101083182101	7/11/2019 14:59	492	8/14/2019 18:00	415	Llagas 2103 circuit on 7/11/2019	Yes	421	Yes	104.8	108.3	103.8
Pleasant Grove 2109152442109	9/30/2019 0:00	43	8/15/2019 19:00	455	SCADA Average Amps Bad thru summer. Average was	No	455	No	105.5	108.2	103.9
Saratoga 1107083371107	8/15/2019 17:53	433	8/15/2019 18:00	433	n/a	Yes	406	Yes	95.2	99.7	98.7
Rincon 1101043321101	8/15/2019 18:50	496	8/15/2019 19:00	500	Distribution Engineer	Yes	494	Yes	99.7	102.8	100.3
Gualala 1111042841111	9/4/2019 20:08	224	9/1/2019 20:00	129	carried Gualala 1112 load for all 2019. Extrapolated Gualala 1111 amps	No	129	No	83.5	86.9	76.9

7.1.2 Determine Load and DER Annual Growth on System Level – Step 2

The system level check included reviewing a post processing of the CEC forecast which includes peak load and energy forecasts prior to disaggregation. This is shown on the spreadsheet in Figure 7-4. A copy of this spreadsheet is available in Appendix D.

Figure 7-4: Peak and Energy Forecasts Based on CED 2018 Forecast

PGE TAC Peak and Energy Forecasts: CEDU 2018 Forecast, Mid Baseline-Mid AAEE/AAPV

Coincident Peak 1 in 2 (MW)

A	B	C	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	ANNUAL MW GROWTH OF DISTRIBUTION SYSTEM														
1	*Line 1 of Mid-Baseline Forecast*	Total End Use Load from Mid-Baseline-Mid AAEE tab	21559	21651	22028	22387	22794	23126	23452	23801	24104	24399	24662	24923	25176
2	*Line 2 of Mid-Baseline Forecast*	System-level EV forecast (will be disaggregated at feeder level)	96	115	144	172	203	238	267	288	311	337	351	373	395
3	*Line 9 of Mid-Baseline Forecast*	System-level Other Private Generation (will not be disaggregated at feeder level)	1159	1163	1165	1167	1169	1170	1171	1171	1170	1170	1170	1170	1170
4		Transmission-Only Loads	2230	2240	2250	2260	2270	2280	2290	2300	2310	2320	2330	2340	2350
5	*line 1 minus line 2 minus line 3 minus line 4*	Total Modified Distribution System Load	18084	18133	18470	18789	19152	19438	19725	20042	20312	20572	20810	21041	21262
6	*(Year(X+1)-(Year X))*	Annual incremental MW growth of distribution system load at peak			337	319	363	286	287	317	270	260	238	231	221
7															
8	CUSTOMER CLASS CONTRIBUTION TO INCREMENTAL PEAK LOAD GROWTH (MW) BY YEAR														
9	Residential	40%			135	128	145	114	115	127	108	104	95	92	88
10	Commercial	12%			40	38	44	34	34	38	32	31	29	28	27
11	Industrial	33%			111	105	120	94	95	105	89	86	79	76	73
12	Agricultural	15%			51	48	54	43	43	48	40	39	36	35	33
13															
14	KNOWN CUSTOMER CLASS PEAK LOAD GROWTH (MW) BY YEAR*														
15	Known Commercial Loads (minimum 5 MW assumed known in any year), 2020, 2021, and 2022 applications averaged due to timing uncertainty				96	96	96	12	5	5	5	5	5	5	5
16	Known Industrial Loads (minimum 40 MW assumed known in any year), 2020, 2021, and 2022 applications averaged due to timing uncertainty				93	93	93	40	40	40	40	40	40	40	40
17	Known Agricultural Loads (minimum 10 MW assumed known in any year), 2020, 2021, and 2022 applications averaged due to timing uncertainty				57	57	57	10	10	10	10	10	10	10	10
18															
19	REMAINING ANNUAL INCREMENTAL GROWTH BY CUSTOMER CLASS THAT SHOULD BE ALLOCATED TO FEEDERS (CORPORATE FORECAST)														
20	*equals Line 9 (Known adjustments not applied in LoadSEER)*	RESIDENTIAL			135	128	145	114	115	127	108	104	95	92	88
21	*equals Line 10 minus Line 15, 0 if negative, total must match Line 10 sum*	COMMERCIAL			0	0	0	5	5	5	5	5	5	5	5
22	*equals Line 11 minus Line 16, 0 if negative, total must match Line 11 sum*	INDUSTRIAL			18	12	27	54	55	65	49	46	39	36	33
23	*equals Line 12 minus Line 17, 0 if negative, total must match Line 12 Sum*	AGRICULTURAL			0	0	0	31	31	33	28	27	24	23	21
		TOTAL REMAINING INCREMENTAL GROWTH			153	140	172	205	206	229	190	182	163	156	147
		2020 TO 2029 GROWTH			1796										

*Note that application data was pulled 4 months prior to final forecasts, so numbers may not exactly match known load applications at time the forecasts were finalize

It was confirmed these values were used as part of the disaggregation procedure.

7.1.3 Disaggregate Load and DER Annual Growth to the Circuit Level – Step 3

PG&E uses the results of the LoadSEER software to disaggregate system-level load and DER forecasts to each circuit. Table 7-2 shows the system-level load forecasts by customer class derived from the CEC IEPR (verified in Step 2) that are an input to this step. Table 7-3 shows the aggregated circuit-level loads by customer class. It can be observed that the loads in the tables match reasonably well, except for the year 2020. We are following up with PG&E to determine the cause of this difference.

Table 7-2: System-level load forecasts derived from the CEC IEPR

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
RESIDENTIAL	135	128	145	114	115	127	108	104	95	92
COMMERCIAL	0	0	0	5	5	5	5	5	5	5
INDUSTRIAL	18	12	27	54	55	65	49	46	39	36
AGRICULTURAL	0	0	0	31	31	33	28	27	24	23
TOTAL	153	140	172	205	206	229	190	182	163	156

Table 7-3: Aggregated circuit-level load forecasts derived from LoadSEER results

Table y: Aggregated circuit-level load forecasts derived from LoadSEER results	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
RESIDENTIAL	53	124	107	123	105	90	104	98	94	78
COMMERCIAL	4	4	4	30	28	24	24	24	20	16
INDUSTRIAL	3	18	37	55	45	34	42	36	43	22
AGRICULTURAL	1	2	21	29	34	27	23	19	23	22
TOTAL	61	148	169	237	212	174	193	176	180	138

7.1.4 Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads not in CEC forecast) – Step 4

PG&E accepts the CEC forecast and does not assume there are other loads that will connecting to the PG&E distribution system not included in that forecast. However, they do identify specific loads they expect with a high degree of confidence will be connected on specific circuits. These make up the “new known distribution loads” adjustment made to the CEC system load forecast. After the adjusted system load is allocated to the circuits, these new known distribution loads are added to their specific circuit. The new known loads represent about 55% of the total customer load growth in year 1 of the planning period and by year 10 that drops down to 33% of the total load.

