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R2106017

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Modernize
the Electric Grid for a High Distributed
Energy Resources Future.

Rulemaking 21-06-017

**PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)
INDEPENDENT PROFESSIONAL ENGINEER PG&E 2025
DISTRIBUTION PLANNING ADVISORY GROUP REPORT**

(PUBLIC VERSION)

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Dated: November 6, 2025

Attorney for
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Pursuant to Decision (D.) 24-10-030, Ordering Paragraph (OP) 3, and the *Administrative Law Judges’ Ruling Setting Schedule for the 2025-2026 Distribution Investment Deferral Framework Cycle* (Ruling), issued March 6, 2025, Pacific Gas and Electric Company (PG&E) respectfully submits its Independent Professional Engineer PG&E 2025 Distribution Planning Advisory Group Report (Report). The IPE DPAG Report is attached as Attachment A.

Pursuant to the Administrative Law Judge (ALJ) Ruling regarding confidential treatment and redaction of Distribution System Planning Data,¹ issued July 24, 2018, D.24-10-030 clarifying the definition of the 15/15 Rule,² and Section 3.3 of General Order 66-D, PG&E is concurrently filing a motion to file under seal unredacted versions of the Report, based on

¹ See generally Rulemaking (R.) 14-08-013, *Administrative Law Judge’s Ruling Ordering Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to File Separate Motions for Confidential Treatment and Redaction of Distribution System Planning Data Ordered by Decisions 17-09-026 and 18-02-004* (July 24, 2018).

² Decision (D.) 24-10-030, Ordering Paragraph (OP) 31 (defined the 15/15 Rule, for the purposes of the GNA and DUPR, as “a data set containing 15 customers with no customer receiving no more than 15 percent of the load.”).

customer privacy considerations, as set forth in the Declaration of Satvir Nagra, attached to the motion.

Respectfully submitted,

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Dated: November 6, 2025

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT A



Independent Professional Engineer PG&E 2025 DPAG Report

PUBLIC VERSION

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

Date: November 6, 2025

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1. Introduction and Background

Summary of CPUC Rulemaking 14-08-013 and Other Rulemakings

In August 2014, the CPUC issued Rulemaking (R.) 14-08-013, which established guidelines, rules, and procedures to direct California's IOUs to develop Distribution Resources Plans (DRPs).

In February 2018, the Commission issued Decision (D.) 18-02-004 which adopted the Distribution Investment Deferral Framework (DIDF) and directed the IOUs to file a Grid Needs Assessment (GNA) by June 1 of each year and a Distribution Deferral Opportunity Report (DDOR) by September 1 of each year. The GNA, as adopted by this decision, limits reported grid needs to four types of forecasted circuit level system deficiencies associated with the four distribution services that DERs can provide, as adopted in D.16-12-036: capacity, voltage support, reliability (back-tie) and resiliency (microgrid).

In May 2019, the assigned Administrative Law Judge (ALJ) issued a ruling that directed IOUs to file both the GNA report and DDOR on August 15 annually.

In April 2020, the assigned ALJ issued a ruling modifying the DIDF process and filings with respect to the Independent Professional Engineer (IPE) scope of work. This ruling also updated the 2020-2021 DIDF cycle schedule and defines the DIDF cycle to start on January 1 of each year and concludes July 31 the following year. 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 to the Ruling are attached as Appendix A of this report. This ruling also included a new IPE Post-DPAG Report deliverable within the IPE scope of work.

In May 2020, the assigned ALJ issued a ruling modifying the DIDF process. This Ruling established 56 new reform requirements including process changes for approval for the Integrated Energy Policy Report (IEPR) dataset used for forecasting, requests for certain datasets to be hosted on the DRP Data Portals, value stacking that may result in deferral projects that exceed the cost cap, changes to how Locational Net Benefit Analysis (LNBA) data is presented, and recommendations for potential 2021-2022 DIDF cycle reforms.

In February 2021, the Commission issued IDER D. 21-02-006 which introduced the Partnership Pilot and the SOC Pilot and streamlined the DIDF RFO.

In June 2021, the assigned ALJ issued a ruling on recommended reforms to the DIDF process and revisions to some previous reforms to align with requirements adopted by D. 21-02-006.

In November 2021, the Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future (R.21-06-017)⁵ was filed to replace the 2014 Distribution Resource Plan and now stands as the OIR home for GNA and DDOR compliance.

In 2022, the Commission issued the 2022 DIDF Ruling, establishing seven reforms to three solicitation frameworks.

In May 2023, the Commission's 2023 DIDF Ruling focused primarily on updates to known load tracking and reporting, as well as terminating the SOC Pilot.

In June 2024, the assigned ALJ granted the motion filed by SDG&E and SCE, as well as a separate motion filed by PG&E, requesting that portions of the DIDF process be suspended temporarily and removing solicitation-related reporting requirements within the 2024 GNA/DDOR reporting period, as well as off-ramping the Partnership Pilot.

In October 2024, Decision 24-10-030 eliminated the DIDF solicitations process. The decision focused on measures to enhance the transparency of the distribution planning process. This included renaming DDOR to Distribution Upgrade Project Report (DUPR) and additional reporting requirements in the DUPR.

In March 2025, the ALJ issued a ruling that set the schedule for the 2025-26 DIDF cycle as shown in Table 1-1 below.

Table 1-1 Proposed DPAG Schedule for 2025-26 DIDF Cycle (Partial table from the March 2025 ALJ Ruling)

Activity	Date
Pre-DPAG 2025	
Pre-DPAG meetings and workshops, including Draft IPE Plans review	May-June 2025
DPAG 2025	
IOU GNA/DUPR filings Final IPE Plans Circulated	August 15, 2025
IPE Preliminary Analysis of GNA/DUPR data adequacy circulated	September 5, 2025
DPAG meetings with each IOU	Mid to Late September 2025
Participants provide questions and comments to IOUs and IPE	September 26, 2025
IOU responses to questions	October 6, 2025

Follow-up IOU meetings via webinar (Optional)	Week of October 13, 2025
IPE DPAG Reports	November 6, 2025
Post-DPAG 2025 and 2026	
IPE Post-DPAG Report (covering all three Utilities)	March 15, 2026

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). Through a contract with Resource Innovations, PG&E engaged Mr. Sundar Venkataraman¹, PE, to serve as the advisory engineer (referred to as the Independent Professional Engineer (IPE)).

The Independent Professional Engineer (IPE) services for the 2025-26 Distribution Investment and Deferral Framework (DIDF) Process is per CPUC decision (D.18-02-004), Administrative Law Judge's Ruling (R. 14-08-013) issued May 7, 2019, and Administrative Law Judge's Ruling Modifying DIDF (R.14-08-013) issued April 13, 2020 which defined the original IPE scope of work. This original scope of work has been modified by subsequent orders and rulings, as well as updates to the scope of work made by the Energy Division on March 4, 2025 which modifies the original scope and includes additional scope items to support the High DER proceeding. This updated scope of work is included as Appendix A.

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 verify and validate the GNA/DDOR results. The plan was developed using a three-step process:

1. In step 1, IPE developed a draft IPE Plan working with the Energy Division and PG&E by mid-May 2025.

¹ Consistent with the CPUC decision, the contract with Resource Innovations (RI) provides for other individuals within RI to assist Mr. Venkataraman 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. Venkataraman is required to meet.

2. The Plan was distributed to the service list and also discussed at the CPUC Distribution Forecasting Working Group meeting - both in an attempt to obtain stakeholder feedback on the plan.
3. Based upon stakeholder feedback received and under the direction of the Energy Division, the IPE revised the plan and made its IPE Final Plan available on August 15, 2025.

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

The IPE Plan covers the business processes that the IOUs use to identify which distribution or sub-transmission projects are recommended to proceed to implementation. One of the core purposes of the plan is to answer the question - Are the IOUs identifying every project that will be needed to provide the new or additional service requirements of their customers early enough to provide the service in a timely manner?

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, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level, adjusted for known and pending loads and then used to determine if there is an overload or other issue during the planning period. For circuits that have a need, the best planned investment is selected.

In every DIDF cycle, the IPE reviews the plan to determine if any of the steps could be streamlined or eliminated in that cycle without compromising the intent of the verification and validation process. Such streamlining allows the IOUs and the IPE to focus additional time on more recent additions in the IPE's scope. Based on this review, the following steps were skipped since the business process used by the utility did not change from the prior cycle²:

- Steps 5-7 - Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load
- Steps 9-11 - Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings after No Cost Solutions
- Step 14 - Development of capital costs for the planned investments.

In addition, the verification and validation of the following steps related to the identification and prioritization of Candidate Deferral Opportunities (CDOs) are no longer required since the requirement for DIDF solicitations have been eliminated as per the October 2024 Decision.

² PG&E confirmed that the business process for these steps have not changed from prior cycles. Hence, the IPE will not perform a verification and validation of Steps 6 and 7.

- Step 15 - Development of Candidate Deferral Projects
- Step 17 - Prioritization of Candidate Deferral Projects into Tiers
- Step 16 - Development of operational requirements for CDOs
- Step 18 - Calculation of LNBAs for planned projects

In addition, based on inputs from the ED, the following steps were also skipped in this cycle.

- Step 21 - Review plan for changes to the planning process for the next cycle
- Step 22 - Review implementing of planning standard and/or planning process.
- Step 23- Review list of internally approved capital projects.
- Step 25 - Track solicitation results to inform next cycle.

Two new steps were added specifically for this cycle referred to as Steps 27 and 28. A description of the two new steps can be found in the IPE plan in Attachment C.

- Step 27 - Review Methodology used for Prioritization of Planned Projects
- Step 28 - Review Project Execution Tracking Data and Metrics

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 necessary planned solutions and investments. 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, 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 services capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations; and
- Resiliency (micro-grid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations.”

1.4. Approach to Information Collection

The data required for the verification and validation of each business step, as well as the date when the data was due were specified in the Final IPE plan that was issued on August 15, 2025. This data was provided by PG&E to the IPE using their secure FTP site. In addition, 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.
- Participation in PG&E’s DPAG Webinar (September 17, 2025).

- A review of publicly available materials referred to in the discussions with PG&E or materials previously filed with the CPUC.

A list of the data provided by PG&E is included as Appendix D.

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 2025 and 2024 reports. 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 DUPR Report, which briefly discusses the contents of the PG&E DUPR Report, and any significant differences noted in PG&E's reports between the 2025 and 2024 reports. Observations, comments, and recommendations that result from the Validation review with respect to the DUPR Report are included in this section.
- **Section 4** - IPE Recommendations
- **Section 5** - Known Load Tracking Data and Metrics, which reviews the known load tracking data and the known load metrics calculated by the utilities.
- **Section 6** - Verification Approach and Results, which reviews the approach and results of the verification performed by the IPE
- **Appendix A** - Revised IPE Scope of work
- **Appendix B** - Comments Received from the DPAG Members and IOU and IPE responses.
- **Appendix C** - IPE Final IPE Plan - PG&E
- **Appendix D** - PG&E Data Requests and Responses

Confidential Information

There are a number of instances where information is confidential and such information is highlighted in gray or yellow 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 DUPR 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 Reports

PG&E filed its Grid Needs Assessment (GNA) Report on August 15, 2025, as required by the CPUC.

The objective of the 2025 GNA is to provide transparency into the assumptions and results of PG&E's annual distribution planning and execution process (DPEP). The grid needs that are reported in this GNA submittal are limited to the forecast deficiencies associated with the four distribution services that DERs can provide as adopted in D.16-12-036, distribution capacity, voltage support, reliability (back-tie) and resiliency (microgrid).

The scope of the GNA is same as in prior DIDF cycles and is to identify substation, distribution bank and circuit level needs after free or no-cost load transfers have been reflected in load forecasts. The needs identified 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. PG&E's Distribution Resources Planning Methodology and Assumptions

This section of the report provides a description of the methodology and assumptions used to forecast and identify distribution grid needs as reported in PG&E's 2025 GNA report. The methodology and assumptions are the same as those used in the last cycle including the process used to develop the base load profiles for circuits (8760 hourly load profile derived primarily from AMI data versus 576 hourly load profile derived primarily from SCADA data). Other notable changes to the GNA include the following:

- Grid needs for banks and feeder are identified over a 13-year forecast period (10-year forecast period used in prior cycles).
- New category of needs called "other" grid needs, in addition to the four needs specified in the DIDF, included for transparency.

- New report section included an alternate forecast with pending loads as an early implementation scenario
- Included the Known Load data and metrics in the GNA report as opposed to the DUPR report in past cycles.

2.2.1. Grid Needs Assessment Scope

PG&E's 2025 GNA includes the identification of substation/bank, feeder, and line section needs that are primarily due to the forecast deficiencies associated with the four distribution services that DERs can provide as adopted in D.16-12-036, which are distribution capacity, voltage support, reliability (back-tie) and resiliency (microgrid). This year's GNA also includes a new category of needs called "other" discussed later in this section.

2.2.2. PG&E's Distribution Resources Planning Horizon

PG&E's planning horizon is same as the one used in previous cycles. PG&E used a five-year planning horizon as the study horizon for identifying substation and feeder grid needs and a three-year planning horizon for line section Capacity and Volt/Var needs.

2.2.3. PG&E's Distribution System Load Forecast Assumptions

PG&E used the CEC-approved 2023 IEPR Local Reliability Scenario³ consisting of the system-level baseline demand forecast, Additional Achievable Energy Efficiency (AAEE) scenario 2, Additional Achievable Fuel Substitution (AAFS) scenario 4, and Additional Achievable Transportation Electrification (AATE) scenario 3, for the PG&E distribution service area as the starting point for forecasting circuit-level loads.

2.2.4. PG&E's Distribution System Load Forecast Methodology

PG&E's Distribution System Load Forecast Methodology is the largely the same as the one used in the prior cycle. The Baseline Load Growth (not including peak load contributions from Transport Electrification (TE) loads or other DERs) for each forecast year is calculated from the 8760-hourly file corresponding to the CEC-approved 2023 IEPR Local Reliability Scenario for PG&E. Known Loads are subtracted from the Baseline Load Growth and the resultant growth is distributed out by customer class (residential, industrial, commercial, and agricultural) and is then allocated to PG&E's distribution feeders using geospatial analysis in LoadSEER. Section 6 of this report (Steps 2 and 3) verifies and validates the process used by

³ As per CPUC Energy Division's August 2024 approval of the Joint IOUs' submittal in June 2024 regarding the IEPR datasets to use in the 2024-25 GNA/DUPR.

PG&E to determine Baseline Load Growth at the system and circuit levels. A summary of all the files used in the load forecasting methodology is provided below.

- From CEC:
 - CED 2023 Hourly Forecast - PGE - Local Reliability
 - CED 2023 Mid Baseline Forecast - Local Reliability - LSE and BA Tables
 - CEC 2023 TE Demand Forecast - PGE Territory PEV Count
 - CEC 2023 TE Demand Forecast - PGE Territory PEV Energy Forecast
- From PG&E:
 - Aggregated Customer level metering data
 - Known load from load service applications
 - Hourly Load shapes
- From other sources:
 - Integral Analytics - economic, geographic, demographic data
 - Integral Analytics - historical weather data

2.2.5. PG&E's Distribution System DER Growth Forecast Assumptions

The process used by PG&E to develop DER Load Growth forecast at the circuit level is largely the same as the one used in the previous cycle. PG&E uses the 8760-hourly file corresponding to the CEC-approved 2023 IEPR Local Reliability Scenario to develop system-level forecasts for solar photovoltaics (PV), residential and non-residential energy storage discharge (ES), energy efficiency (EE), fuel substitution (AAFS), and electric vehicles (LDEV, MDHDEV, AATE-LDEV, AATE-MDHDEV) components. The methodology that it uses to disaggregate the system-level forecasts to circuit-level forecasts, including the adoption models that are DER specific, is described in Appendix C of the GNA report and was also presented at the Distribution Forecast Work Group (DFWG) meeting in May 2025. Section 6 of this report (Steps 2 and 3) presents the findings of the IPE verification and validation of the DER Growth forecasts at the system and circuit levels.

2.2.6. Methodology for Substations and Feeders

The methodology used by PG&E for developing the base load profiles for feeders and substations was updated in the last cycle. In years prior to the last cycle, PG&E engaged Integral Analytics to develop 576 hourly load profiles (base load shape) which relied on past three years of SCADA data for feeders and 15 years of circuit loading and weather data. In the last cycle, as well as the current cycle, PG&E used Integral Analytics' software which uses AMI aggregate data for developing 8760 hourly load profiles for feeders and substations. To develop the AMI aggregate data for each feeder, PG&E first gathers the service points (smart meters) associated with each feeder. It then uses the AMI data from the smart meters, which could be 5-minute or 15-minute interval data to construct 8760 historical load profile for each

feeder. The AMI aggregates are then compared with the SCADA data by PG&E engineers to validate the profile.

PG&E converts each feeder's AMI Aggregate data into a TLY hourly shape. Each TLY shape contains three percentiles: low, typical, and extreme. LoadSEER uses a weather normalization algorithm to generate the TLY Base Shapes as described in the GNA report. Using each feeder's 8760 load profile for the years 2020-present, a relationship between temperature and load is determined which is then applied of 30 years of temperature data yielding 30 years of hourly load for each feeder.

As described in the GNA report, historical months from the 30-year dataset are ranked by peak load, and three historical months (corresponding to the three percentiles) are selected for each month of the year. Finally, the 12 historical months corresponding to each percentile are concatenated to generate an hourly Typical Load Year profile. PG&E's engineers may opt to replace the weather-normalized base shape with an alternate non-weather normalized base shape, constructed from the historical load dataset only.

The process used by PG&E to arrive at the final TLY Base Shape for each feeder and substation was verified by the IPE, the results of which can be found in Section 6 (V&V of Step 1) of this report.

To this Base Load Shape for a feeder, PG&E adds the load profiles of the known loads, EV load growth forecasts and DER growth forecasts that have been disaggregated to the feeder level for each forecast year. The typical load profiles for all DERs are included in Section 6 of this report. PG&E uses the resultant profile for each forecast year for determining overloads on feeders and substation for determining the needs.

In this cycle, PG&E developed the forecasts for feeders and substations for 13 years compared to 10 years in the prior cycles.

2.2.7. Methodology for Line Sections

This process is unchanged from prior years in that PG&E uses the CYME Power Engineering Software for modeling line section demand forecasts and identifying line section needs over a three-year period CYME Power Engineering Software.

2.2.8. Methodology for Voltage Support Needs

Similar to prior cycles, PG&E forecasts voltage on all energized primary nodes for nearly every feeder for up to three years using the CYME Power Engineering Software.

2.2.9. Methodology for Reliability (Back-tie) Needs

As in prior cycles, PG&E typically conducts an N-1 contingency study for each bank/feeder where that bank/feeder experiences an outage and the customers it normally serves need to be switched over to adjacent feeders for temporary service restoration. In addition, two other reliability needs are identified by PG&E – (i) Feeders with loading greater than 600 Amps, and (ii) Overloads on substation and feeders due to planned transmission line maintenance.

2.2.10. Methodology for Resiliency (Microgrid) Needs

PG&E identifies resiliency needs in this cycle due to one or more of the following: (i) inability to transfer load to a backup source in an emergency bank loss condition, (ii) customer count on feeder exceeding 6000, (iii) inability to transfer load to a backup source in an emergency line loss condition, (iv) Load growth interfering with FLISR scheme, and (v) inability to transfer load to a backup source in the event of an unplanned transmission outage.

2.2.11. Other Needs

In this year's GNA, PG&E included a new category of needs called "other" needs that correspond to the following projects: (i) projects that may already be in construction or significant expense have been incurred since inception while the current cycle may not show a need, (ii) project is needed to meet PG&E's design standard power factor at the distribution bank level, (iii) project is needed for compliance with General Order (GO) No. 95 ground current return path standards, (iv) project is needed to prevent equipment damage to overstressed equipment under fault conditions.

2.2.12. PG&E's Load Transfers and Switching Assumptions

As in prior cycles, Engineers at PG&E look for planned load transfers and switching operations are used to balance the load between feeders and banks. Only grid needs that require a capacity project to either directly mitigate a need or to enable distribution switching and load transfers that mitigate the need are identified as needs in the GNA.

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)	Other	
Substation Bank	133	0	33	24	10	200
Feeder	215	0	67	27	52	361
Distribution Line	375	131	0	0	0	506
Totals	723	131	100	51	62	1067

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

Anticipated Need Date					Total
2025	2026	2027	2028	>=2029	
713	218	66	39	31	1067

2.3.2. Distribution Capacity Needs

The majority of the grid needs are distribution capacity needs. Of the 723 needs, 348 are at the substation/feeder level while 375 are at the distribution line level. Of the 723 needs, 672 are needed within the next 3 years, leaving 51 capacity needs with anticipated need dates of 2028 or later. There are no capacity needs driven by backflow from PV that have been identified this year.

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. There are 131 distribution line voltage needs.

2.3.4. Reliability (Back-Tie) Needs

More projects were identified as having reliability needs in this cycle when compared to previous cycles due to a feature in the planning tool that allowed Engineers to identify reliability projects. PG&E identified 67 reliability or back-tie needs at the feeder level compared to 14 in the last cycle. There were 33 back-tie needs at the substation bank and zero needs at the distribution line level.

2.3.5. Resiliency (Micro-Grid) Needs

More projects were identified as having resiliency needs in this cycle when compared to previous cycles due to a feature in the planning tool that allowed Engineers to identify resiliency projects. PG&E identified 51 resiliency needs in this cycle compared to 16 in the last cycle. (i) 18 needs were due to customer count exceeding 6000, (ii) 26 needs were due to emergency bank loss condition, (iii) five needs were due to emergency line loss condition, and (iv) one need was due to transmission line emergency loss condition.

2.3.6. Other Needs

PG&E identified 62 other needs. (i) nine needs were due to common neutral/primary neutral issues, (ii) 35 needs were due to in-flight project near completion, (iii) 15 needs were due to overstressed equipment, and (iv) three needs were due to power factor requirement.

2.3.7. Alternate Forecast

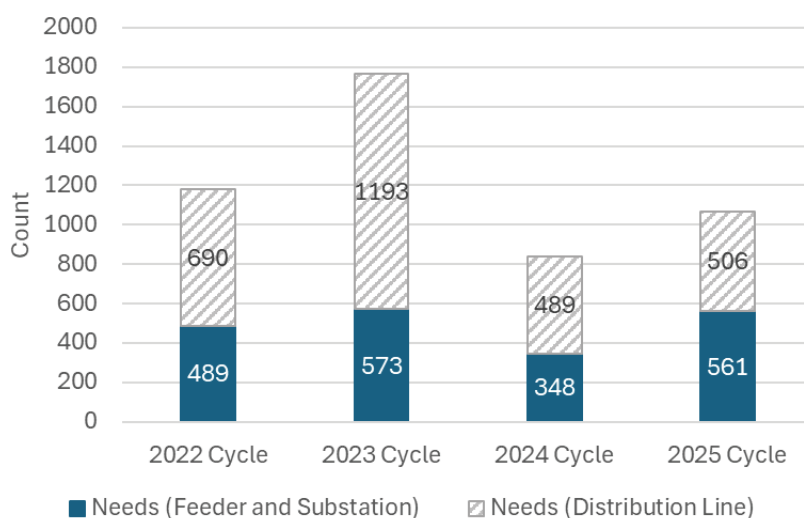
PG&E GNA included an Alternate Planning Scenario which included pending loads from two main resources: (i) Electric Vehicle (EV) loads derived from ongoing coordination with fleet operators, transit agencies, and large commercial customers, and (ii) Loads obtained through PG&E's Capacity Planning questionnaire. PG&E identified incremental needs in the Alternate Forecast but did not use the results in the identification of scoping of Planned Investments or Planned Solutions in the 2024-2025 DPP Cycle.

2.4. GNA - Observations and Conclusions

- Figure 2-1 shows the number of needs at the substation/feeder level, as well as at the distribution line level in the last four planning cycles. The number of needs at the substation bank and feeder level have remained fairly steady (except for a dip in the 2024-25 cycle) while the number of needs at the circuit level has fluctuated in the past few cycles. It should be noted that the number of needs at the circuit level have been published in GNA tables only in the last two cycles. Prior to that, circuit-level needs were published in a supplementary report. PG&E also changed their tools and methodology for forecasting line section needs. This may explain the drop in needs between the 2023 and 2024 cycles as seen in the figure.
- In the 2025 GNA, 70 Needs were in years 4 and beyond, compared to 49 Needs in the 2024 GNA.

