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

Pacific Gas & Electric Company
ELC (Corp ID 39)
Status of Advice Letter 6766E
As of December 20, 2022

Subject: Request for Approval to Not Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities

Division Assigned: Energy

Date Filed: 11-15-2022

Date to Calendar: 11-18-2022

Authorizing Documents: None

Disposition:	**Accepted**
Effective Date:	**12-15-2022**

Resolution Required: No

Resolution Number: None

Commission Meeting Date: None

CPUC Contact Information:

edtariffunit@cpuc.ca.gov

AL Certificate Contact Information:

Kimberly Loo
(415)973-4587
PGETariffs@pge.com

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

To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

The Energy Division of the California Public Utilities Commission has processed your recent Advice Letter (AL) filing and is returning an AL status certificate for your records.

The AL status certificate indicates:

Advice Letter Number
Name of Filer
CPUC Corporate ID number of Filer
Subject of Filing
Date Filed
Disposition of Filing (Accepted, Rejected, Withdrawn, etc.)
Effective Date of Filing
Other Miscellaneous Information (e.g., Resolution, if applicable, etc.)

The Energy Division has made no changes to your copy of the Advice Letter Filing; please review your Advice Letter Filing with the information contained in the AL status certificate, and update your Advice Letter and tariff records accordingly.

All inquiries to the California Public Utilities Commission on the status of your Advice Letter Filing will be answered by Energy Division staff based on the information contained in the Energy Division's PAL database from which the AL status certificate is generated. If you have any questions on this matter please contact the:

Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

Pacific Gas and Electric Company

Sidney Bob Dietz II
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 15, 2022

Advice 6766-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Request for Approval to Not Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities**

Purpose

In accordance with Reform #40 in the Administrative Law Judge's (ALJ) Ruling Modifying the Distribution Investment Deferral Framework (DIDF)-Filing and Process Requirements (Ruling), issued May 11, 2020[1], and Revised Reform #40 in the June 21, 2021 ALJ's Ruling Modifying the DIDF Filing And Process Requirements (June 2021 ALJ Ruling)[2] in Rulemaking (R.) 14-08-013, Pacific Gas and Electric Company (PG&E) respectfully submits this Tier 2 advice letter seeking the California Public Utilities Commission's (Commission's or CPUC's) approval to not issue competitive solicitations in the 2022-2023 DIDF Request for Offer (RFO) to procure distributed energy resource (DER) solutions for identified electric distribution deferral opportunities in PGE's 2022 Distribution Deferral Opportunities Report (DDOR).

1. Regulatory 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

[1] May 11, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework – Filing and Process Requirements, Attachment A, pp. 96. Attachment A was subsequently revised on June 12, 2020
[2] June 21, 2021, Administrative Law Judge's Ruling on recommended reforms for the Distribution Investment Deferral Framework Process, Revised Reform #40. pp. 9

tracks: Track 1 – Tools and Methodologies, Track 2 – Field Demonstration Projects, and 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 DDOR by September 1 of each year. Subsequently, the May 2019 ALJ Ruling modified the DIDF to align the submission of both GNA and DDOR reports to August.

There were two improvement rulings modifying the DIDF process by ALJ Mason in 2020. The April 13, 2020 ALJ's Ruling Modifying the DIDF 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 2020 ALJ Ruling further modifies the DIDF process and filings requirements by focusing on the comments and reforms related to aspects of the DIDF.

In June 2021, the assigned ALJ issued a ruling on recommended reforms to the DIDF process and addressed alignment with requirements adopted by Decision D. 21-02-006. Specifically, the ruling introduced eight new reforms and amended eight reforms. As a result of this ruling, the Partnership and Standard Offer Contract (SOC) Pilots will align within the current DIDF process and are subject to DIDF reforms while pilots are active.

In November 2021, the Order Instituting Rulemaking (OIR) to Modernize the Electric Grid for a High Distributed Energy Resources Future (R.21-06-017) was filed to replace the 2014 DRP and now stands as the OIR home for GNA and DDOR compliance. In June 2022[3], the assigned ALJ issued a ruling on recommended reforms for the DIDF process, the Partnership and SOC Pilots. In this Advice Letter, PG&E is seeking approval for no additional RFO for distribution deferral projects in compliance with Revised Reform No. 40 in the June 2021 and June 2022 ALJ Rulings.

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, the May 2020 ALJ Ruling and the June 21, 2021 ALJ Ruling, PG&E has completed the following:

- August 15, 2022: Submitted PG&E's 2022 GNA Report
- August 15, 2022: Submitted PG&E's 2022 DDOR

[3] June 16, 2022, Administrative Law Judge's ruling on recommended reforms for the Distribution Investment Deferral Framework process, the Partnership Pilot, and the Standard-Offer-Contract Pilot

- September 22, 2022: Hosted PG&E's Distribution Planning Advisory Group (DPAG) Meeting #1 via Webinar
- October 17, 2022[4]: Submitted Supplements to PG&E's 2022 GNA on Line Section Needs and PG&E's 2022 DDOR on Known Load Project Tracking
- October 19, 2022: Submitted Supplement to PG&E's 2022 DDOR on Line Section Planned Investments
- October 21, 2022: Hosted PG&E's Follow up DPAG Meeting via Webinar

3. Proposal to Not Solicit Candidate DER Distribution Deferral Projects

PG&E recommended 7 Candidate deferral projects that have the best likelihood of success via the 3 DER sourcing mechanisms (DIDF RFO, SOC pilot RFO and Partnership pilot). PG&E published this in the DDOR and presented it during the DPAG. Table1, Section 5.1, has the summary of the recommendations. PG&E is requesting approval to not solicit additional DER distribution deferral projects for the Fall 2022 DIDF RFO. PG&E does not currently recommend pursuing competitive solicitations of DER for additional projects due to their low likelihood of achieving a successful outcome. Moreover, focusing developer efforts on only the 7 selected projects may improve their probability of success.[5] The other Tier 2 and Tier 3 Candidate Deferral Opportunities include characteristics that decrease their likelihood of success, thus are not recommended for solicitation.

4. 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.

The May 11, 2020 ALJ Ruling[6] modified several elements of the DIDF Process, including changes to the Prioritization Metrics Workbook. A Joint Prioritization Metrics Workbook Template (JPMWT) was developed jointly by the IOUs and was approved by Energy Division on May 18, 2021, with minor updates to the workbook approved by the Energy Division on July 30, 2022.

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[4] As per June 16, 2022, Administrative Law Judge's Ruling, Attachment A, Optional due date for line section data supplement to GNA/DDOR (October 15, 2022), where dates fall on a weekend or holiday, the activity is intended to occur/be due on the following business day.

[5] In the August 30, 2021 Independent Evaluation Report for Pacific Gas & Electric's 2021 Distribution Investment Deferral Framework Request for Offers, the Individual Evaluator (IE) considers that while providing many opportunities may develop a wide array of offers, it may have a negative effect in providing too many options, diffusing the bidding community's attention, and decreasing the likelihood of Participants submitting enough offers at any one location to meet the location's needs.

[6] May 11, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework, Attachment A (subsequently revised on June 12, 2020), — Prioritization Metrics, DIDF Reform #20. pp.92.

PG&E's preliminary prioritization and ranking of candidate deferral opportunities were published in PG&E's 2022 DDOR. One of the candidate deferral projects dropped from Tier 2 (2022 DDOR Appendix C - Filed on August 15th, 2022) to Tier 3 (PG&E DPAG on Sept 22nd, 2022 – slide # 37). As discussed during PG&E's DPAG workshop, there was an error (which was identified by the IPE during the verification and validation process) and fixed prior to the DPAG presentation. The prioritization metrics and tiering were then thoroughly discussed throughout the DPAG process, and the updated Appendix C of the 2022 PG&E DDOR is included in Attachment A.

Per the June 2022 ALJ Ruling Section 4.1[7] (Joint Prioritization Metrics Updates), Utilities were required to work jointly with the IPE to develop a proposal for revisions to the JPMWT no later than November 15, 2022. Utilities are in alignment with not proposing any changes to the JPMWT at this time and will collaborate on revisions to the JPMWT after the release of the IPE Report in future working sessions.

5. Candidate Deferral Opportunities

5.1 Candidate Deferral Opportunities Recommended for Solicitation

PG&E is pursuing competitive solicitations for the Candidate Deferral Opportunities listed in Table 1. This was presented in PG&E's 2022 DDOR and DPAG. Per D.21-02-006[8] and revised reform #40[9], Tier 2 Advice letter seeking approval to launch the RFO was eliminated. PG&E launched the RFO for the DIDF RFO and SOC pilot RFO on Sept 15, 2022. Additional details are provided on the respective websites for the Fall 2022 DIDF RFO[10], and 2022 DIDF SOC Pilot[11]. PG&E will file a separate advice letter requesting approval to launch the three candidate deferral opportunities recommended as Partnership Pilots. PG&E partnership pilot website[12] provides additional details on all partnership pilots currently under active solicitation.

[7] June 16, 2022, Administrative Law Judge's Ruling on Recommended Reforms for the DIDF process, the partnership pilot and the Standard offer contract pilot, pp. 15
[8] February 11, 2021, Decision adopting pilots to test two frameworks for procuring distribution energy resources that avoided or defer utility capital investment Decision 21-02-006, Ordering Paragraph 11. pp. 84
[9] June 21, 2021, Administrative Law Judge's Ruling on recommended reforms for the Distribution Investment Deferral Framework Process, Revised Reform # 40. pp. 9
[10] Fall 2022 Distribution Investment Deferral Framework ("DIDF") RFO (pge.com)
[11] 2022 Distribution Investment Deferral Framework ("DIDF") SOC pilot RFO (pge.com)
[12] Distribution Investment Deferral Framework ("DIDF") Partnership Pilot (pge.com)

Table 1: Candidate Deferral Opportunities Recommended for Solicitation

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Sourcing Mechanism
Tier 1	DDOR109	Blackwell Bank 1	6/1/2025	CC	SOC Pilot
Tier 1	DDOR1001	Camden 1106	5/31/2025	CC	DIDF RFO
Tier 1	DDOR1007	Carlotta Bank 2	5/31/2025	2.0	Partnership Pilot
Tier 1	DDOR079	Gabilan Bank 2	5/1/2025	CC	Partnership Pilot
Tier 1	DDOR1008	Old River Bank 2	5/31/2025	CC	DIDF RFO
Tier 1	DDOR1005	San Joaquin Bank 2	5/31/2025	CC	DIDF RFO
Tier 1	DDOR066	Vasona 1109	6/1/2025	CC	Partnership Pilot

5.2. Candidate Deferral Opportunities Not Recommended for Solicitation

PG&E seeks approval to not pursue competitive solicitations for the Tier 2 and Tier 3 candidate deferral opportunities listed in Table 2.

Table 2: Candidate Deferral Opportunities Not Recommended for Solicitation

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Sourcing Mechanism
Tier 2	DDOR1029	7th Standard Bank 2	5/1/2025	CC	Not Recommended
Tier 2	DDOR1030	Famoso Bank 1	5/1/2025	CC	Not Recommended
Tier 3	DDOR1027	Millbrae Substation	5/2/2025	CC	Not Recommended
Tier 3	DDOR091	Chualar Bank 1	5/1/2025	CC	Not Recommended
Tier 3	DDOR105	Lockeford Bank 5	5/1/2025	CC	Not Recommended
Tier 3	DDOR102	Montague Bank 2	5/1/2025	CC	Not Recommended
Tier 3	DDOR1026	Ravenswood Substation	4/1/2025	72.5	Not Recommended
Tier 3	DDOR1031	Semitropic Bank 4	5/1/2025	CC	Not Recommended
Tier 3	DDOR1032	Tevis Bank 1	5/1/2025	CC	Not Recommended
Tier 3	DDOR1034	Tulucay Bank 4	5/31/2025	CC	Not Recommended
Tier 3	DDOR1033	Weber Bank 7	5/1/2025	CC	Not Recommended

Tier 2 Candidate Deferral Opportunities Not Recommended for Solicitation:

Tier 2 Candidate Deferral Opportunities scored in the middle (2nd and 3rd quartile) in relation to all other Candidate Deferrals and include characteristics that indicate they are unlikely to be successfully deferred now. PG&E seeks approval to not pursue these Candidate Deferral Opportunities.

Table 3: Tier 2 Candidate Deferral Opportunities Not Recommended for Solicitation

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
Tier 2	DDOR1029	7th Standard Bank 2	5/1/2025	CC	-1	1	0
	DDOR1030	Famoso Bank 1	5/1/2025	CC	0	0	0

The 7th Standard Bank 2 candidate deferral opportunity was presented as a Tier 2 Candidate deferral opportunity during the October DPAG webinar. PG&E does not recommend this opportunity for competitive solicitation for the following reasons:

- It has a very low Locational Net Benefit Analysis (LNBA) value and low-cost effective score.
- The market assessment metric shows the operational requirement to be for a long duration need for most of the year and with a high frequency of calls per year at any time of the day. This candidate deferral opportunity has more than one grid need location which introduces additional complexity and potential interconnection costs. This reduces the likelihood of successfully deferring the project since all three grid needs (located on 7th Standard Bank 1, 7th Standard 2102, and 7th Standard 2102) would need to be addressed.
- This candidate deferral opportunity was not selected as a partnership pilot for the reasons above, as well as there were relatively large needs with high overloads (e.g., >75%) which require a high penetration of DERs on the overloaded facility.

The Famoso Bank 1 candidate deferral project was also presented as a Tier 2 Candidate deferral opportunity during the October DPAG webinar. PG&E does not recommend this opportunity for competitive solicitation for the following reasons:

- It has a very low LNBA value and low-cost effectiveness score.
- The grid need certainty score for this candidate deferral is -21 due to asset health risk. The forecast certainty score also reflects close freeway or highway proximity. The market assessment metric shows the operational requirement to be for a long duration need that can be called at any time of the day.
- This candidate deferral opportunity was not selected as a partnership pilot for the reasons above, as well as the forecasted growth being not incremental and hence not suitable for ratable procurement.

Tier 3 Candidate Deferral Opportunities:

PG&E does not recommend pursuing competitive solicitations for Tier 3 candidate deferral opportunities. The Tier 3 projects have one or more flagged attributes that have been identified and/or achieved a negative Red-Amber-Green (RAG) score, which indicates that it is unlikely a DER deferral solution can successfully be sourced.

Table 4: Tier 3 Prioritization Metrics Tiering Summary

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
Tier 3	DDOR1027	Millbrae Substation	5/2/2025	CC	0	-1	0
	DDOR091	Chualar Bank 1	5/1/2025	CC	-1	-1	-1
	DDOR105	Lockeford Bank 5	5/1/2025	CC	0	0	FLAG
	DDOR102	Montague Bank 2	5/1/2025	CC	-1	0	FLAG
	DDOR1026	Ravenswood Substation	4/1/2025	72.5	0	-1	-1
	DDOR1031	Semitropic Bank 4	5/1/2025	CC	0	1	FLAG
	DDOR1032	Tevis Bank 1	5/1/2025	CC	0	1	FLAG
	DDOR1034	Tulucay Bank 4	5/31/2025	CC	-1	-1	0
	DDOR1033	Weber Bank 7	5/1/2025	CC	0	0	-1

As discussed during PG&E's DPAG workshop, changes were made to the prioritization metrics as identified by the IPE during their verification and validation process and presented to the DPAG. Although there were minor changes to the project ranking and tiering, there were no impacts to the projects selected for the three sourcing mechanisms.

Millbrae substation candidate deferral project dropped from Tier 2 (2022 DDOR Appendix C - Filed on August 15th, 2022) to Tier 3 (PG&E DPAG on Sept 22nd, 2022 – slide # 37).

A summary of the primary reasons the Tier 3 Candidate Deferral projects scored poorly is listed below:

- **Cost Effectiveness Metrics**
  - Chualar Bank 1, Montague Bank 2, and Tulucay Bank 4 candidate deferral projects scored poorly in the cost effectiveness metrics
  - Sums of normalized LNBA values fall within bottom quartile
  - All three candidates have very low LNBA ($/MW-yr) values
  - Average of all three candidates is $0.03/MW-yr
  - Chualar Bank 1 and Tulucay Bank 4 have very low LNBA ($/MWh-yr) values
  - Average of all three candidates is $9/MWh-yr

- **Forecast Certainty Metrics**
  - Millbrae Substation, Chualar Bank 1, Ravenswood Substation and Tulucay Bank 4 candidate deferral projects scored poorly in the forecast certainty metrics
  - Sums of normalized and scaled Grid Need Certainty fall within bottom quartile
  - All four have close freeway or highway proximity
  - All four have high asset health risk
  - All four have significant load growth inquiries.

- **Market Assessment Metrics**
  - Chualar Bank 1, Lockeford Bank 5, Montague Bank 2, Ravenswood Substation, Semitropic Bank 4, Tevis Bank 1 and Weber Bank 7 candidate deferral projects scored poorly in the market assessment metrics
  - Sums of normalized Duration and Capacity Need per Circuit fall within bottom quartile
  - All have long durations (10-48 hours per day)
  - High capacity needs per circuit (Chualar Bank 1 and Ravenswood Substation)
  - Lockeford Bank 5 and Montague Bank 2 are flagged for Real-Time requirements
  - Semitropic Bank 4 and Tevis Bank 1 are flagged for high number of grid needs (9 each)

6. Commission Action Requested

For the reasons stated herein, PG&E respectfully requests approval for no additional candidate deferrals or planned investments for the Fall 2022 DIDF RFO.

Tariff Revisions

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

Protests

Anyone wishing to protest this submittal may do so by letter sent electronically via E-mail, no later than December 5, 2022, which is 20 days after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
E-mail: EDTariffUnit@cpuc.ca.gov

The protest shall also be electronically sent to PG&E via E-mail at the address shown below on the same date it is electronically delivered to the Commission:

Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
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 and 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

Pursuant to General Order (GO) 96-B, Rule 5.2, and OP 2.w and 2.x of D.18-02-004, this advice letter is submitted with a Tier 2 designation. PG&E requests that this Tier 2 advice submittal become effective on regular notice, December 15, 2022, which is 30 calendar days after the date of submittal.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service lists for R.14-08-013, R.14-10-003 and R.21-06-017. 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 submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Sidney Bob Dietz II
Director, Regulatory Relations

Attachments
Attachment A – Candidate Deferral Prioritization Metrics Full (Public)
Attachment B – IPE DPAG Report (Public)

cc: Service Lists R.14-08-013, R.14-10-003 and R.21-06-017
Gabe Petlin – Energy Division
Robert Peterson – Energy Division

California Public Utilities Commission

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 U39 E)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Kimberly Loo
Phone #: (415)973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: KELM@pge.com

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

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6766-E

Tier Designation: 2

Subject of AL: Request for Approval to Not Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities

Keywords (choose from CPUC listing): Compliance

AL Type: [ ] Monthly [ ] Quarterly [x] Annual [ ] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:

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? [x] 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: Satvir Nagra, Satvir.Nagra@pge.com

Resolution required? [ ] Yes [x] No

Requested effective date: 12/15/22

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

California Public Utilities Commission Energy Division Tariff Unit Email: EDTariffUnit@cpuc.ca.gov	Contact Name: Sidney Bob Dietz II, c/o Megan Lawson Title: Director, Regulatory Relations Utility/Entity Name: Pacific Gas and Electric Company Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email: PGETariffs@pge.com
	Contact Name: Title: Utility/Entity Name: Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email:

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

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, Satvir Nagra, am the Director of Asset Planning of Pacific Gas and Electric Company ("PG&E"), a California corporation. Martin Wyspianski, the Vice President of Electric Engineering, Asset and Regulatory of 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.21-06-017
3. Title and description of document(s): DIDF Non-Solicitation Advice Letter; Attachment A; IPE DPAG Report
4. These documents contain confidential information that, based on my information and belief, has not been publicly disclosed. These documents have been 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
X	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 6766-E; Attachment A, Attachment B, and IPE DPAG Report
☐	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 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 and/or General Order 66-D ("The subject information: (1) is not customarily in the public domain by providing a declaration in compliance with Section 3.2(c) stating that the subject information is not related to the location of a physical structure that is visible with the naked eye or is available publicly online or in print; **and** (2) the subject information either: could allow a bad actor to attack, compromise or incapacitate physically or electronically a facility providing critical utility service; or discusses vulnerabilities of a facility providing critical utility service"). (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)) [NEED TO EXPLAIN HOW THE PUBLIC INTEREST SERVED BY NOT DISCLOSING THE RECORD CLEARLY OUTWEIGHS THE PUBLIC INTEREST SERVED BY DISCLOSURE]): ______________________________	

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 15th day of November 2022, at San Francisco, California.

Satvir Nagra_____________
Satvir Nagra
Director, Asset Planning
Pacific Gas and Electric Company

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

R.21-06-017
ATTACHMENT TO DECLARATION
11/15/2022

ATTACHMENT NAME	DOCUMENT NAME	CATEGORY OF CONFIDENTIALITY	LOCATION
Advice Letter 6766-E	Advice Letter requesting approval to not include in the DIDF RFO process any remaining candidate deferral opportunities or other planned investments	Customer-specific data	Marked as “Customer Confidential” or “CC” in the Advice Letter 6766-E and Attachment A

Attachment A

Candidate Deferral Prioritization Metrics Full

(Public)

Glossary

Note:
1) The worksheet is only applicable where the utility has three or more candidate deferral projects, anc
2) in the event the utility has one or two candidate deferral projects, the utility will a) develop a recommendation as to the Tiering of the projects along with the rationale, and b) review this recommendation with the DPAG.