Typical new known distribution loads include loads such as, industrial, commercial, agricultural, and residential projects, cannabis growers, and electric vehicle DC charging stations. This information is obtained from service planning applications for new loads.

As seen in Table 7-4, the sizes of these loads varies greatly from 0.01 MW to 10 MW with most loads being relatively small.

Table 7-4: New Known Distribution Load Size

Incremental Load Growth Projects				
Size (MW)				
0.01 to 0.5	0.51 to 0.99	1.0 to 4.99	5 to 10	TOTAL
712	342	416	12	1482

As shown in Table 7-5, most of these loads occur in 2020.

Table 7-5: New Known Distribution Load In-Service Dates

Year								
2020	2021	2022	2023	2024	2025	2026	2027	TOTAL
1013	273	94	42	45	7	6	2	1482

7.1.5 Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load – Steps 5, 6, and 7

PG&E uses the circuit-level peak load growth forecast by customer class (verified in Step 3) and standard 576-hourly profiles for each customer class to develop the Peak load growth 576 hourly profile for each feeder for each forecast year. This is done using LoadSEER which calculates the 576-hourly load growth profiles at different percentile levels such as P5, P25, P75, and P95.

Similarly, PG&E uses the circuit-level DER growth forecast by customer class (if applicable) and standard 576-hourly profile for each DER to develop the DER growth 576 hourly profile for each feeder for each forecast year.

The IPE obtained the 576 hourly base load, load growth, and DER growth profile from LoadSEER for several feeders as shown for Pleasant Grove 2109 in Figure 7-5. The IPE also obtained standard load profiles for new loads by customer class and various DERs by customer class, as applicable. We then used the peak load and DER forecast at the feeder level (verified in Step 3) and the standard profiles to develop 576 hourly profiles and compared it with those from LoadSEER. Figure 7-6, Figure 7-7, and Figure 7-8 show the comparison of the 576 profiles from LoadSEER and those calculated by the IPE for commercial PV and electric vehicles as a few example for circuit Pleasant Grove 2109. Since comparisons of 576 hourly data for 10 forecasts years is difficult to show, only a comparison of the hourly load profiles for January 2020 and 2029 are shown in these figures. It can be observed from these figures that the IPE calculated load shapes for select DERs match with those from LoadSEER.

Figure 7-5: Load profile for Commercial PV for the Pleasant Grove 2109 circuit from LoadSEER

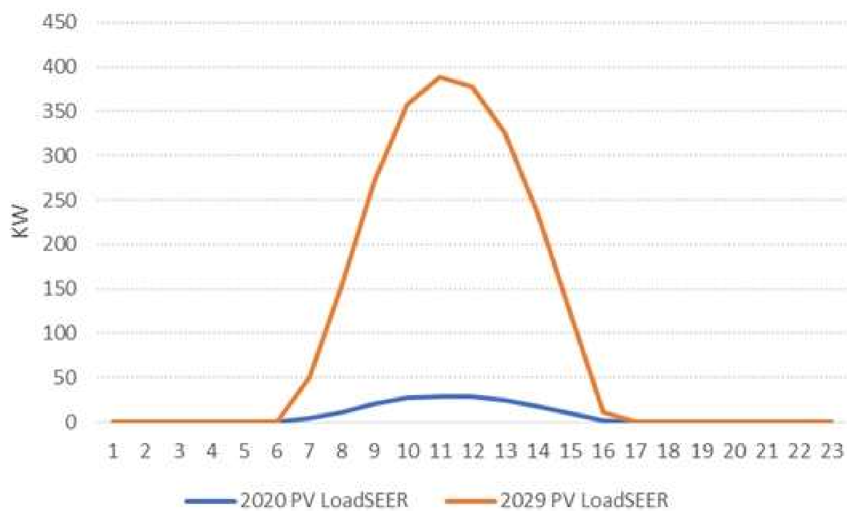


Figure 7-6: Load profile for Commercial PV for the Pleasant Grove 2109 circuit calculated by the IPE

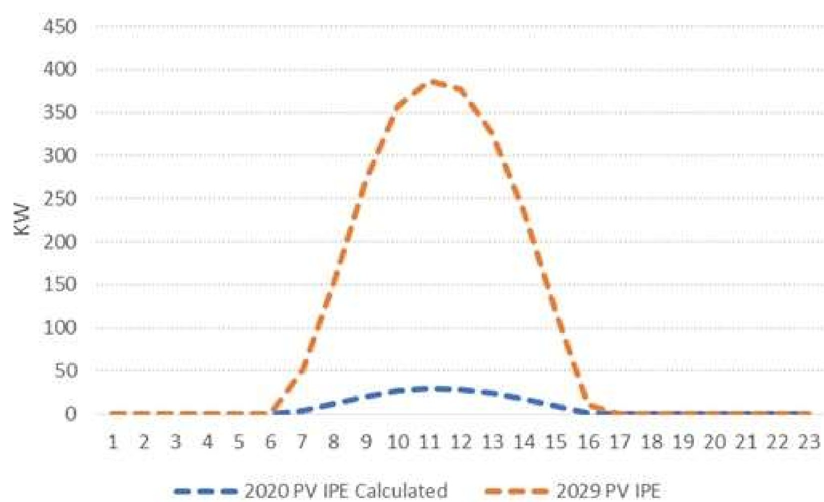
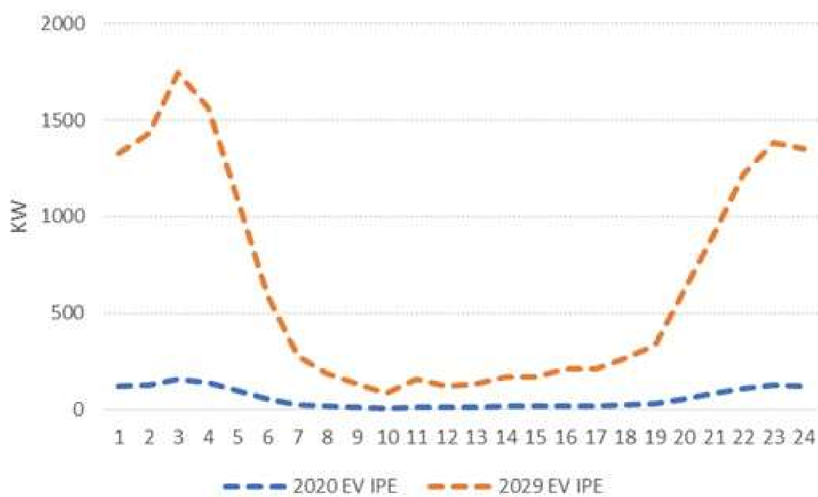


Figure 7-7: Load profile for EV for the Pleasant Grove 2109 circuit from LoadSEER

Figure 7-8: Load profile for EV for the Pleasant Grove 2109 circuit calculated by the IPE



The IPE then determined the net peak load (and net peak load hour) using the 576 hourly load profiles for the feeders shown in Table 7-6Figure 7-7.