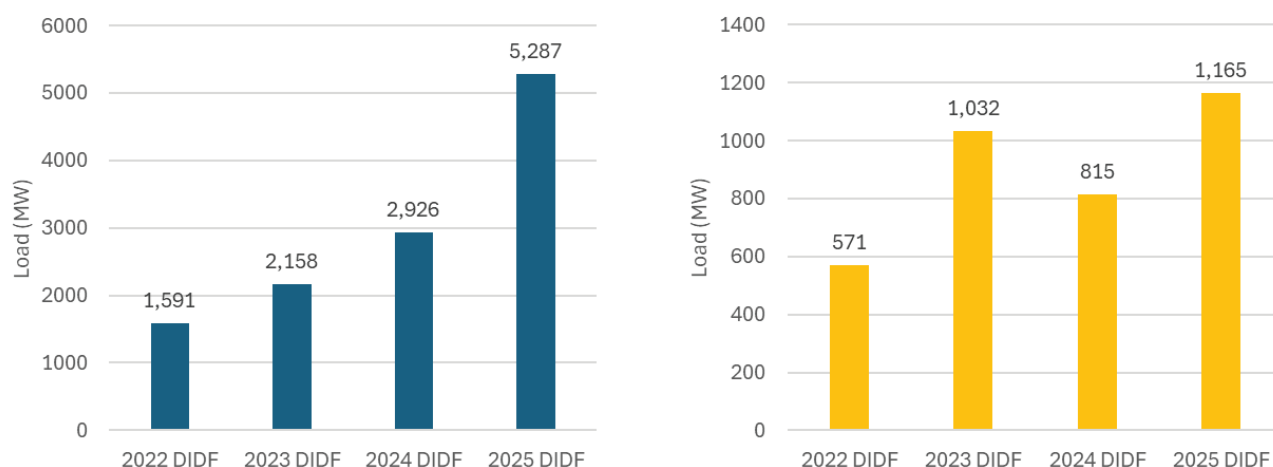
- Figure 2-2 shows a comparison of the known loads for the last four GNAs. The plot on the left shows the total known loads in each cycle not including the Transport Electrification (TE) Known Loads⁴. The plot on the right shows the total TE Known Loads in each cycle. It can be observed that the total Known Loads not including TE loads (plot on the left) increased significantly in the 2025 cycle. The TE Known Loads (plot on the right) in the 2025 cycle is 43% and 13% higher than those from the 2024 and 2023 cycles respectively. Additional information on the change in non-TE and TE Known Loads can be found in Section 4 of this report.

Figure 2-1: Number of Forecasted Grid Needs (2022-2025 GNA)



⁴ Transport Electrification (TE) Known Loads and Electric Vehicle (EV) Known Loads are used interchangeably in this report.

Figure 2-2: Comparison of the Known Load Additions (Left: Total Known Loads not including TE Known Loads; Right: Only TE Known Loads) between the 2022-25 GNAs⁵



- A comparison of cumulative and annual load growth forecasts between the IEPR values and those used in the GNA (a combination of known loads and economic (spatial) loads) are shown in Figure 2-3 and Figure 2-4 respectively. As seen in Figure 2-3, the cumulative value of the GNA forecast after eleven years (3114 MW) is greater than the cumulative IEPR load growth forecast for the same period (3019 MW) by around 85 MW. Therefore, the load growth forecast used in the GNA for the 5-year planning period is substantially higher than the CEC IEPR forecast load forecast. The GNA and the IEPR cumulative forecasts converge in the later forecast years. PG&E adds econometric (spatial) loads starting in year 11 of the forecast. It can also be observed that the two forecasts do not meet at the end of the forecast period (year 16). This is because, as was the case in the last cycle, PG&E is setting aside 10% of the economic forecast to account for known loads that might come in after the load forecast have been finalized. The 10% buffer is further explained in Section 6 of this report.
- Figure 2-4 shows the comparison between annual load growth forecasts between the IEPR and those used in the GNA which is a sum of the known loads and the

⁵ The data for the 2023 and 2025 cycles were obtained from the Known Load Tracking Data filed for those years. Since there was no requirement for filing the tracking data for the 2022 cycle, the data provided by PG&E for the verification of Step 2 (forecasting stage) was used. The final known loads in 2022 may be slightly different from what is shown here.

economic (spatial) forecast. It can also be observed that PG&E is not adding econometric (spatial) loads in years one through 10 of the forecast.

Figure 2-3: Cumulative load forecast for the 16-year forecast period

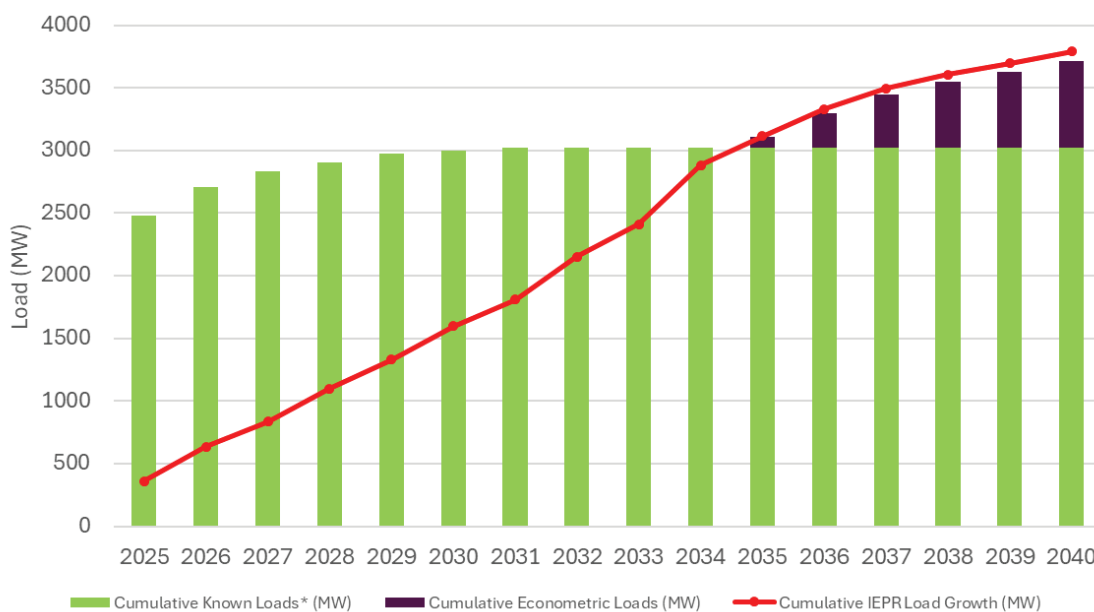
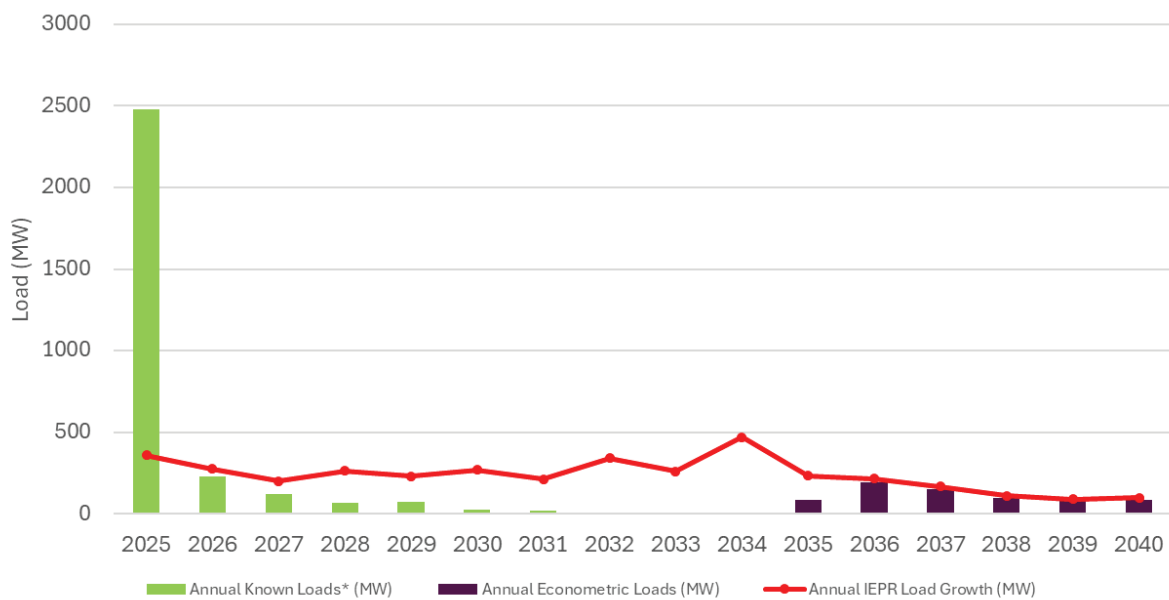
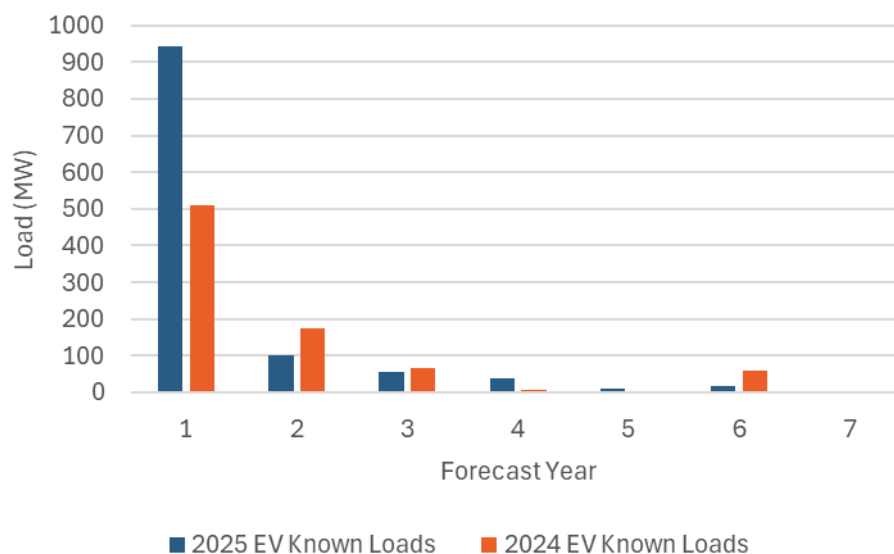


Figure 2-4: Annual load forecast for the 16-year forecast period



- Figure 2-5 shows the known EV loads (MW) for the first six forecast years from the 2024 and 2025 GNAs. It can be seen that in the MW of known EV loads in the first forecast year in the 2025 GNA is higher when compared with the same value from the 2024 GNA, i.e., the EV known loads are more front loaded. The modeling and verification of Known EV loads is discussed in Section 6 (Step 2) of this report.

Figure 2-5: Comparison of the Known EV Load Additions between the 2024 and 2025 GNAs



3. Review of DUPR Report - Planned Investments

In this cycle, the Distribution Deferral Opportunity Report (DDOR) was renamed as Distribution Upgrade Project Report as per ALJ Decision D.24-10- 030 and includes additional reporting requirements. PG&E's DUPR Report was filed concurrently with the GNA Report on August 15, 2025 and an updated version was filed on November 3, 2025. PG&E's 2025 DUPR builds off PG&E's 2025 GNA Report. The main objective of the DUPR for 2025-2026 DIDF was to provide transparency into the assumptions and results of the distribution resources planning process. Pursuant to the Decision 24-10-030, DIDF solicitation process has been eliminated and hence, this report does not cover the solicitation related topics.

As in the previous cycle, PG&E has distinguished between Planned Investments and Planned Solutions. Planned Investments include all proposed distribution planning solutions that are currently funded within the current planning horizon (i.e., 5 years). Planned Solutions are proposed distribution planning solutions for which funding within the current planning horizon is not included in PG&E's 2023 General Rate Case (GRC) application. Therefore, Planned Solutions are not currently Planned Investments within the five-year planning horizon.

In addition to Planned Investments and Planned Solutions, PG&E's 2025 DUPR includes additional distribution capacity project execution data, detailing the start and end dates for various stages of ongoing Planned Investments. This year's DUPR report also includes new sections on project prioritization methods and equity in distribution planning.

In total, there are 358 Planned Investments that are mapped to 612 facilities that solve 544 needs. There are 327 Planned Solutions that are mapped to 556 facilities solving 507 needs. Of the 358 Planned Investments, 127 are at the substation/feeder level and 240 at the distribution line level⁶. Of the 327 planned Solutions, 94 are at the substation/feeder level and 233 at the distribution line level.

Table 3-1 summarizes the Planned Investments by project type and distribution planning region. Table 3-2 shows the Planned Investments by service provided. It can be seen that most of the investments are for distribution capacity as observed in prior cycles.

Table 3-3 summarizes the Planned Investments by in-service date. 307 of the 358 Planned Investments have an in-service date in the first three years and 51 have in-service dates starting in 2028 and beyond.

⁶ There are Planned Solution and Planned Investments that address the same needs.

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	Line Section	
Bay Area	1	9	15	41	66
Central Valley	4	26	24	92	142
North Coast	3	5	5	27	39
North Valley and Sierra	1	4	6	30	40
South Bay and Central Coast	1	14	9	50	71
Totals	10	58	59	240	358*

*There are multiple Planned Investment Projects that have different project types associated with each planned investment (e.g., DUPR ID 6809 has both Feeder and line section project)

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

Distribution Service					Total
Capacity	Reliability	Resiliency	Voltage	Other	
281	11	6	43	50	358*

*There are multiple Planned Investment Projects that address 2 different Distribution Services (e.g., capacity and voltage need) and are thus counted more than once in this table.

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

In-Service Date						Total
2025	2026	2027	2028	2029	2030	
80	147	80	31	17	3	358

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 the 2025 DUPR.

DER-Driven Projects

PG&E stated that there were no Planned Investments for capacity needs driven by backflow from PV identified in the 2025 DUPR.

Pre-Application and Post-Application Projects

PG&E stated that it currently has no Pre-Application Projects or Post-Application Projects that have Planned Investments for sub-transmission or distribution components.

Distribution Capacity Project Execution Data Reporting

Ordering Paragraph 26 of Decision D.24-20-030 required utilities to project execution data consists of additional information for all the Planned Investments and the Grid Needs that triggered these investments. PG&E provided the project execution tracking data in Appendix B of the DUPR report. IPE's verification of the project execution tracking data can be found in Section 6.8 of this report.

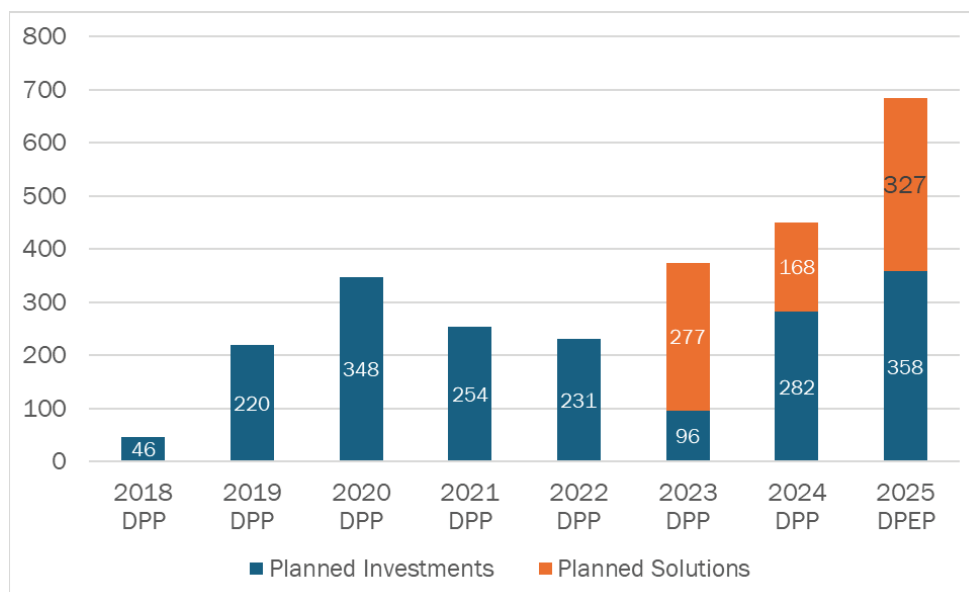
Project Prioritization Methods

Ordering Paragraph 26 of Decision D.24-10-030 required utilities to report the methodology to prioritize projects identified throughout the distribution planning horizon other than the consideration of project need date. PG&E provided information on its tiered prioritization approach. IPE's verification of PG&E's project prioritization can be found in Section 6.7 of this report.

3.1. DDOR Report Planned Investments - Observations, and Conclusions

PG&E started distinguishing between Planned Investments and Planned Solutions starting the 2023 DPP cycle. Prior to that, all the planned projects were Planned Investments. Figure 3-1 shows the total number of substation/feeder-level Planned Investments and Planned Solutions from the past eight planning cycles. It can be observed that the 2025 DPP cycle had the most number of Planned Projects, as well as Planned Investments in the last three cycles.

Figure 3-1: Total Number of Substation/Feeder-Level Planned Projects from Past DDOR/DUPRs



4. IPE Recommendations

- I. As performed in the previous cycle, the IPE plans to review the Known Load Metrics for all three IOUs in its Post-DPAG Report to be completed in March 2026, i.e., the 2026 Post-DPAG report with a focus on Known Load materialization. It is important to understand whether Known Loads materialize considering data from multiple years, since they are an important component of the distribution planning process.
- II. The IPE recommends that, in addition to the Known Loads, the IOUs annually track Pending Loads similar to Known Loads since these loads could have similar impacts to Known Loads. The IPE also recommends that, in addition to the Known Load metrics, metrics for Pending Loads be calculated similar to those for Known Loads. Further, these metrics should be separately calculated for each Pending Load category (A, B, C etc.). In addition, combined metrics for all the loads used in planning, (i.e., Known Loads and Pending Loads that were used in the Base Case) should also be calculated. The exact format for reporting the Pending Load data and the metrics that need to be calculated should be jointly developed by the Energy Division and the IOUs.
- III. The IPE recommends that the Pending Loads identified using studies be updated periodically (ideally, annually) and that the source (i.e., customer study name) be provided in the Pending Load tracking data mentioned above.
- IV. The IPE would like to reiterate the recommendation made in the last cycle (2025 Post-DPAG Report) that the IOUs calculate system-level, as well as a TE-specific materialization metrics similar to what the IPE has calculated in the 2025 Post-DPAG report and include these new metrics in the GNA/DUPR report.
- V. The IPE would also like to reiterate the recommendation made in the last cycle that the Commission suspend the requirement for calculating Known Loads Metrics 14-16 related to service deferral, cancellation and reduction rate by forecast year since these metrics have shown limited value.
- VI. The IPE plans to review and compare in the 2026 Post-DPAG report, the methodologies used by the IOUs to confirm that planned projects identified in prior cycles are still needed and are the appropriate solution based upon planning assumptions for load and DER growth and other planning assumptions used in the current DPP cycle. The IPE gathered some information as a part of Step 13 in this cycle and will use this information, as well as other information gathered from the utilities to perform this review.

5. Known Load Tracking Data and Metrics

The ALJ's June 16, 2022 DIDF Reform order required all three utilities to track known load projects in the 2022 GNA/DDOR. The reform also required the Known Load Tracking data 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.

The May 2023 Ruling required the Utilities to provide a narrative summary report that includes metrics that are calculated using the Known Load Tracking Data and describing the implications of the calculated metrics.

This is the fourth cycle in which the utilities are providing the Known Load Tracking Data and the third cycle in which the utilities are providing the Known Load Tracking Data Metrics.

In this cycle, PG&E provided two known load datasets - one for on-going projects and another for completed projects. The statuses in the on-going project dataset include:

- Service Requested - starts the process which indicates the customer has submitted a complete request for service. From this status several status changes are possible - to Cancelled, Construction Complete or Monitored.
- Cancelled - ends the process for Known Loads whose service request is cancelled by the customer or PG&E. Known Loads that are cancelled will be included for the last time in the dataset following the cycle during which it was cancelled.
- Construction Complete - is an interim status that indicates the construction to serve the requested load has been completed but service has yet not begun. From this state, a KL could proceed to one of the following - Cancelled, Completed, or Monitored. A KL with this status should be considered equivalent to a status of Service Requested for the purpose of calculating Known Load metrics.
- Monitored - indicates that service has been provided to the customer but PG&E does not think that the customer has reached the level of peak load that was estimated. The Known Load would continue to be shown as "Monitored" until PG&E determines that it should be moved to the Completed dataset. A Known Load with this status should be considered equivalent to a status of Completed for the purpose of calculating Known Load metrics.

The completed projects dataset contains Known Load projects that were completed by March 2025. The only status in this dataset is "Completed".

5.1. Known Load Tracking Data

PG&E revised its process for developing the Known Load Tracking Data in the last cycle. The process is depicted in Figure 5-1. A known load is created when a Project Management (PM) order is created in the SAP database. In the cycles prior to the last cycle, these known loads were assigned customized IDs in LoadSEER. However, starting from last cycle, the SAP PM number is used as the unique identifier for each load adjustment in place of the customized IDs. PM Numbers are multiuse project identifiers which represent customer application that map to one or multiple known load(s). Along with this change, the Known Load Tracking Data will keep track of smaller load adjustments which were not included in the prior Tracking Data. Table 5-1 provides a summary of the 2025 Known Load Tracking Data.

Figure 5-1: Known Load Data Process



Table 5-1: Summary of the 2025 Known Load Tracking Data in MW

Forecast Year	2025	2026	2027	2028	2029	2030	2031	2032	2033
Agriculture	156.6	14.2	5.5	1.9	4.0	2.1	0.4	0.0	0.8
Agriculture	156.6	14.2	5.5	1.9	4.0	2.1	0.4	0.0	0.8
Commercial	2485.4	396.4	73.1	33.9	15.4	38.8	6.4	2.4	0.0
Business	2482.4	395.8	71.3	33.9	15.4	38.8	6.4	2.4	0.0
Other	2.9	0.6	1.8	0.0	0.0	0.0	0.0	0.0	0.0
Industrial	875.2	85.4	53.6	11.9	3.3	9.6	10.6	1.4	0.6
Cultivation	156.7	26.4	13.4	4.6	1.6	6.6	0.2	0.0	0.0
Facilities	718.5	59.0	40.2	7.3	1.8	3.0	10.4	1.4	0.6
Residential	576.0	40.8	33.0	14.5	10.4	16.1	2.2	7.1	0.0
Home Construction	576.0	40.8	33.0	14.5	10.4	16.1	2.2	7.1	0.0
Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transportation	943.6	100.5	55.7	37.4	9.7	18.3	0.0	0.0	0.0
LD EV	639.4	71.1	39.4	24.9	6.3	14.0	0.0	0.0	0.0
MD/HD EV	297.2	6.9	15.8	12.5	3.4	1.3	0.0	0.0	0.0
Commercial	7.1	22.6	0.5	0.0	0.0	3.0	0.0	0.0	0.0
Other	252.6	34.0	2.2	1.4	4.2	2.8	0.0	0.0	0.9
Other	162.0	10.5	1.3	0.1	3.7	2.7	0.0	0.0	0.0
Mixed Residential Commercial	89.7	22.5	0.9	1.3	0.5	0.1	0.0	0.0	0.9
Streetlight	0.9	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total	5289.3	671.4	223.1	101.0	47.0	87.6	19.7	10.8	2.4

5.2. Known Load Metrics

The May 2023 Ruling required the Utilities to provide a narrative summary report that includes metrics that are calculated using the Known Load Tracking Data and describing the implications of the calculated metrics. PG&E provide a narrative summary of Known Load Tracking Metrics in Section 6 of their DDOR report. Only a few of the metrics are summarized here. For a detailed discussion of all the metrics, please refer to PG&E's GNA/DDOR report.

- Metrics 1-4: Total and Annual Known Load Changes** - PG&E reported metrics 1-4 that provided information on Known Loads by forecast year and type, as well as changes to these Known Loads when compared with values from the last cycle. On a cumulative basis (i.e., total Known Loads across all the forecast years), the non-TE and TE Known Loads increased by 81% and 43% respectively. Most of the increase in the non-TE Known Loads came from Commercial loads, which increased by 140%. Table provides a summary of the cumulative Known Loads by type from the last two cycles.

Table 5-2: Changes to Cumulative Known Loads by Customer Type

Type	2025-26 Cycle	2024-25 Cycle	Percentage Change from 2024-25 Cycle
Agriculture	185.4	225.0	-18%
Commercial	3051.8	1270.1	140%
Industrial	1051.8	818.7	28%
Residential	700.1	536.6	30%
Transportation	1165.2	815.3	43%
Other	298.1	75.7	294%
Total Non-TE	5287.1	2926.1	81%
TE	1165.2	815.3	43%

- Metric 5-7: Service Amount Deferred (MW or MVA) (MW or MVA, %)** - PG&E provided a calculation of Metric 5. PG&E noted that it interpreted deferred as the amount of known load (MW) that appear in both 2024 and 2025 DDF cycle known load data, and that has a later expected in-service date in 2025 cycle. PG&E calculated that 2065 MW out of 3776 MW or 55% of the known loads (in MW) in the 2024 cycle were deferred in the 2025 cycle. For comparison, this metric was 80% in the last cycle showing that the deferral varies significantly from year to year. The IPE also observed that there were no significant differences in deferral rate by customer type as calculated in Metric 7 by PG&E.

- **Metric 8: Cancellation Rate Total (%)** – PG&E provided a calculation of this metric. PG&E noted that the cancellation rate calculation was based on the number of known load projects that were cancelled. PG&E reported that out of 17920 known loads in the 2024 cycle, 1963 or 10.95% were cancelled. Residential loads contributed to 36% of the cancellations, followed by commercial at 25% and transportation at 12%. Cancellations were lower in the prior cycle but this was due to the fact that Known Loads were derived from the SAP database for the first time in the prior cycle and some of the cancelled projects may not have been included.