Step	Column Name	Description
Raw Data	Project ID	The project identifier.
	Project Description	A brief description of the project scope
	LNBA ($/MW-yr)	Calculated using the Commission approved LNBA methodology, based on the peak capacity need during the deferral period
	LNBA ($/MWh-yr)	Calculated using the Commission approved LNBA methodology, based on the maximum annual energy need during the deferral period
	LNBA ($/MWh-day) (Info Only)	Calculated using the Commission approved LNBA methodology, based on the maximum peak day energy need during the deferral perioc
	Unit Cost of Traditional Mitigation ($)	Cost of the traditional mitigation project designed to meet the maximum capacity need for each project.
	Grid Need Certainty	The IOU-specific, maximum grid need certainty score of all the assets associated with a project. (e.g. for SCE this is the Location of Certainty matrix score of the project's load growth drivers weighted by the size of the load growth)
	Operating Date (Info Only)	The expected operating date of a candidate deferral project
	Year of Need	The earliest starting year among all assets associated with a project.
	Year of Need Indicator	Year of need indicator based on the possible range of all the years of need for this cycle of DIDF (i.e. between 2020 and 2029)
	Duration (Hours)	The maximum number of hours that DER is needed in a peak day, during the deferral period, to meet the need that the project mitigate
	Capacity Need (MW)	The maximum capacity need mitigated by the project during the deferral perioc
	Circuits	The number of circuits that DER can be interconnected to which will meet the need that the project mitigates
	Capacity Need (MW)/Circuit	The max capacity need per number of circuits to which DERs can connect and meet the grid need
	Operational Requirement	The operational requirement of the need.
	Number of Grid Needs	The number of grid needs that the project mitigates.
Step 1: Normalize Raw Data	LNBA ($/MW-yr)	The "LNBA ($/MW-yr)" value is normalized between 0 and 1, based on the range of the "LNBA ($/MW-yr)" values of all the candidate deferral projects
	LNBA ($/MWh-yr)	The "LNBA ($/MWh-yr)" value is normalized between 0 and 1, based on the range of the "LNBA ($/MWh-yr)" values of all the candidate deferral projects
	Unit Cost of Traditional Mitigation ($)	
	Grid Need Certainty	The "Grid Need Certainty" value is normalized between 0 and 1 based on the range of the "Grid Need Certainty" values of all the candidate deferral projects
	Year of Need	
	Duration (Hours)	The "Duration (Hours)" value is normalized between 0 and 1, based on the range of the "Duration (Hours)" values of all the candidate deferral projects. The shorter the duration, the higher the normalized Duration value.
	Capacity Need (MW)/Circuit	The "Capacity Need (MW)/Circuit " value is normalized between 0 and 1 based on the range of the "Capacity Need (MW)/Circuit" values among all the candidate deferral projects. The smaller the capacity needs per circuit, the higher chance for a feasible DER solution, the higher the normalized Capacity Needs/Circuit value
	Operational Requirement	
	Number of Grid Needs	
Step 2: Apply Red Flags	LNBA ($/MW-yr)	
	LNBA ($/MWh-yr)	
	Unit Cost of Traditional Mitigation ($)	If the "Unit Cost of Traditional Mitigation ($)" for a project is below the respective threshold, it will be Red Flagged and relegated to Tier 3
	Grid Need Certainty	
	Year of Need	If the "Year of Need" for a project is above the respective threshold, it will be Red Flagged and relegated to Tier 3
	Duration (Hours)	
	Capacity Need (MW)/Circuit	
	Operational Requirement	If the "Operational Requirement" for a project is not Day Ahead, it will be Red Flagged and relegated to Tier 3
	Number of Grid Needs	If the "Number of Grid Needs" is above the respective threshold, it will be Red Flagged and relegated to Tier 3
Step 3: Determine Quantitative Metric Scores	Cost Effectiveness	The sum of normalized "LNBA/MW-yr" and normalized "LNBA/MWh-yr" values.
	Scaled Forecast Certainty	The normalized "Grid Need Certainty" score scaled up to match the range of the other metrics.
	Market Assessment	The sum of normalized "Duration (Hours)" and normalized "Capacity Need (MW)/Circuit" values
Step 4: Rank Quantitative Metric Scores	Cost Effectiveness	Cost Effectiveness scores in descending order (i.e. the highest score ranks 1
	Scaled Forecast Certainty	Forecast Certainty scores in descending order (i.e. the highest score ranks 1
	Market Assessment	Market Assessment scores in descending order (i.e. the highest score ranks 1
Step 5: Assign RAG Scores	Cost Effectiveness	The Red Amber Green (RAG) score of the Cost Effectiveness rankings. Projects ranked in the Bottom Quartile are assigned a RAG score of -1, projects ranked in the Top Quartile are assigned a RAG score of +1, all other projects are assigned a RAG score of 0
	Scaled Forecast Certainty	The RAG score of the Forecast Certainty rankings. Projects ranked in the Bottom Quartile are assigned a RAG score of -1, projects ranked in the Top Quartile are assigned a RAG score of +1, all other projects are assigned a RAG score of 0.
	Market Assessment	The RAG score of the Market Assessment rankings. Projects ranked in the Bottom Quartile are assigned a RAG score of -1, projects ranked in the Top Quartile are assigned a RAG score of +1, all other projects are assigned a RAG score of 0
	Final RAG Score	The sum of the RAG scores across the three metrics. Projects with Red Flags are automatically binned into Tier 3
Step 6: Determine Final Score and Ranking	Final Score	The sum of the Cost Effectiveness, Forecast Certainty, and Market Assessment scores
	Final Ranking	Final Score in descending order (i.e the highest score ranks 1)
	Final Tiering	The tiered recommendation. Red Flagged projects and projects with a <0 RAG score are in Tier 3, projects with a >0 RAG score are in Tier 1, and projects with a RAG score = 0 are in Tier 2.
	Approval Status	Per Reform 37 of the 2020 May Ruling, information about the approval status of Pre-Application and Post-Application projects in the GNA/DDOR

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Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
Tier 1	DDOR109	Blackwell Bank 1	6/1/2025	CC	1	0	1
Tier 1	DDOR1001	Camden 1106	5/31/2025	CC	1	1	0
Tier 1	DDOR1007	Carlotta Bank 2	5/31/2025	2.0	0	0	1
Tier 1	DDOR079	Gabilan Bank 2	5/1/2025	CC	1	0	1
Tier 1	DDOR1008	Old River Bank 2	5/31/2025	CC	1	0	1
Tier 1	DDOR1005	San Joaquin Bank 2	5/31/2025	CC	1	1	1
Tier 1	DDOR066	Vasona 1109	6/1/2025	CC	0	1	0
Tier 2	DDOR1029	7th Standard Bank 2	5/1/2025	CC	-1	1	0
Tier 2	DDOR1030	Famoso Bank 1	5/1/2025	CC	0	0	0
Tier 3	DDOR1027	Millbrae Substation	5/2/2025	CC	0	-1	0
Tier 3	DDOR091	Chualar Bank 1	5/1/2025	CC	-1	-1	-1
Tier 3	DDOR105	Lockeford Bank 5	5/1/2025	CC	0	0	FLAG
Tier 3	DDOR102	Montague Bank 2	5/1/2025	CC	-1	0	FLAG
Tier 3	DDOR1026	Ravenswood Substation	4/1/2025	72.5	0	-1	-1
Tier 3	DDOR1031	Semitropic Bank 4	5/1/2025	CC	0	1	FLAG
Tier 3	DDOR1032	Tevis Bank 1	5/1/2025	CC	0	1	FLAG
Tier 3	DDOR1034	Tulucay Bank 4	5/31/2025	CC	-1	-1	0
Tier 3	DDOR1033	Weber Bank 7	5/1/2025	CC	0	0	-1

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Prioritization Metrics Template

Template Inputs

	Cost Effectiveness			Forecast Certainty		Market Assessment			
	LNBA ($/MW-yr)	LNBA ($/MWh-yr)	Unit Cost of Traditional Mitigation ($)	Grid Need Certainty	Year of Need	Duration (Hours)	Capacity Need (MW)/Circuit	Operational Requirement	Number of Grid Needs
DIDF Baseline Year					2022				
Max value for normalization	0.49	998		-12		24	24.2		
Min value for normalization	0.02	5		-40		9	1.0		
Flag threshold			1,000,000		4			RT DA + RT	5
Top quartile threshold		5.0		5.0			5.0		
Bottom quartile threshold		14.3		12.8			14.3		

Metrics Legend	RAG Score	
Red Value	-1	
Amber Value	0	
Green Value	1	
Tier 1	Less Than	0
Tier 2	Equal To	0
Tier 3	Greater Than	0

Raw Data																
Project ID	Project Description	LNBA ($/MW-yr)	LNBA ($/MWh-yr)	LNBA ($/MWh-day) (Info only)	Unit Cost of Traditional Mitigation ($)	Grid Need Certainty	Operating Date (Info Only)	Year of Need	Year of Need Indicator	Duration (Hours)	Capacity Need (MW)	Circuits	Capacity Need (MW)/Circuit	Operational Requirement	Number of Grid Needs
DDOR066	Vasona 1109	0.15	33	54,440	2,775,000	-13	6/1/2025	2025	3	CC	CC	1	CC	DA	1
DDOR079	Gabilan Bank 2	0.19	108	202,480	13,802,000	-31	5/1/2025	2022	0	CC	CC	3	CC	DA	2
DDOR091	Chualar Bank 1	0.02	5	12,086	15,742,000	-33	5/1/2025	2022	0	CC	CC	4	CC	DA	4
DDOR1001	Camden 1106	0.23	234	143,498	13,808,000	-17	5/31/2025	2022	0	CC	CC	8	CC	DA	5
DDOR1005	San Joaquin Bank 2	0.28	526	258,931	13,264,000	-12	5/31/2025	2022	0	CC	CC	6	CC	DA	3
DDOR1007	Carlotta Bank 2	0.20	64	163,462	7,500,000	-31	5/31/2025	2025	3	9	2.0	2	1.0	DA	2
DDOR1008	Old River Bank 2	0.18	608	202,270	11,600,000	-19	5/31/2025	2022	0	CC	CC	6	CC	DA	3
DDOR102	Montague Bank 2	0.04	17	19,736	9,400,000	-28	5/1/2025	2023	1	CC	CC	3	CC	DA + RT	1
DDOR1026	Ravenswood Substation	0.05	6	15,265	40,747,000	-40	4/1/2025	2023	1	24	72.5	3	24.2	DA	2
DDOR1027	Millbrae Substation	0.11	53	60,889	18,026,000	-34	5/2/2025	2023	1	CC	CC	12	CC	DA	4
DDOR1029	7th Standard Bank 2	0.05	7	14,138	20,464,000	-14	5/1/2025	2023	1	CC	CC	5	CC	DA	3
DDOR1030	Famoso Bank 1	0.09	28	27,149	12,480,000	-21	5/1/2025	2022	0	CC	CC	6	CC	DA	2
DDOR1031	Semitropic Bank 4	0.05	17	21,988	24,179,000	-18	5/1/2025	2022	0	CC	CC	17	CC	DA	9
DDOR1032	Tevis Bank 1	0.06	33	34,702	35,547,000	-18	5/1/2025	2022	0	CC	CC	13	CC	DA	9
DDOR1033	Weber Bank 7	0.06	9	18,514	18,101,000	-31	5/1/2025	2023	1	CC	CC	3	CC	DA	2
DDOR1034	Tulucay Bank 4	0.04	6	12,674	17,080,000	-38	5/31/2025	2024	2	CC	CC	5	CC	DA	3
DDOR105	Lockeford Bank 5	0.09	149	12,536	13,705,000	-22	5/1/2025	2022	0	CC	CC	2	CC	RT	1
DDOR109	Blackwell Bank 1	0.49	998	426,004	7,500,000	-19	6/1/2025	2022	0	CC	CC	2	CC	DA	1

	Step 1: Normalize Raw Data									Step 2: Apply Flags								
Project ID	LNBA ($/MW-yr)	LNBA ($/MWh-yr)	Unit Cost of Traditional Mitigation ($)	Grid Need Certainty	Year of Need	Duration (Hours)	Capacity Need (MW)/Circuit	Operational Requirement	Number of Grid Needs	LNBA ($/MW-yr)	LNBA ($/MWh-yr)	Unit Cost of Traditional Mitigation ($)	Grid Need Certainty	Year of Need	Duration (Hours)	Capacity Need (MW)/Circuit	Operational Requirement	Number of Grid Needs
DDOR066	0.27	0.03		0.96		CC	CC											
DDOR079	0.37	0.10		0.32		CC	CC											
DDOR091	0.00	0.00		0.25		CC	CC											
DDOR1001	0.45	0.23		0.82		CC	CC											
DDOR1005	0.55	0.52		1.00		CC	CC											
DDOR1007	0.38	0.06		0.32		1.00	1.00											
DDOR1008	0.33	0.61		0.75		CC	CC											
DDOR102	0.04	0.01		0.43		CC	CC										FLAG	
DDOR1026	0.06	0.00		0.00		0.00	0.00											
DDOR1027	0.18	0.05		0.21		CC	CC											
DDOR1029	0.05	0.00		0.93		CC	CC											
DDOR1030	0.15	0.02		0.68		CC	CC											
DDOR1031	0.06	0.01		0.79		CC	CC											FLAG
DDOR1032	0.07	0.03		0.79		CC	CC											FLAG
DDOR1033	0.08	0.00		0.32		CC	CC											
DDOR1034	0.03	0.00		0.07		CC	CC											
DDOR105	0.14	0.15		0.64		CC	CC										FLAG	
DDOR109	1.00	1.00		0.75		CC	CC											

	Step 3: Determine Quantitative Metric Scores			Step 4: Rank Quantitative Metric Scores			Step 5: Assign RAG Scores				Step 6: Determine Final Score and Ranking			
Project ID	Cost Effectiveness	Scaled Forecast Certainty	Market Assessment	Cost Effectiveness	Scaled Forecast Certainty	Market Assessment	Cost Effectiveness	Scaled Forecast Certainty	Market Assessment	Final RAG Score	Final Score	Final Ranking	Final Tiering	Approval Status
DDOR066	0.30	1.93	1.27	7	2	12	0	1	0	1	3.50	5	Tier 1	N/A
DDOR079	0.47	0.64	1.93	5	12	4	1	0	1	2	3.05	11	Tier 1	N/A
DDOR091	0.00	0.50	1.07	18	15	16	-1	-1	-1	-3	1.57	16	Tier 3	N/A
DDOR1001	0.68	1.64	1.57	4	4	9	1	1	0	2	3.90	4	Tier 1	N/A
DDOR1005	1.07	2.00	2.00	2	1	2	1	1	1	3	5.07	2	Tier 1	N/A
DDOR1007	0.44	0.64	2.00	6	12	2	0	0	1	1	3.08	9	Tier 1	N/A
DDOR1008	0.94	1.50	1.88	3	7	5	1	0	1	2	4.32	3	Tier 1	N/A
DDOR102	0.05	0.86	1.77	16	11	7	-1	0	FLAG	Tier 3	2.68	12	Tier 3	N/A
DDOR1026	0.07	0.00	0.00	14	18	18	0	-1	-1	-2	0.07	18	Tier 3	N/A
DDOR1027	0.23	0.43	1.82	9	16	6	0	-1	0	-1	2.48	13	Tier 3	N/A
DDOR1029	0.06	1.86	1.27	15	3	13	-1	1	0	0	3.19	7	Tier 2	N/A
DDOR1030	0.17	1.36	1.52	10	9	10	0	0	0	0	3.05	10	Tier 2	N/A
DDOR1031	0.07	1.57	1.50	13	5	11	0	1	FLAG	Tier 3	3.15	8	Tier 3	N/A
DDOR1032	0.10	1.57	1.59	11	5	8	0	1	FLAG	Tier 3	3.26	6	Tier 3	N/A
DDOR1033	0.09	0.64	1.22	12	12	15	0	0	-1	-1	1.95	15	Tier 3	N/A
DDOR1034	0.03	0.14	1.25	17	17	14	-1	-1	0	-2	1.43	17	Tier 3	N/A
DDOR105	0.28	1.29	0.71	8	10	17	0	0	FLAG	Tier 3	2.28	14	Tier 3	N/A
DDOR109	2.00	1.50	2.08	1	7	1	1	0	1	2	5.58	1	Tier 1	N/A

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Project Name	DDOR ID	In-Service Date	Real Time (RT) or Day Ahead (DA)	Min of Year of Need	Max of Duration (Hours)	Sum of Grid Need (MW)	Sum of Circuits (that DER can connect to)	Count of GNA ID
Vasona 1109	DDOR066	6/1/2025	DA	2025	CC	CC	1.0	1
Gabilan Bank 2	DDOR079	5/1/2025	DA	2022	CC	CC	3.0	2
Chualar Bank 1	DDOR091	5/1/2025	DA	2022	CC	CC	4.0	4
Camden 1106	DDOR1001	5/31/2025	DA	2022	CC	CC	8.0	5
San Joaquin Bank 2	DDOR1005	5/31/2025	DA	2022	CC	CC	6.0	3
Carlotta Bank 2	DDOR1007	5/31/2025	DA	2025	9	2.0	2.0	2
Old River Bank 2	DDOR1008	5/31/2025	DA	2022	CC	CC	6.0	3
Montague Bank 2	DDOR102	5/1/2025	DA + RT	2023	CC	CC	3.0	1
Ravenswood Substation	DDOR1026	4/1/2025	DA	2023	24	72.5	3.0	2
Millbrae Substation	DDOR1027	5/2/2025	DA	2023	CC	CC	12.0	4
7th Standard Bank 2	DDOR1029	5/1/2025	DA	2023	CC	CC	5.0	3
Famoso Bank 1	DDOR1030	5/1/2025	DA	2022	CC	CC	6.0	2
Semitropic Bank 4	DDOR1031	5/1/2025	DA	2022	CC	CC	17.0	9
Tevis Bank 1	DDOR1032	5/1/2025	DA	2022	CC	CC	13.0	9
Weber Bank 7	DDOR1033	5/1/2025	DA	2023	CC	CC	3.0	2
Tulucay Bank 4	DDOR1034	5/31/2025	DA	2024	CC	CC	5.0	3
Lockeford Bank 5	DDOR105	5/1/2025	RT	2022	CC	CC	2.0	1
Blackwell Bank 1	DDOR109	6/1/2025	DA	2022	CC	CC	2.0	1

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Project Name	DDOR ID	Estimated LNBA Value ($/kW-yr)	Estimated LNBA Value ($/MWh-yr)	Estimated LNBA Value ($/MWh-day)	Project Cost ($k)
Vasona 1109	DDOR066	148	33	54,440	2,775
Gabilan Bank 2	DDOR079	194	108	202,480	13,802
Chualar Bank 1	DDOR091	23	5	12,086	15,742
Camden 1106	DDOR1001	232	234	143,498	13,808
San Joaquin Bank 2	DDOR1005	277	526	258,931	13,264
Carlotta Bank 2	DDOR1007	198	64	163,462	7,500
Old River Bank 2	DDOR1008	177	608	202,270	11,600
Montague Bank 2	DDOR102	40	17	19,736	9,400
Ravenswood Substation	DDOR1026	52	6	15,265	40,747
Millbrae Substation	DDOR1027	107	53	60,889	18,026
7th Standard Bank 2	DDOR1029	48	7	14,138	20,464
Famoso Bank 1	DDOR1030	93	28	27,149	12,480
Semitropic Bank 4	DDOR1031	51	17	21,988	24,179
Tevis Bank 1	DDOR1032	57	33	34,702	35,547
Weber Bank 7	DDOR1033	61	9	18,514	18,101
Tulucay Bank 4	DDOR1034	37	6	12,674	17,080
Lockeford Bank 5	DDOR105	86	149	12,536	13,705
Blackwell Bank 1	DDOR109	487	998	426,004	7,500

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DDOR ID	Project Name	Grid Need Certainty Score
DDOR091	Chualar Bank 1	-33
DDOR079	Gabilan Bank 2	-31
DDOR1030	Famoso Bank 1	-21
DDOR1031	Semitropic Bank 4	-18
DDOR1032	Tevis Bank 1	-18
DDOR1029	7th Standard Bank 2	-14
DDOR1007	Carlotta Bank 2	-31
DDOR1034	Tulucay Bank 4	-38
DDOR105	Lockeford Bank 5	-22
DDOR1027	Millbrae Substation	-34
DDOR102	Montague Bank 2	-28
DDOR1001	Camden 1106	-17
DDOR1026	Ravenswood Substation	-40
DDOR1008	Old River Bank 2	-19
DDOR1005	San Joaquin Bank 2	-12
DDOR066	Vasona 1109	-13
DDOR109	Blackwell Bank 1	-19
DDOR1033	Weber Bank 7	-31

Attachment B

IPE 2022 PG&E DPAG Report

(Public)

Independent Professional Engineer PG&E 2022 DPAG Report

PUBLIC VERSION

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

Date: November 14, 2022

Contents

1. Introduction and Background

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

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

The April 13, 2020, CPUC 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. Attachments A and B of the Ruling include 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 Appendix 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 followed by a ruling in June 2021 establishing new reforms and modifying some of those included in the May 11, 2020, ruling.

The CPUC issued Ruling 14-10-003 on 2/12/21 titled Decision Adopting Pilots to Test Two Frameworks for Procuring Distributed Energy Resources that Avoid or Defer Utility Capital Investments. In that ruling the CPUC added two additional procurement mechanisms to the DIDF cycle and spelled out how pilots of these two mechanisms are to be implemented over the next few DIDF cycles. The two new mechanisms are called the Standard Offer Contract, which applies to in front of the meter DERs, and the Partnership Pilot, which applies to behind the meter DERs. The ruling also includes some revisions to the DIDF process and timing which are followed in this cycle's IPE review and this report.

The IPE scope of work outlined in Attachment 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 2021 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 April 13, 2020, CPUC 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 April 13, 2020, Ruling states 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 and as modified in subsequent rulings are shown below as they apply to the 2022/2023 DIDF cycle.

DPAG Schedule for 2022-2023 DIDF Cycle

Activity	Date
Pre-DPAG	
Pre-DPAG meetings and workshops, including Draft IPE Plans review	May 2022
DPAG	
IOU GNA/DDOR filings	August 15, 2022
IPE Preliminary Analysis of GNA/DDOR data adequacy circulated	September 5, 2022
DPAG meetings with each IOU, Final IPE Plans circulated	September 19, 2022 (week of)
Participants provide questions and comments to IOUs and IPE	September 25, 2022
IOU responses to questions	October 5, 2022
Follow-up IOU meetings via webinar	October 15, 2022 (week of)
IPE DPAG Reports	November 11, 2022
DIDF Advice Letters submitted	November 15, 2022
Post-DPAG	
Provide draft RFO launch materials to Energy Division for approval in consultation with IPE and IE	December 10, 2022
Launch RFOs for DERs	January 15, 2023 (or within 30 days of DIDF Advice Letter approval if approval is after December 15, 2022)

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. (now a part of Resource Innovations), 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 are as modified by subsequent rulings.

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 2022 DIDF 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 2022.
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 September 21, 2022.

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

The IPE Plan covers the business processes that PG&E uses to identify which distribution 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 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 2021, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level adjusted for known loads and then used to determine if there is an overload or other issue during the planning period. For circuits that have a need, a planned project is selected to address one or more needs, capital costs developed for that project, and the planned projects/investments are screened on the basis of their in-service date to develop a list of potential candidate deferral projects. These candidate deferral projects are then prioritized into three tiers using several metrics, with the projects in the first tier normally recommended for solicitation. In this cycle, for the second time, projects were selected from the candidate deferral list to participate in the two CPUC Pilots – the Standard Offer Contract and Partnership Pilot.

[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.

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 circuit 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

[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

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:

- Conference calls with PG&E held to review material, respond to IPE questions, and 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. Responses from PG&E were made during follow up conference calls or in writing. All written requests and responses were provided through a secure file transfer protocol established by PG&E. A copy of documents provided in response to these requests are included as Appendix D.
- Participation in PG&E's DPAG Webinar (September 22) and its follow up DPAG Webinar (October 21).
- 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 2022 and 2021 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 2022 and 2021 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 – Documents Received

Identifying Confidential Information

There are a number of instances where information is confidential and such information is highlighted in gray 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 or are otherwise declared confidential by PG&E. They include, but are not limited to, such things as certain entries in the GNA and DDOR report appendices, screenshots of planning software 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 several Appendices, Appendix D: GNA Results - DER Growth Forecast, Appendix E: GNA Results – Demand Forecast and Bank & Feeder Capacity Needs, Appendix F: GNA Results – Reliability/Resiliency Needs and Appendix G: GNA Results – Line Section Capacity and Voltage Needs. These Excel-based workbooks provide the potential grid needs on PG&E's 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 15, 2022, as required by the CPUC. Pursuant to the August 30, 2022 Administrative Law Judge (ALJ) Ruling, PG&E filed the DDOR Supplemental Report containing the Known Load Project Tracking Data on October 17, 2022 and the Line Section Capacity and Voltage Needs (Appendix G) and LNBA-Planned Investments – Line Sections (Appendix H) on October 19, 2022.

Summary of PG&E's 2022 GNA Report

The GNA covers all identified substation, distribution circuit and circuit/segment[3] level needs after free or no-cost load transfers have been reflected in load forecasts. The needs listed include among other information, the following:

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

2.2. Changes to GNA for 2022

PG&E received a Motion for Extension approval on August 30, 2022, to delay publishing of grid needs resulting from line section analyses, which are primarily voltage support and distribution capacity needs. PG&E provided a supplemental filing on October 19, 2022, per the approved Motion for Extension. The GNA and DDOR were not revised because no candidate deferral opportunities were identified in the supplemental filing (due to the application of the timing screen).

[3] Line section needs were provided in a supplemental filing on October 19, 2022.