Table 7-6: Peak load, peak load hour and ratings for select feeders

Note: This table has confidential peak load data for the San Luis Obispo 1108 feeder which has been redacted and replaced with C.C.

	Pleasant Grove 2109	Gualala 1111	Llagas 2102	Rincon 1101	San Luis Obispo 1108	Saratoga 1107
Peak load hour	WD-Jul-1600	WE-Dec-1800	WD-Jun-1900	WD-Sep-1300	WD-Sep-1300	WD-Mar-1700
Summer rating	18,630	7,120	21,110	11,333	12,190	11,568
Winter rating	20,630	7,120	22,230	12,188	12,190	11,910
Peak load 2020	20,185	4,423	18,728	11,016	C.C.	9,530
Peak load 2021	20,386	4,423	18,631	10,827	C.C	9,509
Peak load 2022	20,756	4,422	18,489	10,646	C.C	9,483
Peak load 2023	21,252	4,441	18,475	10,535	C.C	9,480
Peak load 2024	22,186	4,446	18,368	10,387	C.C	9,439
Peak load 2025	22,754	4,453	18,292	10,270	C.C	9,410
Peak load 2026	23,676	4,461	18,167	10,160	C.C	9,373
Peak load 2027	24,730	4,477	18,120	10,081	C.C	9,360
Peak load 2028	25,220	4,496	18,125	10,024	C.C	9,366
Peak load 2029	25,233	4,496	17,962	9,897	C.C	9,308

7.2 PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA

7.2.1 Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings After No Cost Solutions – Steps 9, 10, and 11

Facility or equipment ratings for existing banks, feeders and line sections are available in GNA Appendices 6.5, 6.6, and 6.7. However, the load data prior to the application of no cost solutions is not provided in either the GNA or DDOR reports. The process of comparing loading and equipment ratings before and after load transfers was demonstrated with load transfers from the Evergreen 2103 circuit to the Evergreen 2104 circuit which is discussed below.

Evaluating potential load transfers involves both LoadSEER and the CYME load flow program. The LoadSEER program provides bank and feeder loading and capacity information, while the CYME load flow program determines loading between sectionalize devices and identifies any voltage or conductor loading problems. Loads to be transferred between sectionalizing devices are obtained by the Distribution Planning Engineer from the CYME load flow program and entered into LoadSEER for new bank and feeder loading results. The transfers are also reflected in CYME (new loading and circuit reconfiguration) to ensure no line section voltage or capacity problems result.

PG&E demonstrated a no cost load solution from the Evergreen 2103 circuit to the Evergreen 3104 circuit. This transfer is being made to reduce the load Evergreen Bank 2 which is forecast to be overloaded by moving that load to Evergreen Bank 3.

The pre-load transfer bank overload was identified in LoadSEER and the Distribution Planning Engineer confirmed the overload. The initial review of transfers was between adjacent banks and feeders. In this case a transfer from Bank 2 to Bank 3 by way of a transfer from Evergreen 2103 to Evergreen 2104 was identified.

The load between sectionalizing devices on the Evergreen 2103 circuit is obtained from CYME. This load is removed from the Evergreen 2103 circuit and added to the Evergreen 2104 circuit in LoadSEER to obtain final loading results which are shown in Figure 7-9 below. In addition, the circuit arrangements is are changed in CYME to account for the transfer and new power flow analyses are completed to ensure no overloads or voltage violation result from this load transfer.

For this project, the need to reduce load on Evergreen Bank 2 is accomplished by transferring 4.1 MW (109 amps) from Evergreen 2103 circuit to Evergreen Bank 3 via the Evergreen 2104 circuit. As can be seen from Figure 7-9, the loading before and after the transfer can be seen for both circuits. Similar information is available for the two banks, but not captured during this demonstration.

Figure 7-9: Evergreen Circuits Load Transfer

A comparison was made of three randomly selected feeders and three randomly selected banks not associated with the DDOR to compare loading through 2024 with the rating of the feeder or bank. As can be seen in Table 7-7, the load did not exceed the facility rating through 2024.

Table 7-7: Facility Rating Vs. Facility Loading, 2020-2024

Note: This table has confidential Peak Facility Loading (%) for Napa 1105 under the 15/15 Rule. This information is identified as C.C in this table

Facility Name	Facility Rating (MW)	Peak Facility Loading (%) 2020-2024
Balfour 1101	4.08	80
Clayton 2218	6.27	29
Napa 1105	C.C.	C.C.
Balfour Bank 1	3.87	75
Clayton Bank 5	10.6	68
North Tower Bank 6	15.84	59

7.2.2 Compile GNA Tables Showing Need and Timing – Step 12

A comparison of 4 potential Candidate Deferral Opportunities was done to compare the drivers, need date and deficiencies in GNA, Appendix 6.5 with projects identified in DDOR. The results are shown in Table 7-8. In each case and especially for Ripon 1705, the deficiency in DDOR was greater than the deficiency shown in GNA. This is because GNA uses a five year planning horizon while DDOR uses a ten year planning horizon. Unless there is some expected load decrease beyond five years because of new banks or feeders in the service area, a relative small increase is expected. The Ripon increase is consistent with the LoadSEER Load Forecast shown in Section 7.4.3, Figure 7-10.

Table 7-8: Review of Drivers and Deficiencies of Potential Candidate Deferral Opportunities

Review of Drivers and Deficiencies of Potental Candidate Deferral				
Project	Driver	In-Service Date	Deficiency in DDOR (MW)	Deficiency from GNA Appendix 6.5 (MW)
Zamora 1108	Zamora Bk 1	2023	1.1	1.02
Ripon 1705	Vierra 1707	2024	3.7	0.85
Belle Haven Bk 4	Belle Haven Bk 3	2023	5	4.16
Willow Pass Bk 1	Willow Pass Bk 1 Willow Pass Bk 3	2023	5.3	5.09

7.3 PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS

7.3.1 Develop Recommended Solution – Step 13

PG&E has a design criteria, “Guide for Planning Area Distribution Facilities” dated 8/15/18 which has been revised to include LoadSEER forecasting, DER inclusion, and GNA and DDOR requirements and timeline. This guideline provides the distribution planners with the explanation and rational for distribution system and component planning, capability of assets, load forecasting, and normal and emergency planning.