6. Verification Approach and Results

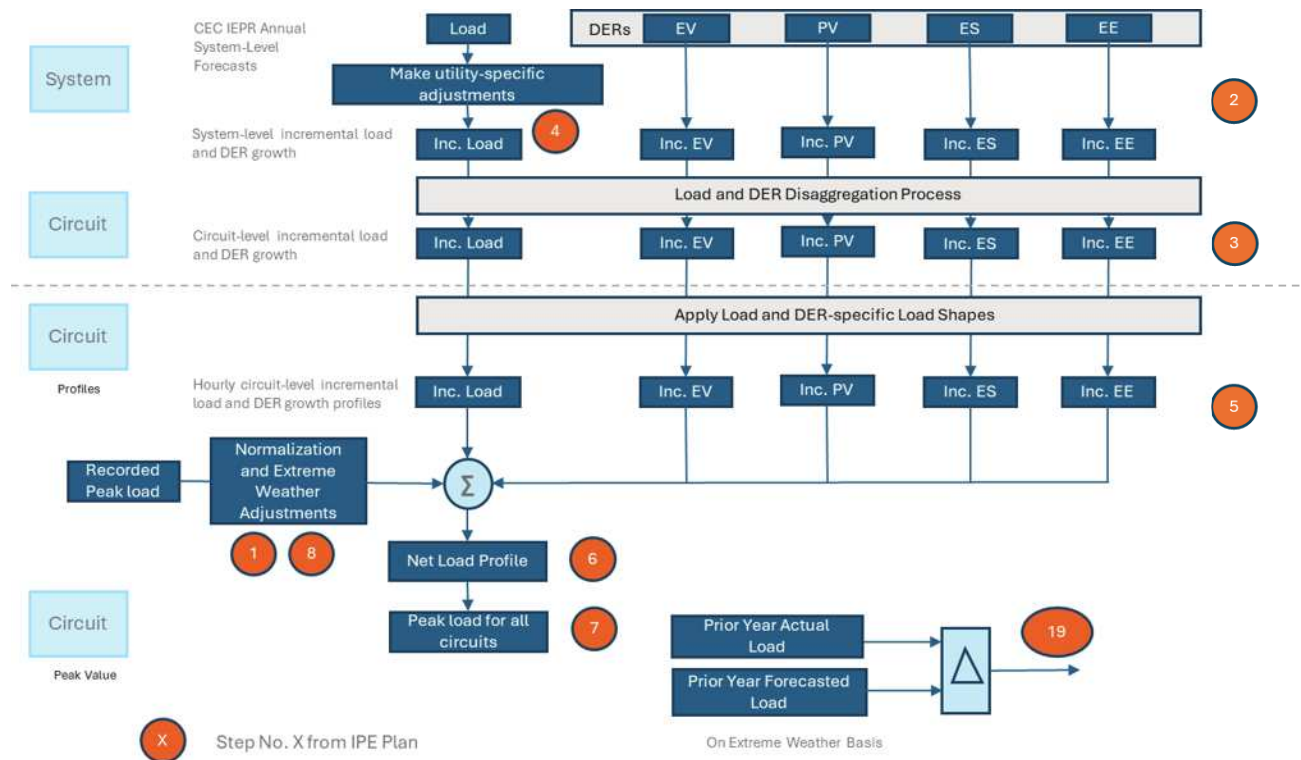
The results of the step-by-step verification process followed by the IPE is presented in this section. This verification process follows the framework set out in the Final IPE Plan included in Appendix C. Any differences from last year's process are discussed in this section.

The following graphic provides an overview of Steps 1 through 8 and 19 in the review process.

- Steps 1, 8 verify and validate the process used to normalize the peak load and adjust for 1-in-10 weather conditions
- Step 2 verifies and validates the process used to develop the GNA system-level annual load and DER forecasts using CEC's IEPR forecasts as the starting point
- Step 3 verifies and validates the process used for disaggregating the system-level loads to the circuit level
- Step 4 verifies and validates the process used for making adjustments to the forecasts to account for known loads
- Steps 5, 6 and 7 verify and validate the process used for developing the 8760 hourly loads profile and the peak load forecast for each circuit
- Step 19 compares the recorded 2024 peak load (adjusted to 1-in-10) with the forecasted 2024 peak load obtained from the 2024 GNA-DDOR report.

As mentioned in Section 1 of this report, the verification and validation of Steps 5-7 have been skipped in this cycle.

Figure 6-1: Business Steps Overview



A summary of the verification and validation steps that were performed and the ones that were skipped are summarized in the Table 6-1 below.

Table 6-1: Status of Verification and Validation Steps

Verification and Validation Step	Status for 2025 DIDF
Steps 1 and 8 - Collect 2024 Actual Circuit Loading, Normalize and Adjust for Extreme Weather	Performed
Step 2 - Determine Load and DER Annual Growth on System Level	Performed
Step 3 - Disaggregate Load and DER Annual Growth to the Circuit Level	Performed
Step 4 - Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads not in CEC forecast)	Performed

Steps 5-7 - Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load	Skipped in this cycle
Steps 9-11 - Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings after No Cost Solutions	Skipped in this cycle
Step 12 - Compile GNA Tables Showing Need and Timing	Performed in this cycle
Step 13 - Develop Recommended Solution	Performed in this cycle
Step 14 - Estimate Capital Cost for Candidate Deferral Projects	Skipped in this cycle
Step 15 - Development of Candidate Deferral Projects	No longer required due to the elimination of DIDF solicitation requirement
Step 16 - Development of Operational Requirements	No longer required due to the elimination of DIDF solicitation requirement
Step 17 - Prioritization of Candidate Deferral Projects into Tiers	No longer required due to the elimination of DIDF solicitation requirement
Step 18 - Calculate LNBA Values	No longer required due to the elimination of DIDF solicitation requirement
Step 19 - Compare 2024 Forecast and Actuals at Circuit Level [proposed change would increase from ~10% of circuits to include all circuits if possible]	Performed in this cycle
Step 20 - Analyze known load tracking dataset and verify the calculation of known load metrics	Performed in this cycle
Step 21 - Review plan for changes to the planning process for the next cycle	Not Required
Step 22 - Review implementing of planning standard and/or planning process	Not Required

Step 23 - Review list of internally approved capital projects	Not Required
Step 24 - Respond to and incorporate DPAG comments	Performed
Step 25 - Track solicitation results to inform next cycle	Not Required
Step 26 - Treating confidential material in the IPE report	Performed
Step 27 - Review Methodology used for Prioritization of Planned Projects	Performed
Step 28 - Review Project Execution Tracking Data and Metrics	Performed

6.1. Processes to Develop System Level Forecasts at Circuit Level

6.1.1. Collect 2024 Actual Circuit Loading, Normalize and Adjust for Extreme Weather - Steps 1 and 8

The process used by PG&E to collect 2024 actual circuit loading and deriving TLY base load profiles (low, typical and extreme profiles) was same as the one used in the last cycle. In cycles prior to the last cycle, PG&E primarily used the SCADA data for determining the peak load for each circuit and for developing the 576 base load profiles. In the last two cycles, PG&E used the LoadSEER 4.0 model which uses AMI aggregate data for developing 8760 hourly load profiles for feeders and substations. To develop the AMI aggregate data for each feeder, PG&E first gathers the service points (smart meters) associated with each feeder. It then uses the AMI data from the smart meters, which could be 5-minute or 15-minute interval data (includes 60-minute interval meters) to construct 8760 historical load profile for each feeder.

The process of developing extreme load profile for planning was also similar to the one used in the last cycle. A detailed description of the new process is provided in the GNA report and also summarized in Section 2.2.6 of this report. In short, using each feeder's 8760 load profile for the years 2020-present developed using AMI data, a relationship between temperature and load is determined which is then applied of 30 years of temperature data yielding 30 years of hourly load for each feeder, from which low, typical and extreme profiles are developed. The TLY load profiles that are correlated to weather are then compared with the AMI data by PG&E engineers who may opt to replace the weather-normalized base shape (referred to as "Method 2" profiles) with an alternate

non-weather normalized base shape (referred to as “Method 3” profiles), constructed from the historical AMI dataset only.

Table 6-2 shows the number of feeders using the Method 2 and Method 3 base load profiles in the last two cycles. Approximately 98% of all feeders used Method 3 compared to 64% in the prior cycle. PG&E current methodology favors the derivation of planning load profiles from recent historical AMI data as opposed to synthesized profiles using a weather model that uses 30 years of weather data.

Table 6-2: Number of Feeders and Banks using Method 2 and 3 Base Load Profiles

Year	Method 2	Method 3	Total
2024	1,126	1,978	3,104
2025	61	3,044	3,105

The IPE obtained the AMI data for the years 2020-2024 for ten randomly selected circuits from PG&E. The peak load for each historical year as observed in the AMI data is shown in Table 6-3 (first five rows) for several circuits. The IPE also obtained the 2025 TLY base (extreme, typical and low) profiles for these circuits. As discussed earlier, the TLY profiles are developed using the 2020-24 AMI data using Method 2 (LoadSEER statistical method that uses 30 years of weather data) or Method 3 (simpler method constructed from the historical AMI data only). The table shows the peak of the extreme, typical and low profiles for each circuit. The method employed for developing the TLY profile is also provided in the last row of the table. It can be observed that for the circuits that were chosen using Method 3, the peak load of the extreme TLY profile is same as the peak load of one of the five historical years. In other words, the peak of the extreme TLY profile (which is used in planning) is the peak observed in the last five years. It can be observed that for the circuits that were chosen using Method 2, the peak load of the extreme TLY profile is different from the peak loads observed in the past five historical years. This is because the extreme TLY peak is driven by 30-year weather data and it is possible that the weather in one or more of those years were more extreme than the weather in the past four years.

Table 6-3: Comparison of Historical and Base Profile Peak Loads in KW

(Confidential Data highlighted in grey has been redacted in the public version of this report)

	Oakland C 1101	Barrett 0401	Rossmoor 1103	East Grand 1105	Bell 1109	River Bank 1714	Jarvis 1109
2020	6318	1795	4506	4610		7952	8335
2021	5644	1974	3808	4231		9336	8079
2022	5925	2058	4040	4739		9925	9823
2023	5264	1878	3387	4874		7177	8493
2024	5002	1677	4133	4546		7584	8682
2025 Base Profile (Extreme)	6317	2058	4506	4874		10909	10616
2025 Base Profile (Typical)	5301	1758	3098	4147		11145	10149
2025 Base Profile (Low)	4665	1633	1970	3940		9729	9126
Method 2/Method 3	3	3	3	3		2	2

6.1.2. 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 Baseline Peak Load, EV Peak Load and DER Growth forecasts from the CEC IEPR forecasts is verified. The process used by PG&E in this cycle is similar to the one employed in the last cycle.

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

- First, PG&E determines what portion of the PG&E Transmission Access Charge (TAC) level load constitutes the PG&E planning area load. The most recent PG&E TAC area Peak and Energy Forecast from the CEC (CED 2023 Mid Baseline Forecast - LSE and BA Tables Mid Demand Case) is used to determine this percentage for all the forecast years and an average value is calculated. Based on this analysis, PG&E has determined that the PG&E Planning Area load is 91.78% of the TAC level load.
- Next, PG&E uses "CED 2023 Hourly Forecast-PGE-Local Reliability" file from the CEC as the starting point for the load forecasts. Using this hourly file, PG&E calculates the Annual Base Peak Load for each forecast year. The Annual Baseline Peak Load does not include the peak load contributions from EV loads (Baseline and AATE) and DERs.
- PG&E calculates the Annual Baseline Peak Load growth for each forecast year for the PG&E TAC area (the growth is simply the difference in peak load between two successive forecast years).
- PG&E then calculates the Planning Area level IEPR Annual Baseline Load Growth using the percentage value discussed in the first step.
- PG&E then compares the cumulative IEPR load growth for the Planning Area with the cumulative Known Loads (not including EV Known Loads) for each forecast year. If the cumulative Known Loads are greater than the cumulative IEPR load growth, then no econometric or spatial loads are modeled for that year - only the Known Loads are used for load growth in that year. For the first two years of the forecast alone, PG&E uses 90% of the cumulative Known Loads to account for the fact that some of these Known Loads could be cancelled.
- If the cumulative IEPR load growth is higher than the cumulative Known Loads in a forecast year, PG&E sets aside 10% of the difference as a buffer for future known loads. This is because PG&E continues to receive applications for service even after the known loads are frozen for performing the calculation discussed in the previous step.
- The remaining difference is then allocated to customer classes (residential, industrial, and commercial). The allocation of Econometric Loads to customer classes is based on the proportion of these loads in the Known Loads (Residential 18%, Commercial 45%, Industrial 22% and Agricultural 15%). These loads are then disaggregated to the circuits as described in Section 2.2.5 of this report.

- PG&E models the following DERs explicitly: Photovoltaic Solar (PV), Energy Storage (ES), Additional Achievable Energy Efficiency (AAEE), Additional Achievable Fuel Switching (AAFS), Light Duty Electric Vehicles (LDEV), and Medium & Heavy-Duty Electric Vehicles (MDHDEV). It uses the “CED 2023 Hourly Forecast-PGE-Local Reliability” file to obtain the forecast (maximum of the hourly values for each forecast year multiplied by 0.92, the TAC Area to Planning Area multiplication factor discussed earlier in this section) for PV, ES, AAEE and AAFS.
- PG&E uses additional transportation forecasts from the CEC (LDEV and MDHD EV counts and energy consumption) as the basis for modeling EV loads in the GNA. This includes:
 - PG&E Territory PEV Count
 - PG&E Transportation Forecast
- PG&E uses a comprehensive methodology to reconcile the difference between the IEPR LDEV and MDHDEV forecasts discussed above and EV Known Loads in order to determine the econometric (spatial) EV growth forecast that needs to be included in the forecast. This is discussed in more detail later in this section.

Table 6-4, Table 6-5 and Table 6-6 show the system-level Baseline Peak Load growth, DER growth and EV growth forecasts respectively, used in the GNA. The IPE verified the values in these tables using the process described above.

Table 6-4: PG&E's System-level Baseline Peak Load Growth Forecasts

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ANNUAL MW GROWTH OF DISTRIBUTION SYSTEM (2023 IEPR)																	
Annual Baseline Consumption Peak for Mid-Baseline Growth without EV	25303	25694	25995	26214	26500	26752	27044	27275	27646	27930	28442	28696	28931	29112	29231	29328	29434
Transmission Non Conforming Loads	2613	2613	2613	2613	2613	2613	2613	2613	2613	2613	2613	2613	2613	2613	2613	2613	2613
Annual Baseline Growth		391	301	219	286	252	292	231	371	284	512	254	235	181	119	97	106
Annual Baseline Growth (PGE Service Area)		359	276	201	262	231	268	212	341	261	470	233	216	166	109	89	97
Cummulative Baseline Growth (PGE Service Area)		359	635	836	1099	1330	1598	1810	2150	2411	2881	3114	3330	3496	3605	3694	3791
CUSTOMER CLASS CONTRIBUTION TO INCREMENTAL PEAK LOAD GROWTH (MW) BY YEAR																	
Residential allocation 18.0%		64	50	36	47	42	48	38	61	47	84	42	39	30	20	16	17
Commercial allocation 45.1%		162	124	91	118	104	121	96	153	117	212	105	97	75	49	40	44
Industrial allocation 22.3%		80	62	45	59	52	60	47	76	58	105	52	48	37	24	20	22
Agricultural allocation 14.7%		53	40	29	38	34	39	31	50	38	69	34	32	24	16	13	14
Total		359	276	201	262	231	268	212	341	261	470	233	216	166	109	89	97
KNOWN ADJUSTMENTS BY CUSTOMER CLASS PEAK LOAD GROWTH (MW) BY YEAR*																	
90% confidence rate applied to account for cancellation and overestimated demand in 2024 and 2025																	
Known Residential Loads, applications 2025 and beyond		476	40	18	2	3	0	0	0	0	0	0	0	0	0	0	0
Known Commercial Loads, applications 2025 and beyond		1051	105	74	64	31	21	21	0	0	0	0	0	0	0	0	0
Known Industrial Loads, applications 2025 and beyond		564	51	22	2	32	2	0	0	0	0	0	0	0	0	0	0
Known Agricultural Loads, applications 2025 and beyond		391	31	8	1	8	0	1	0	0	0	0	0	0	0	0	0
TOTAL KNOWN LOAD APPLICATIONS BY YEAR (INCREMENTAL)		2482	227	123	69	74	23	22	0	0	0	0	0	0	0	0	0
RUNNING TOTAL KNOWN ADJUSTMENTS (CUMULATIVE)		2482	2709	2832	2900	2974	2998	3019	3019	3019	3019	3019	3019	3019	3019	3019	3019
GEOSPATIAL ANNUAL INCREMENTAL GROWTH BY CUSTOMER CLASS THAT SHOULD BE ALLOCATED TO FEEDERS (CORPORATE FORECAST)																	
Cummulative Baseline Growth (PGE Service Area)- Known Loads		0	0	0	0	0	0	0	0	0	0	95	310	476	586	675	772
Incremental Baseline Growth (PGE Service Area)- Known Loads		0	0	0	0	0	0	0	0	0	0	95	216	166	109	89	97
10% Allocation of Incremental Baseline Growth, Buffer for Future Known Loads		0	0	0	0	0	0	0	0	0	0	9	22	17	11	9	10
90% Allocation of Incremental Baseline Growth for Future & Existing Points		0	0	0	0	0	0	0	0	0	0	85	194	150	98	80	88
RESIDENTIAL		0	0	0	0	0	0	0	0	0	0	15	35	27	18	14	16
COMMERCIAL		0	0	0	0	0	0	0	0	0	0	38	87	67	44	36	39
INDUSTRIAL		0	0	0	0	0	0	0	0	0	0	19	43	33	22	18	20
AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	12	28	22	14	12	13
KNOWN ADJUSTMENTS + GEOSPATIAL GROWTH RUNNING TOTAL (CUMULATIVE)		2481.5	227.4	122.9	68.6	73.6	23.5	21.5	0.0	0.0	0.0	85.5	194.1	149.5	98.3	80.1	87.6

Table 6-5: PG&E's System-level DER Growth Forecasts

	2025	2026	2027	2028	2029	2030	2031	2032
PV Forecast (MW)	544	595	620	643	677	704	653	612
ES-Residential Forecast (MW)	42	47	51	53	61	64	55	49
ES-Commercial Forecast (MW)	11	11	12	13	13	13	12	12
AAEE Forecast (MW)	115	78	69	58	58	57	50	49
AAFS Forecast - Heating & Boiler(MW)	38	221	393	502	678	721	697	717
AAFS Forecast - Cooling (MW)	42	87	136	168	230	227	227	235
	2033	2034	2035	2036	2037	2038	2039	2040
PV Forecast (MW)	484	339	227	124	123	120	116	118
ES-Residential Forecast (MW)	25	11	3	0	0	0	0	0
ES-Commercial Forecast (MW)	10	6	6	4	5	4	4	5
AAEE Forecast (MW)	48	36	28	24	16	11	6	3
AAFS Forecast - Heating & Boiler(MW)	713	705	717	643	700	748	687	660
AAFS Forecast - Cooling (MW)	220	217	214	220	235	240	206	177

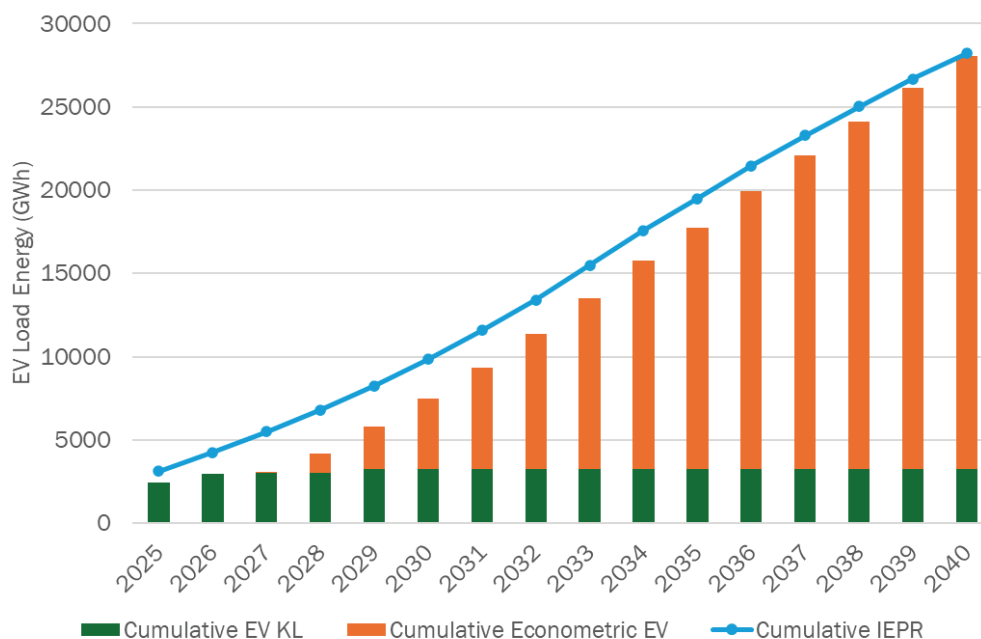
Note: The PV, ES and AAEE reduce the peak load while AAFS increases the peak load

Table 6-6: PG&E's System-level LDEV and MDHDEV Growth Forecasts

	2025	2026	2027	2028	2029	2030	2031	2032
LDEV Energy Growth (GWh)	1,021	1,146	1,235	1,278	1,459	1,609	1,665	1,758
MDHDEV Energy Growth (GWh)	196	210	262	290	302	332	435	425
LDEV Stock Growth (Count)	225,071	229,768	252,314	278,500	321,463	368,477	408,194	445,073
MDHDEV Stock Growth (Count)	5,983	6,196	7,608	8,866	9,631	10,754	12,168	13,221
	2033	2034	2035	2036	2037	2038	2039	2040
LDEV Energy Growth (GWh)	1,835	1,887	1,658	1,753	1,635	1,572	1,511	1,447
MDHDEV Energy Growth (GWh)	678	607	627	590	549	485	426	358
LDEV Stock Growth (Count)	457,296	501,964	424,096	454,258	442,603	431,133	419,916	404,645
MDHDEV Stock Growth (Count)	14,706	14,664	14,566	17,093	17,266	16,329	15,275	14,282

PG&E uses a comprehensive methodology (same as the one used in the last cycle) to reconcile the difference between the IEPR LDEV and MDHDEV forecast and EV Known Loads in order to determine the Econometric (spatial) EV growth forecast that needs to be included in the forecast. This process is described in detail in Appendix C.5 of PG&E’s GNA report. The IPE was able to verify that on an energy basis, the IEPR forecast for EVs matches with what was used in the DPEP. Figure 6-2 shows the cumulative energy from EV Known Loads and EV Econometric Loads used in the DPEP. The sum of these two matches closely with the IEPR forecast on a cumulative energy basis as seen from the figure.

Figure 6-2: Comparison of IEPR Forecast with DPP Forecast for EV Loads



6.1.3. Disaggregate Load and DER Annual Growth to Circuit Level - Step 3

PG&E uses the results of the LoadSEER software to disaggregate the adjusted system-level load (Econometric) and DER growth forecasts to each of its 3000 plus circuits. The disaggregation processes are similar to those used in the previous cycle and described in the DFWG meeting in May 2025. Table 6-7 shows the system-level load growth forecasts by customer class derived from the CEC IEPR after adjusting for the known loads as described in Step 2. LoadSEER is then used to disaggregate this adjusted system-level load growth forecasts to the circuits. Table 6-8 shows the aggregated circuit-level load growth by customer class developed by LoadSEER.

It can be observed that the total system-level values in the last row of the tables match. However, the values by customer class don’t match. This is because LoadSEER uses different ratios to allocate the total loads between the classes which is more accurate than the

estimates in Table 6-7 which are obtained by assigning the total loads to the classes based on their proportion in the current year's known loads.

Table 6-7 : System-level load forecasts derived from the CEC IEPR

	2035	2036	2037	2038	2039	2040	Total
Residential	15	35	27	18	14	16	125
Commercial	38	87	67	44	36	39	313
Industrial	19	43	33	22	18	20	155
Agricultural	12	28	22	14	12	13	102
Total	85	194	150	98	80	88	695

Table 6-8: Aggregated circuit-level load forecasts derived from LoadSEER results

	2035	2036	2037	2038	2039	2040	Total
Residential	59	130	101	67	54	56	468
Commercial	11	21	17	9	9	10	76
Industrial	15	40	28	18	14	18	133
Agricultural	0	3	4	4	3	4	18
Total	86	194	150	98	80	88	695

Similarly, PG&E disaggregates system-level DER growth forecasts down to the circuit level for the following four DERs: Photovoltaics (PV), Energy Storage (ES) and Additional Achievable Energy efficiency (AAEE), as well as Additional Achievable Fuel Switching (AAFS). The IPE verified that the sum of the disaggregated circuit-level forecasts matches with the system-level forecasts.