2.3. GNA Results

2.3.1. 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 Facility Type

Facility Type	Distribution Service				Total
	Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency (Microgrid)	
Substation/Bank	167	0	5	3	**175**
Feeder	282	0	6	15	**303**
Distribution Line	0	0	11	0	**11**
Totals	**449**	**0**	**22**	**18**	**489**

*Additional Grid Needs and associated Planned Investments resulting from line section analysis will be provided as a supplemental filing on October 17, 2022

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

Anticipated Need Date					Total
2022	2023	2024	2025	>=2026	
327	61	41	40	20	**489**

2.3.2. Distribution Capacity Needs

The majority of the Grid Needs are Distribution Capacity needs. Of the 449 needs in this category, 389 are needed within the next 3 years, leaving 60 capacity needs with Anticipated Need Dates of 2025 or later.

PG&E has two Distribution Capacity Needs, Blackwell Bank 1 and Huron Bank 1, that are designated as DER Driven which are driven by reverse flow from PV solar generation on the distribution system. These needs and proposed planned Investments are discussed briefly in Section 3.

2.3.3. Voltage Support Needs

There are no voltage support needs at the substation, bank or feeder level as seen from Table 2-1. Most Voltage Support Needs are associated with line sections. PG&E received approval on August 30, 2022, for an extension of time to complete its line section analysis. Any Grid Needs and related Planned Investments for line segments were provided in a supplemental filing on October 19, 2021. There were 129 line segment level voltage support needs identified in this analysis. All of the planned projects associated with these needs had an in-service date within the first three years.

2.3.4. Reliability (Back-Tie) Needs

PG&E identified 22 Reliability or Back-Tie Needs. All of these needs had an Anticipated Need Date of 2022. Of the 22 Back-Tie Needs, 11 were needs related to line sections.

2.3.5. Resiliency (Micro-Grid) Needs

PG&E identified 18 Resiliency Needs. All of these needs had an Anticipated Need Date of 2022. Fifteen of the needs were for feeders with greater than 6,000 customers. As mentioned earlier, these needs were categorized as a Reliability Need prior to the 2021 DIDF. PG&E justified this change by stating "In order for a DER solution to provide a reliability benefit in the same manner as reducing customer count on a circuit, a set of customers on the circuit would need to be immediately served by other means during an outage. This can be accomplished by islanding a part of the circuit so that those customers are not affected by the outage." This is consistent with the design goal stated in PG&E's, Guide for Planning Area Distribution Facilities, dated 8/5/18. This guide states "The feeder design goal is to limit the total number of customers to no more than 6,000."

2.4. GNA - Observations, Conclusions and Recommendations

- We observe the total number of Needs, not including the line segment needs, increased from 392 in 2021 to 489 in 2022. The majority of the changes between the 2022 and 2021 GNA were due to Distribution Capacity-related Needs. The number of Reliability and Resiliency Needs were around the same between the two years. At the line segment level, the total number of Capacity and Voltage Needs increased from 217 in 2021 to 306 in 2022.

- In the 2022 GNA, all 60 of the needs were in years 4 and beyond, whereas in the 2021 GNA, only 25 Needs were in these years.

- One potential reason for the increase in number of Needs in the 2022 GNA when compared to the 2021 GNA is the increase in known loads in the first three forecast years, and particularly in the first year of forecast. The Figure 2-1 shows a comparison of the known loads for the first three forecast years between the 2022 and 2021 GNA. The cumulative three year known loads increased from 814 MW to 1320 MW between the 2021 and 2022 GNAs and the first year known loads increased from 301 MW to 893 MW[4]. Figure 2-2 shows the components of the known load growth in the first three forecast years between the 2021 and 2022 GNAs. It can be seen that the known load total MW are almost uniformly higher in all customer sectors (Residential, Commercial, Industrial and Agricultural) when comparing the 2022 values with those from 2021. On a percentage of the total MW basis, the

[4] It should be noted that in the 2021 GNA, PG&E took the average of the service requests for load additions for the first three years and assumed 100% of this average as the known load addition for the first forecast year, 90% for the second and 80% for the third. In the 2022 GNA, PG&E changed its methodology to account for cancellations or delays associated with service requests. PG&E assumed that the known load additions for year 1, 2 and 3 would be 90% of the service requests for load additions for each of those years. This is covered in Section 7.1.2 of this report.

Agriculture and Commercial components are the largest and are also have increased in share of the total.

Figure 2-1: Comparison of the Known Load Additions between the 2022 and 2021 GNAs

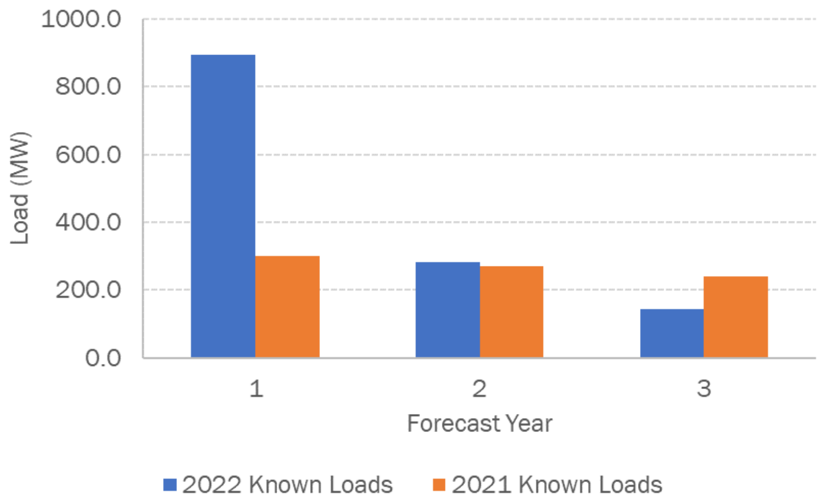
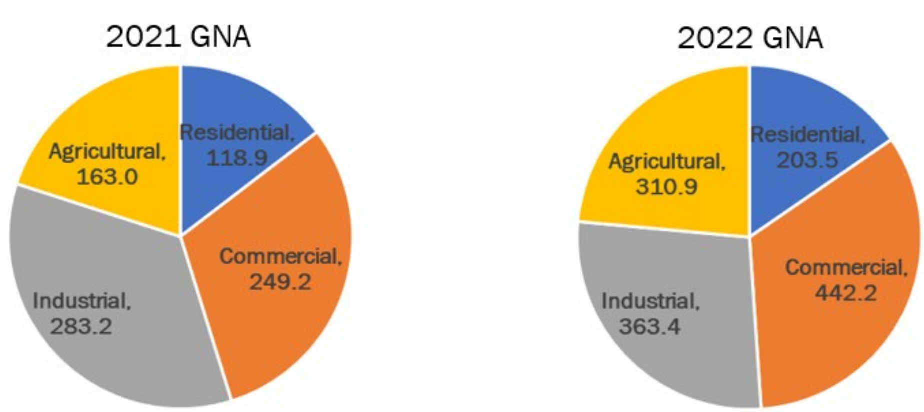


Figure 2-2: Known Load Adjustment Types and Load (MW) in the 2021 and 2022 GNA for the First 3 Forecast Years



- A comparison of cumulative and annual load growth forecasts between the IEPR values and those used in the GNA are shown in Figure 2-3 and Figure 2-4 respectively. As seen in Figure 2-3, the cumulative value of all known loads after three years (1320 MW) is greater than the cumulative IEPR load growth forecast for the same period (812 MW) by around 500 MW. Therefore, the load growth forecast used in the GNA for the first three years is substantially higher than the CEC IEPR forecast load forecast. The GNA and the IEPR cumulative forecasts finally converge in year 10. This is a result of the limited number of applications and therefore new known loads in the later years. As observed in prior years, this approach will likely result in more investment in the earlier years than if the IEPR forecast was used without adjustments. The verification for the calculations performed to develop the GNA load forecast can be found in Section 7.1.2.

Figure 2-3: Cumulative load forecast for the 10-year period

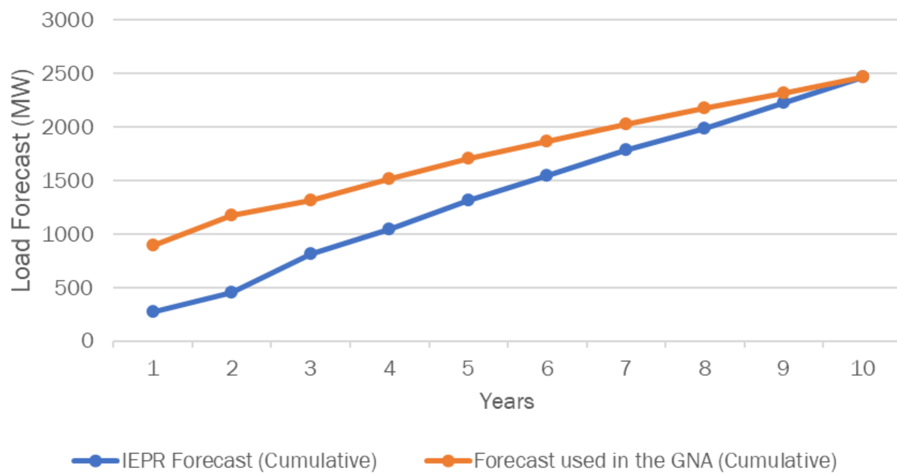
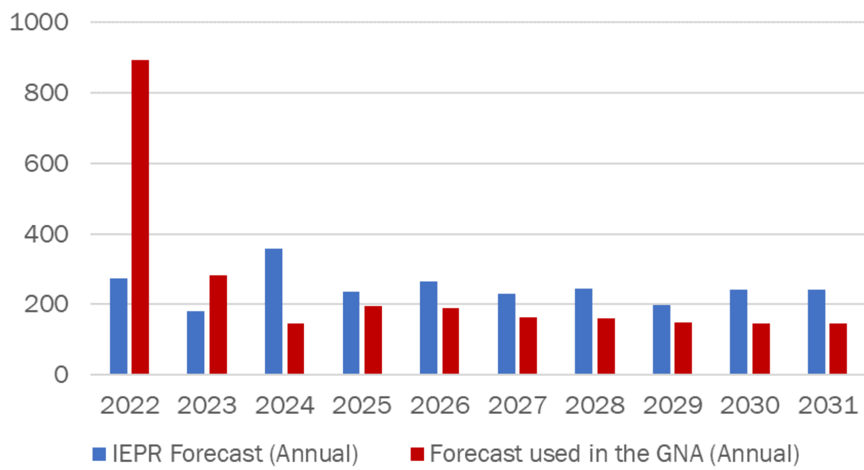


Figure 2-4: Annual load forecast for the 10-year period



- Starting with GNA 2021, PG&E has identified circuits with more than 6000 customers as a resiliency need with the reasoning that a non-wire solution would require some customers to be served by a microgrid during an outage. This need is driven by a specific planning criterion for PG&E that states circuits should not serve more than 6,000 in order to limit the impact of circuit outages. Similarly, PG&E considers emergency bank loss that results in unserved load after exhausting all available transfers as a resiliency need since an NWA solution would require a microgrid. Based on an initial review, it appears that the identification of resiliency needs is not consistent across the utilities. The IPE plans to review the approaches used by the three IOUs in identifying and addressing resiliency needs in the IPE Post-DPAG report. Based on this review, recommendations may address 1) the appropriateness of including resiliency needs in the GNA, 2) revisions to the definition of resiliency, if included in the GNA, and 3) the types of resiliency projects that are deferrable.

- With California's goal of 100% zero-emission vehicles by 2035, it can be reasonably expected that the transportation-related loads will increase in the near future. It is not only important for the utilities to know the location, timing and peak load impact of these new loads, but also have this information as far in advance as possible to make sure any grid needs are addressed in a timely manner in order to support California's zero-emissions goal. It is important for utilities to engage with charging station developers and fleet operators and others developing transportation related projects to have the most up-to-date information on their plans. The IPE plans to investigate how the utilities currently engage with these constituents and report the findings in the IPE Post-DPAG report.

3. Review of DDOR Report – Planned Investments

Using the GNA as the foundation, the DDOR identifies Candidate Deferral Opportunities (CDOs) for potential competitive solicitation for cost-effective Distributed Energy Resource (DER) solutions to mitigate the identified distribution system needs. The DDOR also includes descriptions of the methodology used to prioritize CDOs for potential solicitation and procurement and the methodology used to identify CDOs for inclusion in the two pilot frameworks for procuring DERs, the Partnership Pilot and the Standard Offer Contract (SOC) Pilot.

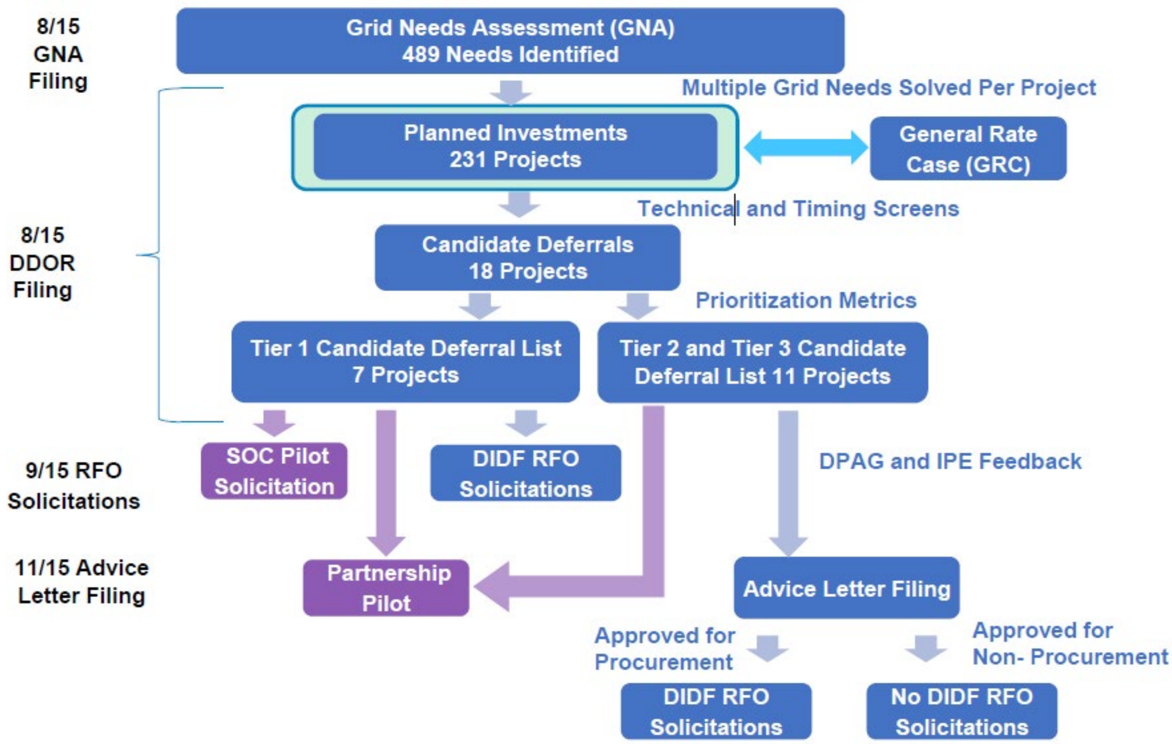
The PG&E DDOR report covers all needs identified in the GNA and includes an Appendix with five Excel-based workbooks each containing several tabs: Appendix A: Planned Investments and Appendix B: Candidate Deferral Opportunities, with tabs for "Planned Investments" and "Candidate Deferral Opportunities"; Appendix C: Prioritization Metric Workbook with tabs for "Tiers Summary, "Introduction", "Prioritization Metrics Template", "Candidate Deferral Inputs", "LNBA Inputs", and "Certainty Score"; Appendix D: LNBA Workbooks for Candidate Deferral Opportunities with tabs "Overview", "General Inputs", "LNBA Results – Candidate Deferrals ", and "Project Specific Inputs"; Appendix E: LNBA Workbooks for Planned Investments, and Appendix F: Forecast Uncertainty Questionnaire with tabs for "Assumptions Documentation", and "Certainty Score".

The data reflected in these workbooks represents a portion of PG&E's traditional infrastructure projects that are planned to 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 GNA identifies 489 grid needs and since projects often fulfill multiple needs, the DDOR identifies 231 associated planned projects. The DDOR Appendix C Candidate Deferral Input tab identifies the 18 candidate deferral opportunities that have passed the technical and timing screen. The DDOR Appendix C Prioritization Metrics Template tab summarizes the individual deferral candidates and their respective raw and normalized metric component evaluations. The use of the Prioritization Metrics to prioritize candidate deferral projects is described in more detail later in this report.

The figure below provides an illustration of the process followed by PG&E to identify CDOs based on GNA data.

Figure 3-1: Process to Identify Candidate Deferral Opportunities



A summary of the 231 identified 2022 DDOR Planned Investments that mitigate 418 grid needs can be seen in the following tables from PG&E's DDOR Report. As shown in Table 3 1, distribution line projects (example, line section switches) make up 37% of the projects while feeders, bank and substation projects make up the rest. Additional capacity and voltage related line section needs, and projects were identified and provided supplemental filing on October 19, 2022.

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

Distribution Planning Region	Project Type				Total
	Substation/ Bank	Bank and Feeder	Feeder	Distribution Line	
Bay Area	3	4	30	13	**50**
Central Valley	9	18	37	37	**101**
North Coast	2	4	4	6	**16**
North Valley and Sierra	4	5	5	16	**30**
South Bay and Central Coast	3	7	10	14	**34**
Totals	**21**	**38**	**86**	**86**	**231**

** Additional Grid Needs and associated Planned Investments resulting from line section analysis provided as a supplemental filing on October 19, 2022, were identified but not included in this table.*

Distribution capacity service needs make up 90.6% 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
Capacity	Reliability	Resiliency	
205	14	12	**231**

**Additional Grid Needs and associated Planned Investments resulting from line section analysis provided as a supplemental filing on October 19, 2022, were identified but not included in this table.*

Table 3-3 shows 92% of the projects or 213out of 231 projects have an in-service or operational date earlier than 2024.

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

In-Service Date					Total
2022	2023	2024	2025	2026	
97	75	41	18	0	**231**

IOU Ownership

PG&E stated that it does not have any DER solutions planned for IOU ownership for PG&E's list of Planned Investments in PG&E's 2022 DDOR. The Blackwell Bank 1 Planned Investment was evaluated as a CDO in the 2020 DDOR and bids were sought for IOU ownership for this bank during the 2020-2021 DIDF RFO cycle. No cost-effective bids were received.

DER-Driven Projects

PG&E has two Planned Investments for a DER driven Distribution Capacity need, Blackwell Bank 1 and Huron Bank 1 since the 2019 DIDF cycle. Both Planned Investments are replacements of substation banks because backflow caused by photovoltaic generation on the distribution system is projected to exceed the normal rating of the bank.

For Blackwell Bank 1, PG&E sought bids for IOU ownership in the 2020-21 RFO and no cost-effective bids were received. The Blackwell Bank 1 Planned Investment was also re-evaluated as a Candidate Deferral Opportunity in PG&E's 2021 DDOR, although was not recommended for DER solicitation. Blackwell Bank 1 is again evaluated as a Candidate Deferral Opportunity in PG&E's 2022 DDOR and is recommended for solicitation via the SOC Pilot.

For the Huron Bank 1 Planned Investment, PG&E solicited, contracted, and received approval for a DER solution to address the DER-driven needs in the 2019- 2020 DIDF Cycle. After the DER contract was terminated in November 2019, it was determined that an alternate DER deferral project was not available, and the planned investment (transformer bank) was resumed.

3.1. DDOR Report Planned Investments - Observations, Conclusions and Recommendations

We observe that the total number of substation/bank and feeder projects for 2022 is very similar to the number in 2021 (145 vs. 150). The number of distribution line projects in 2022 was slightly lower when compared to 2021 (86.vs. 104). Please note that these distribution line projects are primarily for addressing capacity, reliability and back-tie needs that have been identified at the substation, bank and feeder level. As mentioned previously, additional capacity and voltage related line section needs, and projects were provided in the supplemental filing.

4. Review of DDOR Report – Screening and Prioritization of CDOs

This section contains a discussion of the process used for screening and prioritizing the candidate deferral opportunities.

4.1. Project Screens

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

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 in-service date associated with the planned project. For this DDOR, a 2025 or later in-service date is considered as adequate lead time. Using the Timing Screen, 213 out of 231 projects are screened out. The remaining 18 projects are shown in Table 4-1. As seen in the table, 90% of the projects are substation/bank related, and only 5% each are feeder or distribution line related.

Table 4-1: Summary of Candidate Deferral Opportunities by Project Type and Distribution Planning Region After Screening

Distribution Planning Region	Project Type				Total
	Substation / Bank	Bank and Feeder	Feeder	Distribution Line	
Bay Area	0	2	0	0	2
Central Valley	2	7	1	0	10
North Coast	1	0	0	0	1
North Valley and Sierra	0	1	0	0	1
South Bay and Central Coast	1	2	0	1	4
Totals	4	12	1	1	18

Table 4-2 shows, 94% of the projects provide Distribution Capacity and the remaining 6% of the projects provide Resiliency service.

Table 4-2: Summary of Candidate Deferral Opportunities by Distribution Service After Screening

Distribution Service				Total
Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency	
17	0	0	1	18

After screening, all the projects have an in-service date of 2025. There are no projects in 2026 or later as shown in Table 4-3.

Table 4-3: Summary of Candidate Deferral Opportunities by In-Service Date After Screening

In-Service Date					Total
2022	2023	2024	2025	2026	
0	0	0	18	0	18

4.2. Project Prioritization

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

PG&E used the Prioritization Metrics Workbook Template jointly developed by the three IOUs and approved by the Energy Division on May 18, 2021. As in prior years, the prioritization process included three prioritization metrics – Cost Effectiveness, Forecast Certainty, and Market Assessment. However, some of the sub-metrics and how they were evaluated have changed.

The relative ranking of the individual metrics and each Deferred Candidate Opportunity is identified with a color code as shown in Table 4-4.

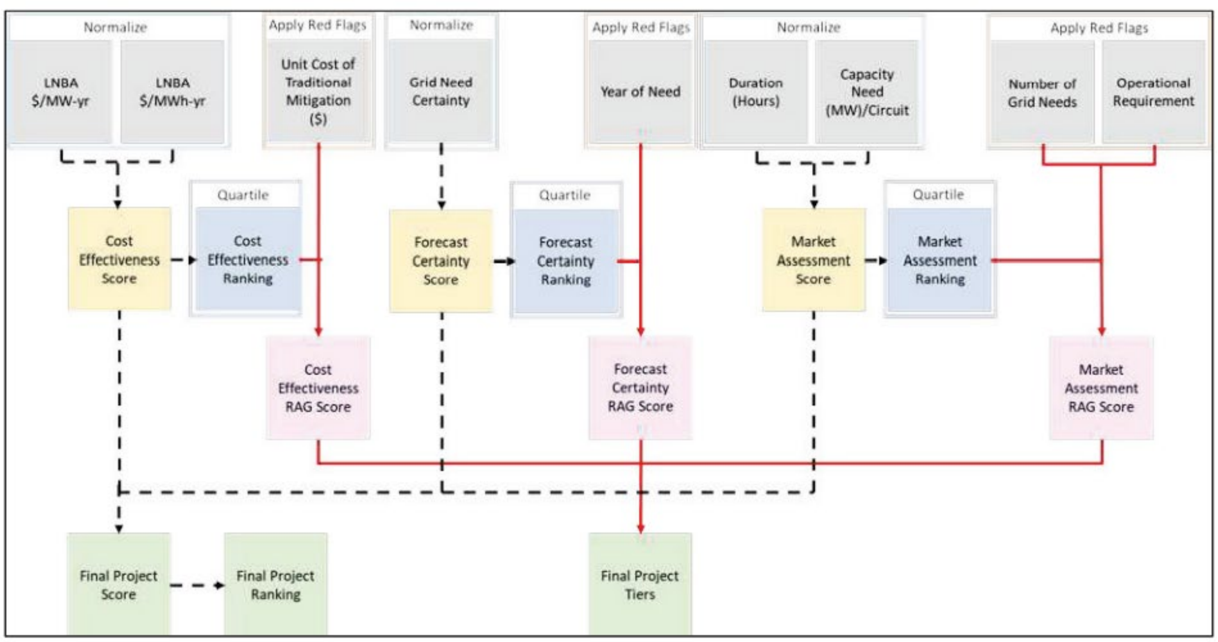
Table 4-4: 3-Tier Prioritization System

Tier	Color Designation	Definition
1		Relatively High Ranking
2		Relatively Moderate Ranking
3		Relatively Low Ranking

All rankings are 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. It only indicates the ranking of the Candidate Deferral Opportunity relative to other Candidate Deferral Opportunities.