The development of two potential Candidate Deferral Opportunities were demonstrated – one for a feeder, Morgan Hill 2103 and one for a bank, Mountain View Bank 1. In each instance the approach was consistent with the “Guide for Planning Area Distribution Facilities”.

7.3.2 Morgan Hill 2103 (Tier 2)

Morgan Hill substation has 3 banks, two-30 MVA banks (Banks 1 and 3), and one 20 MVA bank (Bank 1). Banks 2 and 3 are forecast to have overloads of 3.8 MW and 2.8 MW respectively in 2023.

Bank 1 has transformer available capacity but has limited circuit capacity.

The first step in the process was to identify available transfers to adjacent banks and stations in the Distribution Planning Area (DPA). The Planning Engineer determined there was insufficient transfers available to resolve this problem.

Bank 1 and 2 had a vacant breaker position, but since this bank is overloaded, any additional circuits on this bank would require the bank to also be replaced.

Installing a new breaker in the vacant position on Bank 1 was determined to be the most cost effective solution. Transfers out of the DPA were considered but the costs exceeded the cost of the new feeder at Bank 1. Note this cost comparison was done informally and not documented during this demonstration.

7.3.3 Mountain View 115 kV Bank 1 (Tier 2)

LoadSEER forecast an overload on Mountain View Bank 1 (30 MVA) of 5.3 MW in 2023 because of future EV charging load.

Review of the two adjacent banks capability found them to be loaded to 94% and 98% capability and transfers to other feeders were not possible without extensive reinforcement.

The cost effective solution is determined to be the replacement of Mountain View Bank 1 with a 45 MVA bank.

7.3.4 Estimate Capital Cost for Candidate Deferral Projects – Step 14

Estimated project costs evolve as a project develops and the scope of work becomes more defined. PG&E considers the definition of the Candidate Deferral Opportunities as conceptual with a relatively general definition of scope. They consider the unit cost uncertainty level for all these projects as Class 5 as defined by the American Association of Cost Engineers (AACE).

PG&E considers the project as being at the earlier stages of the project development and the associated costs are estimated using either estimates of specific equipment and unit costs for work required, or historical costs from completed projects. While none of these projects were included in previous GRCs, they will be included in PG&E's upcoming 2023 GRC.

Cost breakdown for six Tier 1 and 2 Candidate Deferral Projects are shown below in Table 7-9. The costs provided in this table are consistent the costs shown in DDOR Appendix A, Planned Investments. These costs cannot be reproduced independently because they use PG&E data based on their historic costs and equipment bids.

It is observed that many of PG&E's unit costs derived from 2017 data and are not escalated. It is recommended PG&E costs be escalated to provide a more up to date reflection of the project costs.

Table 7-9: Cost Data for Selected Candidate Deferral Opportunities

COST DATA FOR CD PROJECTS		
PROJECT NAME	ROUGH PROJECT DEVELOPMENT COST	SCOPE
Willow Pass Bank 1	$14,740,500	Install 45MVA Transformer & New OH Bus @ $7M; Reconfigure 115kV Bus with Ring Bus @ 5.5M; Distribution Line work; 3,000' UG cable w/Trench @ $305/ft: 2 Autotransformers @ $650 each: 4 UG switches @$80K each: 2 OH switches @$30K
Blackwell Bank 1	$6,000,000	Replace Substation Transformer @ cost of $6M
San Luis Obispo 1106	$3,130,000	Install new feeder bay and breaker @ $1.2M; expand substation yard @ $100k; 6,000' new UG @ $305/foot
Zamora 1108	$1,200,000	1 breaker at $1.2M
Beresford 401 Cut-Over	$1,000,000	4,000' UG cable No Trench @$235/ft; Replace 6 UG transformers @ $12K ea
Peabody 2106 Circuit	$110,000	500' of UG @ $220/ft

7.4 PROCESSES TO DEVELOP CANDIDATE DEFFERAL LIST AND PRIORITIZE

7.4.1 Development of Candidate Deferral Projects – Step 15

As mentioned earlier, the technical screening is a continuous process. As capacity and/or reliability projects are identified and created, they are entered into LoadSEER and create a list of projects to mitigate overloads and reduce the number of customer potentially impacted by outages. Projects which do not provide one of the four distribution services, such as pole replacements or road widening, are not entered into LoadSEER. This LoadSEER list is used as input for capacity projects into the GNA. The need date for capacity project are identified in LoadSEER and entered in the GNA. Because of project lead times, an in-service date may be later than the need date. In these cases, PG&E must develop a “work around” alternative until the project can be completed.

Line segment overload and low voltage conditions are identified from the CYME, PG&E’s load flow, and voltage analyst tool. Each line segment with an overload or low voltage condition based on the load forecast is entered into the GNA. Normally these conditions are near term and are filtered out by the timing screen.

The GNA in-service dates are used for as the timing screen.

7.4.2 Development of Operational Requirements – Step 16

Operational requirements are developed using data from LoadSEER which provides loading by month and hour for the peak weekday and/or on a weekend day of the month. An hourly profile is developed for the peak weekday and weekend day for the month, identifying the times and duration of any overload.

Since a weekday could be any weekday in the month, it is assumed for the purposes of determining the maximum calls (or days) per month, the DER could be called upon every weekday that month. The same approach is taken for weekend days. Therefore a need for a DER on one week day would result in a requirement of approximately 20+ calls per month (depending upon the number of weekdays in the month) and a maximum of approximately 8 calls per month (depending upon the number of weekend days per month) if the overload only occurs during a weekend day.

The profile identifies the time and duration of the overload for both the week day and weekend day. PG&E adds an hour to each side of the overload time to reflect where an overload extends to part of an hour before or after the hour identified by LoadSEER. PG&E demonstrated the development of operational requirements for two Candidate Deferral Opportunities; one for a feeder and one for a bank.

7.4.3 Ripon 1705 (new feeder) operational requirements

The driver for this new feeder is the forecasted overload of Vierra 1707 circuit. Therefore the operational requirements are determined by the Vierra 1707 load profile. In Figure 7-10: Vierra 1707 LoadSEER Forecast below, the Vierra 1707 is expected to have an overload beginning in 2024. The maximum overload is forecast to be 3.68 MW by 2029.