A comparison of the system-level forecasts and the cumulative circuit-level forecasts for PV, ES, AAEE and AAFS are included in Table 6-9,

	2025	2026	2027	2028	2029	2030	2031	2032
CEC System-level Forecast (MW)	499	546	569	590	621	646	599	562
Sum of Circuit-level Forecast (MW)	499	546	569	590	621	646	599	562
	2033	2034	2035	2036	2037	2038	2039	2040
CEC System-level Forecast (MW)	444	311	208	114	113	110	106	108
Sum of Circuit-level Forecast (MW)	444	311	208	114	113	110	106	108

Table 6-10,

	Residential Energy Storage							
	2025	2026	2027	2028	2029	2030	2031	2032
CEC System-level Forecast (MW)	39	43	47	49	56	59	50	45
Sum of Circuit-level Forecast (MW)	39	43	47	49	56	59	50	45
	2033	2034	2035	2036	2037	2038	2039	2040
CEC System-level Forecast (MW)	23	10	3	0	0	0	0	0
Sum of Circuit-level Forecast (MW)	23	10	3	0	0	0	0	0
	Commercial Energy Storage							
	2025	2026	2027	2028	2029	2030	2031	2032
CEC System-level Forecast (MW)	10	10	11	12	12	12	11	11
Sum of Circuit-level Forecast (MW)	10	10	11	12	12	12	11	11
	2033	2034	2035	2036	2037	2038	2039	2040
CEC System-level Forecast (MW)	9	6	6	4	5	4	4	5
Sum of Circuit-level Forecast (MW)	9	6	6	4	5	4	4	5

Table 6-11 and

	2025	2026	2027	2028	2029	2030	2031	2032
CEC System-level Forecast (MW)	106	72	63	53	53	52	46	45
Sum of Circuit-level Forecast (MW)	106	72	63	53	53	52	46	45
	2033	2034	2035	2036	2037	2038	2039	2040
CEC System-level Forecast (MW)	44	33	26	22	15	10	6	3
Sum of Circuit-level Forecast (MW)	44	33	26	22	15	10	6	3

Table 6-12 respectively. It can be seen from these tables that the system-levels forecasts match exactly with the cumulative circuit-level forecasts indicating that the system-level forecasts have been accurately disaggregated to all the circuits.

Table 6-9: PV forecast verification at the circuit level

	2025	2026	2027	2028	2029	2030	2031	2032
CEC System-level Forecast (MW)	499	546	569	590	621	646	599	562
Sum of Circuit-level Forecast (MW)	499	546	569	590	621	646	599	562
	2033	2034	2035	2036	2037	2038	2039	2040
CEC System-level Forecast (MW)	444	311	208	114	113	110	106	108
Sum of Circuit-level Forecast (MW)	444	311	208	114	113	110	106	108

Table 6-10: Residential and Commercial ES forecast verification at the circuit level

	Residential Energy Storage							
	2025	2026	2027	2028	2029	2030	2031	2032
CEC System-level Forecast (MW)	39	43	47	49	56	59	50	45
Sum of Circuit-level Forecast (MW)	39	43	47	49	56	59	50	45
	2033	2034	2035	2036	2037	2038	2039	2040
CEC System-level Forecast (MW)	23	10	3	0	0	0	0	0
Sum of Circuit-level Forecast (MW)	23	10	3	0	0	0	0	0
	Commercial Energy Storage							
	2025	2026	2027	2028	2029	2030	2031	2032
CEC System-level Forecast (MW)	10	10	11	12	12	12	11	11
Sum of Circuit-level Forecast (MW)	10	10	11	12	12	12	11	11
	2033	2034	2035	2036	2037	2038	2039	2040
CEC System-level Forecast (MW)	9	6	6	4	5	4	4	5
Sum of Circuit-level Forecast (MW)	9	6	6	4	5	4	4	5

Table 6-11: AAEE forecast verification at the circuit level

	2025	2026	2027	2028	2029	2030	2031	2032
CEC System-level Forecast (MW)	106	72	63	53	53	52	46	45
Sum of Circuit-level Forecast (MW)	106	72	63	53	53	52	46	45
	2033	2034	2035	2036	2037	2038	2039	2040
CEC System-level Forecast (MW)	44	33	26	22	15	10	6	3
Sum of Circuit-level Forecast (MW)	44	33	26	22	15	10	6	3

Table 6-12: AAFS forecast verification at the circuit level

AAFS H&B	2025	2026	2027	2028	2029	2030	2031	2032
CEC System-level Forecast (MW)	35	203	361	461	622	662	640	658
Sum of Circuit-level Forecast (MW)	35	203	361	461	622	662	640	658
	2033	2034	2035	2036	2037	2038	2039	2040
CEC System-level Forecast (MW)	654	647	658	590	642	687	631	606
Sum of Circuit-level Forecast (MW)	654	647	658	590	642	687	631	606
AAFS Cooling	2025	2026	2027	2028	2029	2030	2031	2032
CEC System-level Forecast (MW)	38	80	125	154	211	208	209	216
Sum of Circuit-level Forecast (MW)	38	80	125	154	211	208	209	216
	2033	2034	2035	2036	2037	2038	2039	2040
CEC System-level Forecast (MW)	202	199	196	202	216	220	189	163
Sum of Circuit-level Forecast (MW)	202	199	196	202	216	220	189	163

6.1.4. Add Known Load Growth Projects to Circuit Level Forecast - Step 4

PG&E accepts the CEC IEPR forecast and does not assume that 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 “known loads” adjustment made to the CEC annual system load growth forecast as described in Section 6.1.2. After the adjusted system load is allocated to the circuits, these new known distribution loads are added to their specific circuits. 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.

Table 6-13 and

	2025	2026	2027	2028	2029	2030	2031	2035
New Residential	529	44	18	2	3	0	0	0
New Commercial	1168	117	74	64	31	21	21	0
New Industrial	626	57	22	2	32	2	0	0
New Agricultural	434	35	8	1	8	0	1	0
Total	2757	253	123	69	74	23	22	0

Table 6-14 show the MW and count of Known Loads broken down by Residential, Commercial, Industrial and Agricultural (includes cannabis cultivation) classes. The known loads shown in Table 6-13 match reasonably well with those used in Step 2 (rows 11-14 of Figure 5-2), but don't match the numbers exactly (Note: In Step 2, only 90% of the Known Loads in the first two years of the forecast shown in the table, are assumed to materialize). This is because PG&E continuously updates known loads and list used for Table 6-13 is more current. Please note that EV Known Loads are not included in these tables.

The Known Load data shown in these two tables were provided by PG&E earlier in the cycle in order to verify the adjustments to the IEPR forecast as described previously. The total non-TE Known Loads shown in Table 6-13 (3320 MW) was significantly different from the corresponding Known Loads reported in the Known Loads Tracking Data (5287 MW). PG&E informed the IPE that the primary reason for this difference is due to data center loads that were included in the Known Load Tracking Data but not the Known Loads reported earlier for adjusting the IEPR forecast. The IPE plans to gather additional information on the difference between the two sets of Known Loads and report it in the Post-DPAG report.

Table 6-13: MW of New Known Distribution Load by year

	2025	2026	2027	2028	2029	2030	2031	2035
New Residential	529	44	18	2	3	0	0	0
New Commercial	1168	117	74	64	31	21	21	0
New Industrial	626	57	22	2	32	2	0	0
New Agricultural	434	35	8	1	8	0	1	0
Total	2757	253	123	69	74	23	22	0

Table 6-14: Count of New Known Distribution Load by Year

	2025	2026	2027	2028	2029	2030	2031	2035
New Residential	5978	83	17	4	5	0	0	0
New Commercial	2246	86	26	11	13	7	4	1
New Industrial	566	20	4	6	9	1	0	0
New Agricultural	2438	33	9	3	2	1	1	0
Total	11228	222	56	24	29	9	5	1

6.1.5. Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load - Steps 5, 6, and 7

PG&E uses the circuit-level peak load growth forecast by customer class (verified in Step 3) and typical 8760-hourly profiles for each customer class to develop the Peak load growth 8760 hourly profile for each circuit for each forecast year. Similarly, PG&E uses the circuit-level DER growth forecast by customer class (if applicable) and typical 8760-hourly profile for each DER to develop the DER growth 8760 hourly profile for each circuit for each forecast year.

The verification of Steps 5-7 was excluded in this cycle. However, the typical profiles of the DERs are included for reference. These load shapes are normalized in LoadSEER before being applied to a forecast. Most of the load shapes are same as last year's except the AAFS cooling and heating shapes.

Figure 6-3: Typical Daily Profile for EV Fleet⁷

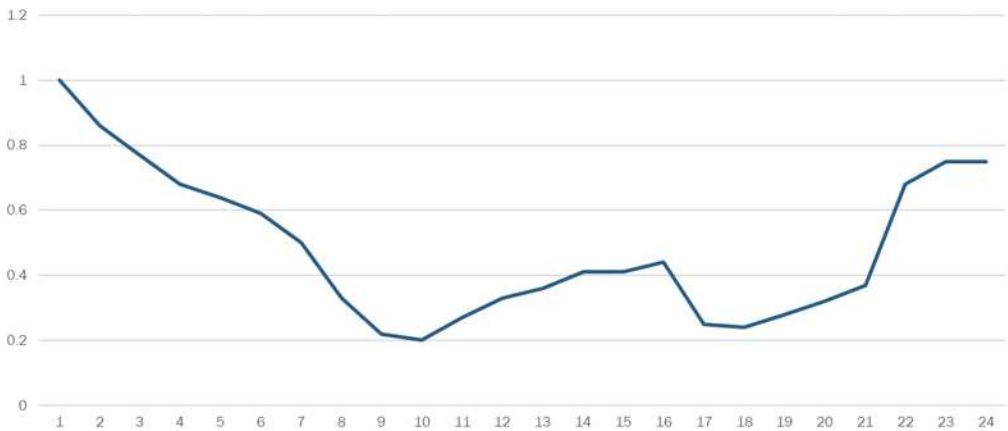
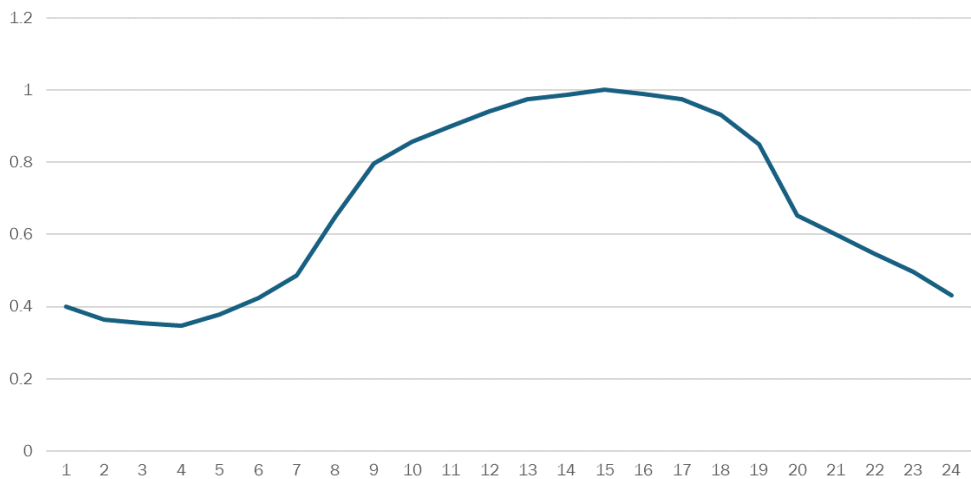


Figure 6-4: Typical Daily Profile for EV Public L2



⁷ For Fleet, Public L2, Residential L1 & L2 and Workplace the daily profile repeats for all days of the year.

Figure 6-5: Typical Daily Profile for EV Residential L1 and L2

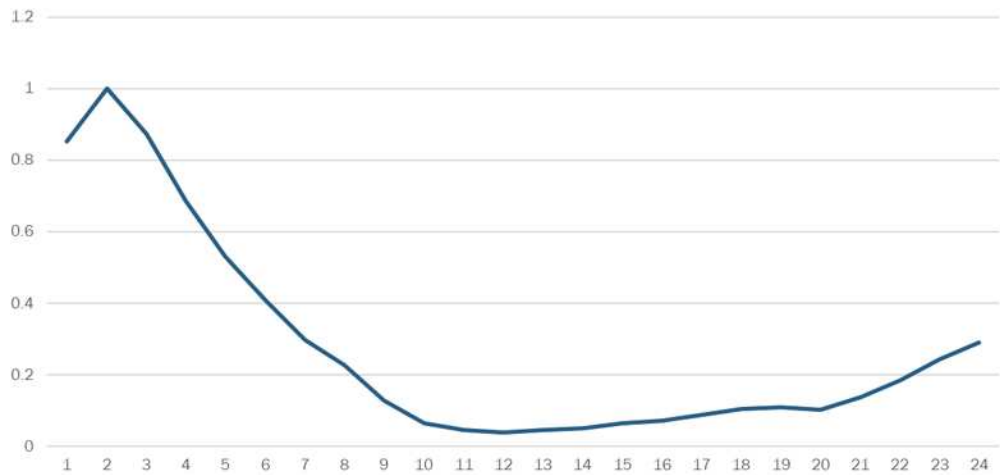


Figure 6-6: Typical Daily Profile for EV Workplace

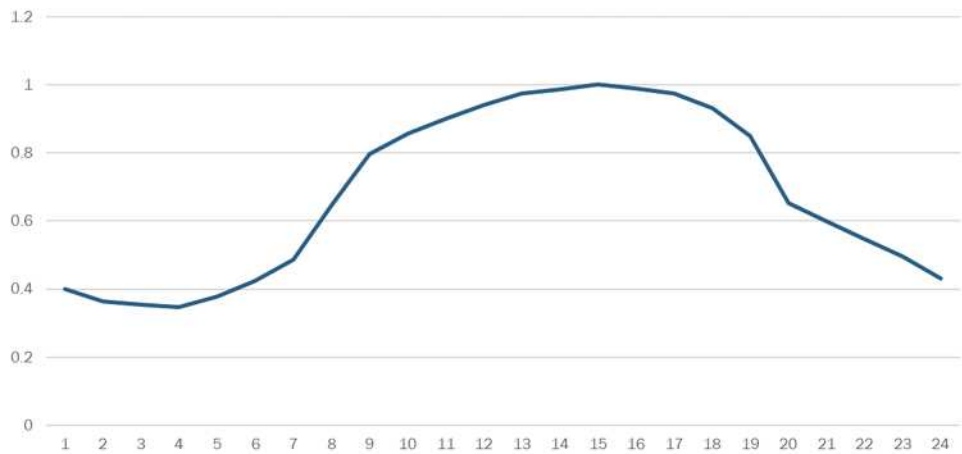
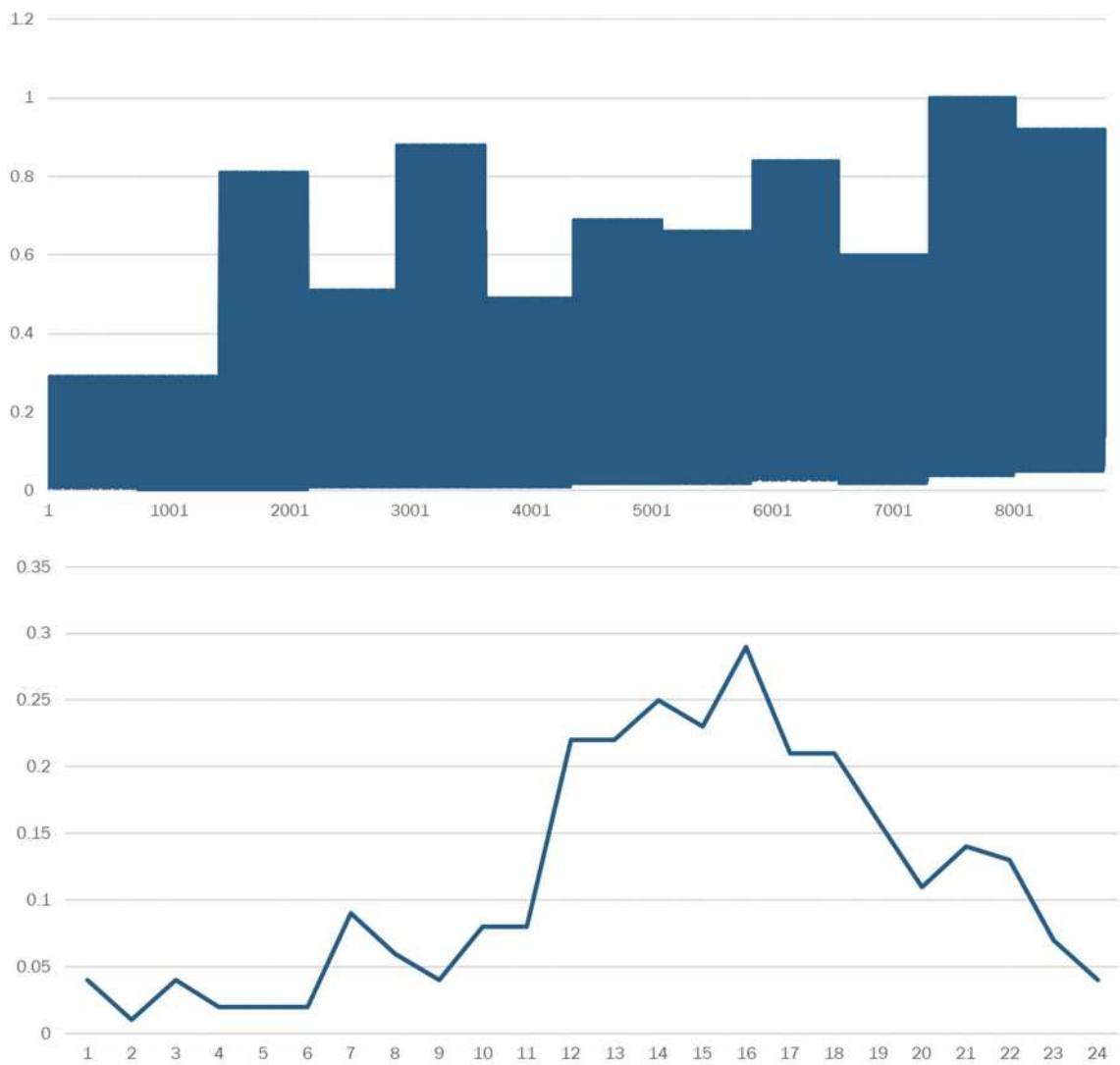


Figure 6-7: Typical Annual and Daily Profiles for EV Rural DCFC⁸



⁸ DCFC load profile changes seasonally. The top plot shows the seasonal variability in the load and the bottom plot shows the daily variability (for the first day of the year).