The Joint Prioritization Metrics Workbook Template places CDOs into three tiers based on a step-by-step process, as illustrated in Figure 4-1. The development of the three-prioritization metrics is based on the evaluation of the sub-metrics of each of the three metrics. Each metric has two to four sub-metrics for a total of nine sub-metrics. Five of the sub-metrics are normalized and four are flagged if they don't meet a certain requirement. The five quantitative sub-metrics are normalized first (based on the maximum and minimum values for each sub-metric). The normalized values for each sub-metric are summed[5] to create a score for each Prioritization Metric. Each of the three Prioritization Metric scores are separated into quartiles. The top quartile of Prioritization Metric scores is assigned a "1", the middle two quartiles assigned a "0", and the bottom quartile assigned a "-1". These are known as the Red-Amber-Green (RAG) score. If one of the sub-metrics is flagged for a given Prioritization Metric, that Prioritization Metric is flagged. The total RAG score for each Candidate Deferral Opportunity is then summed across the three Prioritization Metrics. Those with a total RAG score greater than zero are placed in Tier 1; those with a total RAG score of zero are placed into Tier 2; and those with a total RAG score less than zero are placed into Tier 3. As the total RAG score is summed across the three Prioritization Metrics, a Candidate Deferral Opportunity can be assigned a "-1" for one of the Prioritization Metrics (e.g., Forecast Certainty) and still be placed into Tier 1. However, if any of the sub-metrics are flagged, the Candidate Deferral Opportunity will be placed into Tier 3 automatically.

Figure 4-1: Prioritization Metrics, Final Scoring, and Tiering



[5] The Forecast Certainty Metric is based on one sub-metric and therefore is weighted by a factor of 2 (the other Prioritization Metrics have two quantitative sub-metrics summed with equal weighting).

Prioritization Metrics Included in Joint Prioritization Workbook Template

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 two quantitative sub-metrics, Estimated LNBA ($/KW-yr.) and Estimated LNBA ($/MWh-yr). The LNBA-related metrics are developed by taking the deferral value for the project and dividing that value by the summation of all maximum MW needs associated with project during the deferral period and the maximum MWh-yr. For the metric evaluation, these two sub-metrics are normalized and added together. For informational purposes only, the Estimated LNBA ($/MWh-day) value for each Candidate Deferral Opportunity is also shown. The MWh-day value is the maximum energy need for the day of the forecasted peak demand. There is also one sub-metric, Cost of Traditional Mitigation, which is flagged if the cost is less than $1 million. The Unit Costs are the estimated project capital costs at the time of the report. This topic is discussed further in Section 7.3.

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

- High unit cost of a traditional solution.
- High LNBA ($/kW-year); and
- High LNBA per MWh of deferral ($/Megawatt-hour (MWH)-year).

The Forecast Certainty Metric is intended to give a relative indication of the certainty of the forecasted grid need. This metric contains two components, a Grid Need Certainty Score and a Year of Need.

The Grid Need Certainty Score is developed from a Forecast Questionnaire (included as Appendix F in the DDOR report), which PG&E revised for this cycle. This questionnaire, completed by local distribution engineers, provides local engineering judgement potentially impacting the certainty of the forecast, such as the health and condition of assets and other activity in the area which may impact the forecast loading. The questionnaire is significantly different from the one used in the previous cycle. See Section 4.2.2 for additional discussion of the Forecast Questionnaire.

The Forecasted Year of Need identifies the earliest Anticipated Need date of all the Grid Needs associated with that particular Candidate Deferral, as derived from the LoadSEER forecast. PG&E considers needs in later years as having more uncertainty. This is a flagged sub-metric that identifies CDOs with a year of need of 2027 and beyond.

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

- Nearer term need (2025 vs. 2026); and
- A higher (less negative) Grid Need Certainty Score from the Forecast Questionnaire completed by the distribution engineers.

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 four sub-metrics. Two quantitative sub-metrics, Duration (hours) and Capacity Need (MW/circuit), are normalized and summed. The other two sub-metrics, Operational Requirement (Real Time or Day Ahead) and Number of Grid Needs, are flagged sub-metrics.

For the Duration (hours) sub-metric, a project with shorter duration receives a higher quantitative score. For a CDO with one need location this value would be the CDO's DER duration needs as determined in the planning process. For CDOs with multiple needs the value would be the maximum duration of any of the need locations included in the project.

The Capacity Need (MW) per Circuit sub-metric receives higher quantitative scores for CDOs that have less capacity needed per circuit which can be met by the DER.

The Operational Requirement sub-metric is flagged when the requirement is Real Time because it is believed developers may view a Real Time five-minute dispatch notice to be too difficult and costly to achieve in practice and likely to impact potential revenue streams.

For the Number of Grid Needs sub-metric, a CDO with more than five grid needs are flagged. The reason for this is implementing DER solutions for fewer locations will be easier (and less costly) than implementing DER for many locations.

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

- Day Ahead, rather than Real Time, operational requirement.
- Low number of electric facilities experiencing grid needs in the CDO.
- Shorter duration

As mentioned above, numerical values are determined for each prioritization metric and each of the three prioritization metrics are divided into quartiles based on these scores. Metrics in the first quartile receive a RAG score of one, metrics in the second and third quartile receive a RAG score of 0, and metrics in the fourth quartile receive a score of -1. The three prioritization metric RAG scores for each CDO are summed and those CDOs with a sum greater than 0 are placed in Tier 1; those with a sum of zero are placed in Tier 2; and those with a score of less than zero are placed in Tier 3. Any CDO with a Red Flag is automatically placed in Tier 3.

The results of the application of these three metrics are shown in Table 4-5 below. Using the prioritization table, PG&E has identified 7 Tier 1, 2 Tier 2 and 9 Tier 3 Candidate Deferral Opportunities.

Table 4-5: Preliminary Prioritization Metrics and Rankings of Candidate Deferral Opportunities

Note: This table has confidential information highlighted in gray which will be redacted in the public report

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
Tier 1	DDOR109	Blackwell Bank 1	6/1/2025		1	0	1
Tier 1	DDOR1001	Camden 1106	5/31/2025		1	1	0
Tier 1	DDOR1007	Carlotta Bank 2	5/31/2025	2.0	0	0	1
Tier 1	DDOR079	Gabilan Bank 2	5/1/2025		1	0	1
Tier 1	DDOR1008	Old River Bank 2	5/31/2025		1	0	1
Tier 1	DDOR1005	San Joaquin Bank 2	5/31/2025		1	1	1
Tier 1	DDOR066	Vasona 1109	6/1/2025		0	1	0
Tier 2	DDOR1029	7th Standard Bank 2	5/1/2025		-1	1	0
Tier 2	DDOR1030	Famoso Bank 1	5/1/2025		0	0	0
Tier 3	DDOR1027	Millbrae Substation	5/2/2025		0	-1	0
Tier 3	DDOR091	Chualar Bank 1	5/1/2025		-1	-1	-1
Tier 3	DDOR105	Lockeford Bank 5	5/1/2025		0	0	FLAG
Tier 3	DDOR102	Montague Bank 2	5/1/2025		-1	0	FLAG
Tier 3	DDOR1026	Ravenswood Substation	4/1/2025	72.5	0	-1	-1
Tier 3	DDOR1031	Semitropic Bank 4	5/1/2025		0	1	FLAG
Tier 3	DDOR1032	Tevis Bank 1	5/1/2025		0	1	FLAG
Tier 3	DDOR1034	Tulucay Bank 4	5/31/2025		-1	-1	0
Tier 3	DDOR1033	Weber Bank 7	5/1/2025		0	0	-1

Please note that the table shown is a revised version provided by PG&E during the DPAG meeting on September 22, 2022. This table includes two minor changes (Cost Effectiveness Score for Carlotta Bank 2 and Market Assessment Score for Millbrae Substation) in the table included in the DDOR report issued on August 16, 2022. However, these changes do not result in the projects identified for procurement in the 2022 DIDF cycle.

4.2.1. IPE Review of Non-Tier 1 CDOs

The IPE believes the Cost Effectiveness metric, in general, is very important to the overall ranking process . If there are insufficient funds or 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, CDOs with high Cost Effectiveness rankings, and not initially recommended by PG&E for one of the DER sourcing mechanisms, were evaluated to determine if they should be considered for procurement.

The IPE performed a Cost Effectiveness (CE) Sensitivity Analysis for all the Tier 2 and Tier 3 projects that had a CE score that was not in the first quartile. The sensitivity analysis answers the question "How much higher does the deferral cost need to be for the CE score for a project to move up in CE ranking to become the lowest project in the top quartile?" The answer to this question is in the form of a multiplier, for example, the deferral cost has to be 2 times higher for the project to be at the bottom of the top quartile for Cost Effectiveness. A low value of multiplier (i.e., 1.2) indicates that a project has a cost effectiveness score that is relatively close to projects in the top quartile. If the other metrics, i.e., Forecast Certainty and Market Assessment are in the second quartile and not flagged, a project with a low multiplier might be worth considering for procurement. Based on this analysis, the IPE found one project (Millbrae Substation) that could be considered for procurement.

4.2.2. Project Prioritization - Observations Conclusions and Recommendations

- Forecast Questionnaire

  The Forecast Certainty Metric contains two components, a Grid Need Certainty Score and a Year of Need. As mentioned earlier, the Grid Need Certainty Score is developed from a Forecast Questionnaire (included as Appendix F in the DDOR report), which PG&E revised for this cycle. In this revised questionnaire, there are six questions and the responses to these questions are assigned a score on a 10-point scale. The Grid Need Certainty score is the sum of these scores. A higher value of Grid Need Certainty score indicates the potential for additional load being added to the circuit that has not been taken into account in the forecasting process. The

  - Q2: Is the area served by the project within two miles of (select one):
    - 0 freeway or highway
    - 1 freeway or highway
    - 2 freeways or highways
    - 3 freeways or highways"

  - Q3: Have you received an inquiry about new load growth application (e.g., fast charging connection) in the area that is not yet reflected in the load forecast?

  - Q4: If you've answered "Yes" in the previous question about new load growth application, please specify the type of load(s) below

  - Q5a-e: What type of project is planned – a) New Substation, b) New Substation Transformer, c) Replaced Substation Transformer, d) New Circuit Breaker, e) Line Work Creates Tie?

  - Q6: What is the asset health risk based on condition for the project and all grid need locations

Response to question Q2 indicates the possibility of additional load growth in the area due to EV charging stations which are likely to locate near highways that are not in the current load forecast. Response to questions Q3 and Q4 also indicate the potential for new load interconnecting to the circuit. The response to question Q5 indicates the scope of the planned project. We assume that a larger project such as a substation gets a higher certainty score since it's most likely to provide the largest amount of margin (capacity in excess of identified need) and thus be able to accommodate the most unforecasted increase in load. Finally, the response to question Q6 indicates the asset health risk for assets in the area. We believe that the rationale behind this question is that if there are assets with a high risk of failure that a non-wires solution would rely on, and thus they are likely to be replaced during the life of the non-wires contract which would make the non-wire project solution moot.

The questions appear to address primarily the possibility of additional load materializing in the area that is not currently in the load forecast. One question is related to the potential failure and replacement of high-risk asset which may undermine DER solution .

The IPE plans to compare the methodology used by the three IOUs for determining the Forecast Certainty score and, as appropriate develop recommendations in the Post-DPAG report.

5. Review of DDOR Report – Pilot Project Selections

Table 5-1 shows the summarizes PG&E's 2022 DDOR Candidate Deferral Opportunities including location, targeted In-Service Date, minimum grid capacity needed (i.e., deficiency), and initially recommended sourcing mechanism.

Table 5-1: Candidate Deferral Opportunities Summary

Note: This table has confidential information highlighted in gray which will be redacted in the public report

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Sourcing Mechanism*
Tier 1	DDOR109	Blackwell Bank 1	6/1/2025		Standard Offer Contract (SOC)
Tier 1	DDOR1001	Camden 1106	5/31/2025		DIDF RFO
Tier 1	DDOR1007	Carlotta Bank 2	5/31/2025	2.0	Partnership Pilot (PP)
Tier 1	DDOR079	Gabilan Bank 2	5/1/2025		Partnership Pilot (PP)
Tier 1	DDOR1008	Old River Bank 2	5/31/2025		DIDF RFO
Tier 1	DDOR1005	San Joaquin Bank 2	5/31/2025		DIDF RFO
Tier 1	DDOR066	Vasona 1109	6/1/2025		Partnership Pilot (PP)
Tier 2	DDOR1029	7th Standard Bank 2	5/1/2025		Not recommended
Tier 2	DDOR1030	Famoso Bank 1	5/1/2025		Not recommended
Tier 3	DDOR1027	Millbrae Substation	5/2/2025		Not recommended
Tier 3	DDOR091	Chualar Bank 1	5/1/2025		Not recommended
Tier 3	DDOR105	Lockeford Bank 5	5/1/2025		Not recommended
Tier 3	DDOR102	Montague Bank 2	5/1/2025		Not recommended
Tier 3	DDOR1026	Ravenswood Substation	4/1/2025	72.5	Not recommended
Tier 3	DDOR1031	Semitropic Bank 4	5/1/2025		Not recommended
Tier 3	DDOR1032	Tevis Bank 1	5/1/2025		Not recommended
Tier 3	DDOR1034	Tulucay Bank 4	5/31/2025		Not recommended
Tier 3	DDOR1033	Weber Bank 7	5/1/2025		Not recommended

PG&E has identified the following 3 Tier 1 candidates for competitive solicitation via the RFO mechanism:

- Camden 1106
- Old River Bank 2
- San Joaquin Bank 2

PSG&E has selected the following Tier 1 CDOs for the Partnership Pilot:

- Gabilan Bank 2
- Carlotta Bank 2
- Vasona 1109

PG&E has selected the following Tier 1 CDO for the Standard Offer Contract (SOC) Pilot:

- Blackwell Bank 1

PG&E provided a demo of the Excel workbook that implemented the logic for selecting CDOs for the Partnership Pilot, SOC Pilot and the RFO. The process used for selecting the candidates for the various procurement mechanisms is described below.

- Screen out CDOs that have any flags or have at least one 24-hour need. This step filtered out 9 CDOs – 4 CDOs that had flags and 5 CDOs that had at least one 24-hour need.
- Determine the trend (MW of the need over time) of the remaining 9 needs. Needs that have a growing MW are suitable for ratable procurement under the Partnership Pilot. The Workbook showed 4 CDOs that had growing needs. Three (Gabilan Bank 2, Carlotta Bank 2 and Vasona 1109) out of the 4 were selected for Partnership Pilot. The remaining CDO (Blackwell Bank 1) was recommended for the SOC Pilot. The reason for this is discussed below.
- Identify CDOs with load profiles that do not have charging constraints. These CDOs are candidates for the SOC Pilot since most FTM NWA resources tend to be energy storage. One CDO (Blackwell Bank 1) was found suitable because it had a single need for reverse flow and no charging constraints.
- The remaining CDOs in Tier 1 were then selected for the DIDF RFO (Camden 1106, Old River Bank 2, San Joaquin Bank 2).

In addition, the selection of the Candidate Deferral Opportunities for the Partnership Pilot was based on the PG&E's application of the following criteria:

1. At least one Tier 1 deferral opportunity and two Tier 2 or Tier 3 deferral opportunities selected.
2. Candidate Deferral Opportunities that could demonstrate Ratable Procurement (e.g., opportunities with low to moderate capacity needs that have incremental procurement goals).
3. Candidate Deferral Opportunities where Ratable Procurement could potentially address the challenge of changing distribution system needs and risk of over and under procurement.
4. Candidate Deferral Opportunities with grid needs occurring within two to five years of Pilot launch.
5. At least one deferral opportunity with a grid need forecast 4 to 5 years out to ensure the subscription period was sufficiently long in duration to test payments.
6. Clusters of deferral opportunities and planned investments.
7. Planned investments that service Disadvantaged Communities (DACs).

The selection of the CDO for the SOC Pilot is based on the Prioritization Metrics discussed above and examination of the following criteria:

- At least one Tier 1 Candidate Deferral Opportunity selected.
- A single Grid Need location to defer the Candidate Deferral Opportunity, in order to facilitate a single Point of Interconnection for an In-Front-of-the-Meter (IFOM) DER solution.
- Indications that there is sufficient capacity at the location of the Grid Need for a DER to charge from the grid, so that IFOM DERs (including energy storage) may be able to charge from the location of need. PG&E notes that this assessment is only indicative, and the DER solution would still need to pursue the interconnection process.
- Earlier In-Service Dates to test the impact of the SOC pilot on the ability of DERs to meet the In-Service Date.
- Candidate Deferral Opportunities with larger Grid Needs (MW), as those needs may be most appropriate for Utility-Scale IFOM DER solutions.

6. Other Items of Interest

6.1. Known Load Project Tracking

The ALJ's June 16, 2022 DIDF Reform order required all three IOUs to track known load projects in the 2022 GNA/DDOR. The reform also required the known load tracking dataset to include a unique project identifier, impacted circuit, initial service request date, load amount, current expected in-service date or indication if service request was cancelled, if appropriate, and type/category of load and, if appropriate, the actual date service was initially provided and the amount. PG&E provided this data as Appendix J in a Supplemental Report filed on October 17, 2022.

The IPE reviewed the data sent by the three IOUs and found that there were various interpretations of the request and different approaches to provide the data. The IPE recommended that a set of definitions similar to the one shown in Table 6-1 be used by all three utilities. The IPE plans to follow up with all three utilities and the Energy Division to better understand the data that is being provided and to ensure that the data will be able to be used to perform the tracking analysis envisioned in the ALJ's June 16th reform order.

Table 6-1: Suggested Definitions for Known Load Project Data Elements

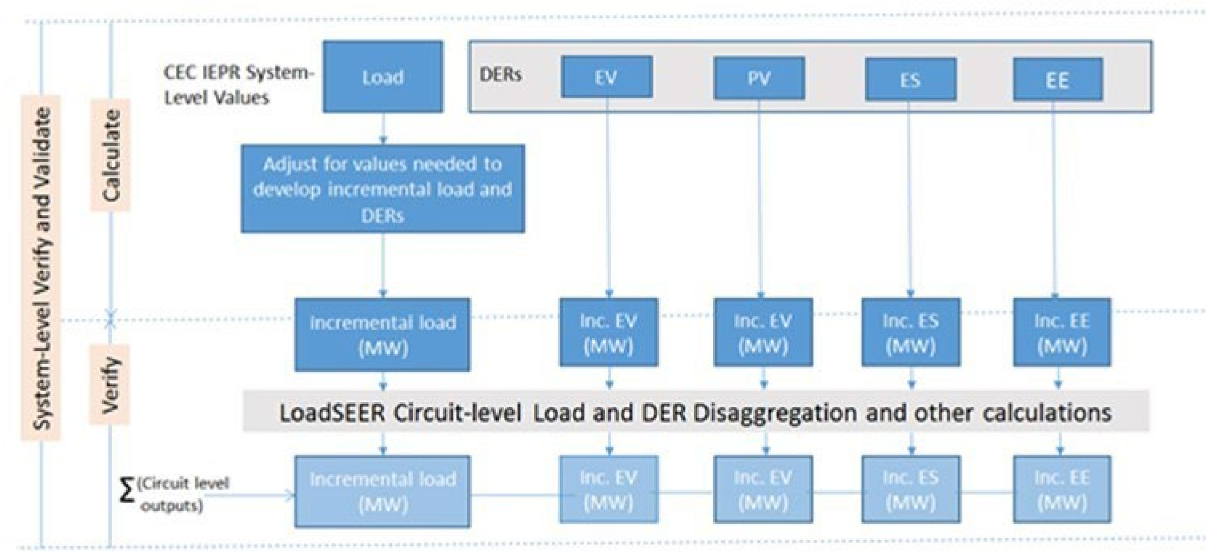
Database Element	Definition
Unique Identifier	This should be a unique identifier associated with each known load. The identifier can be for a new load (no existing meter) or incremental load at an existing customer meter. Only one identifier should be used for each known load even if the load is expected to be served by multiple circuits.
Circuit	This is the name/ID for the circuit(s) that the new load is expected to be served by.
Sector	Residential, Commercial, Industrial or Agricultural
Category	Information on load category such as EV charger, cannabis cultivation, hospital, tract homes etc.
IEPR Status	Embedded or incremental (currently, incremental load only used by SCE).
Load Amount (MW)	This is the load (MW) expected during the peak load hour after adjustments, if any, are made to the load requested by customer. For a new load, this is the peak for the entire load. For an incremental load, it's the peak for just the increment of load requested by the customer. This value should be the same as the value used in the planning process.
Initial Service Request Date	This is the date on which the service request for a new load or incremental load at a customer meter was made. This is not the date that an existing customer first received service. This

	is the date on which the existing customer made a request for an incremental service.
Current Expected In-Service Date	This is the utility planned in-service date associated with the known load. In the case that the known load is an incremental load at an existing business, this date is the date at which service for this incremental load is expected to be provided.
Status	This is the status of the service request that is driving the known load which would be one of the following: in-service, ongoing or cancelled
Actual In-Service Date	This is the date on which the new or incremental service was provided.
Actual Load Amount	The usability of this data will be discussed with the IOUs and this data element will be modified as necessary.