Figure 7-10: Vierra 1707 LoadSEER Forecast

Note: All of the information on this figure is confidential and is redacted

[redacted]

Redacted Text

[redacted]

Figure 7-11: Vierra 1707 Peak Weekday Hourly Load Profile

Note: All of information on this figure is confidential and is redacted

[redacted]

Figure 7-12: Vierra 1707 Peak Weekend Hourly Load Profile

Note: All of the information on this figure is confidential and is redacted

[redacted]

Table 7-10: Vierra 1707 Operational Requirements

Note: All of the information on this table is confidential and is redacted

[redacted]

7.4.4 Greenbrae Bank 2 Replacement

Note: All of the information in this section has been identified as confidential and is redacted

Figure 7-13: Greenbrae Bank 2 LoadSEER Forecast

Note: All of the information in this figure is confidential and is redacted

[redacted]

Figure 7-14: Greenbrae Bank 2 Load Profile – Summer

Note: All of the information in this figure is confidential and is redacted

[redacted]

Figure 7-15: Greenbrae Bank 2 Load Profile – Winter

Note: All of the information in this figure is confidential and is redacted

[redacted]

Redacted Text

Table 7-11: Greenbrae Bank 2 Operational Requirements

Note: All of the information in this table is confidential and is redacted

[redacted]

7.4.5 Prioritization of Candidate Deferral Projects into Tiers – Step 17

As part of this step, we reviewed the prioritization metrics spreadsheet in the PG&E DDOR Report Appendix C: Planned Investments (Prioritization Metrics) to assess prioritization rankings, and calculated indices such as costs and LNBA/kW-yr and LNBA/MWh-yr. The prioritization metrics and prioritization approach was discussed in Section 4. As discussed in that section it is difficult to verify the prioritization of these projects. The boundaries between the Prioritization Tiers are not defined. A review of the prioritization was limited to reviewing opportunities that could possibly move from Tier 2 to Tier 1.

7.4.6 Calculate LNBA Ranges and Values – Step 18

The Locational Net Benefits Analysis (LNBA) value is the net present value (NPV) of the annual costs associated with deferring a planned project. The annual cost of deferral is the revenue requirement associated with the planned project which includes annualized capital and operations and maintenance (O&M) costs. The LNBA value can be expressed in a number of ways – as an absolute value ($), as an annualized number ($/yr) or as part of a metrics ($/kW-year). The latter value expressed as a $/KW-yr value is determined by dividing the NPV of the deferral costs by the product of two values – the number of years of deferral and the maximum amount (KW) of need during the deferral period. The LNBA value is used as an indicator as an indication of the economic feasibility of a non-wire solution. A non-wire solution project with a higher value of LNBA would indicate, in general, that it is a more economically feasible than a project with a lower value.

Methodology

We reviewed the methodology PG&E used to develop the LNBA values included in its DDOR Report. A summary of that review follows.

Deferral Timeframe

Deferral period is a key input to the LNBA calculation. PG&E used a deferral time frame from the in-service date of the Planned Investment until the end of the 10-year forecast horizon for all projects. To determine the maximum need, PG&E used a 10-year forecast period for all projects, except line sections in which case they used a forecast horizon of three years.

LNBA Calculation

The deferral value associated with the deferral of a planned project is the NPV of all the annual deferral values during the deferral timeframe. For example, the 10-year deferral value is the sum of the Net Present Values (NPV) of the 1-year deferral value of the proposed solution for the first ten years. The 1-year deferral value of the proposed solution is the sum of the 1-year deferral value of the equipment capital cost and the operations and maintenance (O&M costs) associated with the new equipment that would have been added if the traditional project had been built.

The 1-year deferral value associated with equipment is calculated by multiplying the revenue requirement for the project with the RECC factor.

*1-Year deferral value = Project Revenue Requirement * RECC,*

Where RECC is defined by the following equation:

$$\text{RECC} = \frac{(r-i)}{(1+r)}\left(\frac{(1+r)^N}{(1+r)^N-(1+i)^N}\right)$$

Where, i = assumed inflation over the period of interest, r = assumed discount rate, and N = is the assumed life of the traditional project.

The Project Revenue Requirement is calculated by multiplying the estimated capital cost of the equipment with the Revenue Requirement Multiplier (RRQ Multiplier or RRM). The RRQ Multiplier represents costs recovered from utility customers and includes costs such as taxes, franchise fees, utility authorized rate of return, and overheads. In equation form, the Project Revenue Requirement is:

*Project Revenue Requirement = Estimated Project Capital Cost * RRQ Multiplier*

If a DER is procured instead of building a traditional wires project, utility customers also benefit by avoiding any annual O&M activities associated with the traditional wires project equipment which is not built. Since O&M is an expense item that is passed to customers in the year it is incurred, it is not multiplied by the RECC factor or the RRM. Since O&M costs are incurred in the year they are performed O&M is also subject to inflation adjustments.

The complete expression of the cost reduction associated with a one-year deferral is thus:

Deferral Benefit = [[Project Capital Cost] x [RECC Factor] x [RRQ Multiplier] + annual O&M]

To calculate the value of a multiple-year deferral, the yearly deferral values for each year after the first year are calculated and simply discounted to a present value using a discount factor derived from same discount and inflation rates used in the RECC factor and then the discounted values are summed together to form the multiple year deferral value.

The key assumptions for the LNBA calculation include the following:

- Discount Rate: Derived from the utility's weighted average cost of capital;
- Inflation Rate: Inflation rates for equipment and O&M as assumed as per utility's practice;
- Life of a Traditional Project: Assumptions for project life as per utility's practice;
- Equipment Capital Cost: Cost of the project equipment as per utility's practice; and
- O&M Costs: Cost of O&M as per utility's practice. Expressed as a percentage of the project's capital cost.

PG&E used a simplified LNBA calculator which uses calculations similar to those in the E3 LNBA tool. However, PG&E used their own set of assumptions for the key inputs to the deferral calculation. The inputs and outputs of PG&E's LNBA calculation are discussed below.

Verification of LNBA Results

We verified the inputs that went into the LNBA calculation, as well as the calculation itself, as discussed below.

Key inputs

The key inputs to the LNBA calculation are shown in Table 7-12 below. PG&E used a discount rate of 7.12% which is PG&E's after-tax weighted average cost of capital and reflects CPUC authorized cost of equity, cost of debt, and capital structure, as well as current tax rates. One other key input for the LNBA calculation is the capital cost of equipment for each project.

Table 7-12: Key Inputs for LNBA Calculation

Input	General	Substation Bank	Primary Feeder	Poles and towers	Source
Revenue Requirement Multiplier (Fixed Costs)	136.59%	134.80%	138.38%	140.17%	PG&E Assumption
Revenue Requirement Multiplier With O&M	230.58%	182.17%	278.98%	269.91%	PG&E Assumption
Equipment Inflation	2.5%	2.5%	2.5%	2.5%	Standard assumption in LNBA calculator
O&M Inflation	2.5%	2.5%	2.5%	2.5%	Standard assumption in LNBA calculator
O&M Factor	5.00%	2.52%	7.48%	7.00%	PG&E Assumption
O&M Old Eqpt	0.0%	0.0%	0.0%	0.0%	PG&E Assumption
Book Life	46	46	46	44	PG&E Assumption
RECC	0.05002	0.04967	0.04967	0.0504	Calculated
Discount rate net or project inflation (5/yr)	4.51%	4.51%	4.51%	4.51%	Calculated

Results

The LNBA values shown in PG&E's DDOR report were verified using the formula shown in E3's LNBA calculator for one of the planned projects (Project ID: DDOR020, GNA Facility Name: Vasona 1109) as shown in Table 7-13 below. The calculated values (LNBA range) match those provided in the DDOR report for this circuit. In this table, the values from PG&E's LNBA calculation are shown in column 2. The corresponding values calculated using E3's formula, as well as the formula themselves are shown in the 3rd and 4th columns respectively.