Figure 6-8: Typical Annual and Daily Profiles for EV Urban DCFC

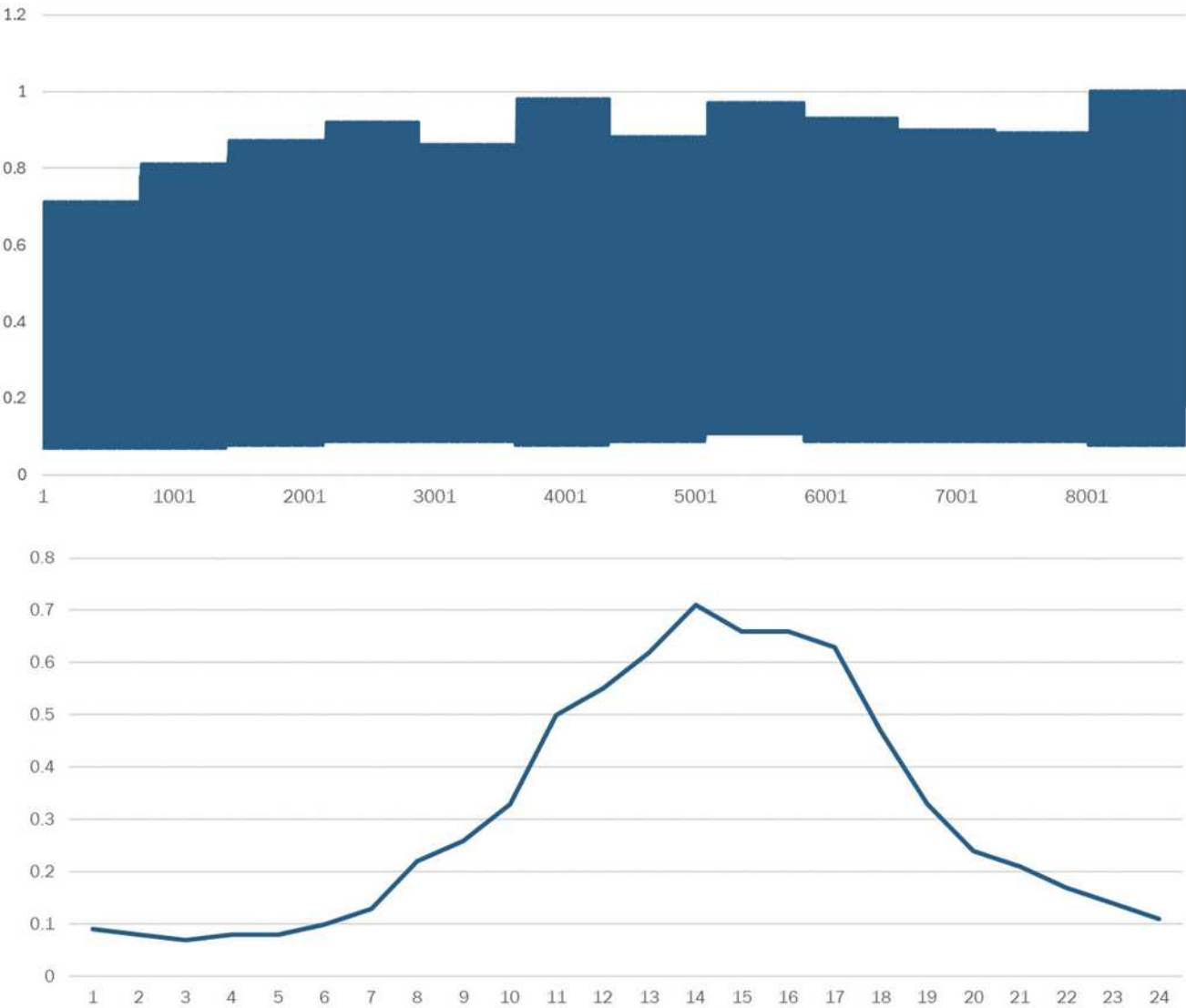


Figure 6-9: Typical Annual and Daily Profiles for PV Solar

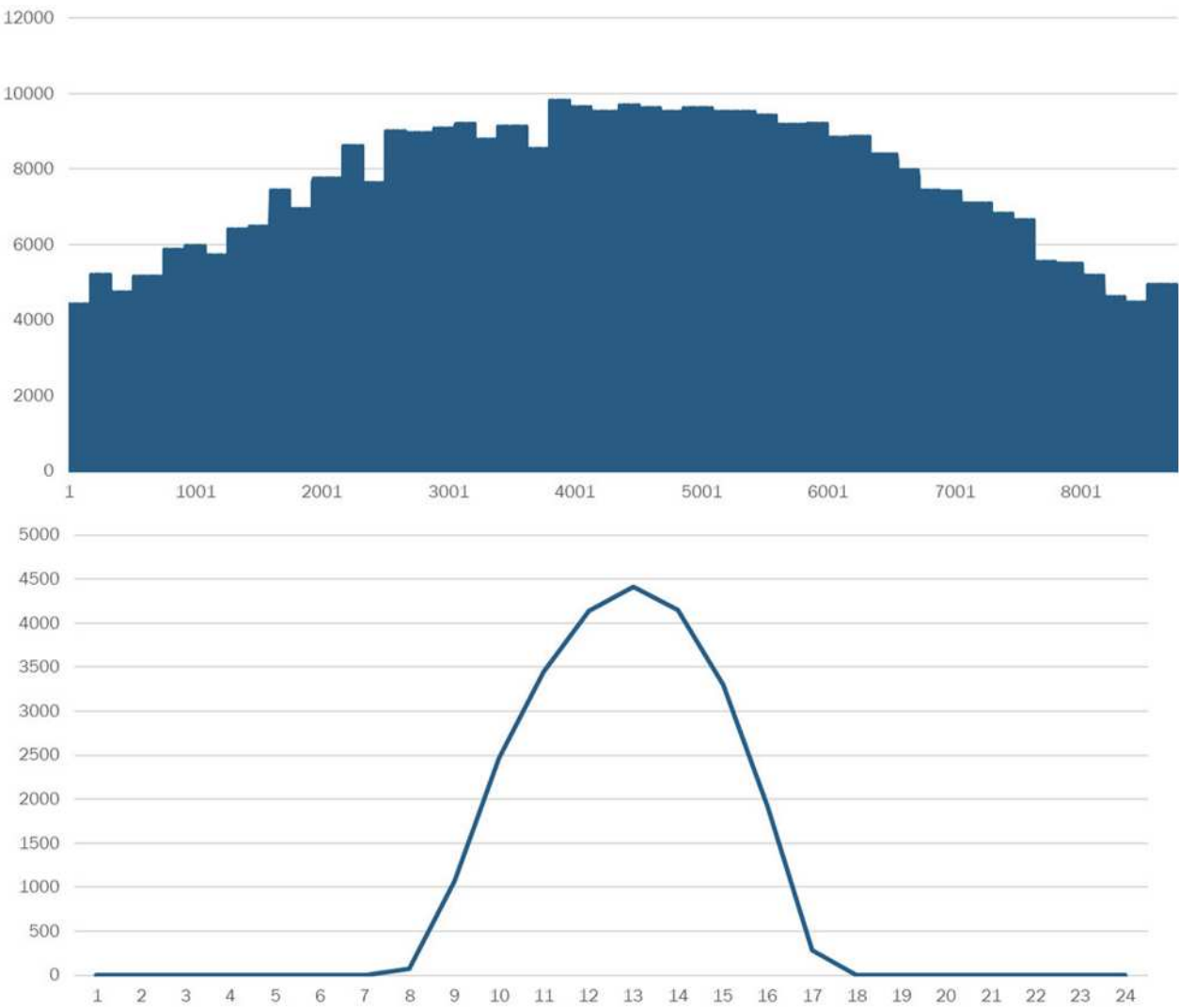


Figure 6-10: Typical Annual and Daily Profiles for Energy Storage-Nonresidential

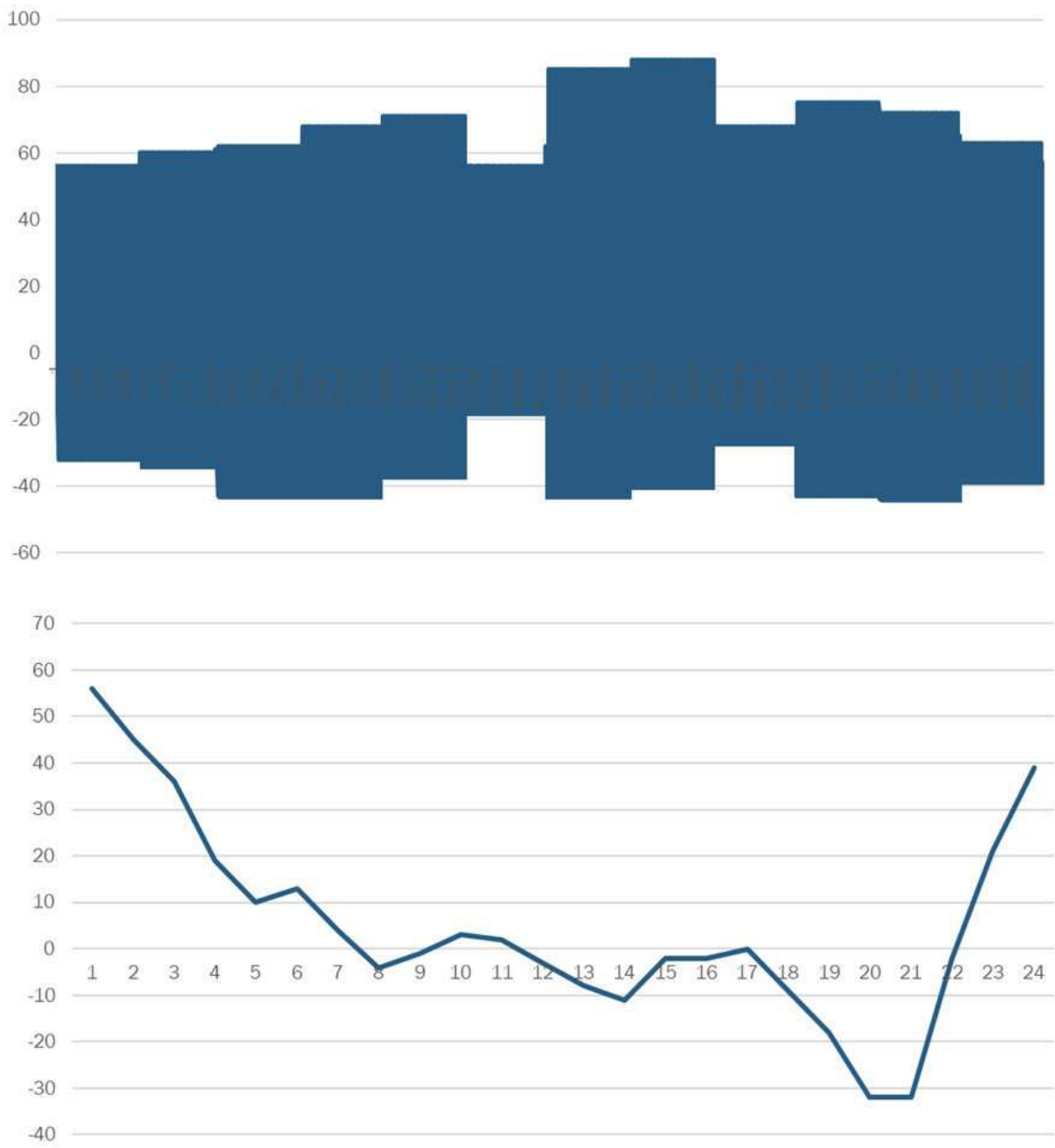


Figure 6-11: Typical Annual and Daily Profiles for AAEE

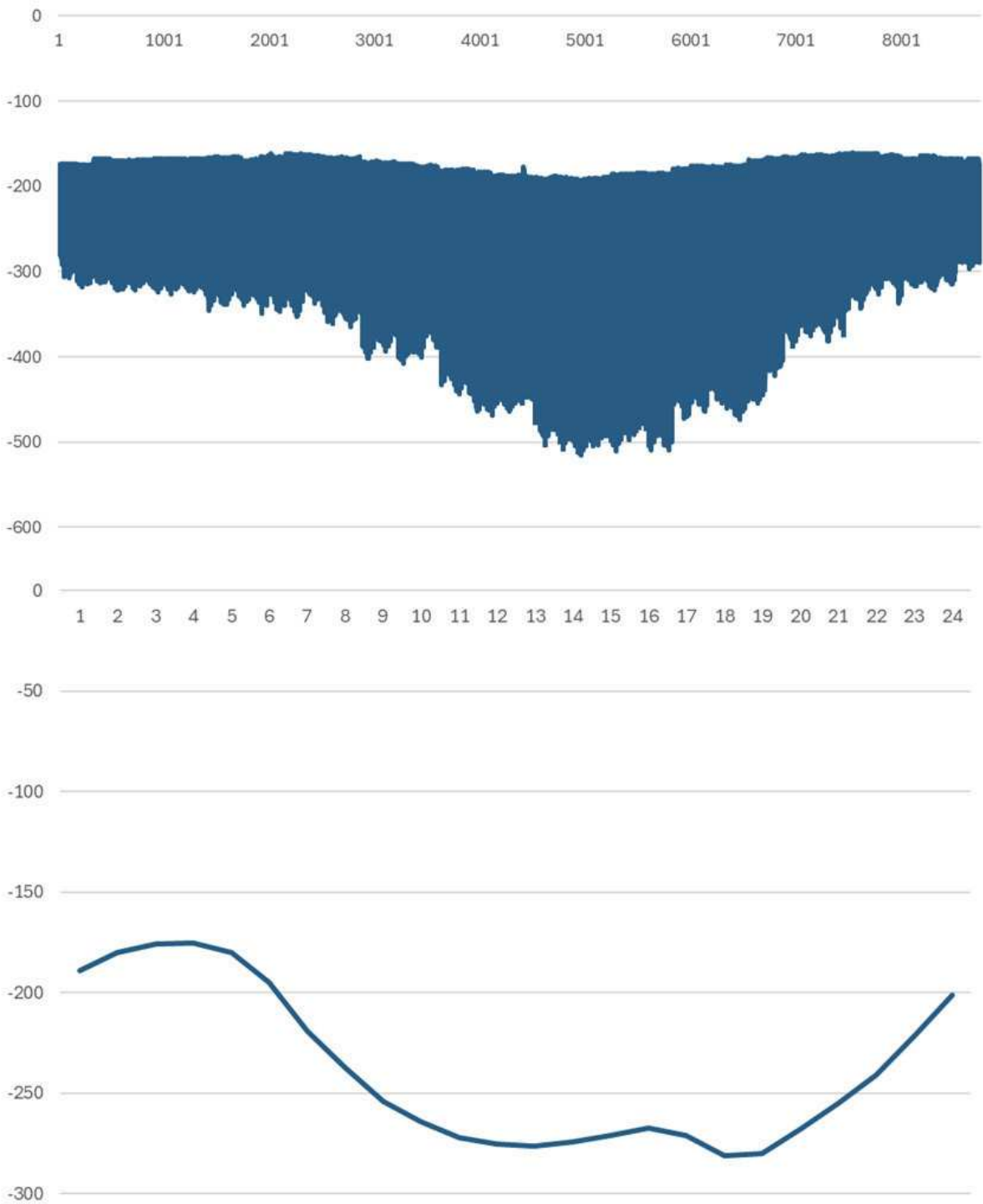


Figure 6-12: Typical Annual and Daily Profiles for AAFS (Heating)

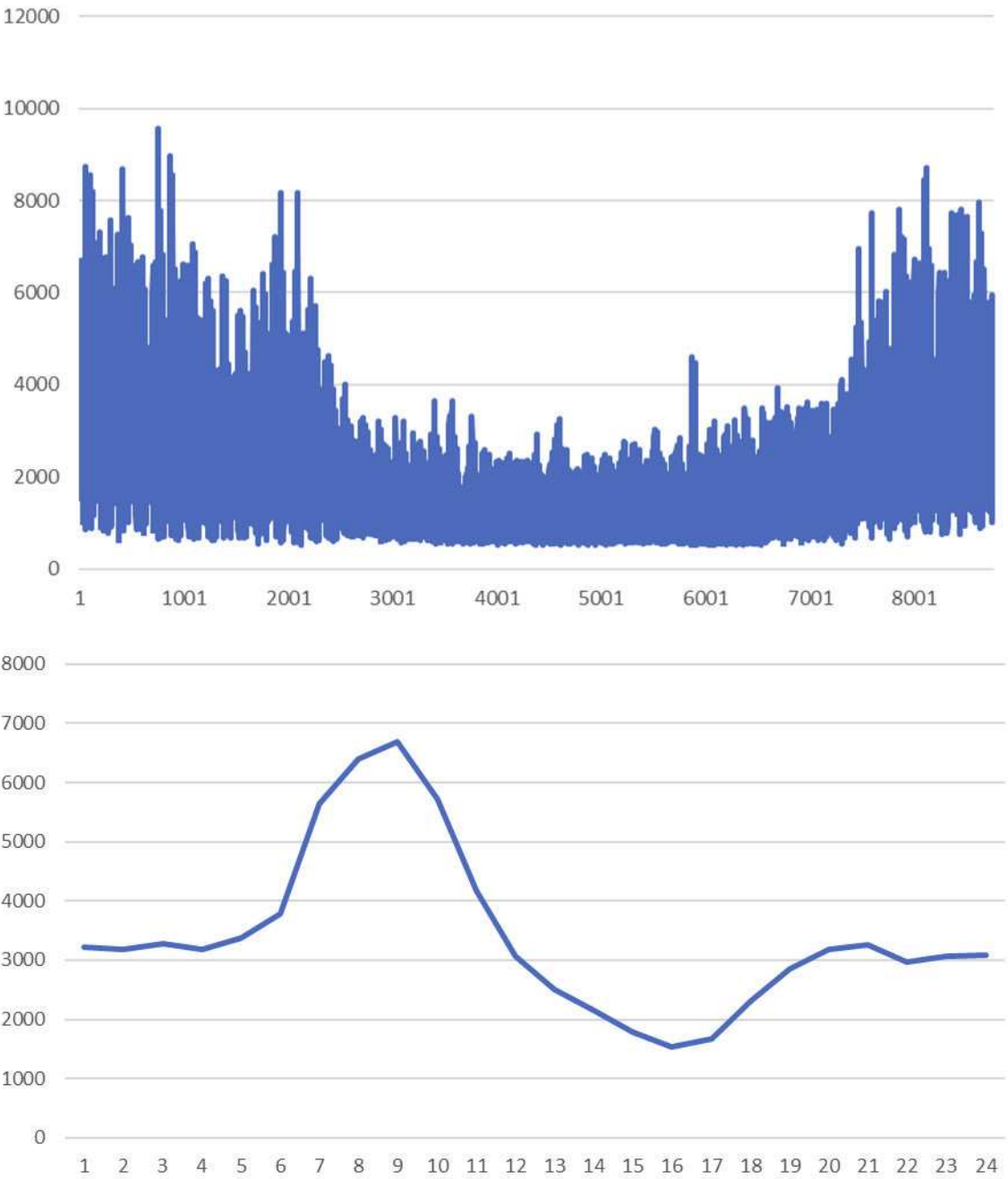


Figure 6-13: Typical Annual and Daily Profiles for AAFS (Cooling)

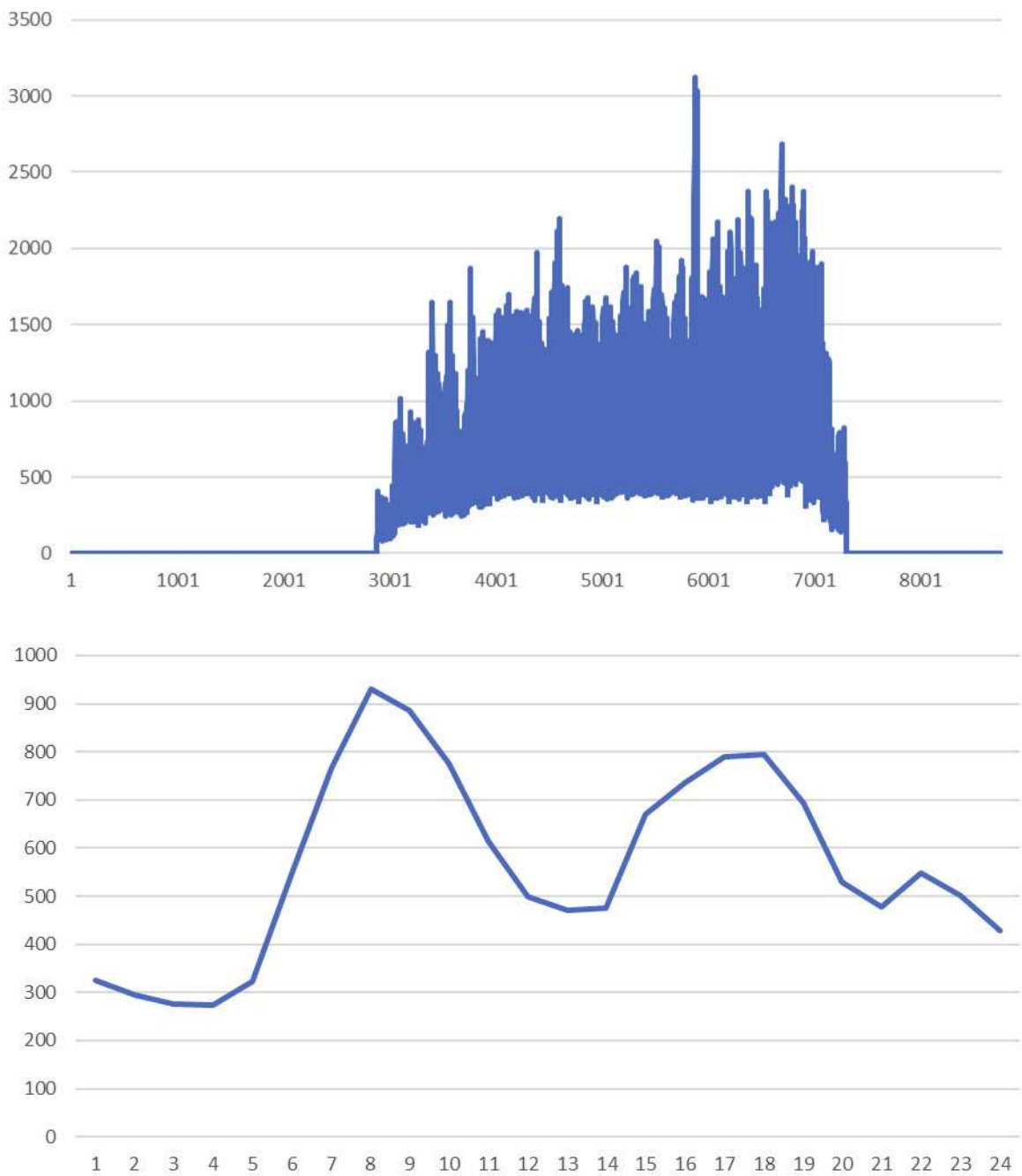


Figure 6-14: Typical Annual and Daily Profiles for Residential Class

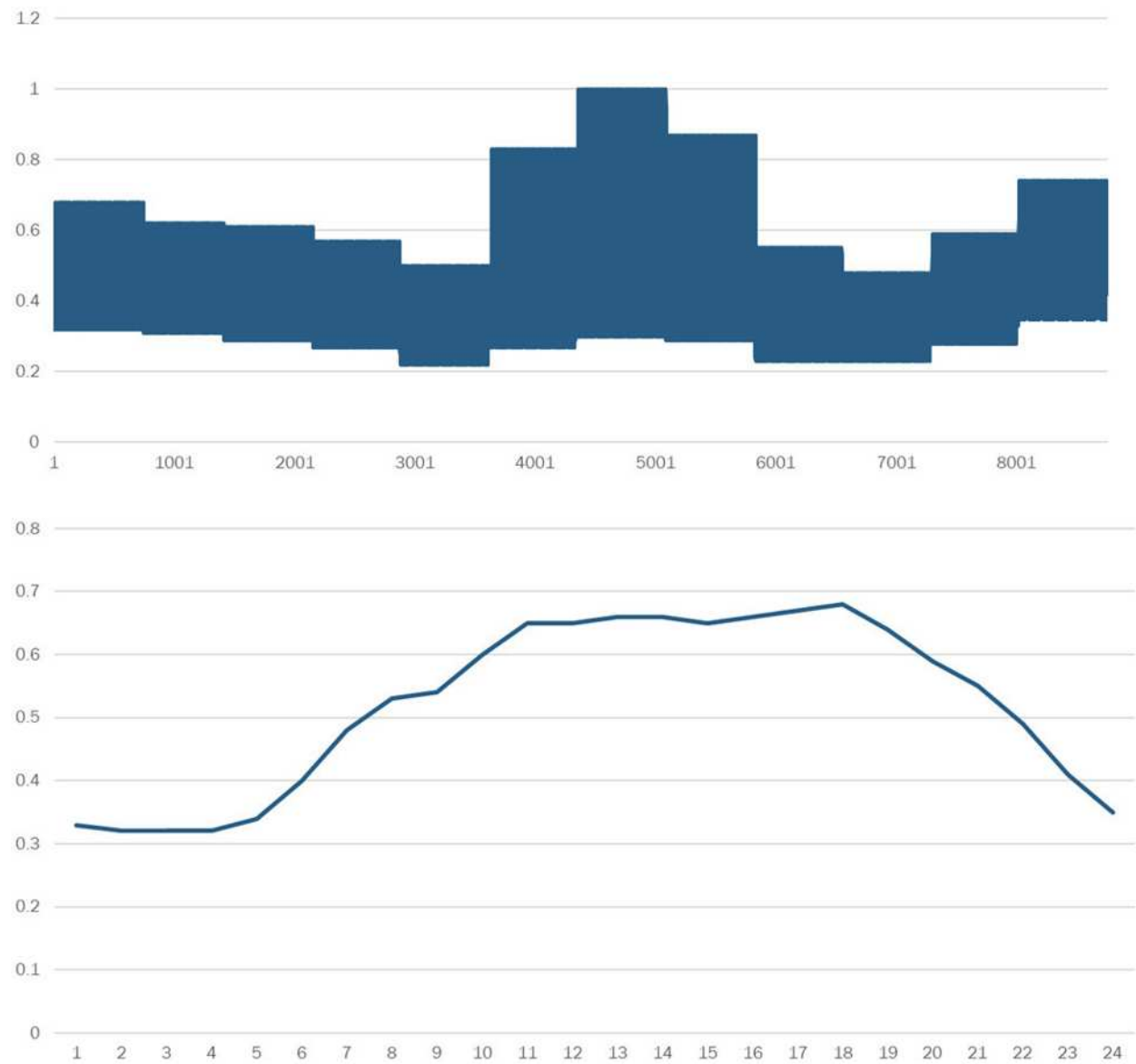


Figure 6-15: Typical Annual and Daily Profiles for Commercial Class

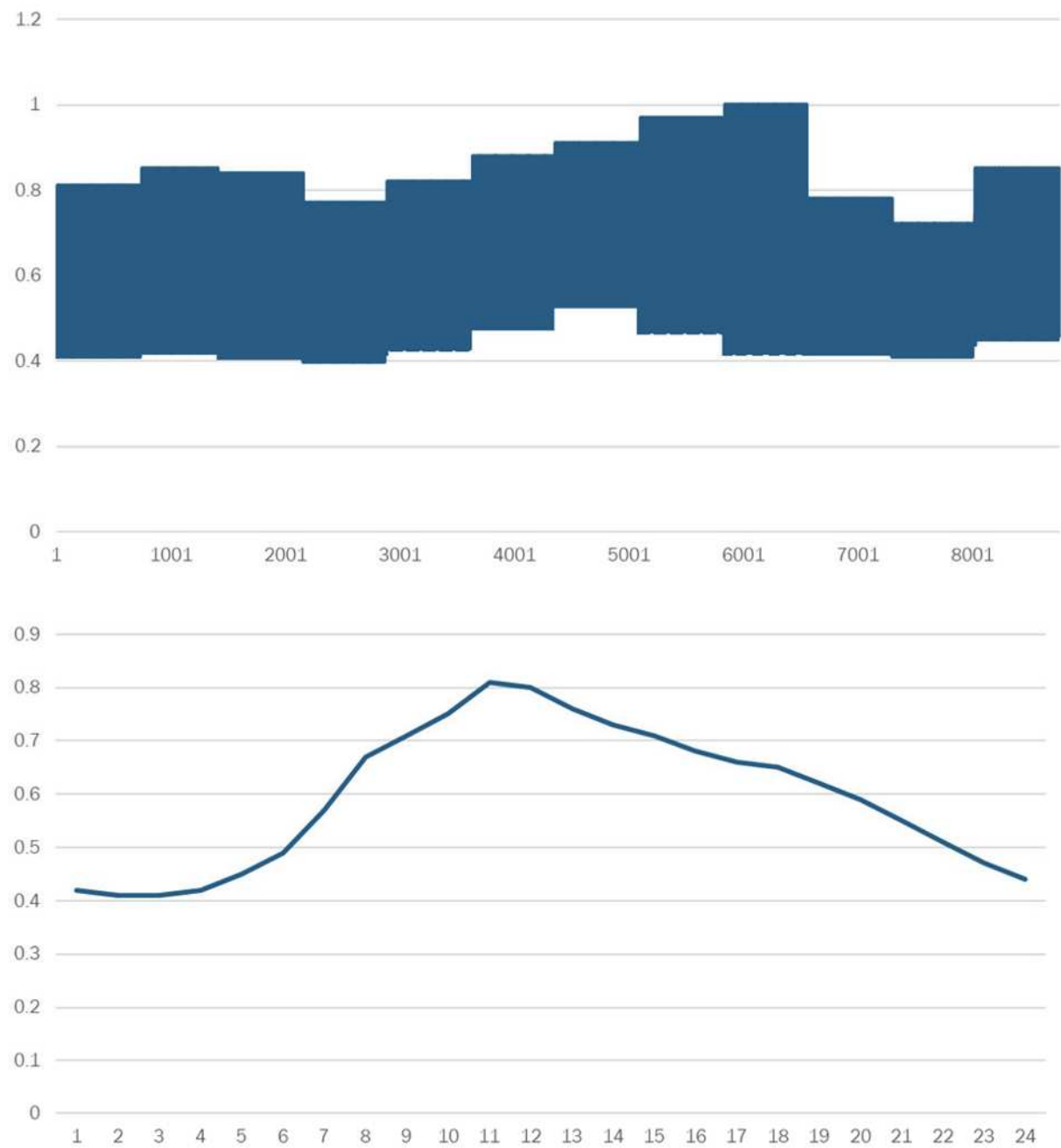


Figure 6-16: Typical Annual and Daily Profiles for Agriculture Class

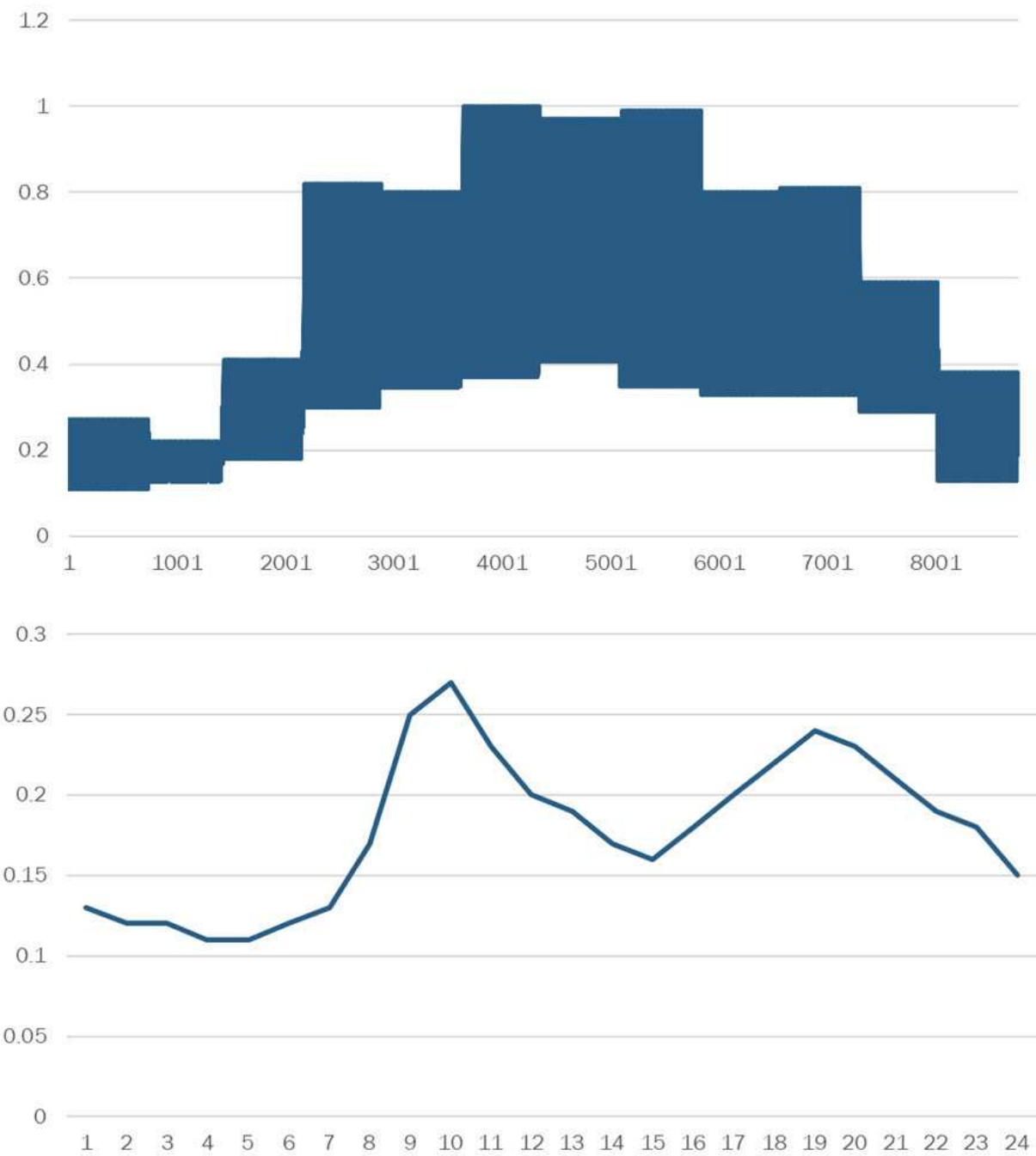
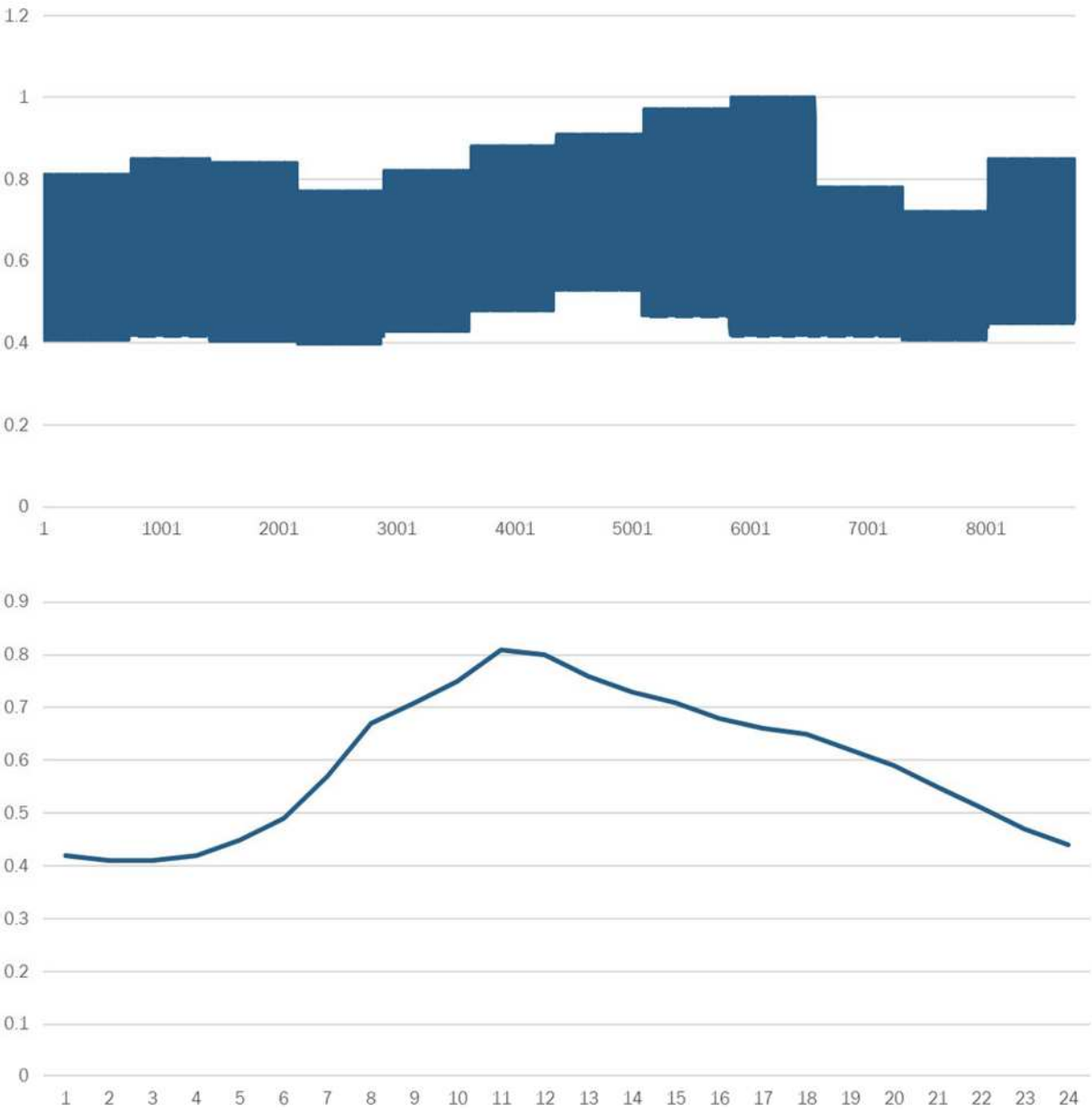


Figure 6-17: Typical Annual and Daily Profiles for Industrial Class



6.2. Processes to Determine Circuit Needs and Develop GNA

6.2.1. Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings after No Cost Solutions - Steps 9, 10 and 11

As per the IPE Plan, the verification and validation of these steps were skipped in this cycle.

6.2.2. Compile GNA Tables Showing Need and Timing - Step 12

The IPE obtained the GNA table in Excel format that showed the forecasted peak load and the components of the peak load and verified that the sum of the components matched the forecasted peak load. There were no changes to the planning standards/criteria in the development of the GNA tables when compared with the prior cycle.

6.3. Processes to Develop Planned Investments and Costs

6.3.1. Develop Recommended Solution - Step 13

Purpose: The purpose of this step was to verify and validate the process PG&E used to identify planned projects to address the needs. Of particular interest was the verification and validation of the process used by PG&E to determine whether planned investments identified in prior cycles are still needed and are the appropriate solution based upon planning assumptions for load and DER growth and other planning assumptions used in the current DPEP cycle.

Verification: PG&E provided a general description of the process that is used to confirm that planned solutions and planned investments identified in earlier DPP cycles are still needed and the appropriate solution or investment when considered using the current DPP load, DER and other DPP assumption. This process is summarized below.

- PG&E uses the CYME loadflow tool to determine if a project identified in a prior cycle is still needed. The CYME tool contains information regarding the planned project as well as the latest forecast for the strategic peak hour. This tool is automated to calculate overloads with and without the planned project with the most recent forecast data. Using the results of this simulation, Planning Engineers can identify whether a project would still be required with the updated load forecast. CYME can be used to evaluate projects at the circuit, feeder and substation levels for the strategic peak hour.
- PG&E also uses LoadSEER to evaluate overloads with and without the planned project for all hours (not just the peak hour) at the feeder and substation bank level, as needed. However, this process is not automated.

- PG&E then makes adjustments to the execution of the planned project based on the results of this analysis and the current status of the project.

The IPE performed verification of process by gathering the current status of three randomly-selected planned projects that were associated with needs that existed in prior planning cycles but not in the current cycle. Table 6-15 shows the information on the three needs, how they have changed over the last four cycles and the planned project that is associated with those needs.

Table 6-15: Table Showing Needs that change with cycle and corresponding Planned Projects

GNA Cycle	GNA NEED ID	Facility Name	Facility Type	Distribution Service Required	Anticipated Need Date	Peak Facility Loading (%) Yr1- Yr5	Planned Project
2022	GNA_183041101_Capacity	BUELLTON 1101	Feeder	None	None	92%	Buellton 1102 Mainline Tie UG Upgrade
2023	GNA_183041101_Capacity	BUELLTON 1101	Feeder	Capacity	2025	114.60%	
2024	GNA_183041101_Capacity	BUELLTON 1101	FEEDER	None	None	96.54%	
2025	GNA_183041101_Capacity	BUELLTON 1101	FEEDER	Capacity	2025	103.21	
2022	GNA_253151102_Capacity	GIFFEN 1102	Feeder	Capacity	2022	160%	Giffen Sub - Install Bank 2 and new feeder
2023	GNA_253151102_Capacity	GIFFEN 1102	Feeder	Capacity	2023	176.77%	
2024	GNA_253151102_Capacity	GIFFEN 1102	FEEDER	Capacity	2027	119.93%	
2025	GNA_253151102_Capacity	GIFFEN 1102	FEEDER	None	None	76.86	
2022	GNA_253571112_Capacity	BARTON 1112	Feeder	Capacity	2022	130%	Airways - Install Bank 3 and Switchgear 3, and Airways 1109 and Airways 1110 Feeders
2023	GNA_253571112_Capacity	BARTON 1112	Feeder	Capacity	2024	131.78%	
2024	GNA_253571112_Capacity	BARTON 1112	FEEDER	Capacity	2024	114.95%	
2025	GNA_253571112_Capacity	BARTON 1112	FEEDER	None	None	96.99	

PG&E provided the following information regarding the status of the three planned projects in the table above. This is the first year that the IPE is performing this verification. The IPE plans to verify more planned projects in the future.

Giffen Sub - Install Bank 2 and new feeder

A large incoming agricultural customer was the reason for the overload in the 2023 and 2024 cycles but the customer cancelled their application during the 2025 planning cycle. Due to this, the project has been deferred indefinitely.

Buellton 1102 Mainline Tie UG Upgrade

Buellton 1102 Mainline Tie UG upgrade is associated with the overload of Buellton 1101 which was driven by a 1.8MW incoming load in the 2025 cycle; however, this load was

replacing a 750kW existing load, and if the load is modeled as only the 1MW difference, the forecast does not show a feeder outlet overload. This caused Buellton 1101 to show as overloaded in the 2025 forecast but this was in error and will be corrected. The cancellation of the project was initiated in August 2025. This was after PG&E completed its 2026 investment plan, so the project is still listed as a Planned Investment, but it will be reflected as cancelled in the updated Project Execution data.

Airways Bank 3 and Switchgear 3; Airways 1109 and Airways 1110 Feeders

This project was due to an overload on the Barton 1112 circuit due to a customer initiation request. The forecasted load was previously mapped to Barton 1112 but this year was incorrectly mapped to Airways 1109, which is the feeder that it will be connected to when the Airways substation project is completed (DUPR 7324 in 2025 report, DDOR 81 in 2024 report). This was in error and the new business will be remapped to Barton 1112. The project is still needed due to other needs identified in the 2025 cycle, so the scope has not changed.

The first project above (Giffen sub) serves as a good example of how PG&E determines whether planned investments identified in prior cycles are still needed and are the appropriate solution based upon planning assumptions for load and DER growth and other planning assumptions used in the current DPEP cycle. As mentioned earlier, the IPE plans to verify more such planned projects in the future.

6.3.2. Estimate Capital Cost for Candidate Deferral Projects - Step 14

As per the IPE Plan, the verification and validation of these steps were skipped in this cycle.

6.4. Processes to Develop Candidate Deferral List and Prioritize

6.4.1. Development of Candidate Deferral Projects - Step 15

As per the IPE Plan, this step is no longer required since there is no requirement for DIDF solicitation.

6.4.2. Development of Operational Requirements - Step 16

As per the IPE Plan, this step is no longer required since there is no requirement for DIDF solicitation.

6.4.3. Prioritization of Candidate Deferral Projects into Tiers - Step 17

As per the IPE Plan, this step is no longer required since there is no requirement for DIDF solicitation.

6.4.4. Calculate LNBA Ranges and Values - Step 18

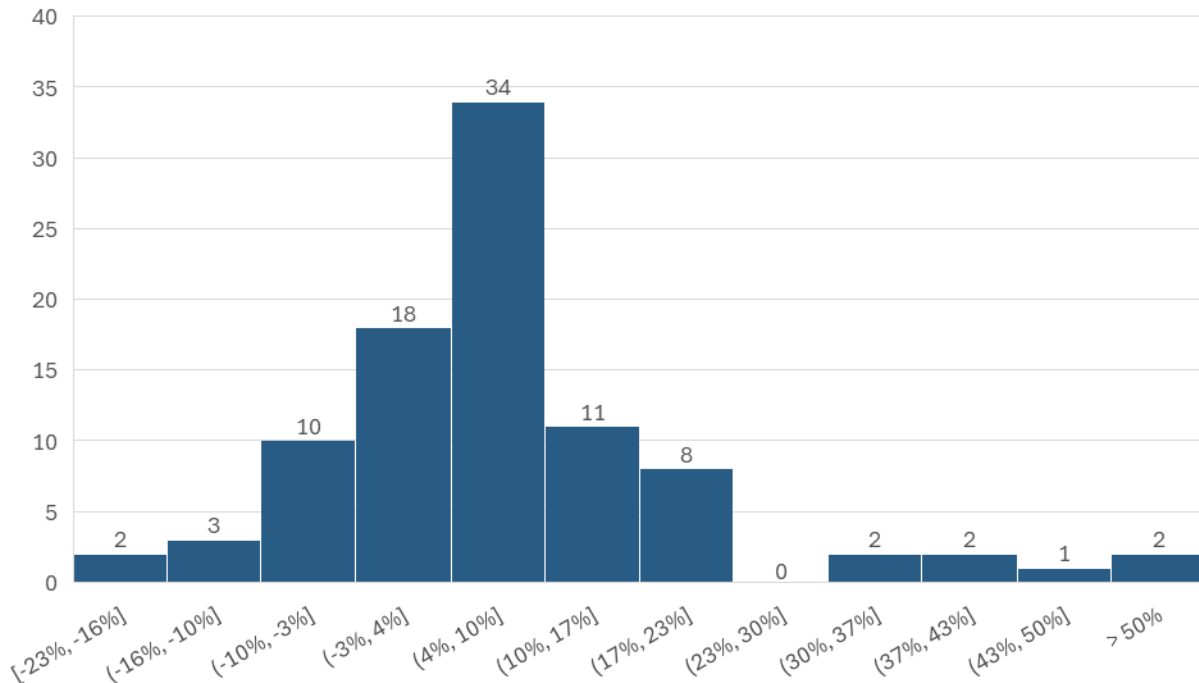
As per the IPE Plan, this step is no longer required since there is no requirement for DIDF solicitation.

6.4.5. Compare 2024 Forecast and Actuals at Circuit Level - Step 19

Purpose: To compare the recorded 2024 peak load (adjusted to 1-in-10) with the forecasted 2024 peak load obtained from the 2024 GNA-DDOR and analyze the results.

Verification: The IPE obtained the forecasted 2024 peak load (peak of the extreme profile) from the 2024 GNA report which was used for planning in the last cycle. PG&E also provided the actual 2024 peak load for all the circuits. Please note that the actual 2024 peak load was not adjusted to extreme weather conditions. The IPE made a comparison between the two for each feeder in PG&E's system as shown in Figure 6-18. This histogram shows the forecast error (forecast minus actual/forecast) from which it can be seen that there are more feeders where the forecast is higher than actuals. This is because we are comparing an extreme peak load forecast against actual peak load. The IPE plans to review this step in the next cycle and make adjustments as needed based on the availability of data to perform this verification as intended.

Figure 6-18: Comparison between Actual versus Forecasted 2024 Peak Load from Extreme Load Profile



6.5. Known Load Tracking Data and Metrics Calculation - Step 20

Purpose: To analyze the Known Load Tracking data and verify the calculation of the Known Load metrics.

Verification: The IPE obtained the 2025 Known Load Tracking data and the calculation of the metrics in Excel format and verified the calculations made by PG&E. This is discussed in Section 4 of this report.

6.6. Other IPE Work

Steps 21, 22, 23 and 25 no longer have to be verified as discussed in Section 1 of this report.

6.6.1. Respond to and Incorporate DPAG Comments - Step 24

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. However, there were several questions addressed to PG&E. The responses from PG&E can be found in Appendix B-1.

6.6.2. Treating confidential material in the IPE report - Step 26

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

6.7. Methodology Used for Prioritization of Planned Projects - Step 27

Purpose: To perform a verification and validation of the process used by PG&E to prioritize planned projects for execution.

Verification: In their DUPR report, PG&E provided information on how they prioritize the planned projects into three categories based on the nature of the project (for example, emergency and public safety projects) and whether the project is required for customer interconnection or general load growth. The IPE requested information on a few randomly selected projects in each priority category to verify that they were correctly assigned to that category. The IPE plans to investigate whether more projects can be included in the verification in future cycles.

Priority 1 Projects:

- DUPR 7188: New Feeders Goose Lake Substation – Planned Investment. There is a large new EV application on this circuit which will severely overload existing facilities Goose Lake Bank 1 and Goose Lake 2104. This project is prioritized Tier 1 because if the new load comes online without the project, the existing equipment would be overloaded beyond its emergency ratings, leading to heightened outage risk.
- DUPR 36483: Boronda Bank and Feeders – Planned Investment. Boronda Bank 1 is a 7MVA bank that has failed testing and is undergoing emergency replacement. Standard practice for PG&E's Asset Strategy department would be to replace the transformer with a bank of equivalent size. Due to load growth in the area, a larger 45MVA bank is being funded for capacity, which will address other forecast overloads like the grid need on Prunedale 1107. To meet the timeline of the emergency replacement, this capacity project must be prioritized immediately.

Priority 2 Projects:

- DUPR 19943 – Replace Britton Bank 1 & Install 2 feeders – Planned Investment. New business customers have applied for service from feeders supplied by Britton Bank 2, and they can't be served until this project is completed.

Priority 3 Projects:

- DUPR 22833 – Newburg_Rio Dell_TBD4 – Replace Overstressed Cutouts – Planned Solution. This project proposes to replace fused cutouts on Eel River 1103 and Rio Dell 1101 in Newburg DPA. This equipment does not have an overload under normal conditions, but is “overstressed”, meaning that it does not have sufficient rated fault current to withstand the available fault current indicated in PG&E’s CYME models.
- DUPR 36450 – Halsey Bank 1 Upgrade – Planned Solution. The overload addressed by this project is caused by forecasted spatial growth in the area, rather than a specific customer.

6.8. Project Execution Tracking Data and Metrics – Step 28

Purpose: To perform a verification and validation of the projection execution tracking data.

Verification: PG&E provided the project execution data as Attachment C of the DUPR report. This is the first cycle in which PG&E is providing this information. PG&E’s project execution data consists of additional information for all the Planned Investments and the Grid Needs that triggered these investments. All on-going projects (from this cycle and prior cycles) were included in this data. Below are IPE’s finding regarding this data.

- PG&E’s project execution data template contains all the fields proposed by the Energy Division.
- The Planned Project DUPR ID is automatically generated. The convention for developing the IDs changed in the last cycle. PG&E is also unable to tie the new DUPR IDs to the old DDOR IDs for the same project. Therefore, information on when the project was first identified is not available. However, going forward the IDs are expected to be the same and this will allow the tracking of projects in the future.
- PG&E also had several entries (row of data) for some of the planned projects, i.e., several rows of information with the same DUPR ID. This is because a project is not tracked at the DUPR ID level. A project would typically consist of sub-projects, each with a unique project management (PM) ID. For example, a project for upgrading a bank and adding a new feeder could be managed as two subprojects – a bank upgrade project and a new feeder project. As such, there is no one single start date and end date for a project – these exist only for the sub-projects.
- PG&E also proposed that, instead of listing the needs in the project execution table (which could lead to multiple rows of data due to multiple needs associated with a

project), the relationship between the planned project (DUPR ID) and the needs (GNA IDs) could be established in a different table.

- The IPE recommends that PG&E and the ED explore whether the project execution data should be tracked on a subproject (PM#) basis as opposed to the overall project (DUPR ID) basis, and whether the needs (GNA IDs) should be tracked in a different table.

Appendix A IPE Scope

Proposed IPE Scope of Work (Draft)

Proposed Changes to Current Scope of Work

Current IPE Scope	Recommendations
Step 1 - Collect 2024 Actual Circuit Loading and adjust/normalize for weather as needed	Keep in future cycles
Step 2 - Determine Load and DER Annual Growth on System Level	Keep in future cycles
Step 3 - Disaggregate Load and DER Annual Growth to the Circuit Level	Keep in future cycles
Step 3a - Check sum of all disaggregated load and DERs same as CEC IEPR System level values	Keep in future cycles
Step 4 - Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads not in CEC forecast)	Keep in future cycles
Step 5 - Convert DER growth load to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 5 - Convert peak of load to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 5 - Convert base forecast and weather normalization adjustment to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 6 - Derive net load profile	Recommend skipping unless process changed.
Step 7 - Determine net peak load	Recommend skipping unless process changed.
Step 8 - Adjust for extreme weather	Keep in future cycles
Step 9 - Initial comparison to equipment ratings to determine if ratings exceeded	Recommend skipping unless process changed.
Step 10 - Evaluate no cost solutions - incorporate load transfers, phase balancing, correct data errors	Recommend skipping unless process changed.
Step 11 - Comparison to equipment ratings to determine if ratings exceeded	Recommend skipping unless process changed.
Step 12 - Compile GNA tables showing need amount and need timing, etc (consistent with IOU's documented planning standards and/or planning process)	Keep in future cycles
Step 13 - Develop Recommended solution and generate list of Planned Investments (follow the IOU's documented planning standards and/or planning process)	Keep in future cycles

Step 14 - Estimate capital cost for candidate deferral projects	Eliminate
Step 15 - Development of Candidate Deferral Projects list through application of screens (timing and technical)	Eliminate
Step 16 - Development of operational requirements for CDO (daily, monthly, annually, etc)	Eliminate
Step 17 - Prioritization of Candidate Deferral Projects into Tiers	Eliminate
Step 18 - Calculation of LNBA ranges and values for all planned projects.	Eliminate
Step 19 - Compare 2023 Forecast and Actuals at Circuit Level [proposed change would increase from ~10% of circuits to include all circuits if possible]	Keep in future cycles
Step 20 - Analyze known load tracking dataset and verify the calculation of known load metrics	Keep in future cycles
Step 22 - Review implementing of planning standard and/or planning process	Eliminate
Step 23 - Review list of internally approved capital projects	Eliminate
Step 24 - Respond to and incorporate DPAG comments	Keep in future cycles
Step 25 - Track solicitation results to inform next cycle	Eliminate
Step 26 - Treating confidential material in the IPE report	Keep in future cycles

Proposed Additions to IPE Scope of Work

Decision	New items	IPE Scope
3.1-Allow Utilities to Use Bottom-Up, Known Load Data to Determine Growth	Definition of Reliable Bottom-up Data (as well as, Customer energization Request, Known Load, Pending Load etc.) (Page 42) Note: Decision 3.1 allows Utilities to use reliable bottom-up data to estimate total load growth in a given year, even if it exceeds the forecasted load growth based on the IEPR for that year. Further, this decision directs that, in years without reliable bottom-up data, total growth should correspond to the forecast amount and not be adjusted downwards.	Annual verification and validation for the use of known loads already being performed as a part of Step 2 of the current V&V process. No new steps required.
3.2 – Require Utilities to Improve Method for Setting Caps on Load Growth from IEPR data.	IOU to work with CEC and CPUC to staff in developing proposals for the method and accounting for discrepancies between the system and circuit level. (Page 43) Decision 3.2 further focuses on developing proposals for the method and accounting for discrepancies between the system and circuit level (forecasts). The forecast at the system level (IEPR) is a coincident peak load forecast and is not necessarily equal to the sum of the peak loads on all the circuits. So, a methodology needs to be devised to develop circuit level forecasts that takes this into account. This decision approves, with one modification, the recommendation to require Utilities to submit Advice Letters proposing how they will improve their methods for setting caps on load growth based on the IEPR forecasts and other data. Utilities shall file Tier 3 Advice Letters. (Page 47)	Verify and validate IOUs' use of methodology for accounting for discrepancies between the system and circuit level load forecasts in the DPP. Annual starting 2025-2026 cycle. Annual verification and validation of methods for setting caps on load growth from IEPR data already covered under Step 2 of the current V&V process. No new steps required.
3.4 – Require Utilities to Expand the DPP Forecast Horizon to Align with IEPR and Expand the Planning Horizon to 10 Years.	To ensure transparency, utilities shall provide a description of the thermal capacity evaluation methodology in the annual GNA report (Page 55)	No new steps required to verify the expanded DPP planning horizon. The current V&V will be extended from 5 years to 10 years. Annual starting 2025-2026 cycle.

3.5 – Require Utilities to Use Scenario Planning to Improve Forecasting and Disaggregation	Workshops to develop scenario planning methodology and process. (Page 59) Utilities shall develop scenario planning capabilities that enable them to: (1) analyze multiple forecasts; (2) identify capacity deficiencies for each scenario and report them in the annual GNA; and (3) develop one investment plan informed by the multiple scenarios and reported in the DDOR or successor filing. (Page 61)	Attend workshop. One Time. Estimated Q1 2025 Verify and validate each DPP scenario and how utilities create one investment plan informed by multiple scenarios in the annual DPEP. Annual starting 2025-2026 cycle. • Develop draft IPE Plan for V&V of scenario planning – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026
3.6 - Require Utilities to Improve Disaggregation Methodology for Load Growth	Require Utilities to Improve Disaggregation Methodology for Load Growth (Page 62) This decision adopts the recommendation to require Utilities to improve disaggregation methodologies for load growth and distributed energy resources but delays implementation to the 2027 GNA and the 2026-2027 DPP cycle. To track progress toward improved disaggregation in the interim, Utilities shall report annually in the GNA on the development of advanced disaggregation methodologies and present these at the annual Distribution Forecast Working Group workshops or successor workshops. (Page 65)	Verify and validate the improved disaggregation methodology. Annual starting 2026-2027 cycle. Q3 2027. • Develop draft IPE Plan for V&V of improved disaggregation methodology – Q2 2027 • Finalize IPE plan – Q3 2027 • Perform V&V Q4 2027
3.7 - Require Utilities to Create Pending Loads Category in the DPP	Utilities are directed to provide pending load data and include the source of the data in the annual known load tracking filing, as part of the GNA/DDOR or successor report and orally reported during the DPAG or successor workshop (Page 76)	Attend workshop. One Time. Estimated Q1/Q2 2025 Verify and validate pending load data and source in annual reports and DPAG or successor workshop. Annual starting 2025-2026. • Develop draft IPE Plan for V&V of Pending Loads – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026

3.8 – Require Utilities to Develop Prioritization Methods Beyond the Current Consideration of Project Need Dates	Utilities to report how projects identified throughout the distribution planning horizon have been prioritized for execution. This decision also requires inclusion of this information in the annual GNA/DDOR or a successor report instead of the previously required Advice Letter (83)	Verify and validate the process used by utilities to prioritize projects for execution. Annual starting 2024-2025 cycle. • Develop draft IPE Plan for V&V of prioritization methodology – Q2 2025 • Finalize IPE plan – Q3 2025 • Perform V&V Q3 2025
3.9 – Require Utilities to Consider Distribution Planning Results in Other Distribution Work	Utilities to consider distribution planning results in other distribution work aka Integrated planning (Page 83) A workshop shall be held by Utilities during the third quarter of 2025 to present Utility proposals for integrated planning and solicit feedback from stakeholders on issues presented, including cost containment considerations. A second workshop shall be held by Utilities no more than eight weeks following the first workshop to present updated proposals based on feedback from the first workshop. (Page 86)	Attend workshop. One Time. Estimated Q3/Q4 2025. Verify and validate that integrated planning projects meet the established requirements. Annual starting 2026-2027. • Develop draft IPE Plan for V&V of integrated distribution planning – Q2 2027 • Finalize IPE plan – Q3 2027 • Perform V&V Q3 2027
3.11 – Require Utilities to Prepare a Load Flexibility DPP Assessment	Require Utilities to Prepare a Load Flexibility DPP Assessment. (Page 98)	Review EIS Part 2 studies and attend workshop. One Time. Estimated Q1 2026.
3.15 – Require Utilities to Include Metrics to Evaluate Equity in Utility Distribution Plan Reporting	Require Utilities to Include Metrics to Evaluate Equity in Utility Distribution Plan Reporting (Page 119) The Commission clarifies that while these metrics are requested for evaluation purposes, there is no framework wherein equity metrics are used for forecasting or planning distribution. The intention of this proposal is an annual evaluation of equity in distribution planning and does not involve modifying the planning process based on equity considerations. (Page 123)	Support the ED and the IOUs in finalizing and standardizing the tracking and reporting of the Equity Metrics. One Time. Estimated Q2 2025. Verify and validate equity metrics calculated by the utilities and reported by the utilities annually. Annual starting 2025-2026 DPP cycle. • Develop draft IPE Plan for V&V of equity metrics – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026

3.16 – Require Utilities to Include Metrics to Track Project Execution in Utility Distribution Plan Reporting	Require Utilities to Include Metrics to Track Project Execution in Utility Distribution Plan Reporting (Page 123) *also see Table 12 and Table 13. Table 12 * Additional Details for All Ongoing and Prior Three Years Completed Distribution Capacity Projects Table 13* Additional Project Execution Tracking Data	Support the ED and the IOUs in finalizing and standardizing the tracking and reporting required to track project execution based on Table 12, 13, and the requirements of R24-01-018 (Appendix B - Decision Establishing Target Energization Time Periods And Procedure For Customers To Report Energization Delays). One Time. Estimated Q2 2025 Verify and validate the project execution data and metrics submitted by the utilities. Annual starting 2024-2025 DPP cycle. • Develop draft IPE Plan for V&V of project execution metrics – Q2 2025 • Finalize IPE plan – Q3 2025 • Perform V&V Q3 2025
3.18 - Require Utilities to Facilitate Better Coordination and Data Sharing Between the DPP and Transportation Electrification Planning	Require Utilities to Facilitate Better Coordination and Data Sharing Between the DPP and Transportation Electrification Planning (Page 135)	Verify and validate how TEPP outputs are used in DPP. Annual starting 2025-2026 earliest. • Develop draft IPE Plan for V&V of TEPP coordination – Q2 2026 • Finalize IPE plan – Q2 2026 • Perform V&V Q3 2026

Appendix B DPAG Survey and Comment Responses

PG&E solicited feedback from the DPAG during their DPAG meeting on September 17, 2025 and also solicited comments by email. PG&E received written comments provided by Stakeholders on September 26, 2025 and provided their response on October 6, 2025. This response is attached below.

PG&E Responses to DPAG Follow-Up Questions

Energy Division Questions

1. (All IOUs) For future DPAG meetings, Energy Division would prefer to host the meeting platform to allow recordings. The recordings will be used within CPUC and shared elsewhere only with the IOUs approval. ED will also provide the recordings to the IOUs and IPE. Please let us know your thoughts on this?

PG&E Response:

Consent is required. So long as it's disclosed that the CPUC will be recording to all participants and all material shared during the meeting is public, PG&E has no concerns. However, an additional consideration is that individual employees or participants have a right to their own privacy and may opt not to participate.

2. (PG&E) For known loads with the same unique identifier, does the "Load Amount (MW)" value, reflect the capacity for each individual project with that unique ID or does this value reflect the capacity for all projects with the same unique ID? If it represents all projects, is it the coincident load of all the projects with the same unique ID?

PG&E Response:

For known loads completed projects (GNA Appendix I.2) the load amount (MW) represents the load of the service application related to the unique identifier. However, the field actual load amount (MW) represents the load of each individual SPID. There is only one service application per unique identifier, whereas there can be multiple SPIDs associated with each service application (e.g. a single service application for a residential subdivision containing multiple homes). Load Amount is an estimate of the coincident load of all SPIDs associated with the service application.

For known loads on-going projects (GNA Appendix I.1) the expected load amount (MW) represents the individual load of each project associated with the same unique identifier.

CalAdvocates Questions

1. **Grid Needs:** PG&E identified the following number of grid needs in its 2021, 2022, 2023, 2024, and 2025 GNAs.

Anticipated Need Date					Total
2021	2022	2023	2024	>2025	
276	66	25	17	8	392

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

Anticipated Need Date					Total
2023	2024	2025	2026	>=2027	
358	90	61	31	33	573

Anticipated Need Date					Total
2024	2025	2026	2027	>=2028	
659	105	54	26	23	867

Anticipated Need Date					Total
2025	2026	2027	2028	>=2029	
713	218	66	39	31	1067

- a. Which key factors in PG&E's GNA are driving the overall increase in grid needs across GNA cycles (e.g., from 392 in PG&E's 2021 GNA to 1,067 in PG&E's 2025 GNA)?

PG&E Response:

Not all GNA cycles are comparable as PG&E has significantly improved its planning tools from 2021 to 2025, as reported in their respective year's GNA reports. It is possible that an increase in known loads over this period may be driving increased grid needs.

- b. What key factors in PG&E's GNA are driving the increase in number of grid needs in the same year across GNA cycles (e.g., for year 2025, increasing from 8 grid needs in PG&E's 2021 GNA to 713 grid needs in PG&E's 2025 GNA)?

PG&E Response:

The key factor driving would be the count of new applications, connections, deferrals, and cancellations of new business applications, especially in the first year of the forecast. These are general observations, and PG&E does not have a specific analysis for it.

- c. On slide 40 of its DPAG presentation, PG&E shows a table with the number of forecasted grid needs from 2025-2037 for two scenarios: the "Base Forecast After Projects" and the "Alternative Forecast". During the DPAG presentation, PG&E explained that some grid needs remain from the base forecast even after projects are completed. Why do a significant number of grid needs remain even after inclusion of planned investments?

PG&E Response:

In its annual capacity study, PG&E requires distribution engineers to design projects that will resolve bank and feeder overloads in the initial five-year window of the forecast (2025-29). Overloads arising after 2029 may not be resolved by these projects.

Furthermore, an overload arising in the initial years of the forecast may be resolved by a project that the engineer estimates will be complete in a later year, e.g. a 2029 project that resolves a 2027 overload. Once the project is identified through the study and initiated, PG&E works with its execution partners to

identify a realistic delivery schedule, and pursues bridging solutions if the overload will indeed arise before the project is complete. Therefore, the number of remaining overloads reaches a minimum at the end of the solutioning window, year 2029, explaining higher overload counts in 2025-28.

For the 70 overloads remaining in 2029, the principal cause is new overloads that arose due to new service applications that were received between the start of the annual capacity study (January 2025) and the compilation of the report (May 2025). Engineers were not required to design mitigations for these emergent overloads – they will be addressed via new business reviews or the subsequent year’s study.

2. **Planned Investments:** PG&E’s planned investments have increased noticeably in the 2025 GNA-DUPR cycle, corresponding with early implementation of pending loads in distribution planning. PG&E identified the following planned investments in its 2021, 2022, 2023, 2024, and 2025 GNAs.

In-Service Date						Total
2021	2022	2023	2024	2025	2026	
59	90	60	34	9	2	254

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

In-Service Date					Total
2023	2024	2025	2026*	2027	
36	22	21	16	1	96

*Includes Carlotta Bank 2 (Partnership Pilot project)

In-Service Date					Total
2024	2025	2026	2027	2028	
28	94	235	26	35	418

In-Service Date						Total
2025	2026	2027	2028	2029	2030	
119	146	46	28	7	1	347

- a. What key factors in PG&E’s GNA are driving the overall increase in planned investments across GNA cycles (e.g., from 254 in PG&E’s 2021 GNA to 347 in PG&E’s 2025 GNA)?

PG&E Response:

PG&E notes that it will be re-filing its 2025 Planned Investment list, and that the numbers above will change. 2021 and 2022 data included both planned investments and planned solutions, and 2023 onwards planned investments and planned solutions were published separately. Therefore, the drop from 2022 to 2023 may be explained by the change in classification. Furthermore, substantial improvements in the planning tools were occurring during this time. For the planned investments from 2023 to 2025, the increase may be attributable to increased funding for projects rather than Planned Solutions.

Please note that PG&E does not agree with PAO's statement that: "PG&E's planned investments have increased noticeably in the 2025 GNA-DUPR cycle, corresponding with early implementation of pending loads in distribution planning." It is unclear if PAO is confusing the use of pending loads in the Alternative Forecast, which was not used in identification of Planned Investments.

- b. GNA after disposition of PG&E's pending loads advice letter:
 - i. How will PG&E align its 2025 GNA with any future GNA that is potentially subject to different pending load rules?

PG&E Response:

PG&E does not plan to make any changes to its 2025 GNA. PG&E plans to implement the Pending Loads Framework in its 2026 GNA, subject to Resolution.

- ii. What happens to any planned investments identified in the 2025 GNA if the disposition of PG&E's pending loads advice letter results in a change to the treatment of pending loads and scenario planning within PG&E's distribution planning framework?

PG&E Response:

PG&E notes that it will be re-filing its 2025 Planned Investment list, as explained at the DPAG. However, PG&E does not plan to make any changes to its 2025 GNA or DUPR upon resolution of the Pending Loads and Scenario Framework Advice Letters. PG&E plans to implement the Pending Loads Framework and Scenario Planning in its 2026 DPEP, subject to Resolution. It is unclear if PAO is confusing the provision of an Alternative Forecast in the 2025 GNA, which was not used in identification of Planned Investments.

- 3. **Incremental Known Loads:** In its GNA, PG&E states, "PG&E does not use a methodology to categorize loads as incremental vs. embedded." Furthermore, PG&E states that it deducts known loads from the annual IEPR forecast, then adds them back as local load adjustments to maintain consistency with the IEPR forecast. Also, PG&E explains that it "reconciles known load applications with the IEPR quantities to prevent

exceeding the total load growth over the forecast, although individual years may vary.”

- a. Does PG&E apply any known loads as incremental to the IEPR forecast in *individual* years (i.e., can known loads exceed the IEPR forecast in individual years, though not over the forecast horizon)?

PG&E Response:

Yes, known loads can exceed the IEPR forecast in an individual year, though it does not over the forecast horizon. PG&E does not classify this as “incremental” to the IEPR. Note this is for the Base forecast (see below for treatment in the Alternative forecast).

- b. Why does PG&E not use a methodology to categorize loads as incremental vs. embedded?

PG&E Response:

Known loads exceed the IEPR forecast in the early years, but the total MWs (over the forecast horizon) does not exceed the IEPR, therefore the known loads are not considered to be incremental. Therefore, PG&E has not created a methodology to categorize loads as incremental vs embedded, but Resolution of the Pending Loads Framework may result in changes for the 2026 DPEP.

4. **Incremental Pending Loads:** In its GNA, PG&E states it “did not categorize the Pending Loads based on certainty or other criteria.” Also, PG&E’s Alternate Forecast Scenario with pending loads “produced a higher volume of post project grid needs when compared to the base case, especially in the mid-term and long-term.” PG&E explains that it “[i]mported Pending Loads into LoadSEER as Load Adjustments.”

- a. By importing pending loads into LoadSEER as load adjustments, does PG&E apply pending loads as incremental to the IEPR forecast in the Alternative Forecast Scenario?

PG&E Response:

Yes, Pending Loads were added to the IEPR for the Alternative Forecast Scenario (and not netted out over the horizon). The treatment of Pending Loads was thus different than in the Base Forecast, and may be applied differently in the 2026 DPEP subject to Resolution. In other words, PG&E does have “incremental” loads (including Pending Loads and Known Loads) beyond the IEPR in the Alternative Forecast, both within an individual year and over the total forecast.

- b. PG&E states that “[p]lanned system upgrades and feeder-level load transfers that were previously developed to mitigate the existing overloads and other constraints identified during the Base Case Scenario were applied.” Does this mean that the additional grid needs identified in Table 33 are after PG&E has completed the planned investments from the Base Case Scenario?

PG&E Response:

Yes, that is correct. Refer to PG&E's response to q1c above for more details about Base Forecast After Projects grid needs.

- c. Why are there significantly more grid needs for the Alternate Forecast Scenario in the mid-term and long-term relative to the short-term?

PG&E Response:

Because of the addition of Pending Loads, and not netting out the loads from the total IEPR growth (which is different than the Base as explained above).

- d. In slide 40 of PG&E's DPAG presentation, are the additional grid needs in the Alternative Forecast vs. the Base Forecast After Projects solely attributable to the inclusion of pending loads? If not, what additional factors drive the increase?

PG&E Response:

No. They are because of the Pending Loads *and* the change in the way loads are not netted out over the horizon versus the IEPR as explained above.

- e. As pending load confidence levels are a key topic of discussion, how does PG&E plan to evaluate pending load confidence levels in its future distribution planning?

PG&E Response:

Please see the recommendation in the advice letter AL-7630.

- f. On slide 37 of its DPAG presentation, PG&E references sources of pending loads.
 - i. When did PG&E initiate the studies mentioned in slide 37?

PG&E Response: PG&E does not have any study data used in the 2025 GNA.

- ii. What questions did PG&E ask in its Capacity Planning Questionnaire?

PG&E Response:

Here is a link to the questionnaire : [Long Term Development plans](#) for reference of all questions.

- iii. How did PG&E validate the pending load data?

PG&E Response: The only validation performed on the data was for completeness. PG&E did not validate the Pending Loads Data for the Alternative Forecast. The actual validation will be determined per Resolution of AL-7630 in future cycles.

- 5. **Known Load Cancellations and Deferrals:** PG&E states that it deferred 77% of known loads (#) relative to the known loads present in both 2024 to 2025 cycles. Additionally, PG&E states that it deferred 55% of the known load amount (MW) that appeared in both 2024 and 2025 cycles.

- a. What are the reasons PG&E or a customer would defer a known load?

PG&E Response: A customer might defer a known load due to changes in their development plans (e.g., changes in financing, permitting, business plans, etc.). PG&E might defer a known load to reflect a customer delay, scope changes, delays to the

energization or upstream capacity work (e.g., due to permitting, long lead time materials, funding, etc), or other reasons.

- b. What are the reasons PG&E or a customer would cancel a known load?

PG&E Response: Distribution planning does not have feedback from customers on their load application cancellation, but customer cancellations are likely due to changes in their development plans (e.g., changes in financing, permitting, business plans, etc.). PG&E may cancel loads due to non-responsive customers to reflect that their projects are no longer being requested.

- c. How often is a known load deferred when a planned investment that addresses that known load is already in-flight?

PG&E Response: PG&E does not have the analysis to answer this question.

- d. How does PG&E account for the uncertainty of known loads in its planning?

PG&E Response: It is important to note that PG&E continuously adjusts its plan, and individual capacity projects are re-assessed throughout its project life cycle. In other words, a Planned Investment identified in a given distribution plan will be re-visited as it enters various stage gates. Therefore, changes in the known load (as will all load) will be considered at various points for the project to account for uncertainty inherent in the planning process.

- e. Does PG&E track deferrals for MDHD loads? If so, what percentage of the TE load deferrals are MDHD loads?

PG&E Response: PG&E does not have the analysis to answer this question.

- f. Is there any correlation between rate of deferral and size of the load project?

PG&E Response: PG&E does not have the analysis to answer this question.

6. **Distribution Capital per Customer Metric:** PG&E reports the following spending amounts in its 2021, 2022, 2023, 2024, and 2025 GNAs/DDORs/DUPRs:

GNA Year	Distribution Capital per Customer
2021	\$470
2022	\$396
2023	\$503
2024	\$620.92
2025	\$679.45

- a. What key factors are driving the overall increase in PG&E's distribution capital per customer?

PG&E Response:

PG&E has not done an analysis to determine the factors driving a change in the Distribution Capital per Customer Metric. Further details on the calculation are provided below.

PG&E surmises there are many factors for this change, including:

- Labor and material costs have increased due to inflation. One index that shows the impact of inflation is the California Construction Cost Index.¹
- Potentially different or more complex customer applications
- New requirements for underground mapping of existing assets (base mapping)
- New and more detailed design requirements for third-party permitting
- More pole replacements than previously due to age and new standards
- Increased third-party permitting fees
- Increased paving and restoration requirements from agencies
- ADA curb ramp compliance requirements which require changes to in-flight work
- More night work requirements by cities which requires overtime premiums for labor.

The Distribution Capital per Customer metric is based on the total imputed authorized GRC capital amount (electric) in PG&E's most recent GRC (2020 or 2023) divided by the number of electric meters as a definition of number of customers. Including both factors used to compute the Distribution Capital per Customer as reference.

GNA Year	Distribution Capital per Customer	GRC year	GRC electric distribution Capital imputed authorized amount (\$)	Number of electric meters in service
2021	\$470	2020	\$2,626,000,000.	5,587,598
2022	\$396	2020	\$2,217,676,000	5,587,595
2023	\$503	2023	\$2,854,181,822	5,677,375
2024	\$620.92	2023	\$3,549,754,000	5,716,913
2025	\$679.45	2023	\$3,916,505,502	5,764,190

¹ <https://www.dgs.ca.gov/RES/RESOURCES/Real-Estate-Services-Division-Resources-List-Folder/DGS-California-Construction-Cost-Index-CCCI>

Appendix C IPE Verification and Validation Plan



Final IPE Plan for 2025-26 DIDF Cycle - Pacific Gas and Electric

Submitted to California Public Utility Commission

August 15, 2025

Submitted by:
Resource Innovations
Sundar Venkataraman
Barney Speckman

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1 Introduction and Background

The Independent Professional Engineer (IPE) services for the 2025-26 Distribution Investment and Deferral Framework (DIDF) Process is per CPUC decision (D.18-02-004), Administrative Law Judge's Ruling (R. 14-08-013) issued May 7, 2019, and Administrative Law Judge's Ruling Modifying DIDF (R.14-08-013) issued April 13, 2020 which defined the original IPE scope of work (Appendix A). This original scope of work has been modified by subsequent orders and rulings, as well as updates to the scope of work made by the Energy Division on March 4, 2025 which modifies the original scope and includes additional scope items to support the High DER proceeding. This updated scope of work is included as Appendix B.

The schedule for the IPE Verification and Validation (V&V) process in this cycle will follow the Administrative Law Judges' ruling setting schedule for the 2025-2026 Distribution Investment Deferral Framework cycle issued on March 6, 2025 and is shown below:

- Draft IPE Plan due week of May 19, 2025.
- Final IPE Plan due August 15, 2025.
- IPE Preliminary Analysis of GNA/DUPR Data Adequacy for all three IOUs due September 5, 2025.
- IPE Distribution Planning Advisory Group (DPAG) report for each IOU presenting GNA/DUPR review findings and Verification & Validation outcomes due November 6, 2025.
- IPE Post DPAG Report covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements due March 16, 2026.

The draft IPE Plan for 2025/2026 DIDF cycle was distributed to stakeholders on May 23, 2025 to facilitate stakeholder comments prior to finalizing the IPE Plan.

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 necessary planned solutions and investments. 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 implementation. One of the core purposes of the plan is to answer the question - Are the IOUs identifying every project that will be needed to provide the new or additional service requirements of their customers early enough to provide the service in a timely manner?

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, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level, adjusted for known and pending loads and then used to determine if there is an overload or other issue during the planning period. For circuits that have a need, the best planned investment is selected.

3 IPE Plan

The heart of the IPE Plan is the material contained in Table 3-1. 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:

- 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 2025/26 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 one or both reviews, an indication is provided in most cases, 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 utilities' numerical 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.

3.1 Revisions to the IPE Plan for this Cycle

As per the updated IPE Scope of Work, the following verification and validation steps will be skipped in this cycle since PG&E has confirmed that the business process they used in these steps are the same as those used in the prior cycle.

- Steps 5-7 - Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load
- Steps 9-11 - Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings after No Cost Solutions
- Step 14 - Development of capital costs for the planned investments.

These steps are not being removed permanently from the IPE scope. In addition, as indicated earlier, these steps are only skipped in this cycle since the utility states that the business process for these steps have not changed from the prior cycle. These steps have been included in the table below and will be followed only if the process used by the utility for this cycle is different than used in the previous cycle.

The Energy Division has requested that Step 13 (Development of Planned Investments using Planned Standards) be retained in this cycle to verify and validate the process used by the utilities to determine whether a planned project identified in a previous cycle is still needed based on the results of the current cycle. We will finalize the data and information that needs to be gathered in this step once we have a discussion with the utilities about their process.

In addition, the verification and validation of the following steps related to the identification and prioritization of Candidate Deferral Opportunities (CDOs) will be skipped in this cycle.

- Step 15 - Development of Candidate Deferral Projects
- Step 17 - Prioritization of Candidate Deferral Projects into Tiers
- Step 16 - Development of operational requirements for CDOs
- Step 18 - Calculation of LNBAs for planned projects

In addition, based on inputs from the ED, the following steps will be skipped in this cycle.

- Step 21 - Review plan for changes to the planning process for the next cycle
- Step 22 - Review implementing of planning standard and/or planning process.
- Step 23- Review list of internally approved capital projects.

- Step 25 - Track solicitation results to inform next cycle.

Two new steps have been added specifically for this cycle referred to as Steps 27 and 28. An outline of the V&V plan for these steps have been included in the draft plan. The IPE will finalize the data and information that needs to be gathered in this step once we have a discussion with the utilities about their process related to these steps.

- Step 27 – Review Methodology used for Prioritization of Planned Projects
- Step 28 - Review Project Execution Tracking Data and Metrics

The IPE V&V steps for 2025/26 DIDF Cycle are shown starting on the following page.

Table 3-1: PG&E IPE Review for 2025/26 DIDF Cycle

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
PROCESSES TO DEVELOP STARTING POINT LOAD, SYSTEM LEVEL VALUES AND DISAGGREGATE TO CIRCUIT LEVEL				
1	Collect 2024 actual circuit loading and adjust for weather as needed (Note: the V&V for Step 1 will be combined with Step 8)	Perform Verification for at least 10 circuits mutually selected by PG&E and the IPE; Verify the following: • Development of the AMI data for these circuits • Development of extreme, typical and low load profiles in LoadSEER. Roles: PG&E to provide a description and demonstration of the processes used for developing extreme, typical and low load profiles in LoadSEER. PG&E to also provide data for 10 sample circuits. PG&E to demonstrate how its approach is comparable to using a 1-in-10 year approach to adjust historical data to account for the potential for extreme weather conditions.	PG&E to provide the process description (specified in the data/information column) by mid to end-July.	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 DIDF cycle. ▪ Development of 8760 profiles for circuits using aggregate AMI data ▪ Process for developing extreme load profiles using Method 2 and Method 3 etc.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 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 demonstrate how its approach is comparable to using a 1-in-10 year approach to adjust historical data to account for the potential for extreme weather conditions.		- Any changes to the load profile development process since the last cycle. Data/Information: - Number of feeders and banks in total using Method 2 and Method 3 base load profiles. - AMI data for 10 sample circuits for the years 2021-2024. - Extreme, typical and low load profiles for the sample circuits that are used in the DPEP Demonstration: PG&E to provide a demonstration of the processes used for peak load collection, scrubbing,

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
				normalization, correction for extreme weather, as well as the development of the planning load profiles in LoadSEER if the process is different from the one used in the prior cycle.
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 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 to provide the data/information (specified in the Data/Information Requirements column), except known load data by mid to end of July. Known load data to be provided by August 15. PG&E to provide the process description (specified in the	PG&E to provide the data/information requested below. IPE to provide the data/information provided in the last cycle as a reference. 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

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		PG&E to provide 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. 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.	Data/Information Requirements column) by mid to end of July.	load growth by customer class. - Excel files containing the zonal forecasts for EV, PV, and ES. Excel file containing busbar forecasts for EE. - All known load additions including amount(s), circuit name, class, type of load and in-service date that we used for determining the amount of CEC IEPR load forecast to disaggregate to circuits. Process Description: - PG&E to provide a description of the process 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

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
				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 DIDF cycle. For example, if PG&E is using the hourly files from CEC in developing the forecast for DERs which is different from previous cycles.
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 mid to end of July. 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: PG&E to provide circuit-level load growth by year and by

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 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 8760-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 mid to end of July.	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 and MHDV). 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. - PG&E to indicate if any of these processes have

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
				changed since the last DIDF cycle.
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. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		Data needed for this step is provided in Step 3
4	Add known loads to circuit level forecasts	Perform V&V for a subset of circuits selected by the IPE. Roles:	PG&E to provide the requested information by Mid July.	PG&E to provide circuit-level known load additions by customer class and type for all circuits that add up to the total

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		PG&E to provide circuit-level known load additions by customer class and type for all circuits that were used to make the adjustments to the CEC IEPR forecast in Step 2. PG&E to also provide information, if applicable, on how forecasted loads (pending loads) are used in the planning process. Verification: IPE to verify that the sum of the circuit-level known load additions by customer class matches with the system-level values in Step 2. IPE to verify that the circuit-level known load additions for selected circuits match with those used in LoadSEER (Starting with Step 5). Validation:		known load values for each year used in Step 2. PG&E to also provide information, if applicable, on how forecasted loads (pending loads) are used in the planning process.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
5	Convert peak growth to 8760 profile as needed [will be skipped since process is unchanged from the last cycle]	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E. Roles: PG&E to provide 8760- 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 8760 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) except f) by first week of August. Data item f) to be provided by first week of August.	PGE&E to provide the 8760 hourly load profiles for selected circuits as shown below: a) (Not required for this cycle) One or more circuits that have sensitivity to temperature and one or more that have sensitivity to water allocation b) (Not required for this cycle) 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) (Not required for this cycle) 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 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		e) (Not required for this cycle) 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 8760 profile as needed [will be skipped since process is unchanged from the last cycle]	Perform V&V for 10-15 circuits mutually selected by the IPE and PG&E in Step 5. Roles: PG&E to provide 8760- 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 mid-July	Data/Information: PG&E to also provide 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 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		Verification: IPE to verify that the 8760 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 [will be skipped since process is unchanged from the last cycle]	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.		No additional data/information is required.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
7	Determine net peak load [will be skipped since process is unchanged from the last cycle]	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 8760 hourly net load profile developed in Step 6. Validation:	PG&E to provide the data requested (specified in the Data/Information Requirements column) by mid-July.	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 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
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 [will be skipped since process is	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:	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.
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IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
	unchanged from the last cycle]	IPE to compare the net peak load from Step 7 before any load transfers are simulated and compare it with the rating 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 [will be skipped since process is unchanged from the last cycle]	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	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 if the process is different from the one used last year. Data/Information: PG&E provides transfer information for each circuit involved. This includes the pre and post loading for the planning

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		the PG&E description and the result are the same as used in subsequent steps in 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.		period for all circuits involved or impacted by the transfers.
11	Final comparison to station outlet ratings or other circuit limiting factor to determine if ratings exceeded [will be skipped since process is unchanged from the last cycle]	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		Data already provided in Step 5.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		calculated by PG&E and included in the GNA). 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:	PG&E to provide the planning standards, if different than provided in the 2024-25 DIDF cycle in the first week of September. 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 2024-25 DIDF cycle.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		

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. This step will include two processes – 1) the process that PG&E used to confirm that planning solutions or investments identified in prior cycles are still needed and are the appropriate solution based upon planning assumptions for load and DER growth and other planning assumptions used in the current DPP cycle; 2) the process to identify the current set of solutions and planned projects identified in the DPP. For this process we request PG&E include a written description of the process that it uses, a demo of the process and supporting data	PG&E to provide a description of the process in early September. Demonstration to be completed by early September.	(1) Description of process used to confirm that planned solutions and planned investments identified in earlier DPP cycles are still needed and the appropriate solution or investment when considered using the current DPP load, DER and other DPP assumptions. (2) Description of process used to develop proposed planned project to address identified need for distribution projects if process is different from the last cycle.
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IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		for selected projects jointly selected by the IPE and PG&E. 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. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
14	Estimate capital cost for each Candidate Deferral Project (Skipped in this cycle)	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 provide the accuracy range for each project.¹ PG&E to provide supporting cost information for a subset of projects.	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.

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 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		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 DEFERRAL LIST AND PRIORITIZE

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.	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
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IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
	(Skipped, no longer required)	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.		
16	Development of operational requirements (daily, monthly annually etc.) (skipped, no longer required)	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,	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 amounts, 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 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		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: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
17	Prioritization of candidate deferral projects into Tiers (skipped, no longer required)	Perform Verification on prioritization process for all candidate deferral projects including process to develop list of projects that PG&E recommends proceed to RFO or PP procurement. Roles: PG&E to provide active version (not just values) of the Excel spreadsheet that	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 PP projects.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		calculates the metrics and their components used to rank the Candidate Deferral Projects overall and into tiers. Note, in the 2021/2022 DIDF 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 procurement using the PP procurement program. Verification: IPE to verify that spreadsheet calculations are consistent with the description of the standard IOU prioritization/ranking and tier placement methodology and PP ranking/selection process. IPE to verify that Excel results match the recommended Candidate Deferral Projects overall rankings and placement		Description of the IOU standardized prioritization metrics, components and tier ranking methodology and process and PP ranking selection process

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		into tiers and recommended for RFO 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.		
18	Calculate LNBA ranges and values for all planned investments (skipped, no longer required)	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:	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 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		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: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
19	Compare 2024 forecast and actuals at circuit level	Perform comparison of forecasted and actual loads for all circuits if data for all circuits can be provided. Roles: PG&E to provide recorded 2024 peak load (adjusted to 1-in-10) used in the 2025-26 DIDF. Verification: IPE to compare the recorded 2024 peak load (adjusted to 1-in-10) provided by PG&E with the forecasted 2024 peak load	PG&E to provide the requested information by early October.	PG&E to provide recorded 2024 peak load (adjusted to 1-in-10) for all circuits, if possible.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		obtained from the 2024 GNA-DDOR report by the IPE and analyze the results. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
20	Analyze known load tracking dataset and verify the calculation of known load metrics	IPE to calculate the metrics mentioned on pages 31 and 32 of the 2023 IPE Post-DPAG Report and verify against the metrics calculated by the utility that are provided in their narrative related to the known load tracking dataset included in the GNA-DDOR report. Roles: PG&E to provide the confidential version of the known load tracking dataset included in their 2025 GNA-DUPR filing. PG&E to also provide information on how they calculated the metrics (for example, Excel workbook showing the formula used for calculating the metrics or something similar) that were included in their	PG&E to provide requested information by early October.	Confidential version of the known load tracking dataset included in their 2025 GNA-DUPR filing. Description of the tracking data set included in their 2025 GNA-DUPR filing. Information on the calculation of metrics (Excel workbook showing the formula used for calculating the metrics or something similar) that were included in their narrative of the known load tracking dataset.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		narrative of the known load tracking dataset. Verification: IPE to analyze the known load tracking dataset provided in the 2025 GNA-DUPR filing and verify the known load metrics calculated by the utility. Validation: IPE to review the approach and process used by the utility to calculate the metrics using known load tracking dataset.		

OTHER IPE WORK

21	Optional - Review plan for changes to the planning process for the next cycle (2025/26 DIDF) (skipped, no longer required)	In this optional step, the IPE will review the planned changes to the planning process in response to the 2024 DIDF reform or any decisions from the High DER Phase 1-Track 1 Proceeding. The data/information required for this step will be determined based on discussions with PG&E.		
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IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
22	Review implementing of planning standard and/or planning process (skipped, no longer required)	No further review is planned for the 2025/2026 DIDF cycle		
23	Review list of internally approved capital projects (skipped, no longer required)	No further review is planned for the 2025/26DIDF cycle.		
24	Respond to and incorporate DPAG comments	Include in IPE DPAG Report.	Completed by IPE in Mid-November	
25	Track solicitation results to inform next cycle (skipped, no longer required)	Part of IPE Post-DPAG Report follow-on activities in coordination with the IE.		
26	Treating confidential	Confidentiality – the following steps will be followed to ensure that the IPE Reports		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
	material in the IPE report	treat confidential material consistent with the rules and procedures of the CPUC. The dates provided for these steps are tentative and will be finalized based on discussions with PG&E. - The IPE will hold an early meeting with IOU (and potentially the ED) to discuss process 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. - Date: October 20, 2025 - The IOU will review all the documents² sent to the IPE for the V&V process for confidential information and highlight any information (in addition to information that is already highlighted) that is confidential. The IOU will also		

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 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		develop an equivalent set of documents with the confidential information redacted. At the end of this process, there should be a set of confidential documents that can be included as a part of the confidential IPE DPAG report and a set of public documents. c. IPE will provide the confidential version of the body of the draft IPE Report to the IOU by <u>October 20, 2025</u> (the body of the report to include all but the documents provided in previous item) for final IOU confidentiality review. d. IOU checks the draft confidential report for confidentiality and correctness and provides their comments/markups by October 30, 2025. e. After review and signoff, the IPE produces the final confidential and draft reports by November 3, 2025.		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		f. IOU requests CPUC confidential treatment using standard procedures. g. IOU files public version of the IPE report based on the schedule provided by the CPUC – DIDF Advice Letters submitted – <u>November 6, 2025</u> h. IOU files revised public report if CPUC rejects any requests for confidential treatment; otherwise, process is complete, and no further action is needed.		
27	Review Methodology used for Prioritization of Planned Projects	Perform verification and validation of the process, if any, used by utilities to prioritize planned projects for execution. Roles: Utility to provide the process, if any, used by utilities to prioritize planned projects for execution. Utility also to	Late September/Early October	TBD

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		provide the results of the prioritization, if applicable. Verification and Validation: The verification and validation process will be determined after discussions with the utility.		
28	Review Project Execution Tracking Data and Metrics	Perform verification and validation of the projection execution tracking data. Roles: Utility to provide the projection execution tracking data. Verification and Validation: The verification and validation process will be determined after discussions with the utility.	Late September/Early October	TBD

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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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.

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- 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)

Appendix B Updated Scope of Word Dated March 4, 2025

Proposed IPE Scope of Work (Draft)

Proposed Changes to Current Scope of Work

Current IPE Scope	Recommendations
Step 1 - Collect 2024 Actual Circuit Loading and adjust/normalize for weather as needed	Keep in future cycles
Step 2 - Determine Load and DER Annual Growth on System Level	Keep in future cycles
Step 3 - Disaggregate Load and DER Annual Growth to the Circuit Level	Keep in future cycles
Step 3a - Check sum of all disaggregated load and DERs same as CEC IEPR System level values	Keep in future cycles
Step 4 - Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads not in CEC forecast)	Keep in future cycles
Step 5 - Convert DER growth load to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 5 - Convert peak of load to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 5 - Convert base forecast and weather normalization adjustment to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 6 - Derive net load profile	Recommend skipping unless process changed.
Step 7 - Determine net peak load	Recommend skipping unless process changed.
Step 8 - Adjust for extreme weather	Keep in future cycles
Step 9 - Initial comparison to equipment ratings to determine if ratings exceeded	Recommend skipping unless process changed.
Step 10 - Evaluate no cost solutions - incorporate load transfers, phase balancing, correct data errors	Recommend skipping unless process changed.
Step 11 - Comparison to equipment ratings to determine if ratings exceeded	Recommend skipping unless process changed.
Step 12 - Compile GNA tables showing need amount and need timing, etc (consistent with IOU's documented planning standards and/or planning process)	Keep in future cycles
Step 13 - Develop Recommended solution and generate list of Planned Investments (follow the IOU's documented planning standards and/or planning process)	Keep in future cycles

Step 14 - Estimate capital cost for candidate deferral projects	Eliminate
Step 15 - Development of Candidate Deferral Projects list through application of screens (timing and technical)	Eliminate
Step 16 - Development of operational requirements for CDO (daily, monthly, annually, etc)	Eliminate
Step 17 - Prioritization of Candidate Deferral Projects into Tiers	Eliminate
Step 18 - Calculation of LNBA ranges and values for all planned projects.	Eliminate
Step 19 - Compare 2023 Forecast and Actuals at Circuit Level [proposed change would increase from ~10% of circuits to include all circuits if possible]	Keep in future cycles
Step 20 - Analyze known load tracking dataset and verify the calculation of known load metrics	Keep in future cycles
Step 22 - Review implementing of planning standard and/or planning process	Eliminate
Step 23 - Review list of internally approved capital projects	Eliminate
Step 24 - Respond to and incorporate DPAG comments	Keep in future cycles
Step 25 - Track solicitation results to inform next cycle	Eliminate
Step 26 - Treating confidential material in the IPE report	Keep in future cycles

Proposed Additions to IPE Scope of Work

Decision	New items	IPE Scope
3.1-Allow Utilities to Use Bottom-Up, Known Load Data to Determine Growth	Definition of Reliable Bottom-up Data (as well as, Customer energization Request, Known Load, Pending Load etc.) (Page 42) Note: Decision 3.1 allows Utilities to use reliable bottom-up data to estimate total load growth in a given year, even if it exceeds the forecasted load growth based on the IEPR for that year. Further, this decision directs that, in years without reliable bottom-up data, total growth should correspond to the forecast amount and not be adjusted downwards.	Annual verification and validation for the use of known loads already being performed as a part of Step 2 of the current V&V process. No new steps required.
3.2 – Require Utilities to Improve Method for Setting Caps on Load Growth from IEPR data.	IOU to work with CEC and CPUC to staff in developing proposals for the method and accounting for discrepancies between the system and circuit level. (Page 43) Decision 3.2 further focuses on developing proposals for the method and accounting for discrepancies between the system and circuit level (forecasts). The forecast at the system level (IEPR) is a coincident peak load forecast and is not necessarily equal to the sum of the peak loads on all the circuits. So, a methodology needs to be devised to develop circuit level forecasts that takes this into account. This decision approves, with one modification, the recommendation to require Utilities to submit Advice Letters proposing how they will improve their methods for setting caps on load growth based on the IEPR forecasts and other data. Utilities shall file Tier 3 Advice Letters. (Page 47)	Verify and validate IOUs' use of methodology for accounting for discrepancies between the system and circuit level load forecasts in the DPP. Annual starting 2025-2026 cycle. Annual verification and validation of methods for setting caps on load growth from IEPR data already covered under Step 2 of the current V&V process. No new steps required.
3.4 – Require Utilities to Expand the DPP Forecast Horizon to Align with IEPR and Expand the Planning Horizon to 10 Years.	To ensure transparency, utilities shall provide a description of the thermal capacity evaluation methodology in the annual GNA report (Page 55)	No new steps required to verify the expanded DPP planning horizon. The current V&V will be extended from 5 years to 10 years. Annual starting 2025-2026 cycle.

3.5 – Require Utilities to Use Scenario Planning to Improve Forecasting and Disaggregation	Workshops to develop scenario planning methodology and process. (Page 59) Utilities shall develop scenario planning capabilities that enable them to: (1) analyze multiple forecasts; (2) identify capacity deficiencies for each scenario and report them in the annual GNA; and (3) develop one investment plan informed by the multiple scenarios and reported in the DDOR or successor filing. (Page 61)	Attend workshop. One Time. Estimated Q1 2025 Verify and validate each DPP scenario and how utilities create one investment plan informed by multiple scenarios in the annual DPEP. Annual starting 2025-2026 cycle. • Develop draft IPE Plan for V&V of scenario planning – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026
3.6 - Require Utilities to Improve Disaggregation Methodology for Load Growth	Require Utilities to Improve Disaggregation Methodology for Load Growth (Page 62) This decision adopts the recommendation to require Utilities to improve disaggregation methodologies for load growth and distributed energy resources but delays implementation to the 2027 GNA and the 2026-2027 DPP cycle. To track progress toward improved disaggregation in the interim, Utilities shall report annually in the GNA on the development of advanced disaggregation methodologies and present these at the annual Distribution Forecast Working Group workshops or successor workshops. (Page 65)	Verify and validate the improved disaggregation methodology. Annual starting 2026-2027 cycle. Q3 2027. • Develop draft IPE Plan for V&V of improved disaggregation methodology – Q2 2027 • Finalize IPE plan – Q3 2027 • Perform V&V Q4 2027
3.7 - Require Utilities to Create Pending Loads Category in the DPP	Utilities are directed to provide pending load data and include the source of the data in the annual known load tracking filing, as part of the GNA/DDOR or successor report and orally reported during the DPAG or successor workshop (Page 76)	Attend workshop. One Time. Estimated Q1/Q2 2025 Verify and validate pending load data and source in annual reports and DPAG or successor workshop. Annual starting 2025-2026. • Develop draft IPE Plan for V&V of Pending Loads – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026

3.8 – Require Utilities to Develop Prioritization Methods Beyond the Current Consideration of Project Need Dates	Utilities to report how projects identified throughout the distribution planning horizon have been prioritized for execution. This decision also requires inclusion of this information in the annual GNA/DDOR or a successor report instead of the previously required Advice Letter (83)	Verify and validate the process used by utilities to prioritize projects for execution. Annual starting 2024-2025 cycle. - Develop draft IPE Plan for V&V of prioritization methodology – Q2 2025 - Finalize IPE plan – Q3 2025 - Perform V&V Q3 2025
3.9 – Require Utilities to Consider Distribution Planning Results in Other Distribution Work	Utilities to consider distribution planning results in other distribution work aka Integrated planning (Page 83) A workshop shall be held by Utilities during the third quarter of 2025 to present Utility proposals for integrated planning and solicit feedback from stakeholders on issues presented, including cost containment considerations. A second workshop shall be held by Utilities no more than eight weeks following the first workshop to present updated proposals based on feedback from the first workshop. (Page 86)	Attend workshop. One Time. Estimated Q3/Q4 2025. Verify and validate that integrated planning projects meet the established requirements. Annual starting 2026-2027. - Develop draft IPE Plan for V&V of integrated distribution planning – Q2 2027 - Finalize IPE plan – Q3 2027 - Perform V&V Q3 2027
3.11 – Require Utilities to Prepare a Load Flexibility DPP Assessment	Require Utilities to Prepare a Load Flexibility DPP Assessment. (Page 98)	Review EIS Part 2 studies and attend workshop. One Time. Estimated Q1 2026.
3.15 – Require Utilities to Include Metrics to Evaluate Equity in Utility Distribution Plan Reporting	Require Utilities to Include Metrics to Evaluate Equity in Utility Distribution Plan Reporting (Page 119) The Commission clarifies that while these metrics are requested for evaluation purposes, there is no framework wherein equity metrics are used for forecasting or planning distribution. The intention of this proposal is an annual evaluation of equity in distribution planning and does not involve modifying the planning process based on equity considerations. (Page 123)	Support the ED and the IOUs in finalizing and standardizing the tracking and reporting of the Equity Metrics. One Time. Estimated Q2 2025. Verify and validate equity metrics calculated by the utilities and reported by the utilities annually. Annual starting 2025-2026 DPP cycle. - Develop draft IPE Plan for V&V of equity metrics – Q2 2026 - Finalize IPE plan – Q3 2026 - Perform V&V Q3 2026

3.16 – Require Utilities to Include Metrics to Track Project Execution in Utility Distribution Plan Reporting	Require Utilities to Include Metrics to Track Project Execution in Utility Distribution Plan Reporting (Page 123) *also see Table 12 and Table 13. Table 12 * Additional Details for All Ongoing and Prior Three Years Completed Distribution Capacity Projects Table 13* Additional Project Execution Tracking Data	Support the ED and the IOUs in finalizing and standardizing the tracking and reporting required to track project execution based on Table 12, 13, and the requirements of R24-01-018 (Appendix B - Decision Establishing Target Energization Time Periods And Procedure For Customers To Report Energization Delays). One Time. Estimated Q2 2025 Verify and validate the project execution data and metrics submitted by the utilities. Annual starting 2024-2025 DPP cycle. • Develop draft IPE Plan for V&V of project execution metrics – Q2 2025 • Finalize IPE plan – Q3 2025 • Perform V&V Q3 2025
3.18 - Require Utilities to Facilitate Better Coordination and Data Sharing Between the DPP and Transportation Electrification Planning	Require Utilities to Facilitate Better Coordination and Data Sharing Between the DPP and Transportation Electrification Planning (Page 135)	Verify and validate how TEPP outputs are used in DPP. Annual starting 2025-2026 earliest. • Develop draft IPE Plan for V&V of TEPP coordination – Q2 2026 • Finalize IPE plan – Q2 2026 • Perform V&V Q3 2026

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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 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.

D.1 List of Documents Provided - Confidential documents include "(confidential)" at the end of the filename

Public Files

-  9-30-2025-10_8_6_OAKLAND C 1101 - Load Types.csv
-  9-30-2025-10_9_37_BARRETT 0401 - Load Types.csv
-  9-30-2025-10_10_53_ROSSMOOR 1103 - Load Types.csv
-  9-30-2025-10_11_43_EAST GRAND 1105 - Load Types.csv
-  10-31-2025-13_48_27_RIVERBANK 1714 - Load Types.csv
-  10-31-2025-13_56_26_JARVIS 1109 - Load Types.csv
-  2024 AAEE Guarantee Calc.xlsx
-  2024 AAFS Guarantee and Shape Calc.xlsx
-  2024 BTM_PV Guarantee Calc.xlsx
-  2024 BTM_STORAGE_NONRES Guarantee Calc.xlsx
-  2024 BTM_STORAGE_RES Guarantee Calc.xlsx
-  BARRETT 0401_Extreme.csv
-  BARRETT 0401_Low.csv
-  BARRETT 0401_Typical.csv
-  EAST GRAND 1105_Extreme.csv
-  EAST GRAND 1105_Low.csv
-  EAST GRAND 1105_Typical.csv
-  FITAdjustmentPortfolio_AAEE.xlsx
-  FITAdjustmentPortfolio_AAFS.xlsx

 FITAdjustmentPortfolio_AAFS_Cooling.xlsx

 FITAdjustmentPortfolio_AAFS_H&B.xlsx

 FITAdjustmentPortfolio_Energy_Storage_NonRes.xlsx

 FITAdjustmentPortfolio_Energy_Storage_Res.xlsx

 FITAdjustmentPortfolio_EV_DCFC.xlsx

 FITAdjustmentPortfolio_EV_Fleet.xlsx

 FITAdjustmentPortfolio_EV_Public_L2.xlsx

 FITAdjustmentPortfolio_EV_Res_L1.xlsx

 FITAdjustmentPortfolio_EV_Res_L2.xlsx

 FITAdjustmentPortfolio_EV_Workplace.xlsx

 FITAdjustmentPortfolio_Mid_Baseline.xlsx

 FITAdjustmentPortfolio_PV.xlsx

 Jarvis_1109_extreme.xlsx

 Jarvis_1109_low.xlsx

 Jarvis_1109_typical.xlsx

 OAKLAND C 1101_Extreme.csv

 OAKLAND C 1101_Low.csv

 OAKLAND C 1101_Typical.csv

 Riverbank_1704_extreme.xlsx

 Riverbank_1704_low.xlsx

 Riverbank_1704_typical.xlsx

 ROSSMOOR 1103_Extreme.csv

 ROSSMOOR 1103_Low.csv

 ROSSMOOR 1103_Typical.csv

 TN257109_20240619T124141_CED 2023 Local Reliability LSE and BAA Tables - Corrected PGE TAC Calculation.xlsx

 TN257301_20240621T155514_CED 2023 Hourly Forecast - PGE - Local_Reliability - Corrected (Original Do Not Edit).xlsx

Confidential Files

-  10-31-2025-13_41_5_BELL 1109 - Load Types (Confidential).csv
-  24_25 DPP EV input workbook (Confidential).xlsx
-  2025 Known Load Metrics_Internal_forIPE (Confidential).xlsx
-  Bell_1109_extreme (Confidential).xlsx
-  Bell_1109_low (Confidential).xlsx
-  Bell_1109_typical (Confidential).xlsx
-  FEEDER BASE SHAPE METHOD 2024-2025 cycle (Confidential).xlsx
-  ForecastSummary_GNA2025_feeders (Confidential).xlsx
-  PG&E EV Forecast Overview Document 072624 (Confidential).docx
-  PGE Load Modifiers - CED 2023 Hourly Forecast - PGE - Local Reliability v3 (Confidential).xlsx
-  PGE.2.2g.01 Mid Baseline Growth Roll Over Process (Confidential).docx
-  PGE.3.3c.01 Mid Baseline Growth Disaggregation (Confidential).docx
-  PGE.3.3d.01 Non EV DER Disaggregation (Confidential).docx