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

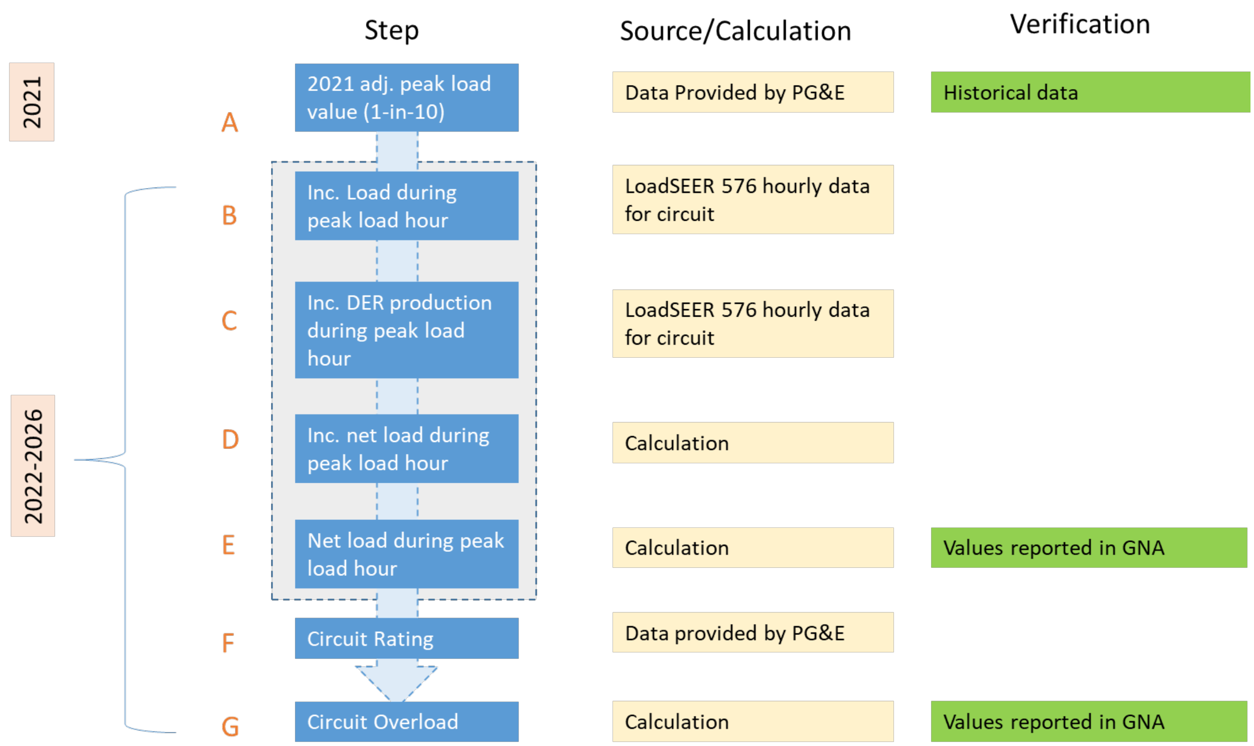


Prior to allocating the CEC IEPR System-Level forecast to distribution circuits, the system load forecast is reduced to account for:

- System-level LDEV,
- System-level Other Private generation,
- Transmission-only load, and
- New known distribution loads.

This adjusted system load is then distributed by customer class and allocated to the circuits in the LoadSEER Geographical Information System geo-spatial load forecasting program created by Integral Analytics. This program is used to model substation and feeder demand forecasts and identify grid needs using satellite imagery and proprietary data analytics to score each acre in PG&E's territory for the likelihood of increased load by customer class. This GIS model also uses historical land aerial imagery to help determine expansion trends that have occurred within specific areas and takes this information into consideration for the acre scoring analysis. The spatial forecasting model is enhanced by utilizing an energy consumption model that is weather normalized and includes economic variables. After area scores are determined, the geospatial program then allocates the CEC customer class load growth projections to each parcel and maps the load growth to feeders based on closest proximity. The output of the geo-spatial program is an annual PG&E peak MW growth by feeder, by customer class for the next 10 years. This growth is then uploaded into the LoadSEER Forecast Integration Tool (LoadSEER FIT) forecasting program. LoadSEER FIT uses customer-class load shapes to turn the system peak growth amount into a 576-hour load shape that can then be applied to the feeder or bank load shape. After the disaggregation of the adjusted system load, the LDEV is reallocated to circuits in LoadSEER based upon propriety algorithms and the new known loads are allocated based upon new application information. The Other Private generation and Transmission-only loads are not disaggregated to individual feeders.

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 Forecasts at Circuit Level

7.1.1. Collect 2021 Actual Circuit Loading, Normalize and Adjust for Extreme Weather – Steps 1 and 8

Monthly peak loads are routinely obtained from SCADA or sometimes from AMI aggregate data or monthly substation meter reads and entered into LoadSEER. 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 then entered into LoadSEER for 1-in-2 and 1-in-10 load forecasts. If a circuit is identified as subject to temperature variations, LoadSEER adjusts the actual peak load according to the temperature at the time of the peak and generates a 1-in-2 and a 1-in-10 load forecast based on this new adjusted peak load. If the circuit is not identified as temperature sensitive, the starting peak load is not adjusted and the forecast starting point for the 1-in-2 and 1-in-10 forecasts in LoadSEER is the most recent historic peak load. Similarly, the starting point peak load for the 1-in-2 and 1-in-10 forecasts for water-sensitive circuits (i.e., circuits that service pumping loads) are developed. Sixteen circuits that were temperature or water-sensitive were selected for verification. Table 7-1 presents the data collected and reviewed. In addition to the data shown in the table, other information such as 3-day weighted average temperature observed during the peak load hour, as well as the 3-day weighted average temperature for 1-in-2 and 1-in-10 forecasts were provided.

Table 7-1: Data for Circuit Net Load Verification

(Confidential information is redacted in the public report)

Feeder Name/ID	Nominal Voltage (kV)	2021 Peak Date/Time in LoadSEER	2021 Peak Amps in LoadSEER	Weather sensitive? (Was temperature selected as a regression variable?)	Water sensitive? (Was a water variable selected as a regression variable?)	2021 (Amps) Corporate 1-in-2 Temp Adjusted Forecast start point	2022 (Amps) - Final 1-in-2	2022 (Amps) - Final 1-in-10
Llagas 2101/083182101	21	6/17/21 16:00	409	Yes	No	409	432	475
Edenvale 2109/082952109	21	8/28/2021 18:00	403	No	No	n/a	457	504
Wyandotte 1107/102911107	12	7/10/21 19:00	490	Yes	No	462	500	522
Lakewood 1104/013531104	12	9/8/21 18:00	366	No	No	n/a	366	416
Yosemite 0402/022490402	4	9/20/2021 01:00	167	No	No	n/a	168	169
Rincon 1101/043321101	12	6/17/21 19:00	413	Yes	No	408	407	430
Meridian 1102/062541102	12	6/26/21 20:00	293	No	Yes, blend not used	n/a	292	319
Figarden 2102/254552102	21	7/9/21 18:00	493	No	No	n/a	540	566
Anita 1101/102841101	12	6/24/21 20:00	135	No	No	n/a	139	158
Wolfe 1114/083671114	12	6/18/21 16:00	427	Yes	No	414	516	557
Vasona 1102/083771102	12	6/17/21 17:00	438	Yes	No	468	542	607
Atascadero 1101/182541101	12	7/10/21 19:00	536	Yes	No	468	465	508
Manteca 1704/162611704	17	7/10/21 19:00	299	Yes	No	303	379	419
Notre Dame 1104/102041104	12	7/10/21 18:00	420	Yes	No	378	378	405

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

In this step, the process used by PG&E to determine the system-level peak load and DER forecasts from the CEC IEPR forecasts is verified. Also, the process used by PG&E to model known loads (customer service requests) and spatial loads (difference between system-level peak load and known loads) is verified in this step.

The overall process used by PG&E for determining system level load and DER forecasts is summarized below:

- PG&E uses the peak load and energy forecasts from CED 2020 Forecast, Mid Baseline, Mid AAEE case as the starting point for load and DER forecasts. Since this forecast goes only up to the year 2030, the forecast for 2031 was developed by extrapolating the forecast for the years 2029 and 2030 per CEC's guidance.
- PG&E adjusts the IEPR peak load forecast for the following: transmission-only loads, other private generation and LDEVs. The adjusted forecast is used for determining the annual peak load growth at the system level.
- The annual peak load growth is then allocated to customer classes (residential, industrial, and commercial) proportional to their forecast annual energy consumption.
- Annual known load additions for each customer class are then subtracted from the annual peak load growth calculated in the previous step. The annual known load additions in the first three years used in this process are 90% of the actual known load requests received by PG&E to account for cancellation. The methodology for accounting for cancellation is different from last year where PG&E used 100%, 90% and 80% of the first three-year average known loads for years 1, 2 and 3.
- For calculating the spatial loads for each year, PG&E takes the difference between cumulative annual peak load growth in the 10-year forecast period and the cumulative known loads and spreads the difference evenly from years 4 through 10. These spatial loads are then disaggregated to each circuit using load allocation factors developed by LoadSEER.
- PG&E models the following DERs explicitly: Photovoltaic Solar (PV), Energy Storage (ES), Light Duty Electric Vehicles (LDEV), and Additional Achievable Energy Efficiency (EE). PG&E uses the zonal forecasts for PV, ES, LDEV stock that the CEC provides corresponding to the Mid-Mid case. PG&E also uses bus-bar level EE forecast (low case) provided by the CEC to develop the system-level forecast.
- These system-level DER forecasts are disaggregated to circuits using DER-specific disaggregation methodologies discussed in the GNA report. This is verified in Step 3.

The results of the process used for developing the system-level peak load the process used for modeling the known loads and spatial loads can be seen in Figure 7-3.

Figure 7-3: Peak Forecast Based on CED 2020 Forecast

		Coincident Peak 1 in 2 (MW)											(Extrapolation)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
LINE #	ANNUAL MW GROWTH OF DISTRIBUTION SYSTEM (2020 IEPR)												
1		*Line 1 of Mid-Baseline IEPR Forecast (2031 extrapolated per CEC gui*	21387	21700	21921	22315	22589	22878	23127	23390	23605	23866	24126
2		*Line 2 of Mid-Baseline IEPR Forecast (2031 extrapolated per CEC gui*	125	164	207	245	285	309	330	350	369	388	407
3		*Line 11 of Mid-Baseline IEPR Forecast (2031 extrapolated per CEC gu*	1157	1145	1133	1122	1110	1099	1088	1077	1066	1055	1044
4			2260	2270	2280	2290	2300	2310	2320	2330	2340	2350	2360
5		*Line 1 minus line 2 minus line 3 minus line 4*	17846	18121	18300	18658	18894	19160	19389	19633	19831	20073	20315
6		*(YearX+1)-(Year X)*		275	180	358	236	266	230	244	197	242	242
7		Running Growth Total (Cumulative MW growth at system peak)		275	454	812	1048	1314	1543	1787	1985	2227	2469
8	CUSTOMER CLASS CONTRIBUTION TO INCREMENTAL PEAK LOAD GROWTH (MW) BY YEAR												
9		Residential allocation 40%		110	72	143	94	106	92	97	79	97	97
10		Commercial allocation 12%		33	22	43	28	32	28	29	24	29	29
11		Industrial allocation 33%		91	59	118	78	88	76	80	65	80	80
12		Agricultural allocation 15%		41	27	54	35	40	34	37	30	36	36
13		Total		275	180	358	236	266	230	244	197	242	242
14	KNOWN ADJUSTMENTS BY CUSTOMER CLASS PEAK LOAD GROWTH (MW) BY YEAR*			90% confidence rate applied to									
15		Known Residential Loads, 2022, 2023, and 2024 applications		143	37	24	4	8	1	1			
16		Known Commercial Loads, 2022, 2023, and 2024 applications		286	100	57	20	20	5	9	2		
17		Known Industrial Loads, 2022, 2023 and 2024 applications		234	100	29	16	14	11	4	1		
18		Known Agricultural Loads, 2022, 2023 and 2024 applications		231	45	35	10			0			
19		TOTAL KNOWN LOAD APPLICATIONS BY YEAR (INCREMENTAL)		894	282	144	49	42	17	14	2	0	0
20		RUNNING TOTAL KNOWN ADJUSTMENTS (CUMULATIVE)		894	1176	1320	1369	1411	1428	1442	1444	1444	1444
21	INCREMENTAL GROWTH BY CUSTOMER CLASS THAT SHOULD BE ALLOCATED TO FEEDERS (CC												
22		RESIDENTIAL		0	0	0	58.56	58.56	58.56	58.56	58.56	58.56	58.56
23		COMMERCIAL		0	0	0	17.57	17.57	17.57	17.57	17.57	17.57	17.57
24		INDUSTRIAL		0	0	0	48.31	48.31	48.31	48.31	48.31	48.31	48.31
25		AGRICULTURAL		0	0	0	21.96	21.96	21.96	21.96	21.96	21.96	21.96
26		TOTAL GEOSPATIAL GROWTH BY YEAR (INCREMENTAL)		0	0	0	146	146	146	146	146	146	146
27		RUNNING TOTAL GEOSPATIAL GROWTH (CUMULATIVE)		0.0	0.0	0.0	146.4	292.8	439.2	585.6	731.9	878.3	1024.7
28													
29	*equals Line 20 plus line 27*	KNOWN ADJUSTMENTS + GEOSPATIAL GROWTH RUNNING TOTAL (CUMULATIVE)		893.5	282.2	144.2	195.3	334.9	455.8	599.4	734.4	878.3	1024.7

7.1.3. Disaggregate Load and DER Annual Growth to 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 load added by customer class by the end of the study period, i.e., year 2031 is the same between the two, but the trajectory is different. In particular, it can be seen that at the system-level, there are no spatial loads in the first three years of the forecast and that the spatial loads increase linearly from 2025 to 2031. This is the target load profile for the spatial loads input into LoadSEER. However, when looking at the aggregate circuit-level spatial loads in Table 7-3, it can be seen that LoadSEER assigns some loads to circuits in the first three years. This has the effect of moving growth from the latter years (2025 to 2031) to the first three years. However, since the load disaggregated to each circuit is small (a total of 262MW in the first three years assigned to over 3000 circuits), this is not expected to increase the number of needs in the first three years by any significant amount. The mismatch between the system-level and aggregate circuit-level spatial load growth was brought to the attention of PG&E and recommended to be fixed in the next cycle.

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

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential	0	0	0	59	117	176	234	293	351	410
Commercial	0	0	0	18	35	53	70	88	105	123
Industrial	0	0	0	48	97	145	193	242	290	338
Agricultural	0	0	0	22	44	66	88	110	132	154
Total	0	0	0	146	293	439	586	732	878	1025

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

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential	33	63	94	187	262	292	323	352	380	410
Commercial	11	22	33	49	65	81	92	103	112	123
Industrial	31	61	91	155	188	219	249	278	308	338
Agricultural	15	30	44	62	77	93	109	123	139	154
Total	89	175	262	453	592	685	772	856	939	1025

Similarly, PG&E disaggregates system-level growth forecasts down to the circuit level for the following four DERs: Additional Achievable Energy efficiency (AAEE), Photovoltaics (PV), Energy Storage (ES), and Electric Vehicles (EV). The IPE verified that the sum of the disaggregated circuit-level forecasts matches with the system-level forecasts provided by the CEC.

Table 7-4 shows a comparison of the disaggregated circuit-level forecasts for AAEE with the system-level forecasts for the Mid-Low case, which is at the WECC busbar level as provided by the CEC. The values shown in this table are incremental, annual AAEE values as opposed to the cumulative values shown in Table 7-3. It can be seen from the table that the two values match very closely except for one year during which AAEE is negative at the system level and assumed to be zero for disaggregation purposes. This mismatch, which is likely due to errors in the bus bar-level CEC forecast was pointed out to PG&E. However, the impact of energy efficiency on peak loads at the circuit level is expected to be small given their magnitude at the system level.

Table 7-4: AAEE forecast verification at the circuit level

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sum of Circuit-level Forecast	51	125	21	0	39	147	45	42	42
CEC System-level Forecast	51	125	21	-58	39	147	45	42	42

PG&E uses the residential light duty electric vehicle (LDEV) stock forecast from the CED 2020 Mid Baseline case at the zonal level (Zones 1-6) for modeling residential LDEV loads. PG&E used the residential LDEV stock mid forecast provided by the CEC to estimate the counts corresponding to a high EV scenario. PG&E assumed a 20% increase in peak load per unit to account for the LDEV High scenario. The kw per unit was increased from 1.2kw to 1.44kw. .These values are then disaggregated to the circuits based on ZIP code level adoption models developed by PG&E.

PG&E does not use the commercial LDEV stock forecast from CEC, rather uses known load EV additions in place of this. PG&E also does not model MHDEV and electric buses as explicit loads in the GNA. Table 7-5 below compares the System-level residential LDEV peak load derived from the CEC forecast as discussed above with the disaggregated circuit-level peak loads. It can be seen from the table that the two values match very closely.

Table 7-5: Residential LDEV forecast verification at the circuit level

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CEC System-level Forecast	156	158	150	147	112	111	111	111	115	115
Sum of Circuit-level Forecast	157	155	146	143	108	106	106	106	109	109

PG&E disaggregates the residential and commercial PV solar forecast provided by the CEC at the zonal level (Zones 1-6) to the circuit-level. The IPE verified that the sum of the disaggregated circuit-level forecasts matches with the system-level forecasts provided by the CEC. It can be seen from Table 7-6 that the two values match exactly for residential PV and closely for commercial PV.

Table 7-6: Residential and Commercial PV forecast verification at the circuit level

	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Residential PV Solar								
CEC System-level Forecast (MW)	264	209	186	179	177	176	174	172	172
Sum of Circuit-level Forecast (MW)	264	209	186	179	177	176	174	172	172
	Commercial PV Solar								
CEC System-level Forecast (MW)	192	199	206	214	222	231	241	250	250
Sum of Circuit-level Forecast (MW)	207	214	221	229	238	246	256	265	265

Similar to PV, PG&E disaggregates the residential and commercial energy storage (ES) forecast provided by the CEC at the zonal level (Zones 1-6) to the circuit-level. It can be seen from Table 7-7 that the two values match very closely.

Table 7-7: Residential and Commercial ES forecast verification at the circuit level

	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Residential Energy Storage								
CEC System-level Forecast (MW)	35.07	36.85	38.21	39.30	40.32	41.31	42.28	43.21	44.10
Sum of Circuit-level Forecast (MW)	36.81	38.18	39.27	40.30	41.29	42.23	43.16	44.07	44.07
	Commercial Energy Storage								
CEC System-level Forecast (MW)	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53
Sum of Circuit-level Forecast (MW)	9.80	8.79	8.80	8.46	8.62	9.24	9.53	9.06	8.57

7.1.4. Add Incremental Load Growth Projects to Circuit Level Forecasts – Step 4

PG&E accepts the CEC ten-year forecast and does not assume there are other loads that will connect 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 because the developer has submitted an application for service. These make up the “new known distribution loads” adjustment made to the CEC annual system load growth forecast. After the adjusted (remaining) system load is allocated to the circuits, these new known distribution loads are added to their specific circuits. As mentioned earlier, the annual known load additions in the first three years are 90% of the actual known load requests received by PG&E to account for cancellation.

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 7-8, there is significant expected load growth in all classes of load including EV charging and cannabis growth. The known loads shown in this table match reasonably well with those used in Step 2 (rows 15-19 of Figure 7-3), but don’t match the numbers exactly. This is because PG&E continuously updates the list of known loads and list used for Table 7-8, is more current than the list of known loads used in Step 2.

Table 7-8: MW of New Known Distribution Load by year

	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
New Residential	143	37	24	4	8	1	1	0	0	217
New Commercial	286	100	57	20	20	5	9	2	0	498
New Industrial	234	100	29	16	14	11	4	1	0	408
New Agricultural	221	44	35	10	0	0	0	0	0	310
TOTAL	884	281	144	49	42	17	14	2	0	1433

As shown in Table 7-9, the in-service dates for most of the known loads are in first two years of the planning window.

Table 7-9: Count of New Known Distribution Load by Year

	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
New Residential	370	107	35	12	10	2	1	0	0	537
New Commercial	459	85	34	14	10	3	3	1	0	609
New Industrial	230	50	22	9	8	4	2	1	0	326
New Agricultural	560	67	54	4	0	0	1	0	0	686

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 (also called Corporate Forecast) by customer class (verified in Step 3) and 576-hourly profiles from LoadSEER 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. If there are any new known loads assigned to a feeder, these loads are also modeled using standard 576-hourly load profiles for each customer class.

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 load growth and DER profiles are added to the base load profile to obtain the net load profile for each year. The peak of this net load profile is compared against the rating of the feeder to determine if there are overloads.

In this step, the IPE obtained the 576-hourly load profiles for base load, Corporate and known load growth, and DER growth from LoadSEER for several circuits. These feeders were chosen based on the following criteria:

1. One or more feeders that have sensitivity to temperature and one or more that have sensitivity to water allocation,
2. One or more feeders that have known load (Residential or Commercial) additions,
3. One or more feeders that have identified needs that are solved using load transfer,
4. One or more feeders that have identified needs that are solved with a planned project,
5. One or more feeders with needs that result in Candidate Deferral Opportunity (CDO) project,
6. One or more feeders with known DCFC addition.

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 our own 576 hourly profiles and compared it with those from LoadSEER. This was done to verify the annual peak loads are being calculated based on the information provided by PG&E.

While this verification was performed on a number of feeders, only the results for Figarden 2102 circuit are presented in this section. This feeder has load growth due to known commercial load addition, as well as growth due to PV, EV, and energy efficiency. Figure 7-4 shows the load profile for a day in January 2022 and 2030 for commercial solar for the Figarden 2012 circuit from LoadSEER. Figure 7-5 shows the same information as calculated by the IPE. As observed, the commercial solar profile calculated by the IPE matches reasonably well with what was produced by LoadSEER. Similarly, Figure 7-6 and Figure 7-7show a comparison of the load profiles for residential LDEVs, and

Figure 7-8 and Figure 7-9 a comparison of energy storage[6]. The figures produced by the IPE match exactly with those from LoadSEER. As mentioned earlier, this circuit also has a known commercial load addition of 2.2 MW. Figure 7-10 and Figure 7-11 show a comparison of the 576-hourly load profiles for new commercial load in 2022 as produced by LoadSEER and as calculated by the IPE. A comparison of the 576-hourly load profile is made since the loads vary by the month and day (weekday vs. weekend).

[6] The comparison of LoadSEER versus IPE calculated load profile for energy storage was made for the Lakewood 1104 circuit since there was no energy storage on the Figarden 1102 circuit.

Figure 7-4: Load profile for Commercial PV for the Figarden 2102 circuit from LoadSEER

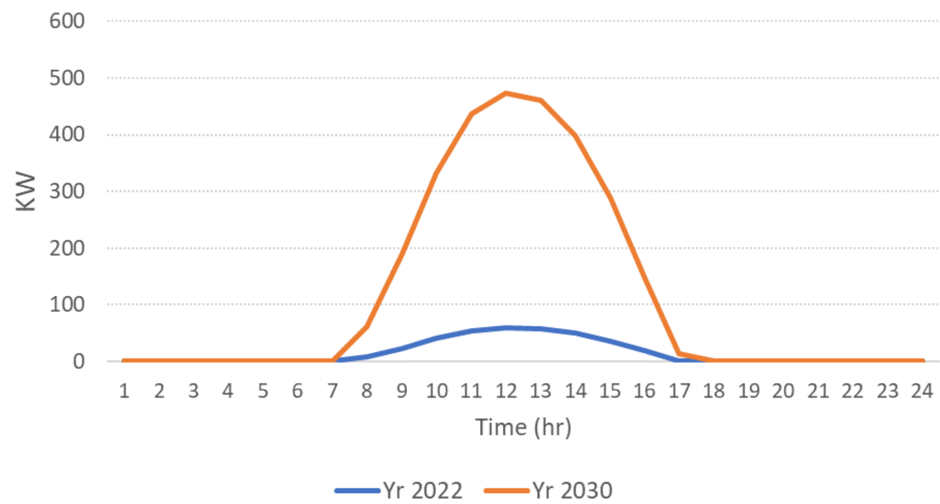


Figure 7-5: Load profile for Commercial PV for the Figarden 2102 circuit calculated by the IPE

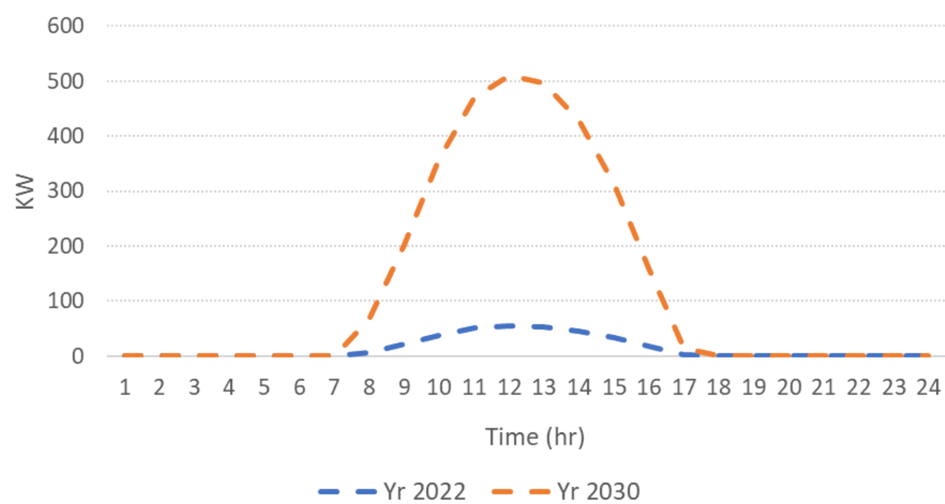


Figure 7-6: Load profile for Residential LDEV for the Figarden 2102 circuit from LoadSEER

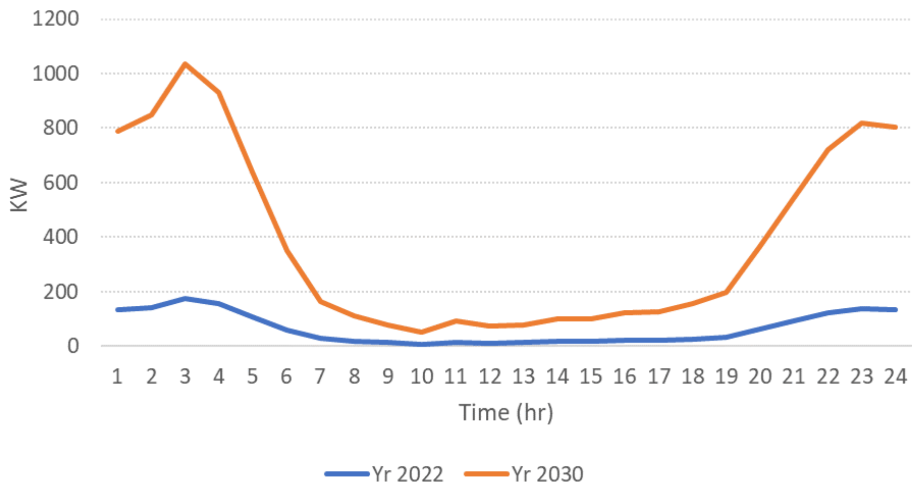


Figure 7-7: Load profile for Residential LDEV for the Figarden 2102 circuit calculated by the IPE

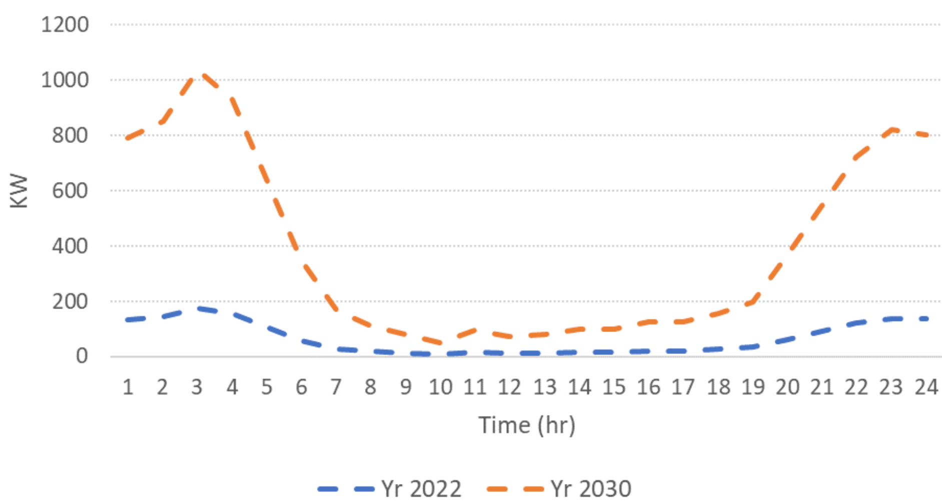


Figure 7-8: Load profile for Energy Storage (Charging) for the Lakewood 1104 circuit from LoadSEER

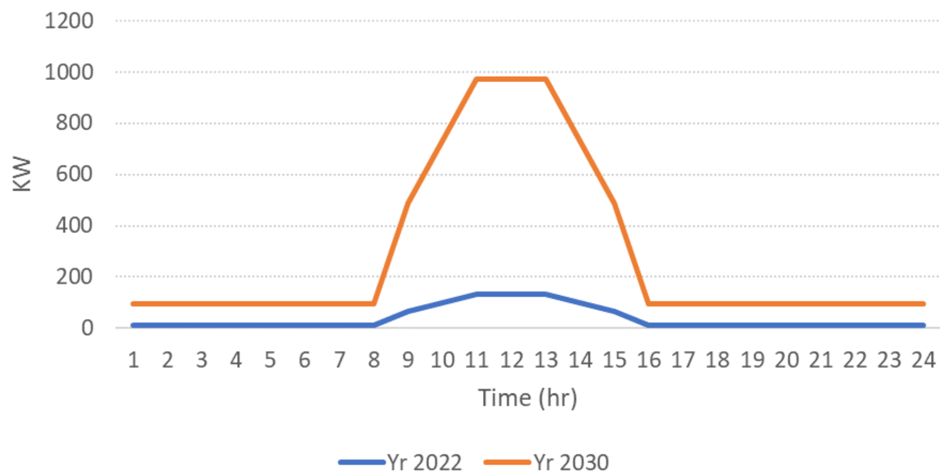


Figure 7-9: Load profile for Energy Storage (charging) for the Lakewood 1104 circuit calculated by the IPE

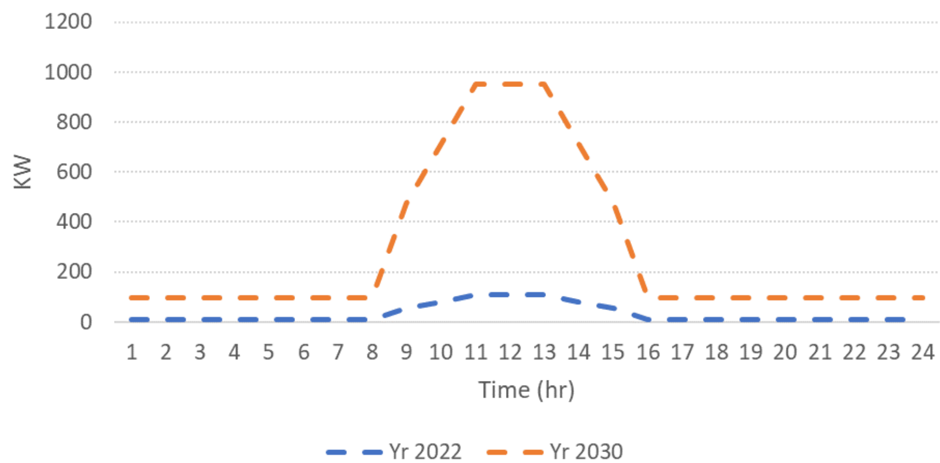


Figure 7-10: Load profile for new commercial load for the Figarden 2102 circuit from LoadSEER

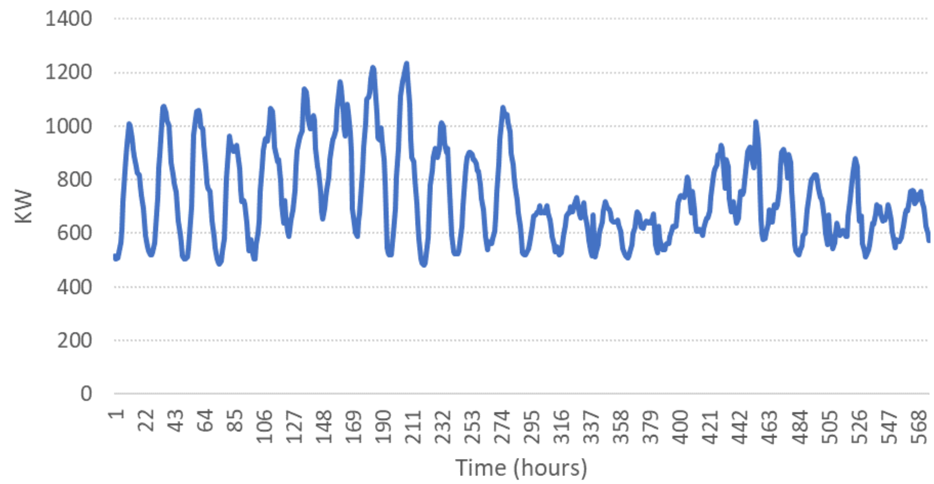
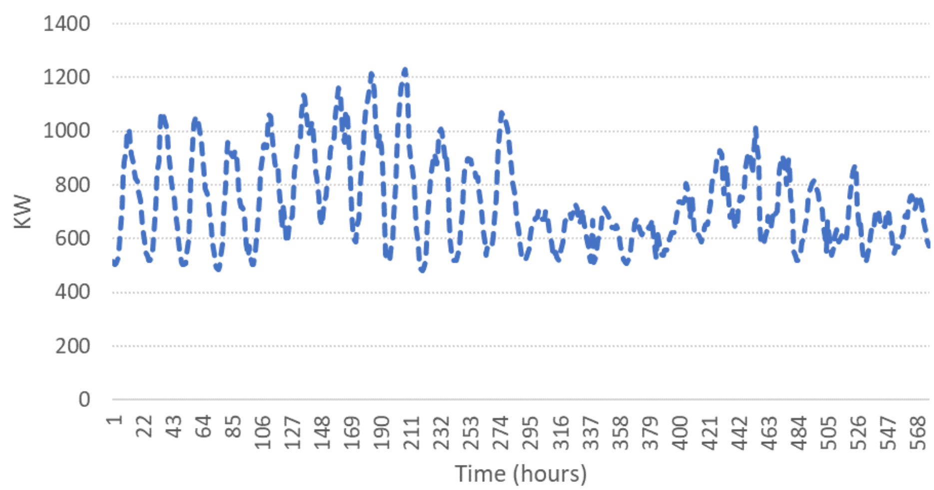


Figure 7-11: Load profile for new commercial load for the Figarden 2102 circuit calculated by the IPE



Since Figarden 2102 circuit does not have any loads due DCFC fast charger, local delivery fleet, or transit agency, other circuits were chosen for this purpose. Figure 7-12 through Figure 7-14 show the EV charging profile for a DCFC, a local delivery fleet and a transit authority from feeders Willows 1101, Barton 1112 and San Luis Obispo 1108 respectively.

Figure 7-12: 24-hour DCFC charger profile

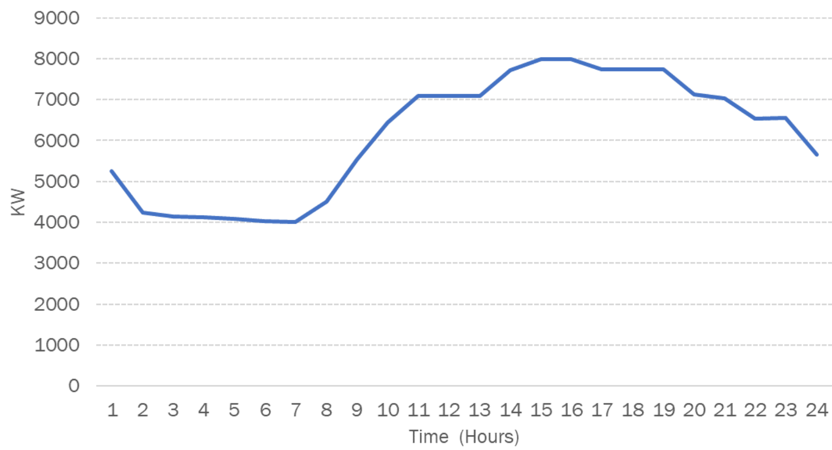


Figure 7-13: 24-hour local delivery fleet charging profile

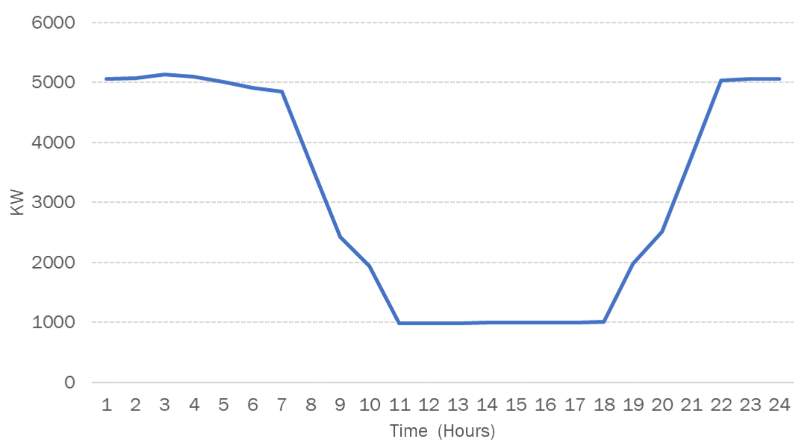
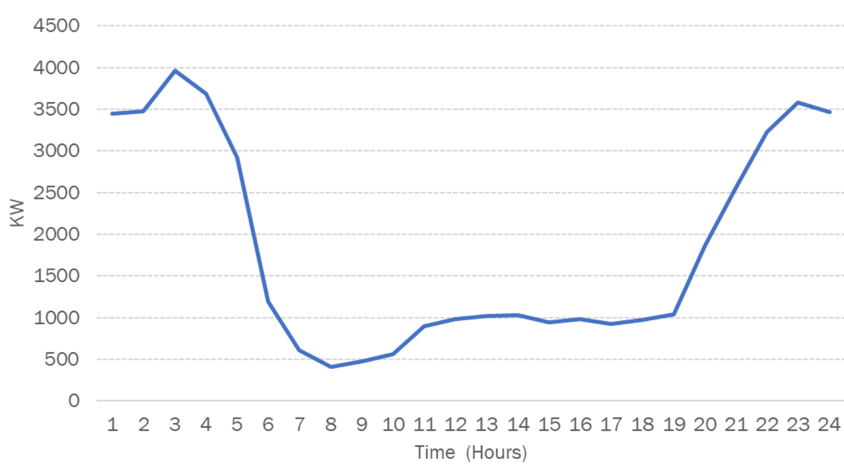


Figure 7-14: 24-hour transit authority charging profile



By using the process described above, the IPE verified the load profiles developed in LoadSEER for load and DER growth. Since the net load is the sum of the base load profile (i.e., existing load) and the growth due to load and DERs, it is reasonable to conclude the net load profile has also been verified by the IPE.

As mentioned earlier, the peak load used for determining circuit and bank overloads is obtained from the peak of the net load profile. Using the 576-hourly data provided by PG&E, the IPE determined the peak load as a percentage of the bank/circuit's rating . Table 7-10 shows the peak load as a percentage of the rate as calculated by the IPE.

Table 7-10: Peak load as a percentage of rating for select circuits as calculated by the IPE

(Confidential information is redacted in the public report)

			Anita 1101		ATASCADERO 1101		EDENVALE 2109		FIGARDEN 2102		LAKEWOOD 1104	
Rating (MW)			11.05		12.19		20.04		21.22		10.76	
	Peak Load (MW)	Over load (%)	Peak Load (MW)	Over load (%)	Peak Load (MW)	Over load (%)	Peak Load (MW)	Over load (%)	Peak Load (MW)	Over load (%)	Peak Load (MW)	Over load (%)
2022			3.39	31%	10.87	89%	18.68	93%	20.98	99%	8.90	83%
2023			3.45	31%	10.76	88%	18.80	94%	23.05	109%	8.97	83%
2024			3.56	32%	10.70	88%	18.96	95%	23.80	112%	9.02	84%
2025			3.67	33%	10.71	88%	19.12	95%	24.01	113%	9.15	85%
2026			3.77	34%	10.72	88%	19.23	96%	24.38	115%	9.21	86%
2027			3.83	35%	10.67	88%	19.30	96%	24.40	115%	9.28	86%
2028			3.94	36%	10.66	87%	19.41	97%	24.41	115%	9.40	87%
2029			4.06	37%	10.65	87%	19.53	97%	24.45	115%	9.51	88%
2030			4.14	37%	10.65	87%	19.67	98%	24.52	116%	9.66	90%
2031			4.26	39%	10.67	88%	19.81	99%	24.56	116%	9.81	91%

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

PG&E uses no-cost solution such as load transfer to a neighboring circuit before evaluating capital projects. 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 sectionalizing 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.

The data provided by PG&E showed that 630 MW was transferred from one circuit to another in 2022 to relieve overloads. The transfer amount was 150 MW for the 2023 and a total of 60 MW for the years 2024 through 2028. The IPE verified the before and after 576 hourly load profile associated with a transfer of 62 Amps (1.33 MW) from Deschutes 1104 to Oregon Trail 1104 to alleviate overload on Deschutes 1104. Figure 7-15 shows load transfer information including the transfer date, transfer amount and the switching device codes. Figure 7-16 and Figure 7-17 show the 576 profiles from LoadSEER for the two feeders before and after the transfer. It can be clearly seen that there is a 1.3 MW reduction in the loading of Deschutes 1104 and a corresponding increase in the loading of Oregon Trail 1104 after the transfer.

Figure 7-15: Load Transfer Information for Deschutes 1104 to Oregon Trail 1104

Description: Deschutes 1104 to Oregon Trail 1104

Switching: Close: 5769 Open: LR 9726

Transfer date: 2022-05-01

- [x] Planned
- [ ] Completed

- [ ] Exclude from forecast
- [ ] Requires Project

From:

Type	Name	kV	Amps	MW
Feeder	DESCHUTES 1104	12.47	-62	-1.33

Edit Clear

To:

Type	Name	kV	Amps	MW
Feeder	OREGON TRAIL 1104	12.47	62	1.33

Edit Clear

Customers:

Customer Class	Count
Domestic	0
Commercial	0
Industrial	0
Agriculture	0
Total	0

Comment: mtn6 - This transfer is to alleviate the sum 2022 projected overload on Deschutes 1104.
Free Transfer

Figure 7-16: Loading before and after Transfer for Deschutes 1104

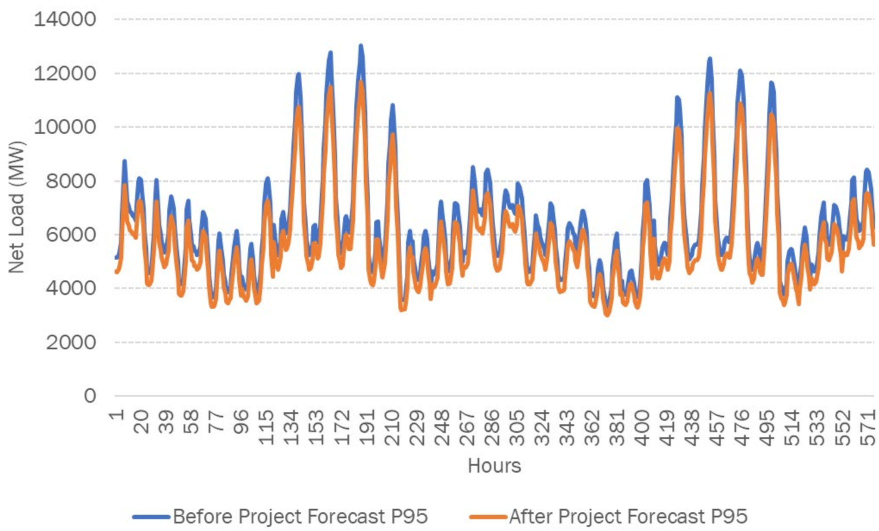
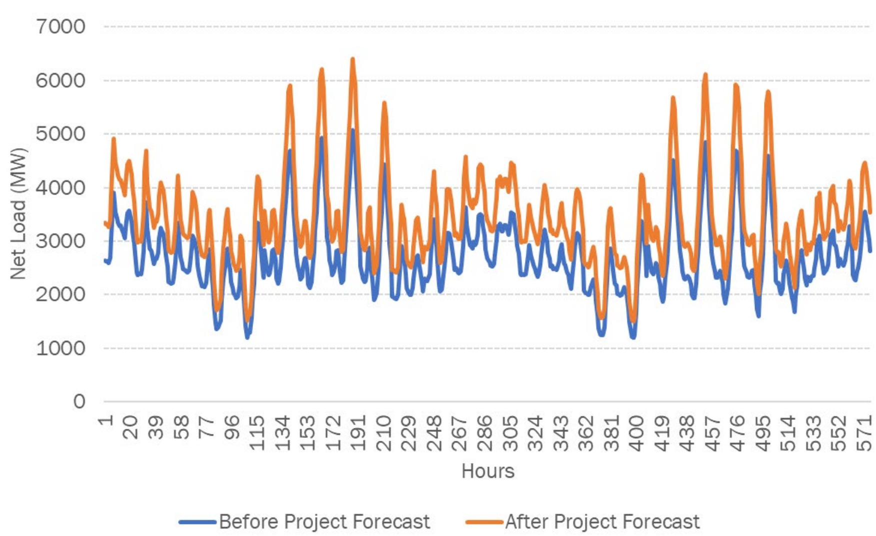


Figure 7-17: Loading before and after Transfer for Oregon Trail 1104



7.2.2. Compile GNA Tables Showing Need and Timing – Step 12

In this step, the IPE compared the loading for select circuit calculated in Step 9 with those reported in the GNA table (Appendix D-F of the GNA Report). Table 7-11 shows the results of the comparison. It can be seen that the values for the loading calculated by the IPE matches exactly with what is reported in the GNA table for the selected circuits. It should be pointed out that the GNA tables show the loading only for the first five forecast years. i.e., 2022-2026.

Table 7-11: Verification of Circuit Loading in the GNA

(Confidential information is redacted in the public report)

			Anita 1101		ATASCADERO 1101		EDENVALE 2109		FIGARDEN 2102		LAKEWOOD 1104	
	Over load calc by IPE (%)	Over load in GNA (%)	Over load calc by IPE (%)	Over load in GNA (%)	Over load calc by IPE (%)	Over load in GNA (%)	Over load calc by IPE (%)	Over load in GNA (%)	Over load calc by IPE (%)	Over load in GNA (%)	Over load calc by IPE (%)	Over load in GNA (%)
2022			31%	31%	89%	89%	93%	93%	99%	99%	83%	83%
2023			31%	31%	88%	88%	94%	94%	109%	109%	83%	83%
2024			32%	32%	88%	88%	95%	95%	112%	112%	84%	84%
2025			33%	33%	88%	88%	95%	95%	113%	113%	85%	85%
2026			34%	34%	88%	88%	96%	96%	115%	115%	86%	86%
2027			35%	35%	88%	88%	96%	96%	115%	115%	86%	86%
2028			36%	36%	87%	87%	97%	97%	115%	115%	87%	87%
2029			37%	37%	87%	87%	97%	97%	115%	115%	88%	88%
2030			37%	37%	87%	87%	98%	98%	116%	116%	90%	90%
2031			39%	39%	88%	88%	99%	99%	116%	116%	91%	91%

7.3. Processes to Develop Planned Investments and Costs

7.3.1. Develop Recommended Solution – Step 13

PG&E has a design criterion, "*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 CODs were demonstrated for the Millbrae substation project (DDOR 1027) in which a new bank (Bank 2) and a new feeder (1109) are added to decrease the loading on the following banks and circuits: Millbrae Bank 4, Millbrae 1107, East Grand Bank 1 and East Grand 1112. The demo showed that the approach to developing a solution was consistent with the "*Guide for Planning Area Distribution Facilities*".

7.3.2. 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 CDOs 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 CDOs as being at the earlier stages of 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. The costs used for the development of these CDOs are the same costs as used in the GRC.

Cost breakdown for four Tier 1 and one Tier 2 CDOs are shown below in Table 7-12. The costs provided in this table are consistent the costs shown in DDOR Appendix A, Planned Investments.

Table 7-12: Cost Data for Selected Candidate Deferral Opportunities

DDOR ID	PROJECT NAME	PROJECT DESCRIPTION	SCOPE	PROJECT DEVELOPMENT COST
DDOR109	Blackwell Bank 1	Replace Bank 1	Blackwell Bank 1 - Replace existing transformer bank	$ 7,500,000.00
DDOR1001	Camden 1106	Install New Camden 1106 Feeder	Install 2 distribution circuit breakers; Distribution Line Work-16,000 feet of reconductor (1106) and 52,800 feet of reconductor (1107)	$ 13,808,000.00
DDOR1007	Carlotta Bank 2	Replace Carlotta Bank 2	Carlotta Bank 2 - Replace existing transformer Bank	$ 7,500,000.00
DDOR079	Gabilan Bank 2	Install Bank 2	Install new Gabilan Bank 2	$ 13,802,320.00
DDOR1027	Millbrae Substation	Install Bank 2 and Millbrae 1109 Feeder	New Millbrae Bank 2 and 1109 Feeder	$ 18,026,000.00

7.4. Processes to Develop Candidate Deferral 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 which creates a list of grid needs. This LoadSEER list is used as input for capacity projects in the GNA. The need date for capacity projects is 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, undervoltage, and overvoltage conditions are identified from the CYME, PG&E's load flow and voltage analysis 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. As mentioned earlier, PG&E received a Motion for Extension approval on August 30, 2022, to delay publishing of grid needs resulting from line section analyses, which are primarily voltage support and distribution capacity needs. PG&E provided a supplemental filing on October 19, 2022, per the approved Motion for Extension.

The DDOR in-service dates are used for as the timing screen. There were 18 projects that passed the technical and timing screen. The IPE verified that the technical and timing screen were applied correctly.

7.4.2. Development of Operational Requirements – Step 16

Operational requirements are developed in LoadSEER that provides loading by month and hour for the peak weekday and weekend day of the month. The process used in this year's DDOR is the same as last year's. 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 weekday 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 LoadSEER results are put into a separate Excel workbook that identifies the service requirements which include the peak year, month ranges, max/min and times and the weekday/weekend needs such as start/end times, load ranges, and potential calls/year. PG&E adds an hour to each side of the overload time to reflect when an overload extends to part of an hour before or after the hour identified by LoadSEER.

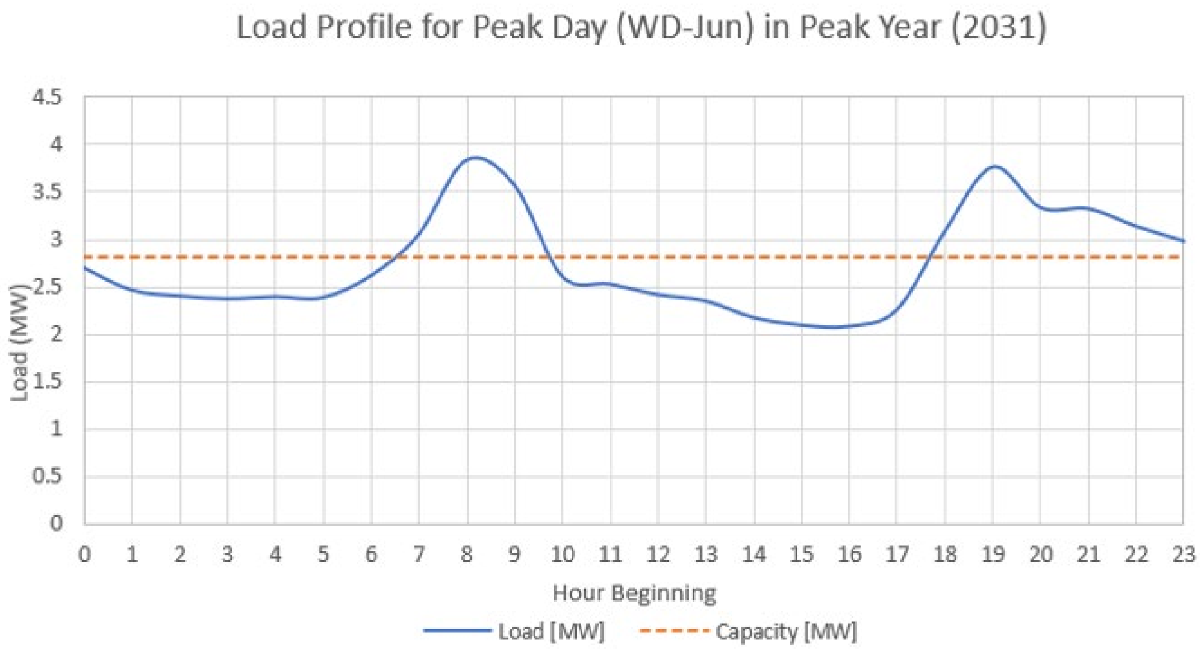
PG&E demonstrated the development of operational requirements for Carlotta Bank 2 – DDOR 1007. In this project, Carlotta Bank 2 is replaced for an overload on Carlotta Bank 1 and Carlotta 1121 feeder. PG&E calculated the operational requirements for the two needs separately. This process involves comparing the 576 Hourly profiles for Carlotta Bank 1 and Carlotta 1121 feeder against their seasonal ratings. The Figure 7-18 below shows the results from this process for Carlotta Bank 1. The top portion of the figure shows the output of the Excel tool that is used for estimating the operational requirements. Quantities such as the need size (MW), the starting and ending months for the need, the starting and ending times and the duration of the need are all estimated. Engineering judgment is the used to fine tune the estimates produced by the Excel tool. This is shown in the bottom half of the figure. Figure 7-19 shows the peak summer day load profile for this circuit. It should be noted that PG&E calculates the operational requirements for all the needs that are associated with CDOs and not just the just the ones selected for procurement.

Figure 7-18: Operational Requirements for Carlotta Bank 1

DER Grid Need (MW)	Grid Need Unit	Starting Need Month	Last Need Month	Calls/Year	Start Time	End Time	Max Need Duration	Peak Year	Number of Events	Anticipated Need Year/First Year
1.02	MW	1	12	365	7:00 AM	12:00 AM	7	2031	2	2025

Grid Need	Grid Need Unit	Month	Calls/Year	Hours	Duration (Hours)	Peak Year	Anticipated Need Year/First Year	WD/WE?
1.02	MW	1-12	365	6 AM-12 AM, 3 PM-12 AM	9	2031	2025	WD/WE

Figure 7-19: Peak Day Load Profile for Carlotta Bank 1



It is observed PG&E has a relatively conservative approach to some of the operational requirements in last year's IPE report, which is repeated here. If there is a peak weekday during 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. This is reasonable for identifying potential availability, but we believe it is overly conservative to use it to develop the total number of calls and/or hours for use in the LNBA metrics (LNBA/MWh-yr.). It is unlikely they will be needed for every day of the month. This approach could have an impact on the LNBA metrics resulting in negative rankings for some CDOs. It is recommended PG&E consider an approach that captures the likely distribution over 8760 hours for identifying the number of hours required.

7.4.3. Prioritization of Candidate Deferral Projects into Tiers – Step 17

As part of this step, the prioritization metrics spreadsheet in the PG&E DDOR Report Appendix C: Prioritization Metrics Workbook was used to review the raw data, normalization process, assignment of red flags and final scoring and ranking of the CDOs. The methodology used followed the description provided by PG&E as discussed in detail in Section 5 of this report. The prioritization or assignment of Tiers for the CDOs are consistent with the calculations in this appendix.

7.4.4. Calculate LNBA Values – Step 18

Development and Use of LNBA Values

The Locational Net Benefits Analysis (LNBA) value is the unitized net present value (NPV) of the savings associated with deferring a planned project. The deferral value is the revenue requirement associated with the planned project which includes annualized capital and operations and maintenance (O&M) costs. The LNBA value is typically expressed as a $/MW-year value, determined by dividing the deferral value by the product of two values – the number of years of deferral and the maximum amount (MW) of need during the deferral period. The LNBA value is used as an indicator 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. In the DDOR report, actual LNBA values (i.e., not ranges) are reported for both Planned Investments and Candidate Deferral projects. The LNBA values are also used in the calculation of prioritization metrics.

Approach

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

Deferral Timeframe

Deferral period is a key input to the LNBA calculation. In the 2022 DDOR, PG&E uses a 10-year deferral timeframe as required by the 2020 May ALJ Ruling Reform #5. For example. If the operating date of a project is in 2025, then the deferral period is 7 years (i.e., defer from 2025 to 2031). PG&E calculated the LNBA values for planned investments (provided in units of $/MW-yr, $/Vpu-yr, or $/MVAR-yr).

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. In the E3-based LNBA calculation tool, the deferral value for a multi-year deferral is calculated using a single NPV formula and not as the sum of the NPV of 1-year deferral values as stated above.

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 cost is also subject to inflation adjustments.

The complete expression of the avoided cost 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 E3-based LNBA calculation tool used by PG&E calculates the multi-year deferral using a single NPV formula with the year of deferral as an input, instead of summing the NPV of 1-year deferrals.

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.
- O&M Costs: Cost of O&M as per utility's practice. Expressed as a percentage of the project's capital cost.

In general, PG&E's LNBA calculations followed the same calculations as those included 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.

Key inputs

The key inputs to the LNBA calculation are shown in the table below. Only the inputs corresponding to substations, primary feeders, and IT are shown in the Table below for simplicity because those were the only ones used. PG&E used a discount rate of 10%. PG&E indicated that the 10% discount rate is equal to PG&E's incremental cost of capital. PG&E's incremental cost of capital is intended to be a forward-looking long-term cost of capital, whereas PG&E's authorized cost of capital is a short-term cost of capital that largely reflects the cost of existing financing, not new or incremental financing. One other key input for the LNBA calculation is the capital cost of equipment for each project.

Table 7-13: Key Inputs for LNBA Calculation

Input	General	Substation Bank	Primary Feeder	Poles and towers	Source
Revenue Requirement Multiplier (Fixed Costs)	145.54%	144.3%	146.8%	150.7%	PG&E assumption
Revenue Requirement Multiplier With O&M	247.78%	186.5%	309.1%	310.5%	PG&E assumption
Equipment Inflation	2.50%	2.50%	2.50%	2.50%	Standard assumption in LNBA Calculator
O&M Inflation	2.50%	2.50%	2.50%	2.50%	Standard assumption in LNBA Calculator
O&M Factor	5.15%	2.13%	8.18%	8.18%	PG&E assumption
O&M Old Eqpt	0%	0%	0%	0%	PG&E assumption
Book Life	46	46	46	44	PG&E assumption
RECC	0.047	0.047	0.047	0.047	Calculated
Discount rate net or project inflation (5/yr.)	4.17%	4.17%	4.17%	4.17%	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: DDOR109, GNA Facility Name: Blackwell Bank 1) as shown in Table 7-14. 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 7-14: Blackwell Bank 1 Work LNBA Verification

(Confidential information is redacted in the public report)

#	LNBA Item	Values shown in DDOR Report	IPE Calculations based on E3 LNBA formula	E3 LNBA formula
1	Project ID / Name	DDOR109	DDOR109	Input Verified
2	GNA Facility Name	Blackwell Bank 1	Blackwell Bank 1	Input Verified
3	Planned Investment Type	Bank	Bank	Input Verified
4	Project Cost ($k)	7500.00	7500.00	Input Verified
5	Revenue Requirement Multiplier	1.44	1.44	Input Verified
6	Discount Rate (%/yr)	7%	7%	Input Verified
7	Equipment Inflation	3%	3%	Input Verified
8	O&M Inflation	3%	3%	Input Verified
9	O&M Factor	0.00	0.00	Input Verified
10	Book Life	46	46	Input Verified
11	DER Install Year	6/1/2025	6/1/2025	Input Verified
12	Cost year basis	8/1/2022	8/1/2022	Input Verified
13	Analysis Year	2022	2022	Input Verified
14	Deferral Years	7	7	Input Verified
15	Number of no deficiency years after the DER Install yr	0.00	0.00	Input Verified
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)	0.04	0.04	(1+C6)/(1+C7)-1
19	RR Install Yr $'s	11607.69*	11554.18	C4*C5*(1+C7)^((C11-C12)/365.25)
20	RR * RECC	548.06	545.56	C19*C17
21	Capital Benefit in Install Year	3405.63	3390.07	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	[redacted]	[redacted]	[redacted]

24	Value of Deferral Benefit ($000s) in 2022			
25	Max Need (MW/Vpu/MVAR)*			
26	Normalized Deferral Benefit ($000s/MW-yr)			

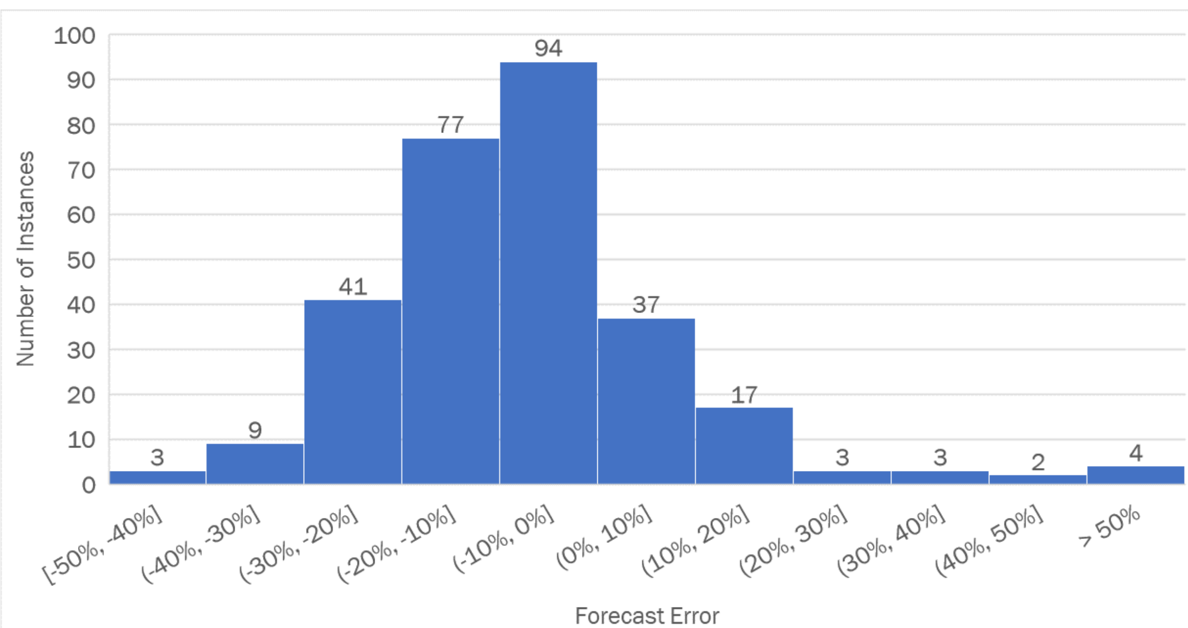
Note: This table has confidential information highlighted in gray which will be redacted in the public report

*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.

7.4.5. Compare 2021 Forecast and Actuals at Circuit Level for 2021 – Step 19

A comparison of the actual 2021 peak load (adjusted to 1-in-10) and the 2021 forecasted 1-in-10 peak load from the 2020 GNA was conducted for roughly 10% of the feeders. PG&E provided the 2021 actual scrubbed peak loads adjusted to 1-in-10 and the corresponding forecast was obtained by the IPE from the 2020 GNA appendix. The analysis process included calculation of the delta between the actual and forecasted load, percent difference and overloads. Figure 7-20: Percent Difference Distribution, below shows the percent difference distribution for 291 circuits.

Figure 7-20: Percent Difference Distribution



It can be inferred from the figure that the distribution is a little skewed (forecasts higher than actuals more than actuals higher than forecasts) and that the about 45% of the forecasted loads are within +/-10% of the actual values and about 78% of the forecasted loads are within +/-20% of the actual values.

7.5. Other IPE Work

7.5.1. 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 by stakeholders. There were no written comments or questions directly addressed to the IPE.

7.5.2. Track Solicitation Results to Inform Next Cycle – Step 22

This review was completed in Q3 of 2022. A solicitation tracking tool (XCEL workbook) was developed at the Direction of the Energy Division. The IPE participated in the definition of the data to be tracked. Going forward the IEs for each utility will update the information in the tracking tool on a regular basis.

7.5.3. 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)

- 1 -

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;

  - 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.

<u>DPAG Period</u>

- 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.

- 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.

Appendix B DPAG Survey and Comment Responses

PG&E solicited feedback from the DPAG during their DPAG meeting on September 22, 2022 and also solicited comments by email. There were a number of comments from the Energy Department and the Public Advocates Office directed to PG&E. The responses to these questions were posted by PG&E to the R.21-06-017 Service List on October 5, 2022 and discussed during their DPAG follow-on meeting on October 21, 2022

Appendix C Copy of the IPE Plan

Note: The 2022/2023 IPE Plan for PG&E is included in a separate file from the file containing this report.

Independent Professional Engineer Plan for Pacific Gas and Electric

Submitted to California Public Utility Commission

9/21/2022

Submitted by:
Resource Innovations
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Contents

1 Introduction and Background

This document is the draft version of the Independent Professional Engineer Plan for the 2022/2023 Distribution Investment Deferral Framework (DIDF) cycle for Pacific Gas and Electric. The requirements for the plan and oversight by the Energy Division are spelled out in a recent CPUC Ruling 14-08-013 (April 13, 2020) which is attached as Appendix A. The Ruling modified the Distribution Investment Deferral Framework (DIDF) process and previous rulings with respect to the Independent Professional Engineer (IPE) scope of work and provided the updated 2020-2021 DIDF cycle schedule. As of writing this draft report, the 2022/2023 cycle schedule has not been finalized.

As a result of stakeholder comments regarding improving the effectiveness of the IPE process, schedule and expected results, a number of modifications were made by the Ruling and implemented for the first time in the 2020-2021 DIDF cycle. These changes have been incorporated in the IPE Plans developed ever since. Some of these changes are highlighted below:

- The IPE review process now starts earlier to allow for more time for the IPE, utilities and the Energy Division to perform the necessary production of data in response to data requests, verify and validate the data, produce reports and address the confidentiality of data in the reports prior to the IPE Report deadline. The review process starts in the late-April timeframe.
- The IPE scope includes development of a draft IPE Plan for each utility by mid-May in each cycle. The plan goes through a stakeholder review cycle and will be issued in final form by the IPE in August.
- The scope of the IPE review was expanded to include several new business processes
- The scope of the review was expanded to include the new CPUC Standard Offer Contract (SOC) and Partnership Pilots (PP).
- The original schedule for IPE deliverables was established in the CPUC 2020 Rulings for the 2020/2021 cycle[1]:
    - Draft IPE Plan. Due May 13, 2020
    - Final IPE Plan. Due August 15, 2020.
    - IPE Preliminary Analysis of GNA/DDOR Data Adequacy for all three IOUs. Due September 5, 2020.

[1] Dates shown below were originally set forth per the 2020 Ruling. The CPUC plans to issue a ruling with dates for the 2022/2023 DIDF cycle in May. These updated dates will be included in the Final PG&E IPE Plan.

  - IPE DPAG Report for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes. Due November 15, 2020.

  - IPE Post DPAG Report covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements and DIDF reform. Due February 5, 2021.

- The May 2022 draft IPE Plan for 2022/2023 DIDF cycle will be distributed to stakeholders in May to facilitate stakeholder comments prior to finalizing the IPE Plan in August 2022.

2 Description of the Plan

2.1 Definitions Used in the Plan and Other Deliverables

To facilitate understanding of the IPE scope of work, the following definitions are included and will be used in the Plan and throughout all of the IPE work products and deliverables.

> 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 and described 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?"

The IPE Plan covers the business processes that the IOUs use to identify which distribution or sub transmission projects are recommended to proceed to 1) an RFO, 2) Standard Offer Contract or 3) Partnership Pilot 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 2021, 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 (nominally 2022 through 2026). 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. Candidate deferral projects are also considered for SOC or PP pilot programs based upon the results of the prioritization process along with additional set of metrics for SOC and PP pilots.

As indicated earlier, in the 2021/2022 cycle two new pilot programs were initiated that are testing new mechanisms to procure DERs. They are called the Partnership Pilot and a Standard Offer Contract. These pilots impact other parts of the business processes covered in the IPE Plan.

3 IPE Plan

The heart of the IPE Plan is the material contained in Table 3-1 below. This table lists the business processes, roles of the utility and IPE, target timing and information requirements for each business process in the IPE scope. Listed below is a more detailed description of the contents of Table 3-1:

- IOU Business Process / IPE Review Step – This column includes a number for each business process included in the table. To make it easier for readers who will be looking at more than one utility IPE Plan, the process was started with the same numbering for all three utilities and that set of numbers was maintained as much as possible. In cases where additional steps needed to be added to accommodate a utilities specific unique process a letter was added to the previous number. For example, the step after Step 3 was added and was number Step 3a. For cases where steps are not needed, they will be spelled out in the table.
- Business Process / IPE Review Step Description – This column contains a general description of the business process being reviewed.
- Plan for 2022/23 DIDF Cycle – This column includes several types of information:
    - A brief description of what the review will include and whether it would include review of a subset of the total number of elements (i.e., circuits) or all elements and what is being examined.
    - Roles which include the role of the utility overall and the role of the IPE for both the verification and validation review. For both reviews, an indication is provided for what the IPE will be checking for or confirming in the review.
      Note that there are generally two approaches to performing a verification. The first is a demonstration wherein the utility develops the necessary spreadsheet or other mechanism to show how the business process developed the results of interest and the IPE performs a walk through to view the demonstration by the utility. The second approach is wherein the IPE develops a spreadsheet or other mechanism to calculate the results of interest using data provided by the utility and then compares the results to the numerical utilities results.
- Target Timing – This column includes a target timing for the reviews in the business process in this row or in the timing that data will be provided to the IPE.
- Data/Information Requirements – This column includes the data or information that the IPE needs to perform its review and in some cases the date the information is required.

Table 3-1 PG&E IPE Review for 2022/23 DIDF Cycle is shown starting on the following page.

Table 3-1: PG&E IPE Review for 2022/23 DIDF Cycle

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
PROCESSES TO DEVELOP STARTING POINT LOAD, SYSTEM LEVEL VALUES AND DISAGGREGATE TO CIRCUIT LEVEL				
1	Collect 2021 actual circuit loading and adjust for weather as needed	Perform Verification for at least 10 circuits mutually selected by PG&E and the IPE; Verify the following: • Collection and correction of peak load data for the circuits • Normalization of corrected peak load based on weather, water allocation or other factors • Development of 1-in-2 and 1-in-10 Baseline load profiles in LoadSEER. Roles: PG&E to provide a description and demonstration of the processes used for peak load collection, scrubbing, normalization and correction for extreme weather. PG&E to provide the information specified in the Data/Information Requirements column.	PG&E to provide the process description (specified in the data/information column) by June 15. PG&E to provide the data/information items (1) and (2) (specified in the data/information column) by June 15. PG&E to provide the data/information item (3) (specified in the data/information column) by June 15.	PG&E to provide the data/information requested below. IPE to provide the data/information provided in the last cycle for reference. **Process Description:** PG&E to provide a description of the following process. PG&E to indicate if any of these processes have changed since the last GNA-DDOR cycle. ▪ Collection and correction of peak load data for the circuits ▪ Normalization of corrected peak load based on

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Verification: IPE to review the data/information and demonstrations provided by PG&E and verify that these results are carried forward in the planning process in subsequent V&V steps. Validation: IPE to review the business process for reasonableness and consistent with the objectives of the DIDF process.	PG&E to provide a demonstration (specified in the data/information column) by June 30.	weather, water allocation or other factors ▪ Development of 1-in-2 and 1-in-10 Baseline load profiles in LoadSEER. **Data/Information:** (1) Summary data for the 10 circuits as shown below. Feeders should consist of at least 4 feeders with temperature as a normalization/adjustment variable, at least 3 feeders whose load is impacted by water allocation and at least 3 feeders without a normalization/adjustment forecast variable. a. Peak data raw (MW and Time) b. Peak data scrubbed (MW and Time) c. Peak data 1 in 2 (MW and Time)

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
				d. Peak data 1 in 10 (MW and Time) e. Temperature or water allocation corresponding to a above f. Temperature or water allocation corresponding to b above g. Temperature or water allocation corresponding to c above h. Temperature or water allocation corresponding to d above h. Data associated with water allocation i. Any other data relative to load measurement adjustments (2) PG&E to provide the 576 hourly (P75 and P95) load profiles from LoadSEER for the selected circuits. (3) PG&E to provide a list of feeders or a breakdown of the

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
				percentage of feeders with loads that are temperature sensitive, water allocation sensitive and those with neither temperature nor water allocation sensitivity. **Demonstration:** PG&E to provide a demonstration of the processes used for peak load collection, scrubbing, normalization, correction for extreme weather, as well as the development of the 1-in-2 and 1-in-10 profiles in LoadSEER.
2	Determine load and DER annual growth on system level	Perform Verification and Validation of how system-level, annual load and DER growth forecasts are developed by PG&E using the CEC IEPR forecasts. Roles:	PG&E to provide the data/information (specified in the Data/Information Requirements column) by June 15.	PG&E to provide the data/information requested below. IPE to provide the data/information provided in the last cycle as a reference.

<table>
<tr><th>IOU Business Process / IPE Review Step</th><th>Business Process / IPE Review Step Description</th><th>Plan for 2022/23 DIDF Cycle</th><th>Target Timing</th><th>Data/Information Requirements</th></tr>
<tr><td></td><td></td><td>PG&E to provide data and information on how the system-level annual load and DER growth forecasts are developed by PG&E using the CEC IEPR forecasts PG&E provides description of CEC forecast used (name of the forecasts used), the EXCEL spreadsheet used and a link to CEC table(s) used.
PG&E provides description as to how known load values are developed and how that load is managed if it should exceed the CEC forecast in any given year.

Verification:
The IPE will verify the CEC forecasts are used as described by PG&E to calculate the load and DER forecast values at the system level for 10 years.

IPE to review spreadsheet results and compare the result from its spreadsheet model to the results developed by PG&E.</td><td>PG&E to provide the process description (specified in the Data/Information Requirements column) by June 15.</td><td>PG&E to provide the following:
Data/Information:
• Name(s) of the CEC IEPR forecast files and links to those files.
• Excel spreadsheet used to calculate the system-level load growth by customer class.
• Excel files containing the zonal forecasts for EV, PV and ES. Excel file containing busbar forecasts for EE.
• Known load additions including amount, circuit name, class, type of load and in-service date.
Process Description:
• PG&E to provide the description of the process</td></tr>
</table>

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the process used to PG&E to adjust the CEC system-level load forecasts for known load additions. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		used to develop system-level load growth (for customer classes) and DER growth from the CEC forecast. • PG&E to provide description as to how known loads are developed and how that load is modeled should it exceed the CEC forecast. • PG&E to indicate if any of these processes have changed since the last GNA-DDOR cycle
3	Disaggregate load and DER annual growth to the circuit level	Perform verification and validation for circuit-level load and DER disaggregation. Roles: PG&E to provide the inputs and outputs, as well as a general description of the processes used for disaggregating system-level load growth to circuit-level	PG&E to provide the data/information (specified in the Data/Information Requirements column) by June 30. PG&E to provide the process description	PG&E to provide the data/information requested below. IPE to provide the data/information provided in the last cycle for reference. **Data/Information:**

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		and further at a class level (Domestic, Commercial, Industrial) using LoadSEER. PG&E to provide the inputs and outputs, as well as a general description of the processes used for disaggregating system-level DER capacity to circuit-level capacity. Verification: IPE to verify that the load and DER growth values at the circuit level match with the 576-hourly profiles for specific circuits that are chosen in Step 6. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	(specified in the Data/Information Requirements column) by June 30.	▪ PG&E to provide circuit-level load growth by year and by customer class (AGR, COM, DOM, IND). ▪ PG&E to provide circuit-level values by year for the following DERs: PV, ES, EE and EV (LDV). **Process Description:** ▪ General description of the process used for disaggregating system-level load to circuit-level loads and further at a class level (Domestic, Commercial, Industrial) using LoadSEER. ▪ General description of the process used for disaggregating system-level DER capacity to circuit-level capacity and the tools/techniques used.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
				PG&E to indicate if any of these processes have changed since the last GNA-DDOR cycle. ▪ 576 hourly load profile for selected circuits provided in Step 5.
3a	Check sum of all disaggregated load and DERs same as CEC IEPR System Level values	Perform Verification on this aggregation for all circuit values as well as cross check values used in other V&V checks. Roles: Information provided by PG&E in Step 3 will also be used in this step. Verification: IPE to verify that the sums of all load and DER growth forecasts at the circuit level match the starting point system values verified in Step 2.		Data needed for this step is provided in Step 3

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
4	Add Incremental known loads to circuit level forecasts (in CEC forecasts and others not in CEC forecast)	Perform verification of the known load additions at the circuit level. Roles: Information on circuit-level known loads is already obtained in Step 2. In this step, the IPE will verify that the 576 hourly load profiles for selected circuits match with the values provided in Step 2. Verification: IPE to verify that the circuit-level known load additions provided as a part of Step 2 match with the 576 hourly load profiles for specific circuits that are chosen in Step 6.		576 hourly loads for selected circuits profiles provided in Step 5.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
5	Convert peak growth to 576 profile as needed	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E. Roles: PG&E to provide 576- hourly profiles for selected circuits, as well as the typical load profiles used for new residential, commercial, industrial and agricultural loads, as well as the typical corporate load forecast profile. Verification: IPE to verify that the 576 hourly load profiles for new loads (DOM, COM, IND, AGR) and corporate load forecast match with those values determined in Step 3 and 4. Validation:	PG&E to provide the data requested (specified in the Data/Information Requirements column) by July 15.	PGE&E to provide the 576 hourly load profiles for selected circuits as shown below: a) One or more circuits that have sensitivity to temperature and one or more that have sensitivity to water allocation b) One or more circuits that have known load (Residential or Commercial) additions c) One or more circuits that have identified needs that are solved using load transfer d) One or more circuits that have identified needs that are solved using phase balance

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		e) One or more circuits that have identified needs that are solved with a planned project f) One or more circuits with needs that result in Candidate Deferral Opportunity (CDO) project g) One or more circuits with known DC Fast Charger (DCFC) loads
5a	Convert DER growth to 576 profile as needed	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E in Step 5. Roles: PG&E to provide 576- hourly profiles for selected circuits, as well as the typical hourly profiles for DERs (PV, ES, EE, and LDEV).	PG&E to provide the data requested (specified in the Data/Information Requirements column) by July 15.	**Data/Information:** PG&E to also prove the hourly load profiles of the DERs (PV, ES, EE, and LDEV) for selected circuits. **Process Description:**

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Verification: IPE to verify that the 576 hourly load profiles for the DERs match with those values determined in Step 3. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		PG&E to provide information on how these typical profiles are developed.
6	Derive net load profile	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E in Step 5. Roles: No new data required from PG&E for this step. Verification: IPE to use the results of Steps 5 and 5a to calculate net load profile and compare with the profile provided by PG&E. Validation:		No additional data/information is required.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
7	Determine net peak load	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E in Step 5. Roles: PG&E to provide the calculated peak load forecast for the selected circuits for the peak load hour that was used in the GNA. Verification: IPE to verify the value for these circuits provided by PG&E against the value obtained for the peak day from the 576 hourly net load profile developed in Step 6. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	PG&E to provide the data requested (specified in the Data/Information Requirements column) by July 15.	PG&E to provide the calculated peak load for the selected circuits used in the GNA.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
8	Adjust for "extreme weather" (1 in 10)	Performed as part of Step 1 (See Step 1 above)	Performed as part of Step 1 (See Step 1 above)	Provided in Step 1 (See Step 1 above)

PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA

9	Initial comparison to station outlet ratings or other circuit limiting factor to determine if ratings exceeded	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E in Step 5. Roles: PG&E to provide station outlet, transformer or other circuit limiting ratings for the selected circuits if not included in the GNA/DDOR Report. Verification: IPE to compare the net peak load from Step 7 before any load transfers are simulated and compare it with the rating	Data will be obtained in mid-August after GNA/DDOR report is published. Date for verification and Validation	Station outlet or other circuit limiting factor will be obtained from GNA Appendices or provided by PG&E if not included in the GNA Appendices.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		to determine if there is an overload (and the overload value matches with the value calculated by PG&E). Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
10	Incorporate load transfers, correct data errors	Perform V&V for 5-10 circuits mutually selected by the IPE and PG&E. Roles: PG&E to demonstrate how it adjusts for load transfers. Demonstration will include the impact of transfers and the data is used to predict the impact of making the proposed changes. Verification: IPE to verify the process reflected in the PG&E demonstration is consistent with the PG&E description and the result are the same as used in subsequent steps in	PG&E to provide the information requested (specified in the Data/Information Requirements column) by mid-August.	**Process Description:** PG&E provides a description of the load transfer process and how it determines the impact on individual circuits involved. **Data/Information:** PG&E provides transfer information for each circuit involved. This includes the pre and post loading for the planning period for all circuits involved or impacted by the transfers.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		process of developing the needs reflected in the GNA. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
11	Final comparison to station outlet ratings or other circuit limiting factor to determine if ratings exceeded	Perform V&V for 10-20 circuits mutually selected by the IPE and PG&E. Roles: Information provided in Step 5 will be used for the verification of this step. Verification: IPE to compare the net peak load from Step 8 after any load transfers and compare it to station outlet ratings or other circuit limiting factor to determine if there is an overload (and if so that the overload matches with the value calculated by PG&E and included in the GNA).		Data already provided in Step 5.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
12	Compile GNA tables showing need amount and need timing, etc. (per IOU's documented planning standards and/or planning process)	Perform V&V on development of GNA table entries for select circuits also confirming that planning standard/process was followed. Roles: PG&E to provide confidential version of Planned Investment tables in Xcel format that can be filtered by the IPE. PG&E to provide list of planning standards/criteria that were used in the development of the GNA tables. Verification: IPE to review projects in the GNA report against planning standards/criteria. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	PG&E to provide the planning standards, if different than provided in the 2021 cycle in mid-August. PG&E to provide the data/information requested (specified in the Data/Information Requirements column) by mid-August after GNA/DDOR report is completed.	**Data/Information:** Confidential GNA tables in Xcel format **Process Description:** Copies of planning standards/criteria if different than provided in the 2021 cycle.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS				
13	Develop recommended solution and generate list of Planned Investments (follow the IOU's documented planning standards and/or planning process)	Perform V&V for three to four projects selected by the IPE confirming that planning standard/process was followed. Projects to cover a range of project types. Roles: PG&E to demonstrate/describe process used to determine recommended planned solution for a subset of projects. PG&E to demonstrate the application of the process in developing the planned investment for selected projects. Verification: IPE to verify the PG&E demonstration reflects the description of the process provided by PG&E. IPE to verify that results shown in the demonstration follow the described process are same as included in DDOR.	PG&E to provide the description of the process in early September. Demonstration to be completed by early September.	**Process Description:** Description of process used to develop proposed planned project to address identified need for distribution projects if not included in the GNA/DDOR report.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
14	Estimate capital cost for each Candidate Deferral Project	Perform Verification and Validation for subset of five Candidate Deferral Projects selected by the IPE working with PG&E. Roles: PG&E to provide information describing the processes used to develop the capital cost estimates included in the DDOR. PG&E to describe the Expected Accuracy Level (as defined by AACE or by another method that describes the expected accuracy range in terms of % lower and higher than the estimate) of the capital costs for the projects included in the DDOR. If the Expected Accuracy is different for different projects, PG&E to	PG&E to provide the information requested in early September.	Information describing the processes used to develop costs. Expected Accuracy associated with the process described. Support cost data for projects in DDOR.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		provide the accuracy range for each project.[1] PG&E to provide supporting cost information for a subset of projects. Verification: IPE to verify that the supporting information for the selected projects confirms the process that was used and that the cost data supplied supports the final cost estimate provided by PG&E and included in the DDOR. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
PROCESSES TO DEVELOP CANDIDATE DEFFERAL LIST AND PRIORITIZE				

[1] During the course of implementing the IPE Plan, the ED in coordination with the IPE will seek to understand the effort and cost associated with improving the accuracy of capital cost estimates (i.e., from a Class 4 estimate accuracy to a Class 3 estimate accuracy).

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
15	Development of Candidate Deferral Projects list through application of screens (timing and technical)	Perform Verification for all projects put through screens Roles: PG&E to provide confidential version of Planned Investment table in Excel format that can be filtered by the IPE. PG&E to describe the process it used to develop its Candidate Deferral Projects. Verification: IPE to use the Excel tables to develop a list of Candidate Deferral Projects following the process described by PG&E. IPE to verify its result (list of Candidate Deferral Projects) match the PG&E results included in the DDOR. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	Post GNA/DDOR Report release – to be completed by early September	▪ Confidential version of Planned Investment table in Excel format that can be filtered by the IPE. ▪ Description of process used to develop Candidate Deferral Projects ▪ DPAG materials

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
16	Development of operational requirements (daily, monthly annually etc.)	Perform V&V for five projects mutually selected by the IPE and PG&E. Roles: PG&E to provide description and/or demonstration of how LoadSEER and other techniques are used to determine operational requirements. (Required load, months and hours needed, duration of call and number of calls per year). Verification: IPE to utilize description to confirm operational requirements for selected circuits are developed using the process described and that the values developed are the same as included in subsequent steps of the process (DDOR and DPAG) Validation:	PG&E to provide the requested information in early September	PG&E to provide description and/or demonstration of how operational requirements are established. Operational requirements are expected to be load, months and hours needed, duration of call and number of calls per year

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
17	Prioritization of candidate deferral projects into Tiers	Perform Verification on prioritization process for all candidate deferral projects including process to develop list of projects that PG&E recommends proceed to RFO, SOC or PP procurement Roles: PG&E to provide active version (not just values) of the Excel spreadsheet that calculates the metrics and their components used to rank the Candidate Deferral Projects overall and into tiers. Note, in the 2021/2022 cycle the IOUs have agreed to use a single standard methodology to prioritize/rank Candidate Deferral Projects and to place them in various tiers based upon the prioritization results. PG&E to provide active version of spreadsheet (if one is used) used to rank and select candidate deferral projects for	PG&E to provide the requested information in early September	Demonstrate active spreadsheet that calculates prioritization metrics, components and ranks projects on those results. To include spreadsheets for prioritization of CDOs and for ranking/selecting SOC and PP projects. Note PG&E is implementing a database structure for the GNA/DDOR reporting process this cycle. The exported data from this database will be provided and the calculations will be explained where needed. ▪ Description of the IOU standardized prioritization metrics, components and tier

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		procurement using the SOC or PP procurement programs Verification: IPE to verify that spreadsheet calculations are consistent with the description of the standard IOU prioritization/ranking and tier placement methodology and SOC and PP ranking/selection process. IPE to verify that Excel results match the recommended Candidate Deferral Projects overall rankings and placement into tiers and recommended for RFO, SCO or PP procurement included in the DDOR and presented at the DPAG meetings. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		ranking methodology and process and SOC and PP ranking selection process

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
18	Calculate LNBA ranges and values for all planned investments	Perform Verification for a subset (1-2) of candidate deferral projects selected by the IPE in consultation with PG&E. Roles: PG&E to provide an active spreadsheet (not just values) that calculates all LNBA range values that are included in the DDOR for all Candidate Deferral Projects. PG&E to provide an active spreadsheet that calculates all LNBA metrics used in the project prioritization process (if different than values in the spreadsheet previously listed. Verification: IPE to verify that LNBA values are developed using a methodology that is the same as the one described by PG&E. IPE to verify results are the same as those included in the DDOR and project ranking process. Validation:	PG&E to provide the requested information in early October	▪ Description of the process used to develop LNBA ranges and metric values. ▪ Demonstrate active spreadsheet that calculates prioritization metrics and components. Note: PG&E is implementing a database structure for the GNA/DDOR reporting process this year. The exported data from this database will be provided and the calculations will be explained where needed.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
19	Compare 2021 forecast and actuals at circuit level for selected number of distribution circuits	Perform comparison of forecasted and actual loads for a statistically meaningful number of distribution circuits to be selected by the IPE in conjunction with PG&E. As a reference, in the 2021 cycle, 10% of the circuits were examined Roles: PG&E to demonstrate comparison of 2020 actual loads (as recorded and as adjusted) against 2020 Plan Year's forecasted 2020 load values. Verification: IPE to review PG&E demonstrated process, values and compare differences. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.	PG&E to provide the requested information in early October	Forecasted data from 2021 DDOR and recorded data from the 2022 Distribution Planning Process

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
OTHER IPE WORK				
20	Review implementing of planning standard and/or planning process	No further review is planned for the 2022/2023 DIDF cycle		
21	Review list of internally approved capital projects	No further review is planned for the 2022/2023 DIDF cycle.		
22	Respond to and incorporate DPAG comments	Include in IPE DPAG Report.	Completed by IPE in Mid-November (date)	
23	Track solicitation results to inform next cycle	Part of IPE Post-DPAG Report follow-on activities in coordination with the IE.	Q3-2022	
24	Treating confidential material in the IPE report	Confidentiality – the following steps will be followed to ensure that the IPE Reports treat confidential material consistent with the rules and procedures of the CPUC:	Target Dates listed in third column are aligned with the 2021/2022 DIDF cycle schedule and will be	

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		a. Hold an early meeting with IOU (and potentially the ED) to discuss process and for PG&E to flag those items they intend to request Confidentiality treatment and on what basis. IPE may provide feedback to ED in lieu of having the ED attend the meeting with the IOU and IPE. Discussion to be held by September 15. b. IOU provides public version of any documents[2] for which they will seek confidential treatment prior to period IPE is wrapping up report. Date: October 22, 2022. At this point the IPE should have two sets of documents that were provided by PG&E - one that contains documents that can be included in the public version of the report (all confidential information will be redacted) and a second set that has confidential information that is	updated in the Final IPE Plan.	

[2] Documents refers to any document provided to the IPE by the IOU that was not included in the IOU's public version of the GNA/DDOR reports. These documents will be included as attachments to the body of the IPE report as required by a CPUC ruling.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		readable, but such information is highlighted to show that it is confidential. This second set would be included as part of the confidential version of the IPE Report. c. IPE provides the final two sets of documents to the IOU that will be included in the IPE Report for final IOU confidentiality review by October 26. d. IPE provides the confidential version of the body of the draft IPE Report to the IOU by October 29 (the body of the report to include all but the documents provided in previous item) for final IOU confidentiality review. e. IOU provides comments/markups of on documents after final confidentiality review by November 4 and comments/markups of draft IPE report by November 5.		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		Markups of the body of the report will include marking up the confidential version highlighting what data is designated as confidential (data that was not previously designated as confidential). f. After review and signoff, the IPE produces final Confidential Report on CPUC schedule and provides to ED and IOU – November 11. Between November 5th and 11th, the IPE and IOU work together to produce the final public version of the body of the report to ensure all confidential information is properly redacted in the public version of the report. On November 11th the public version is also provided to the ED and IOU. g. IOU requests CPUC Confidential Treatment using standard procedures.		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2022/23 DIDF Cycle	Target Timing	Data/Information Requirements
		h. IOU files Public IPE Report version on CPUC schedule – DIDF Advice Letters submitted – November 15, 2020 i. IOU files revised Public Report if CPUC rejects any requests for confidential treatment; otherwise, process is complete, and no further action is needed. In the 2021/2022 cycle the IPE Plan was revised to avoid the use of tables, plots, graphs or other data in the IPE DPAG Report that end up needing to be redacted to meet the IOU's requirements. This should help to reduce the amount of redaction in the Public version of the IPE DPAG Report and make it easier for stakeholders to understand it.		

Appendix A CPUC 4/13/20 Ruling Excerpts

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

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).

List of IPE DIDF Deliverables

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)

Submitted by:

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Appendix D Documents Received

The IPE received many sets of data from PG&E during the review. Listed below are the public documents provided to the IPE during the course of the review. These actual documents are provided as separate documents from the body of this report due to their size. Please contain the IPE to obtain a copy of these documents.

D.1 List of Documents Provided

- PGE.1.1b 10 Proposed Feeders 2022 Rev1 (Public)
- PGE.1.1c Forecast Shape Export - ANITA 1101 - 2022-06-01 0914
- PGE.1.1c Forecast Shape Export - ATASCADERO 1101 - 2022-06-16 0817
- PGE.1.1c Forecast Shape Export - EDENVALE 2109 - 2022-06-01 0910
- PGE.1.1c Forecast Shape Export - FIGARDEN 2102 - 2022-06-01 0919
- PGE.1.1c Forecast Shape Export - LAKEWOOD 1104 - 2022-06-01 0915
- PGE.1.1c Forecast Shape Export - LLAGAS 2101 - 2022-06-01 0909
- PGE.1.1c Forecast Shape Export - MANTECA 1704 - 2022-06-16 0833
- PGE.1.1c Forecast Shape Export - MERIDIAN 1102 - 2022-06-01 0918
- PGE.1.1c Forecast Shape Export - NOTRE DAME 1104 - 2022-06-16 0835
- PGE.1.1c Forecast Shape Export - RINCON 1101 - 2022-06-01 0918
- PGE.1.1c Forecast Shape Export - VASONA 1102 - 2022-06-16 0803
- PGE.1.1c Forecast Shape Export - WOLFE 1114 - 2022-06-16 0755
- PGE.1.1c Forecast Shape Export - WYANDOTTE 1107 - 2022-06-01 0914
- PGE.1.1c Forecast Shape Export - YOSEMITE 0402 - 2022-06-01 0917
- PGE.2.2a CED 2020 Load Modifiers - Mid Baseline Mid AAEE with CAISO
- PGE.5.5a Forecast Shape Export - Energy Efficiency 1000kW P95
- PGE.5.5ac Forecast Shape Export - DESCHUTES 1104 - 2022-07-08 0742
- PGE.5.5ac Forecast Shape Export - OREGON TRAIL 1104 - 2022-07-08 0741
- PGE.5.5af Forecast Shape Export - CARLOTTA 1121 - 2022-05-25 1218
- PGE.5.5af Forecast Shape Export - CARLOTTA BANK 1 - 2022-05-25 1218
- PGE.5.5ag Forecast Shape Export - WILLOWS A 1101 - 2022-07-08 0807
- PGE.16.16a Carlotta Bank 1 DER service Req+ Load profile Public

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.
Braun Blaising Smith Wynne, P.C.
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
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
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

East Bay Community Energy Ellison Schneider & Harris LLP
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
International Power Technology

Intertie

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
McClintock IP
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.

Resource Innovations

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
Stoel Rives LLP

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