Table 7-13: Vasona 1109 Work LNBA Verification

#	LNBA Item	Values shown in DDOR Report	IPE Calculations based on E3 LNBA formula	E3 LNBA formula
1	Project ID / Name	DDOR020	DDOR020	Input
2	GNA Facility Name	Vasona 1109	Vasona 1109	Input
3	Planned Investment Type	Feeder	Feeder	Input
4	Project Cost ($k)	1650.00	1650.00	Input
5	Revenue Requirement Multiplier	2.79	2.79	Input
6	Discount Rate (%/yr)	0.07	0.07	Input
7	Equipment Inflation	0.025	0.025	Input
8	O&M Inflation	0.025	0.025	Input
9	O&M Factor	0.00	0.00	Input
10	Book Life	46	46	Input
11	DER Install Year	2023	2023	Input
12	Cost year basis	2020	2020	Input
13	Analysis Year	2020	2020	Input
14	Deferral Years	7.00	7.00	Input
15	Number of no deficiency years after the DER Install yr	0.00	0.00	Input
16	Incremental O&M Cost	0.00	0.00	C4*C9
17	RECC	0.05	0.05	(C6-C7)/(1+C6)*(1+C6)^C10/((1+C6)^C10-(1+C7)^C10)
18	Discount rate net or project inflation (5/yr)	0.05	0.05	(1+C6)/(1+C7)-1
19	RR Install Yr $'s	4916.17*	4957.47	C4*C5*(1+C7)^(C11-C12)
20	RR * RECC	244.16	246.21	C19*C17
21	Capital Benefit in Install Year	1503.00	1515.85	PV(C18,C14,-C20,0,1)
22	O&M Deferral Benefit in Install Year	0.00	0.00	PV(C18,C14,-C16,0,1)*(1+C8)^(C11-C12)/(1+C18)^B15
23	Value of Deferral Benefits ($000s) in Install Year	1503.22	1515.85	C21+C22
24	Value of Deferral Benefit ($000s) in 2020	1251.56	1233.23	C23/(1+C6)^(C11-C12)
25	Max Need (MW/Vpu/MVAR)*	3.87	3.87	Verified
26	Normalized Deferral Benefit ($000s/MW-yr)	46.00	45.52	C24/C25/C14

*the value calculated for revenue requirement by PG&E is slightly different since it takes partial year into account in the present value calculation whereas the E3 LNBA does not.

7.4.7 Compare 2019 Forecast and Actuals at Circuit Level for 2019 – Step 19

As part of the IPE plan, a review of the 2019 forecast against the actual 2020 loads was conducted.

The final forecast in GNA is a 1 in 10 forecast. Actual or historical loads are not adjusted to 1 in 10 unless the bank or feeder is identifies weather as a forecast variable.

Load forecasts are found in GNA report, Appendix. 6.5, GNA Results Demand Forecast and Bank/Feeder capacity Needs, 2020 Load Forecast column. The actual loads are found in LoadSEER for each bank and circuit. LoadSEER loads are provided in MWs for all loading, while actual values for bank loading are provided in MW and actual values for circuit loading are provided in amps.

While high temperatures impact many banks and circuits, some PG&E banks and circuits serving agricultural loads in the central valley are impacted by USBR water allocations. If the water allocation is high, electric loads are reduced because of reduced pumping demand. On the other hand, if the allocation is low, electric loads are increased because of increased pumping requirements.

USBR provides a forecast monthly starting in January through June but there can be large changes each month depending on several reasons including reservoir levels, snow level, snow melt rate and political considerations.

PG&E attempts to adjust the actual load value for a bank or circuit if the water allocation is very high or low. But this is a relatively new variable and they are trying several approaches to help them forecast load for this variable.

A results of a review of ten of the Candidate Deferral Opportunities identified in the 2019 DDOR is shown in Table 7-14. This review was conducted with PG&E.

Table 7-14: 2019 Loads, Actual vs. 2019 Forecast Worksheet

Note: This table has confidential information redacted in black.

Project #	Project Name	Asset with Grid Need	Type of Deficiency	2019 Actual	2019 Actual Corrected for Temperature	2019 Forecast (MW) from 2019 GNA	2019 Forecast (AMPS for feeders) from 2019 GNA	Reason for Difference	Confidential?
1	Alpaugh New Feeder	Corcoran Bank 3	Normal Overload	17.69	20.69**	28.7	-	Higher water allocation than forecast - less pumping - reduced loads	
		Corcoran 1112	Normal Overload	[redacted]					
2	Calflax Bank 2	Calflax Bank 1	Normal Overload						
3	Santa Nella New Bank and Feeder	Canal Bank 1	Normal Overload	27.59	Negative Correlation to temp	30.36	-		
		Canal Bank 2	Normal Overload	26.08	Poor Correlation to Temp	28.9	-		
		Ortiga Bank 1	Normal Overload	14.5	Negative Correlation to temp	16.17	-		
		Canal 1103	Normal Overload	508	Poor Correlation to Temp	12.3	575		
		Santa Nella 1104	Normal Overload	[redacted]					
		Ortiga 1106	Normal Overload	390	Negative Correlation to temp	9.18	429		
4	Camp Evers 2107	Camp Evers 2106	>6000 Customers	341	Negative Correlation to temp	13.57	366		
5	FMC 1102	FMC 1101	> 600A	737	Negative Correlation to temp	13.62	637	2019 was 5 degrees warmer than 2018, starting point was based on 2018 actual	
6	Brentwood 2105	Brentwood 2105	Back Tie	388	461*	17.7	478	2019 was not a 1-in-10 temperature	
7	Pueblo Bank 3	Pueblo Bank 1	Emergency Bank Loss	45.85	44.53*	40.73	-		
8	Rob Roy 2105	Rob Roy 2105	>6000 Customers	263	Poor Correlation to Temp	9.13	247		
9	Avenal 22101	Avenal 2101	Back Tie	[redacted]					
10	Edenvale 2108	Edenvale 2108	>6000 Customers	430	435	15.77	426		
11	No project - Example Only	Edenvale 2106	Example	465	489	18.21	492		

* if temperature were used as variable

** 2019 forecast if forcast had known actual 2019 water availability

Projects in Table 7-14 identified as having a negative or poor correlation to temperature (2019 Actual Corrected for Temperature column), do not use temperature as a variable in the forecast. A poor correlation means the R squared relationship between historic temperature and historic peak load is weak or nonexistent. A negative correlation implies the temperature is inversely proportional to load and is not appropriate for summer peak forecasts. In Table 7-14, only the Edenvale 2108 and the example feeder used temperature as a forecast variable

A review of the forecast versus actual loads, adjusted for temperature where appropriate, found the actuals varied from 29.9% under the forecast to 15.7% over the forecast. The majority of the actuals were under their forecast. This review is not intended to be a criticism of the load forecasting process because PG&E goes to great effort to identify and utilize potential impacts on their load forecast. Also, this is a very small number of banks and feeders compared to the total number in the PG&E system. But it does demonstrate the complexity of load forecasting. In addition to weather, other issues such as water allocation, changing technology and societal changes also impact the forecast.

As mentioned earlier, PG&E is working with State and Federal agencies to develop a better water allocation forecasting process. This will be of great value for assets in the Central Valley of California

7.5 OTHER FUTURE IPE WORK

7.5.1 Review Implementing of Planning Standard and/or Planning Process – Step 20

This review is planned for completion after the IPE DPAG Report is published.

7.5.2 Review List of Internally Approved Capital Projects – Step 21

This review is targeted for completion in November according to the IPE Plan. The results of this review will be included in the Post DPAG Report.

7.5.3 Respond to and Incorporate DPAG Comments – Step 22

The IPE was available during the PG&E DPAG meeting and the PG&E Follow-Up DPAG meeting to respond to questions raised and has also responded to written questions posed to the IPE by stakeholders which is included in Appendix B.

7.5.4 Track Solicitation Results to Inform Next Cycle – Step 23

This review is planned for completion in Q1 of 2021.

7.5.5 Treating confidential material in the IPE report – Step 24

The IPE work products have followed the process and steps included in this Business Step in developing its IPE Final Report.

Appendix A IPE Scope

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment A
Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.

2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.

3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.

4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.

5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.

6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

(end of Attachment A)

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Attachment B
IPE Scope of Work for DIDF Implementation

Term

- January 1st each year to July 31st the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Develop an ***IPE Plan*** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
    - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
        - Collecting circuit loadings and performing weather adjustments;
        - Determining load and DER annual growth on the system level;
        - Disaggregating load and DER annual growth to the circuit level;
        - Checking sum of all disaggregated load and DERs against system-level values;
        - Adding incremental known loads to circuit level forecasts;
        - Developing load, DER, and net load profiles and determining net peak loads;
        - Adjusting for extreme weather;
        - Comparisons to equipment ratings to determine if ratings will be exceeded;
        - Incorporating load transfers, phase transfers, correcting data errors;
        - Compiling GNA tables showing need amount and timing; and
        - Following the IOU's planning standard and/or planning process.
    - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
        - Developing recommended solutions (planned investments);
        - Implementing the IOU's planning standards and/or planning process;
        - Estimating capital costs for planned investments;

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- Developing list of candidate deferral projects through application of screens (timing and technical);
- Developing operational requirements;
- Prioritization of candidate deferral projects into tiers;
- Calculating LNBA values; and
- Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.

- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
  - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
- Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
- Review and incorporate comments in the final IPE Plans.
- Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
- Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

DPAG Period

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

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- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.
- Fully implement each IPE Plan as defined in the final IPE Plans.
- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.
- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.
- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.
- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

- Submit the final report to Energy Division and prepare public versions as needed.
- Support Energy Division with their review of DIDF reform comments, including comments on any IPE tasks.
- Support Energy Division's review of RFO materials and RFO outcomes.
- Attend RFO and procurement meetings and provide technical support as requested by Energy Division.
- Coordinate with the Independent Evaluator to support their evaluation and provide technical support at the discretion of Energy Division.
- Other technical support assignments as defined by Energy Division to develop and evaluate potential DIDF reforms and track and evaluate deferral opportunities that may be subject to ongoing review in other proceedings (e.g., pursuant to General Order 131-D).

<u>List of IPE DIDF Deliverables</u>

1. ***IPE Plan*** for each IOU describing the GNA/DDOR review process and approach to Verification & Validation for the underlying data.
2. ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
3. ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
4. ***IPE Post-DPAG Report*** covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements and DIDF reform.

(end of Attachment B)

Appendix B DPAG Survey and Comment Responses

PG&E sent a questionnaire to the DPAG members to solicit feedback from the DPAG and also solicited comments by email. The feedback sought was to be directed to PG&E and/or the IPE per the CPUC Ruling. There were a number of responses and comments as documented here in this appendix.

B.1 Comments and Questions Directed to IPE

CESA

Survey Question:

What questions or comments do you have for the Independent Professional Engineer regarding his presentation and review of PGE's GNA/DDOR and candidate deferral prioritization process?

CESA Response:

Since DPAG stakeholders cannot view redacted project information, the IPE's assessment of these projects, even at a high-level recommendation and qualitative assessment level would be helpful. Please also look into the key specific drivers of forecast uncertainty, which is a flag for two projects.

IPE Response:

The IPE reviewed all projects in the candidate deferral list for the potential of placing them in Tier 1. That included the review of all confidential information not available to DPAG members as well as information received through data requests and direct discussion with PG&E. The results of that review are contained in Section 5 in the body of the report. We suggest projects be moved in Tier 1 in that section.

B.2 PG&E DPAG Survey Responses

Listed below are the responses received from the DPAG to the questionnaire sent out by PG&E on September 20, 2020.

Question 1:

What leads to PG&E proposing a deferrable microgrid opportunity in the DIDF versus one that is considered in the Wildfire Mitigation Plans or in the Microgrids proceeding? CESA [California Energy Storage Alliance] presumes that this is determined based on whether a project has a planned investment (i.e., wires) that could be deferred. Please confirm.

Answer 1:

PG&E confirms that Resiliency (Microgrid) Candidate Deferral Opportunities in the DIDF require there is a Planned Investment that could be deferred. The Microgrid Order Instituting Rulemaking ("OIR") and Wildfire Mitigation Plan ("WMP") proceedings are considering broader tariff, policy and ratemaking issues related to microgrids and wildfire mitigation plans and investments.

Question 2:

In the DDOR [Distribution Deferral Opportunities Report] report, PG&E indicated that it will not introduce a margin for the DER [distributed energy resource] distribution service requirement because it would increase the difficulty of procurement or ability to interconnect cost effectively. However, this is contrary to the DIDF reforms directed in the May/June 2020 Ruling. While the service requirement does not include a margin, please confirm that a margin could be included for DER procurement to mitigate forecast uncertainty and need changes, so long as the DER solution is cost-effective relative to the planned investment. One of the reasons for this reform is that it can be problematic for developers if PG&E can come back to developer and say needs have changed, leading projects to not be deferrable, whereas a procurement margin can mitigate such risks. PG&E Response to DPAG Survey in R.14-08-013 Page 2

Answer 2:

As stated at PG&E's 2020 DPAG meeting, "PG&E's RFO [request for offers] materials will allow and encourage developers to provide options in their bids for 2020-2021 DIDF RFO for the procurement of DER resources above minimum capacity requirements to the extent it remains cost effective. Grid needs are dynamic and there is inherent forecast uncertainty in distribution planning. Developers are therefore encouraged to provide cost effective options for additional distribution capacity to provide a hedge against changes to forecast." Therefore, a margin can be included for DER procurement to mitigate forecast uncertainty and need changes, so long as the DER solution is cost-effective relative to the planned investment.

Question 3:

San Luis Obispo 1106: CESA supports this project for the 2021 DIDF RFO. Will PG&E only consider resources that will meet both the summer and winter needs, or can these needs be decoupled and addressed by two different solutions?

Answer 3:

PG&E will consider resources that don't meet the full need. PG&E may consider resources that meet the decoupled winter or summer need, either as a single resource or an aggregation. However, to the extent that a Participant is able to, Participant will be encouraged to submit at least one Offer that addresses the entire combined need for the San Luis Obispo 1106 Candidate Deferral.

Question 4:

Dunnigan Bank 1: This project has a very high LNBA [Locational Net Benefit Analysis] score and represents good-fit operational requirements. CESA seeks more information on whether the likelihood of failure due to equipment age can be mitigated. Is there more information on recent equipment performance or benchmark information on the expected lifetime of this equipment that has led PG&E to propose a planned investment in 2020 as opposed to years earlier? This could inform whether and for how long this need can be deferred. We also seek more information about the nature of the new load growth expected in the area.

Answer 4:

Dunnigan Bank 1 is 78 years old. The average age of failure for this type of bank is 68 years old. The age at which repairs are generally not attempted is 70 years old. The planned investment at Dunnigan (Replace Bank 1) is not related to either the age or the condition of the bank at Dunnigan. It is instead driven by two new electric vehicle charging loads coming into the Dunnigan Area along Highway 5. The in-service date for the Planned Investment is 2024. These applications were received by PG&E in 2020 which is why the Planned Investment was not proposed prior to 2020.

Appendix C Copy of the IPE Plan

Note: The IPE Plan for PG&E is included in a separate file from the file containing this report.

Appendix D Data Requests and Responses

Appendix D Data Requests and Responses

The IPE received many sets of data from PG&E during the review. Listed below are the data requests documents and the documents provided to the IPE during the course of the review. In many cases these data sets presentations (Power Point) that were used in demonstrations of the various business processes in the plan. In addition there are numerous spreadsheets and PDFs and/or Word documents. These actual documents are provided as separate documents from the body of this report. The list of documents is broken down into 1) documents that do not have any confidential information which are listed under Documents Provided - Common to Confidential and Public Versions, and 2) documents which have confidential information. In the latter case the Public Version of this report contains a list of the public versions of these documents and the Confidential Version of the report contains a list of the confidential version of these documents.

D.1 List of Documents Provided - Common to Confidential and Public Versions of the Report

- Adjusted PGE Load Modifiers Mid BaselineMid AAEECEDU 2018.xlsx
- Before and After Transfers.pptx
- CEC Load Growth Forecast to Feeders 2020 to 2029.xlsx
- Dunnigan Bank Replacement Forecast Uncertainty Questionaire.xlsx
- ES NonRes Discharging Disaggregation.xlsx
- ES Res Charging Disaggregation.xlsx
- ES Res Discharging Disaggregation.xlsx
- Forecast Shape Export - GUALALA 1111 - 2020-09-18 0425.xlsx
- Forecast Shape Export - LLAGAS 2101 - 2020-09-18 0138.xlsx
- Forecast Shape Export - PLEASANT GROVE 2109 - 2020-09-18 0244.xlsx
- Forecast Shape Export - RINCON 1101 - 2020-09-18 0356.xlsx
- Forecast Shape Export - SAN LUIS OBISPO 1108 - 2020-09-18 0212.xlsx
- Forecast Shape Export - SARATOGA 1107 - 2020-09-18 0322.xlsx
- How EE Profiles Are Derived.docx
- List of 20 Circuits.xlsx
- Mountain View Bank 1 Forecast Uncertainty Questionnaire.xlsx
- PlanningGuideline.pdf

D.2 List of Public versions of Confidential Documents Provided for the Public Version of Report

- PUB_PGE_2020_DDOR Report.pdf
- PUB_PGE_2020_DDOR_Appendices_AtoD_combined.pdf
- PUB_PGE_2020_GNA Report.pdf
- PUB_PGE_2020_GNA_Appendices_63to67_combined.pdf
- PUB_R.14-08-013 PGE 2020_DDOR Cover Pleading.pdf
- PUB_R.14-08-013 PGE 2020_GNA Cover Pleading.pdf
- AAEE - REDACTED MATERIALS (002) (5).pdf
- CONF - 2019 CD Projects 2019 Forecast VS Actuals (3).pdf
- CONF-Future New Load Adjustments (1) (1).pdf
- Confidentiality_Declaration_DDOR_Nakayama.pdf
- Confidentiality_Declaration_GNA_Nakayama.pdf
- Confidentiality_Declaration_IPE_20200825.pdf
- Confidentiality_Declaration_IPE_20200903 (1).pdf
- Confidentiality_Declaration_IPE_20200918.pdf
- Confidentiality_Declaration_IPE_20200930.pdf
- Confidentiality_Declaration_IPE_20201002 (2).pdf
- Confidentiality_Declaration_IPE_20201002 (4).pdf
- Confidentiality_Declaration_IPE_20201020 (2).pdf
- CONF-LMDR Profile (2).pdf
- CONF-PV Non-Res Profile.pdf
- CONF-PV Res Profile.pdf
- CUSTOMER CONFIDENTIAL_GREENBRAE BANK 2 DER Serv Req WDWE.pdf
- CUSTOMER CONFIDENTIALLoadSEER ScreenshotsRiponGreenbrae.pdf
- IPE_DR03_Step 3_Template for Feeder-level Disaggregation (1).pdf

Headquarters
101 2nd Street, Suite 1000
San Francisco CA 94105-3651
Tel: (415) 369-1000
Fax: (415) 369-9700
www.nexant.com

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Cenergy Power
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
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Dept of General Services
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ICF
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Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy