Pacific Gas & Electric

SB 410 Powering Up Californians Act Assessment

November 26, 2025

The better the question. The better the answer.
The better the world works.

Shape the future
with confidence

Shape the future with confidence

November 26, 2025

Pacific Gas & Electric

To Narbir Hothi of Pacific Gas & Electric:

We have completed our second biannual report for Pacific Gas and Electric ("PG&E" or "the Company") assessing its energization processes, timelines and costs, as described in Senate Bill 410, *Powering Up Californians Act* ("SB 410").[1] Our engagement was performed in accordance with our engagement letter ("Contract") dated June 7, 2024, and change orders executed on July 3, 2024 and October 30, 2025, and our procedures were limited to those described in that letter.

Our findings and observations resulting from our procedures are limited to those identified as of this report date and provided throughout the report. Additional information received will be updated in the next report (to be issued on March 1, 2026).

As noted in our statement of work, the engagement is performed under standards promulgated by the American Institute of Certified Public Accountants ("AICPA").

This report is intended solely for the information and use of the Company's management. The Company may disclose this assessment report, or discuss information relating to the Services, with any governmental authority, agency or regulator ("Regulator") with jurisdiction over the Company, provided that the Company provides Ernst & Young LLP ("EY" or "we") with advanced written notice of such disclosure. The Company acknowledges and agrees that (i) EY's Services were not performed, and our report was not prepared for any Regulator and (ii) any such disclosure to a Regulator is for informational purposes only and not for any third party's use and/or benefit.

Very truly yours,

Ernst & Young LLP

1 On August 1, 2025, PG&E made an initial request for an extension of the deadlines for providing the second audit report, as well as all subsequent reports. On August 13, 2025, PG&E revised their August 1, 2025, request, replacing its initial request and limiting the requested extension to the second audit report. PG&E requested that the original due date for this second audit report be extended from September 1, 2025, to November 28, 2025, 60 days after the due date of PG&E's energization report in D.24-09-020. On August 27, 2025, the CPUC Executive Director granted PG&E's request.

Table of Contents

Executive summary

Background

In February 2024, a request for proposal was issued seeking a consultant to assess PG&E's energization projects in accordance with the SB 410 Powering Up Californians Act ("SB 410"), as codified in the California Public Utilities Code Sections 930-939.5. Ernst and Young LLP ("EY" or "we") was selected as the third-party consultant to provide these Services. The contract was executed on June 7, 2024, and change orders were executed on July 3, 2024 and October 30, 2025.

SB 410, signed into law on October 7, 2023, and related Rulemaking (R.) 24-01-018[2] aim to streamline the process for customer energization requests, addressing delays faced by customers of large electric investor-owned utilities ("IOUs") when seeking new or upgraded electric service. SB 410 mandates the CPUC to establish average and maximum target energization timelines and create a reporting mechanism for customers when these targets are not met to expedite California's electrification efforts to help achieve the state's carbon neutrality goals by 2045.

EY submitted its initial SB410 Powering Up Californians Act Assessment in June 2025, which is included in Appendix C of this report. In our first assessment, we reviewed PG&E's energization requests and funding historical data. As part of our ongoing evaluation, EY has further assessed PG&E's business practices and procedures for energizing new customers, as well as PG&E's timeline calculations, list of energization projects and costs associated with energization projects, to determine whether they were reasonably and prudently incurred.

Operational assessment

This section presents EY's assessment of PG&E's operational and financial performance and includes the following subsections:

- **Timeline calculations:** Tested the Company's energization project timeline calculations as presented in the September 2025 Energization Report.
- **Customer demand growth forecast:** Tested the Company's customer demand growth calculations for the New Business (NB) energization program.
- **Qualified staffing levels and future staffing projections:** Reviewed current staffing levels and future staffing projections for PG&E's NB energization program.
- **Training and retaining an adequate workforce:** Assessed policies and procedures around energization workforce training and retention efforts.
- **Forecast and authorized funding:** Reviewed authorized funding and actual spend related to energization projects,[3] with insights into funding trends and their impacts for meeting future growth.
- **Verification of number and scope of energization projects:** Tested total number of energization projects.
- **Recommendations for types of projects similar enough to derive meaningful average costs:** Conducted inquiries with PG&E stakeholders and reperformed the Company's unit cost analysis for the NB energization program.

2 On January 30, 2024, the CPUC issued an Order instituting Rulemaking (R.) 24-01-018, to serve as a venue for the Commission to implement certain provisions of Senate Bill ("SB") 410 and Assembly Bill ("AB") 50.
3 "Energization projects" refers to projects that support "energization" as defined in Pub. Util. Code Section 931(b) and projects in the MWC and MAT code groupings deemed eligible for SB 410 cost recovery in D.24-07-008.

- **Distributed Energy Resource Management Systems (DERMS) and demand flexible rates considerations:** Reviewed DERMS and Demand Flexibility Rates reports for potential impacts to energization performance.
- **Other metrics:** Tested data on other metrics as provided by the Company.

Financial assessment

EY assessed the population of energization-related financial transactions with SAP posting dates from July 1, 2024 to June 30, 2025, as captured in PG&E's books and records. We performed analytical procedures on this population in addition to a statistical sample of orders. Each order is intended to represent an energization project in eligible MWCs and MAT codes as determined in D.24-07-008. As a result, we are testing a statistically valid sample of orders to understand the nature of the work. We further selected expenditures within those orders to understand whether the financial information is accurate, prudent and reasonable.

Limitations and assumptions of the assessment

Our work was performed based on the information provided to us by the Company and statements made by Company personnel as of this report date. EY performed factual analyses and procedures and documented the findings and results from such analyses and procedures.

Our procedures do not constitute an "audit," "review" or "compilation" of the Company's financial statements, as those terms are defined by the AICPA for financial statement audits, nor do we provide any form of assurance on the financial statements as a whole.[4] Additionally, our engagement cannot be relied upon to disclose errors, irregularities, or illegal acts, including fraud or defalcations, that may exist.

EY performed the assessment in accordance with the consulting professional standards in the Statement on Standards for Consulting Services ("SSCS") established by the AICPA. Further, our approach is designed to achieve the principles of the National Association of Regulatory Utility Commissioners ("NARUC") Rate Case and Audit Manual (2003) in an effective and efficient manner. As noted in the manual, we relied on the commonly understood concepts of "prudence" and "reasonableness" when reviewing expenses and corresponding adjustments proposed. The manual states the purpose of applying these concepts is to "determine a revenue requirement and customer rates that are just, fair, reasonable, and sufficient."

The Company may disclose this assessment report, or discuss information relating to the Services, with any governmental authority, agency or regulator ("Regulator") with jurisdiction over the Company, provided that the Company provides EY with advanced written notice of such disclosure. The Company acknowledges and agrees that (i) EY's Services were not performed, and our report was not prepared for, any Regulator and (ii) any such disclosure to a Regulator is for informational purposes only and not for any third party's use and/or benefit.

Our procedures were limited as certain information (as disclosed in each section below) is not available at the time of this report to complete all our planned procedures. Our assessment is multi-year, and we will continue to update our observations in subsequent reports, as more information becomes available. Consequently, this report does not cover all the tasks included in the decisions, and we are unable to provide finalized observations or conclusions at this time. Further details regarding the reconciliation of regulatory decision tasks and the EY report are provided in Appendix A herein.

4 AICPA, AU §508

I. Operational assessment

A. Timeline calculations

Overview

As stated in SB 410, the third-party auditor shall assess "the electrical corporation's performance in meeting energization time periods established by the commission pursuant to this article." R.24-01-018, established by the CPUC to implement SB 410 requirements, requires PG&E to adopt energization targets and timelines and track utilities compliance with those requirements. On September 12, 2024, the CPUC issued a decision, D.24-09-020, establishing target energization time periods and a reporting data set for the large investor-owned utilities in California to report their progress on a biannual basis, with the first report to be submitted on March 31, 2025.

On September 30, 2025, PG&E filed its second Biannual Energization Report pursuant to Decision 24-09-020 (referred to as "the September 2025 Report"). The Report provided data for New Business Orders with complete applications from January 31, 2023, to June 30, 2025.

Approach

EY leveraged PG&E's September 2025 Biannual Energization Report to assess timelines associated with Electric Rule 16, Electric Rule 29, Electric Rule 15/16, Main Panel Upgrades, and Upstream Capacity Projects. Using the project-level detail from the September 2025 Energization Data Reporting Template[5] (referred to as "September 2025 Data Reporting Template"), EY recalculated the reported average energization metrics and reviewed the accuracy of the reported information based on the methodology established by the Company.[6]

Additionally, EY conducted comprehensive sample testing since our first biannual report (referred to as "the EY June 2025 Report")[7] to evaluate the Company's progression of data availability over time. For the selected samples of completed projects, EY extracted the start and end dates for each energization phase from the Company's SAP and Salesforce tool. Using PG&E's methodology, EY then recalculated the timeline for each phase, including Customer Calendar Days,[8] PG&E Calendar Days,[9] and End-to-End Energization Cycle Calendar Days.[10]

Procedures

EY performed testing procedures as follows:

1. Obtained the September 2025 Report and the supporting Energization Data Reporting Template.
2. Obtained data sets for New Circuit/Circuit Upgrades and Substation Upgrades[11] related to Upstream Capacity work.

---

5 The Energization Data Reporting Template is an Excel attachment filed with the PG&E September 2025 Biannual Report.
6 Please note: EY did not review design effectiveness of the methodology for this reporting period, and we make no comment on appropriateness of this methodology.
7 Pacific Gas & Electric SB 410 Powering Up Californias Act Assessment prepared by EY and filed on June 13, 2025.
8 Customer Calendar Days reflect the total number of days across all customer-related phases.
9 PG&E Calendar Days reflect the total time for all IOU-related phases, excluding any days when PG&E activities overlap with customer or third-party activities.
10 End-to-End Energization Cycle reflect the total number of calendar days spanning all phases, from customer intake (Phase 1) to service energization (Phase 8).
11 MAT Codes 06H (New Circuit/Circuit Upgrades) and 46H (Substation Upgrades) correspond to Upstream Capacity Upgrade projects and are included in the September 2025 Biannual Energization Report.

3. Recalculated the Electric Rule 16, Electric Rule 29 and Electric Rule 15/16 and Main Panel Upgrades energization metrics disclosed in the September 2025 Report using the September 2025 Data Reporting Template.
4. Recalculated the Upstream Capacity Upgrades energization metrics disclosed in the September 2025 Report using the New Circuit/Circuit Upgrade and Substation Upgrade data set.
5. Using the Energization Data Reporting Template:
    a. Compared the September 2025 Data Reporting Template against prior versions[12] of the Energization Data Reporting Template to understand changes in the methodology.
    b. Identified completed projects that have start and end dates for each energization phase.
    c. Identified completed projects that have zero total PG&E calendar days.
    d. Compared, by project, calendar days in Phases 7 and 8 to the total PG&E calendar days to identify unusual patterns, such as, projects with total PG&E calendar days that are less than the calendar days stated for Phase 7 and Phase 8.
    e. Identified projects flagged as outliers by PG&E and validated the reason for the exclusion.
    f. Followed up on items identified and documented observations.
6. Selected a judgmental sample of 40 completed projects from the Energization Data Reporting Template, including identified outliers, and performed the following for each project:
    a. Agreed start and end date of each energization phase to the Company's query from SAP and Salesforce.
    b. Recalculated the timeline for each energization phase.
    c. Recalculated the Customer Calendar Days, PG&E Calendar Days, and the End-to-End Energization Cycle Calendar Days, based on the Company's defined methodology.
    d. Identified and reported any outliers and/or discrepancies.

Methodology overview

The following information summarizes our understanding of the data contained within PG&E's September 2025 Data Reporting Template and methodology for obtaining such data:

- The tables below summarize the average energization timelines for completed projects included in the Report, which the Company defines as new business applications submitted between January 31, 2023, and June 30, 2025, that were energized by September 9, 2025. The average timelines do not include projects that were not completed by June 30, 2025, or applications that were cancelled or rejected. Based on the data received, approximately 48%[13] of the applications submitted between January 31, 2023 and June 30, 2025 were completed by June 30, 2025; therefore, the timelines presented in the tables below represent less than half of the applications submitted between January 31, 2023 and June 30, 2025.
- Table 1 below summarizes the energization timelines for completed projects under Electric Rule 16, Electric Rule 29, and Combined Electric Rules 15/16.

Table 1 — PG&E's energization metrics reported*

12 EY had access to the March 2025 Energization Data Reporting Template and requested timeline data in August 2025.
13 PG&E Energization Report Pursuant to Decision 24-09-020, dated September 30, 2025, PDF page 5.

Description	Electric Rule 16	Electric Rule 29	Electric Rule 15/16
Total Projects Submitted 1/31/23 – 06/30/2025 and Energized Through 06/30/25	6,718	86	2,119
Average Energization PG&E Calendar Days**	118	113	117
Average End-to-End Energization Calendar Days***	307	508	389
Percentage of completed jobs under maximum energization days[14]	98.1%	97.7%	96.8%

** PG&E's Energization Report Pursuant to Decision 24-09-020, dated September 30, 2025, PDF page 5.*
*** Average number of days it takes PG&E to complete the steps in the energization process under PG&E's control.*
**** Average number of days from the start date of an energization request (date the customer's application is deemed complete) to the date the customer's request is energized.*

- Table 2 below summarizes the average energization timelines for completed Main Panel Upgrade projects included in the Report.

Table 2 — PG&E's Main Panel Upgrade energization metrics reported*

Description	Main Panel Upgrades**
Total Projects Submitted 1/31/23 – 06/30/2025 and Energized Through 06/30/25	27,742
Average energization PG&E Business Days**	34
Average End-to-End Energization Business Days***	40
Percentage of completed jobs under maximum energization days[15]	71%

**PG&E's Energization Report Pursuant to Decision 24-09-020, dated September 30, 2025, PDF page 6.*
*** Main Panel Upgrade projects are captured under annual blanket orders making it difficult to delineate the required energization phase structure. See Section 3L. Additional Reporting Disclaimers — Main Panel Upgrade (MPU) Projects for more details.*
**** Average number of business days it takes PG&E to complete the steps in the energization process under its control.*
***** Average number of business days from the start date of an energization request (date the customer's application is deemed complete) to the date the customer's request is energized.*

- Table 3 below summarizes the average energization timelines for completed Upstream Capacity Upgrade projects included in the Report.

Table 3 – PG&E's Upstream Capacity Upgrades energization metrics reported*

Description	Calendar Days
New Circuit/Circuit Upgrade	871
Substation Upgrade	1,225
New Substation: No new substations were completed within this filing period.	N/A
Average time between capacity upgrade identification and energization (16 energized customers) **	487

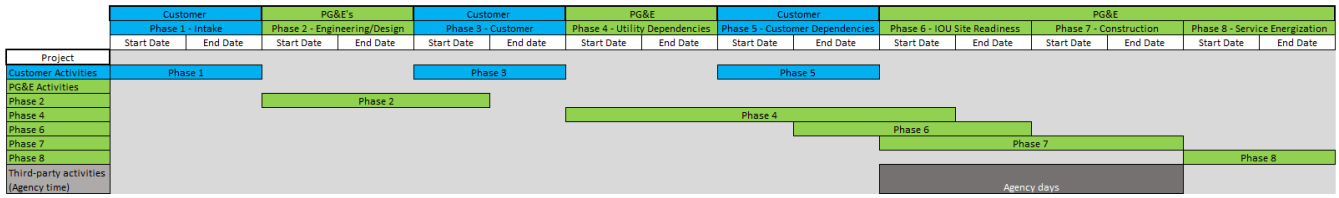
** PG&E's Energization Report Pursuant to Decision 24-09-020, dated September 30, 2025, PDF page 6.*
*** Average number of days between the date the IOU identifies the need for an upstream capacity project and the service energization start date.*

14 Projects were categorized by Electric Rule. For each category, we calculated the number of projects with total IOU-controlled steps that fell within the maximum energization days established in D.24-09-020. The percentage of projects completed within this maximum was then determined by dividing the number of compliant projects by the total number of completed projects.
15 We analyzed completed MPU projects to identify the number of projects that fell within the maximum energization days established in D.24-09-020. The percentage of compliant projects was calculated by dividing the number of projects within this maximum by the total number of completed MPU projects.

- The Company used the following methodology for capturing and reporting the energization metrics in Table 1:
    1. Phase responsibility:
        - PG&E time is attributed to the following phases:
            - Phase 2: Engineering & Design – utility conducts site visits, performs engineering analysis, and estimates project costs.
            - Phase 4: Utility Dependencies – utility submits permit applications and obtains necessary regulatory approvals.
            - Phase 6: IOU Site Readiness – utility schedules and conducts pre-construction inspections.
            - Phase 7: Construction – utility completes the electrical construction.
            - Phase 8: Service Energization – final inspections are completed, and the service is energized.
        - Customer time is attributed to the following phases:
            - Phase 1: Customer Intake[16] – customer submission of energization request.
            - Phase 3: Customer Dependencies – customer secures all required permits, payment of fees, execution of contracts, and obtains third party approvals.
            - Phase 5: Customer Site Readiness – customer prepares the site and formally releases it for utility-side construction to begin.
    2. PG&E's methodology principles:
        - Customer overlap in phases: When a customer phase coincides with a PG&E phase (e.g., a customer-related process occurs simultaneously with a PG&E process), that overlapping time is exclusively categorized as customer time and not attributed to PG&E time. The result is that shared time is not double-counted. Similar to the EY June 2025 Report, EY makes no comments regarding whether this methodology is appropriate.
        - Concurrent PG&E phase work: In cases where PG&E undertakes multiple overlapping phases concurrently (e.g., two PG&E processes happen at the same time), those overlapping days are not counted multiple times. Instead, they are aggregated as a single day within the total PG&E time count. The result is that overlapping time is not double-counted. As mentioned above, EY makes no comment regarding whether this methodology is appropriate.
        - Agency time: In cases where third-party activities (e.g., joint pole intent, land services, environmental services, encroachment permits and Federal Aviation Administration) are performed simultaneously with a PG&E phase, the overlapping time is deducted from the PG&E time. Agency time is only counted on days that do not overlap with customer phases. As mentioned above, EY makes no comment regarding whether this methodology is appropriate.

Figure 1- PG&E Energization methodology

16 While PG&E attributed Phase 1 as customer time, Phase 1 days are not included in the calculation of Customer Calendar Days or Customer Business Days.



Note: The graphic above illustrates the interaction between the different customer phases and PG&E's energization process. It demonstrates how PG&E can execute multiple phases concurrently and shows the potential overlap of certain phases with third-party activities.

- The Company acknowledges that SAP (current system of record) and the Salesforce tool did not track all the required start and end dates needed for the energization timelines. In addition, the Company identified data gaps and outlier data that impacted the energization timelines. Below are the data gaps and outlier data[17] that impacted the metrics in the averages reported:

    1. IOU Site Readiness (Phase 6) is measured by the time between the requested inspection date and the actual first inspection date. The Company noted that IOU site readiness was not a data point it required Company personnel to capture in its systems of record prior to the adoption of D. 24-09-020, and missing historical dates cannot be captured or recreated. To address this gap, the Company adopted the Salesforce tool in March 2025 to capture several previously missing data elements. Inspection dates prior to the Salesforce tool's adoption cannot be recovered. Currently, Salesforce inspection data is available post adoption and the data set will continue to expand over time. It is important to note that not all projects require inspection dates. PG&E Inspections are required for Applicant Trench, with PG&E Installed, and/or Applicant Installed facilities. As of the March 2025 Report, both the start and end dates for IOU site readiness data were available for 21 (0.24%) of the completed projects; by the September 2025 Report, data was available for 557 (6.24%) of the 8,923 completed projects.

    2. The Service Energization phase (Phase 8) is measured by the time between construction complete and meter set. In its March 2025 Biannual Report, the Company reported that due to format inconsistencies, it was unable to consistently integrate meter set data into project timeline records. The Company also noted that missing historical meter set data cannot be recreated. For projects where a meter set date could not be retrieved, the construction completion date is used to indicate project completion. As part of its data enhancement efforts, the Company redirected meter set data to a more refined source. Previously, meter set information was captured across multiple functional areas. Customer Care and Billing (CC&B) serves as the primary record-keeper of meter-related data. The Company now utilizes Customer Revenue Critical Reporting (CRCR), which retrieves data from CC&B, to obtain meter set records. The Company stated that improved data will enable more robust tracking of this phase and may increase total PG&E responsible time. As of PG&E's March 2025 report, meter set data was available for 3,339 completed projects; by the September 2025 submission, data was available for 4,198 of 8,923 energized projects.

        It is important to recognize that not all new business projects will require the installation of a new meter; therefore, there will continue to be projects that have no meter set date. In its September 2025 Report, PG&E noted that during its review of job

17 For a complete list and description of reporting gaps, see Section 3 to the PG&E Energization Report Pursuant to Decision 24-09-020, dated September 30, 2025.

estimate packages, approximately 1,682[18] energized projects identified did not require a meter installation.

3. Main Panel Upgrade (MPU) projects are reported separately from the standard tariff projects (Rule 16, Rule 29, Rule 15) because they do not follow the typical energization process from intake to meter set via a PG&E order. Currently, PG&E captures these projects under annual blanket orders and as such cannot provide detailed energization timelines. MPU reporting does not include the required reportable fields due to the internal order and notification structure used to track Main Panel projects. The timelines provided represent total IOU business days from the time the customer formally notifies PG&E to proceed through project completion, without detailed accounting of customer time.

4. The Company removed outlier data. Outlier data includes items such as data entry errors, measurement anomalies, and extreme deviations from typical values. Below are the outliers identified in the Report:
    - Date Sequence Errors: Occurs when a project phase end date precedes its start date (resulting in negative day aging), or when earlier steps (Steps 1 through 7) are recorded after the energization date (Step 8).[19]
    - Incomplete Status Verification: Occurs when a project is marked as "complete" but missing construction or energization dates, preventing confirmation of closure.
5. The Company excluded the following categories of work from the Report, based on established criteria and previously executed agreements:
    - Streetlights: Streetlights are categorized under MAT 16O at PG&E. Per a joint agreement with the other Investor-Owned Utilities (IOUs) in California, work involving streetlights has been excluded from the Report.[20]
    - Rule 13: Jobs classified as temporary service work have been excluded.
    - Rule 20: Government-requested work (20a) has been excluded because it is primarily categorized under internal orders.

Observations

Below are our observations identified as a result of the procedures performed:

1. Since March 2025, the Company has implemented data collection enhancements and technology upgrades to improve the completeness and accuracy of energization timeline data. In its September 2025 Report, PG&E reported a total of 8,923 completed projects. Of these, 310 projects included start and end dates for all eight energization phases. This represents a significant improvement compared to the March 2025 Report, where only seven completed projects contained start and end dates for all phases. PG&E's advancements in data collection methods and systems are expected to enable more robust tracking of the energization process and may result in an increase in the amount of PG&E controlled time across all projects.
2. We observed that 747 of the 8,923 completed projects were initiated by customers after the adoption of D.24-09-020 on September 17, 2024. Prior to the issuance of this decision, PG&E

18 PG&E Energization Report Pursuant to Decision 24-09-020, dated September 30, 2025, PDF page 23.
19 The Company stated that date sequence errors could be caused by data entry errors or other anomalies within the job process.
20 Although this MAT was excluded from the Report, MAT 16O is still eligible for SB 410 cost recovery.

was not required to track each step of the energization process at the current level of detail. The Company has indicated that historical data cannot be retroactively captured or recreated. Consequently, some projects initiated before the decision may lack start and end dates for all energization phases.

Currently, 73 of the 747 projects initiated after the Decision include complete start and end dates for all energization phases. This represents an improvement compared to the March 2025 Report, where none of the complete projects initiated after the decision contained full phase-level data. Our analysis also determined that while data is available for most energization phases, the limited data for IOU Site Readiness (Phase 6) significantly lowers the overall number of projects with complete energization data across all phases.[21] With the full implementation and adoption of the Salesforce tool in March 2025, we anticipate that the number of projects with full energization process data will increase in the March 2026 submission, reflecting PG&E's ongoing progress toward enhanced data quality.

3. We identified nine completed projects that reported zero total PG&E Calendar Days. All of these projects were submitted prior to the adoption of D.24-09-020. As noted in the observation above, some projects submitted before the issuance of the Decision may lack start or end dates for energization phases. In one of the nine cases, both the total Customer Calendar Days and total PG&E Calendar Days were recorded as zero due to missing dates and sequencing errors. The remaining eight projects exhibited missing dates or date sequencing errors within specific phases, caused by limitations in the outlier query, which did not adequately account for misaligned phase data. PG&E has implemented updates in the query to flag these errors and categorize these projects as outliers, and EY confirmed the implementation of those updates.
4. We identified instances where the calendar day counts for energization phases (Phase 7 and Phase 8) exceeds the total IOU-controlled steps calendar days. This occurs because PG&E's energization process allows concurrent work with customers and third-party activities, such as permitting. This approach accelerates cycle times and promotes more efficient project execution. When project phases overlap during concurrent work, shared time is counted only once. This ensures that the total calendar days for PG&E-controlled steps accurately reflect only the days when PG&E carried out activities under its control.
    a. We identified 22 of the 8,923 completed projects that had a total PG&E Calendar Days less than PG&E Calendar Days for Phase 8 – Service Energization.
        - We identified 1 of the projects within our sample that shows a higher day count for Phase 8 than the total PG&E-controlled steps calendar days. In this case, the total PG&E calendar days were reduced due to PG&E executing multiple project phases concurrently, and agency time overlapping with PG&E time.
    b. We identified 124 of the 8,923 completed projects where total PG&E Calendar Days were less than the PG&E Calendar Days for Phase 7 – Construction.
        - We identified 1 of the projects within our sample that shows a higher day count for Phase 7 than the total PG&E-controlled steps calendar days. In this case, the total PG&E calendar days were reduced due to PG&E executing different phases concurrently, and agency time overlapping with PG&E time.
5. In the EY June 2025 Report, we identified 643 completed projects where the total PG&E Calendar Days were less than the Calendar Days for Phase 7 – Construction. EY found that some of these projects included incorrect totals in the Energization Data Reporting Template

21 Out of the 747 completed projects initiated by customers after the adoption of D.24-09-020; excluding Phase 6, 328 completed projects have data available for all energization phases.

due to a program logic error. EY revisited this observation during our testing and confirmed that the error has been corrected.

6. EY assessed enhancements to PG&E's data availability implemented in March 2025. EY requested project timeline data in August 2025 and compared it against the September 2025 Data Reporting Template. We observed that additional start and end dates became accessible. PG&E indicated that the recent implementation of new tools has facilitated the identification of better data sources. These enhancements exemplify a more comprehensive data set. During this two-month period, we noted a significant increase in data quality and availability, particularly in Phase 4, Phase 5 and Phase 8.
7. We observed that the Company uses the service energization (Phase 8) start date as the energization date, instead of the end date, when calculating the average time between the IOU's identification of the need of an Upstream Capacity Upgrade project and project energization.[22] Calculating the metric based on the start date results in a lower day count compared to using the end date when available. PG&E explained that this approach was adopted to maintain consistency in its methodology, as the service energization end date is not always available or required for all projects. Furthermore, once service energization begins, the dependency on the upstream capacity project no longer impedes energization.
8. As outlined in the September 2025 Report, PG&E proactively flagged projects with date sequence errors and incomplete status verification as outliers to maintain the integrity of its average reporting. By excluding these projects from the aggregate calculations, PG&E intends to ensure that the day counts and averages accurately reflect its performance. We validated the accuracy of the 1,120 projects flagged as outliers, and noted the following:
    a. We identified 755 projects where the project phase end date preceded its phase start date. All were appropriately flagged and excluded from the average reporting.
    b. We identified 57 projects with incomplete status verification; all correctly flagged and excluded from the average reporting.
    c. We identified 265 projects where an earlier energization phase was incorrectly recorded after Phase 8. Of these, 174 were accurately flagged as outliers. For the remaining 91, PG&E determined that the current outlier query does not fully account for misaligned phase data. These discrepancies are linked to projects initiated after the JobForce extension implementation, designed to capture inspection dates. PG&E implemented updates in the query to flag the error. EY validated the changes, and all 91 projects are accurately flagged as outliers.
    d. We observed 319 projects flagged as outliers that did not exhibit sequencing or verification errors. PG&E explained that these were caused by a calculation error in Phase 5, where an incorrect field was used, resulting in negative values. PG&E updated the code to remediate this error. EY validated that the update was implemented, and therefore these projects are no longer categorized as outliers.
9. We identified seven projects within our sample that were incorrectly categorized as outliers. The Company determined that the root cause was a calculation error in Phase 5, which resulted in negative values. PG&E updated the code to remediate this error. EY validated that the update was implemented, and therefore these projects are no longer categorized as outliers.
10. We identified two projects within our sample where the end dates for Phase 5 and Phase 6 were entered after the Phase 8 service energization date. In these cases, the system defaulted to

22 EY recalculated the average number of calendar days between the date the IOU identifies the need for an upstream capacity project and the end date of the service energization phase, resulting in an average of 496 calendar days. This average remains below the target thresholds for both circuit and substation upgrades.

using Phase 8 service energization date as the maximum date for Phase 5 and Phase 6, which reduced the calculated day count for those phases. The Company determined that the root cause was an input error where dates were entered incorrectly into SAP. PG&E stated that it will issue additional guidance to internal job owners on more accurate and timely capture of job task dates to improve the data entry process.

11. We identified five projects within our sample where dates for Phase 8 were available, but no days were counted in the September 2025 Data Reporting Template, resulting in an incorrect day count of PG&E total Calendar Days. The Company determined that the root cause was classification and calculation errors. PG&E has updated the code used to calculate Phase 8, and EY has validated that the correction was implemented.
12. We identified one project within our sample where the Phase 6 end date did not match the Phase 6 end date recorded in Salesforce. The Company stated that this discrepancy was due to a logic error and is working on updating the logic.
13. We identified one project within our sample where the Phase 8 end date did not match the date recorded in the CRCR system. The Company determined that this discrepancy was caused by the meter being removed and reinstalled.

B. Customer demand growth forecast

Overview

SB 410 states the auditor shall assess "the electrical corporation's projections of customer demand growth included in the electrical corporation's distribution plan, including growth in new customers and growth in demand from existing customers." SB 410 also states, "the third-party auditor shall evaluate the electrical corporation's current and future energization performance and make recommendations as to whether the electrical corporation is adequately meeting and anticipating customer demand."

EY requested insight from the Energy Division on its interpretation of "current and future energization performance." The Energy Division responded with the following: "Energy Division believes that this builds on the previous assessments that the CPUC and EY have done in A.21-06-021 and R.24-01-018, including timelines, customer demand, staffing, and funding levels."

Approach

EY assessed PG&E's key assumptions and inputs in its electrical demand growth projections, including growth from new customers and increased demand from existing customers, across PG&E's New Business ("NB") Program. Because customer demand growth is closely tied to staffing, "energization performance," and capital funding plans, EY evaluated demand growth holistically alongside related areas in this report: timelines, staffing, and funding levels. We will continue to update our assessment of customer demand growth, as well as current and future performance, in subsequent reports.

As part of this assessment, EY noted that PG&E has implemented a new bottom-up forecasting process for customer demand growth within the NB program. This change reflects an update in the key assumptions and inputs underlying PG&E's demand growth projections since the 2023 General Rate Case ("GRC").

Through stakeholder inquiry, we determined that the most significant changes since the 2023 GRC occurred within NB and therefore focused our assessment on this program.

Procedures

EY performed testing procedures as follows:

1. Obtained an understanding of the Company's process for developing the forecast for the NB program.
2. Identified key factors/inputs upon which the forecast was developed.
3. Obtained and reviewed internal source data for assumptions, verifying that underlying data and rationale were appropriately incorporated into the forecast, and reviewed formulas to confirm the accuracy of calculations.
4. Inquired about the Company's process improvements for developing the forecast to identify enhancements for forecasting practices in the future.

Methodology overview

PG&E's newly implemented bottoms-up approach for customer demand growth projections, as updated in the 2027 GRC application, is more granular than the previous methodology reviewed in the first biannual report. This new approach leverages historical project-level data, job size classifications, based on estimated construction hours, and accounts for customer service timing. EY reviewed the updated forecast methodology, as described in the 2027 GRC application, and observed the following changes for NB:

- **Base Connects:** Base Connects demand growth projections for residential and non-residential service requests for new or added load are based on historical Applications Deemed Complete ("ADCs"), categorized by job size (large, small/medium, and short cycle) using estimated construction crew-hour estimates. An ADC is an application that has completed intake and received an order number in SAP. Historical ADCs include both active and canceled applications, with a three-year average cancellation rate applied. Forecast growth is then developed using a five-year compound annual growth rate ("CAGR") by job size.

  Using 2024 recorded ADCs, the Company determines customers requested completion in the same year, one year later, or two years later, incorporating energization timelines into the forecast. This rolling forecast through 2030 combines new requests with carryovers.
- **Plug-In Electric Vehicle (PEV):** PEV demand growth is projected using the same methodology as Base Connects, but with a two-year CAGR to reflect the emerging nature of these projects and limited volume in prior years. The updated process incorporates legislative impacts and external forecasts, including California Energy Commission ("CEC") analysis of electric vehicle (EV) adoption and charging infrastructure needed to support statewide electrification goals.

EY has not reviewed full design and operating effectiveness of the process and controls related to the newly implemented demand forecasting methodology.

Observations

1. In the 2027 GRC, PG&E assumes no carryover work for ADCs before 2024, based on the pending SB 410 motion (U 39 E).[23] If the motion results in insufficient funding for the anticipated new business customer requests in 2025 and 2026, there is a risk of carryover work, which was not accounted for in the 2027 GRC.
2. The Company's forecast growth currently relies on a five-year CAGR for base work and a two-year CAGR for PEV work. While this approach provides a historical trend-based estimate, it creates a dependence on past patterns that may not fully capture future variations in customer behavior or system needs.

23 "Pacific Gas and Electric Company's (U 39 E) Motion to Revise 2025 and 2026 Energization Cost Caps," in response to Rulemaking 24-01-018, dated October 4, 2024.

3. To improve forecasting precision, the Company is exploring methods to disaggregate the customer population by customer class and geographic territory. This effort aims to provide more granular trends for ADC planning and better align projections with evolving demand drivers.
4. The methodology relies on 2024 customer request data to estimate energization timing, applying these percentages to allocate forecast units across GRC years. Because the allocation is based on a single year, there is a risk that cost timing may not reflect longer-term customer patterns. PG&E may consider adopting a rolling forecast process in which allocations are recalibrated annually as new data becomes available.

C. Qualified staffing levels and future staffing projections

Overview

SB 410 states that the auditor shall assess "the electrical corporation's qualified staffing levels and future anticipated staffing needs to meet projections for customer demand growth, including the ability of the electrical corporation to sufficiently build its workforce." SB 410 also states that the third-party auditor shall evaluate the "electrical corporation's current and future energization performance and make recommendations as to whether the electrical corporation is … adequately training and retaining an adequate workforce."

EY requested insight from Energy Division on its interpretation of "current and future energization performance," and the Energy Division responded with the following: "Energy Division believes that this builds on the previous assessments that the CPUC and EY have done in A.21-06-021 and R.24-01-018, including timelines, customer demand, staffing, and funding levels."

Approach

EY assessed PG&E's key assumptions and inputs for qualified staffing levels and future staffing projections across PG&E's NB program. Because qualified staffing levels and future staffing projections are closely tied to customer demand growth, "energization performance," and capital funding plans, EY evaluated these areas alongside each other. We will continue to update our assessment of qualified staffing levels and future staffing projections, as well as current and future performance, in subsequent reports.

As part of this assessment, EY noted that under PG&E's new bottoms-up forecasting approach for the NB program, current and future staffing level projections are a central component of the process.

Procedures

EY performed testing procedures as follows:

1. Held inquiries with PG&E stakeholders on qualified staffing levels and future staffing projections.
2. Identified key inputs upon which the forecast was developed.
3. Obtained and reviewed internal source data for assumptions, verifying that underlying data and rationale were appropriately incorporated into the forecast, and reviewed formulas to confirm the accuracy of calculations.
4. Compared projection methodology to customer demand growth and forecasting.

Methodology overview

PG&E's new bottoms-up forecasting process for NB is closely linked to qualified staffing levels and future anticipated staffing needs, as customer demand forecasts directly inform workforce planning decisions. Staffing projections are therefore adjusted and updated as new or changed work priorities and funding levels are established.

Our observations regarding changes to the qualified staffing levels and future anticipated staffing needs for the NB program are as follows:

- Base Connects: PG&E projects staffing needs by applying a three-year average of the internal vs. contractor labor mix by job size to forecast ADCs. Internal labor is capped at 9,500 units annually, consistent with historical capacity, with excess work assigned to contractors.[24] Within this cap, internal resources are allocated across job categories based on historical ratios, which results in a greater share of short-cycle projects being handled internally and larger projects assigned to contractors. PEV units are prioritized for internal labor first, with remaining capacity allocated to Base Connects.
- In parallel, PG&E projects hourly needs for each NB job grouping by applying forecast spending changes to recorded hours. Standard, overtime, and total hours are projected, with standard hours adjusted for the target internal share, then converted into staffing requirements using productive capacity.
- PEV: PEV follows the same steps and 9,500 internal labor cap but with priority in the internal labor allocation. Remaining PEV demand beyond the cap is assigned to external labor.

EY did not review full design and operating effectiveness for the staffing methodology for NB.

Observations

1. PG&E's staffing model sets a maximum of 9,500 internal labor units annually, based on historical averages of ~9,000 units. Any forecast demand above this cap is allocated to contractors, limiting the model's ability to reflect changes in available internal workforce capacity.
2. The model tends to allocate a greater share of internal labor to short-cycle projects, while contractors take on a larger portion of projects with higher estimated construction hours. As a result, longer-duration work is more often performed by external resources, though both internal and contractor labor are used across project types.

D. Training and retaining an adequate workforce

Overview

SB 410 states the auditor shall assess the "electrical corporation's current and future energization performance and make recommendations as to whether the electrical corporation is adequately meeting and anticipating customer demand, adequately training and retaining an adequate workforce, and is funded at sufficient levels to meet forecasted demand growth."

Approach

EY assessed PG&E's current policies and procedures related to training and retaining an adequate workforce. Adequate training and retention of energization personnel are critical for PG&E's ability to work through current energization request backlogs and meet further customer demand growth.

Stakeholder inquiries and policies, data analysis, and procedures documentation were reviewed, and EY assessed the design of the staffing and recruiting practices and associated training program. Our findings are as follows:

24 A "unit" refers to an individual energization project.

Staffing and Recruiting:

PG&E's Workforce Management team employs adequate forecasting practices by leveraging a comprehensive set of data inputs, including growth projections, new business opportunities, ongoing projects, attrition rates, and baseline staffing numbers. Recruitment initiatives encompass a diverse range of programs and outreach activities, which are systematically assessed to ensure sustained effectiveness. These approaches enable PG&E to proactively align staffing resources with customer demand, to support the objective that recruitment and retention practices adequately support operational objectives. Additionally, guided by the governance structure, PG&E secures appropriate funding for capital projects, thereby facilitating the organization's ability to address forecasted demand growth.

Training:

PG&E's Training team employs a structured curriculum and Training Standard, titled Apprentice Lineworker T200 & T300, that integrates instruction, hands-on experience, and knowledge assessments to address essential roles. We reviewed the Training programs for Journeyman and Line Worker, which are aligned with the standard accreditation of Journeyman and Line Worker and include the required knowledge mandatory to meet established standards and accreditation. The four-year program requires completion of an Apprenticeship or its equivalent, paired with a mandatory four-week PG&E bootcamp. These strategic initiatives enable PG&E to effectively and consistently train Journeymen and Line Workers, with the object that they possess the necessary accredited qualifications to meet customer expectations and advance critical operational objectives.

E. Forecast and authorized funding

Overview

SB 410 states the auditor shall assess the "funding requested by the electrical corporation to support energization requests for the previous three years in the general rate case or any other proceeding, and the efficacy of those previous requests in meeting customer demand." SB 410 also states that the "Commission authorized funding for the electrical corporation to support energization for the previous three years, future authorized funding, and authorized changes to the electrical corporation's business practices or structures to improve its ability to respond to changing customer demand."

In addition, Ordering Paragraph 17 of D.24-07-008 states that the third-party auditor shall evaluate that "capital projects are funded at sufficient levels to meet forecasted demand growth."

EY requested insight from the Energy Division on its interpretation of "future authorized funding." The Energy Division responded with the following: "ED interprets 'future authorized funding' to be funding that is already authorized but for future years (e.g., ECNBIMA 2025 and 2026 authorization) and upcoming funding requests in their GRC submission."

Approach

EY previously analyzed PG&E's energization funding requests, commission authorized funding, and actual spend from 2021 to 2023 in the EY June 2025 Report. No further analysis of pre-2024 spending was carried out during this reporting period.

EY evaluated the Decision Resolving Pacific Gas and Electric Company's Motion to Revise its 2025 and 2026 Energization Cost Caps (D.25-08-036) and the Company's requested energization funding in its recently filed 2027 GRC. This analysis also compares PG&E's actual spending in 2024 to forecasts, 2024 GRC authorizations, and Electric Capacity New Business Interim Memorandum Account ("ECNBIMA") cost cap.

Procedures

EY performed testing procedures as follows:

1. Analyzed base and ECNBIMA funding levels in 2024 compared to actual spend.
2. Reviewed D.25-08-036 and supporting workpapers underlying the proposed increase to ECNBIMA cost caps for 2025 and 2026.
3. Assessed PG&E's 2027 GRC request for SB 410 eligible MWCs, including forecasting methodology and assumptions.
4. Discussed inquiries with PG&E stakeholders to understand the forecasting process and obtain additional information on underlying assumptions.

Observations

Our understanding of PG&E's forecast funding, authorizations, and actual spending is provided below:

2023 GRC, D.24-07-008 ECNBIMA cost caps, and 2024 actuals

1. In the 2023 GRC, PG&E received approximately $3.2B in authorized funding for 2024–26 energization-related activities. Pursuant to SB 410, in D.24-07-008 CPUC authorized PG&E to establish the ECNBIMA to record and track energization costs incremental to those authorized in the 2023 GRC. D.24-07-008 authorized yearly cost caps for the ECNBIMA.
2. PG&E reported actual spending of around $1.5B in 2024 for energization-related activities. PG&Es reported spend is approximately $616M greater than base authorizations
3. from the 2023 GRC. However, PG&E's total reported spend did not reach total authorizations when including the ECNBIMA authorized cost caps. The Company's total 2024 spend for SB 410 energization-related activities was reported at around $359M less than cumulative base and ECNBIMA authorizations.

Table 4: 2024 Funding and Actual Spend Analysis by MWC (in thousands)

MWC	Forecast 2024 spend (2023 GRC)*	Authorized 2024 spend (2023 GRC)*	ECNBIMA cost cap authorizations (D.24-07-008)	Total 2024 authorization (2023 GRC plus cost caps)	Actual 2024 spend**
06	$164,270	$129,180	$89,967	$219,147	$209,796
10	$39,223	$34,711	$77,601	$112,312	$42,611
16	$820,269	$682,728	$845,563	$1,528,291	$1,176,504
46	$75,754	$62,207	$(38,065)	$24,142	$97,136
EV	-	$14,440	-	$14,440	$13,367
Total	**$1,099,517**	**$923,267**	**$975,066**	**$1,898,333**	**$1,539,414**

Note: Totals in this table include eligible and partially eligible MAT codes as outlined in D.24-07-008 and are being further assessed in EY's financial analytics procedures. Values may not total due to rounding.
** Forecast and authorized amounts for MWC 10 are derived by applying a factor of 0.24 to total MWC 10 pursuant to D.24-07-008. Forecast amounts were identified within the Column "Reply Brief with Escalation Update."*
*** Actuals for MWC 06, 46, and 16 are based on PG&E's 2027 General Rate Case. MWC 10 actuals are sourced from PG&E's 2024 Capital Additions for Energization Related WRO in the 2024 Annual Electric True-Up (AET) filing.*

Decision resolving Pacific Gas and Electric Company's motion to revise its 2025 and 2026 energization cost caps

1. PG&E filed its Motion to Revise its 2025 and 2026 Energization Cost Caps, citing that the Company at the incremental funding levels adopted in D.24-07-008 "cannot fulfill customers'

connection requests." The Commission issued its decision resolving PG&E's motion on September 4, 2025.

2. The Commission authorized an increase of approximately $1.48B to PG&E's annual cost caps across 2025 and 2026. Additionally, PG&E was granted flexibility to allocate spending toward the cost caps across 2025 and 2026.
3. EY will assess the 2025 – 2026 authorized funding and revised cost caps as part of its financial assessment in March 2026.

Table 5: 2025 – 2026 revised cost caps (in Million $)

	2025	2026	Total
Annual Caps Approved in D.24-07-008	$618.7	$669.4	$1,288.1
Authorized Increase to Annual Cost Caps in D.25-08-036	$456	$1,015.7	$1,475.7
Total Adopted Annual ECNBIMA Cost Caps	$1,074	$1,685.1	$2,759.1

Note: Totals in this table include eligible and partially eligible MAT codes as outlined in D.24-07-008 and are being further assessed in EY's financial analytics procedures. The ECNBIMA cost cap values were pulled directly from Table 7 in D.25-08-036, Please note, for reasons unknown to us, Table 7 in D.25-08-036 does not foot; and therefore, this table does not foot.

2027 GRC funding forecast methodology

The 2027 GRC funding forecast methodology for energization work is closely tied to customer demand growth and staffing projections for NB. EY has observed the following changes as documented in the 2027 GRC in how NB calculates, and projects future spend.

- **Base Connects:** Forecast spend is calculated by multiplying projected internal and contractor labor units by job-size-specific budget unit costs, derived from since-inception labor costs. A cost coefficient (budget unit cost divided by since-inception cost) is applied to adjust for recorded experience and current volumes, producing total budget unit costs per year. The methodology assumes all projects requested before 2027 are energized by that year, with internal and external costs summed to produce the 2027 forecast. For 2028–30, these costs are escalated using IHS Markit indices.
- **PEV:** PEV funding follows the same process as Base Connects, with forecast internal and contractor labor units multiplied by 2024 actual unit costs. For nonresidential PEV, forecasts incorporate CEC EV adoption and charger demand scenarios, then apply a three-year average job-size mix to allocate units. Internal and external costs are combined to produce the 2027 forecast, with 2028–30 costs escalated from 2027 levels using IHS Markit indices.

Observations

1. Compared to prior GRCs, PG&E developed its NB funding forecast for the 2027 GRC at a more granular level, breaking out funding requests by groupings (transformers, PEV, Base Connects, etc.) and job size categories.

F. Verification of number and scope of energization projects

Overview

OP 21 of D.24-07-008 states that the "third-party auditor shall verify and report on the number and scope of energization projects completed each year."

Approach

EY reviewed the Company's SAP data of energization eligible orders from 2021 through 2024, to identify and validate the total number of energization projects completed from 2021 through 2024. We assessed project completion using the Company's defined methodology, which considers a project complete when construction is deemed complete in the SAP system. An alternative method applies for MWC 46, for which the Company uses a separate "Operative Date" to identify that a project is energized.

EY also confirmed that the orders included were energization-related, consistent with the requirements of SB 410 and Decision D.24-07-008. EY will build on this initial assessment by incorporating future data to expand the data set and continue reporting on total energization projects in subsequent reports.

Procedures

EY performed testing procedures as follows:

1. Obtained the data set containing eligible orders completed annually across NB, WRO, and Capacity projects.
2. Reviewed data set and removed ineligible orders and MAT codes not applicable to SB410.

Observations

Table 6: Total number of energization projects completed from Jan 2021 – Dec 2024

Major Work Category ("MWC")	2021	2022	2023	2024	Total
06	130	281	100	385	896
10	365	253	266	289	1,173
16*	8,674	8,487	9,535	13,496	40,192
46**	7	10	10	15	42
Total	**9,176**	**9,031**	**9,911**	**14,186**	**42,304**

Note: Totals in this table include cumulative eligible and partially eligible MAT codes as outlined in Ratemaking Decision (D.24-07-008) and assessed during financial analytics procedures
** Excludes SB410 Ineligible MAT 164 - R29 / AB841*
***Operative Date Is used Instead of CN24 date and is more reliable in SAP. Operative date signals when electricity is flowing at the site*

G. Recommendations for types of projects similar enough to derive meaningful average costs

Overview

SB 410 states the auditor shall assess: "Any other metrics deemed relevant by the commission or third-party auditor to support a thorough evaluation of the electrical corporation's energization performance, including to identify and correct past flaws and to identify future best practices."

In addition, OP 21 of D.24-07-008 states that the "third-party auditor shall … recommend which types of projects are similar enough to provide meaningful average costs or costs that correlate with known data (e.g., transformer size, length and size of installed conductor) along with their average costs or correlations."

Approach

EY evaluated the NB program for this report. Based on EY and the Company's understanding of the audit requirements, in our analysis, we used the "since inception" costs for construction complete projects in PG&E's list of eligible energization orders from 2021 through 2024, defined in Section F above. Additionally, PG&E provided project level data for key cost categories that have been used in the 2027 GRC request. These include GRC grouping, work segment, job size (by projected hours), and contract vs. internal labor. EY took these fields into consideration in reperforming unit cost calculations.

Procedures

EY performed testing procedures as follows:

1. Discussed with PG&E stakeholders to understand project cost procedures for energization projects.
2. Obtained SAP order level data for NB construction complete projects from 2021 to 2024.
3. Reperformed unit cost analysis and compared against PG&E's computed costs to evaluate calculations.

Observations

1. Based on discussions with PG&E stakeholders, the average construction cost from projects completed from 2021 to 2024 reflect since inception costs from SAP through August 2025. However, costs at the time of energization can vary significantly as additional costs are typically incurred and recorded beyond the energization (meter set date) of a project. Energization projects may, for example, not be financially closed until six months to one year after the energization date.
2. EY understands that until a project is financially closed, the costs of installation for completed projects are subject to change. The since inception costs that EY evaluated in its testing procedures are not necessarily final costs. To provide a meaningful assessment of averages and similar projects, EY will consider the costs of installation on a unit basis for financially completed projects as compared to historical costs for similar units in prior periods.
3. In assessing the data provided by PG&E, EY identified no variances in its calculation of total since inception project costs, count of orders, and since inception unit costs. This analysis took into consideration the GRC groupings, work segment, and job sizes used in PG&E's 2027 GRC forecasting efforts.

H. Distributed Energy Resource Management Systems (DERMS) and demand rate considerations

Overview

OP 24 of D.24-07-008 states that "Pacific Gas and Electric Company shall report on its work and funding for Distributed Energy Resource Management Systems and its flexible service connection pilot and their impact on reducing the need for capacity upgrades to the third-party auditor no later than January 1 and July 1 of each year and in its next general rate case." OP 25 of D.24-07-008 similarly states that "Pacific Gas and Electric Company shall report on its work and funding for dynamic and demand flexibility rates and their impact on reducing the need for capacity upgrades to the third-party auditor no later than January 1 and July 1 of each year and these reports shall be submitted as testimony in its next general rate case."

EY requested insight from the Energy Division on its interpretation of the auditor's requirements with respect to the DERMS and dynamic and demand flexibility rates reports. The Energy Division clarified its request that EY take the reports into consideration and reports on findings related to energization.

Approach

EY obtained and reviewed the DERMS and dynamic and demand flexibility rates reports published on July 1, 2025, by PG&E. We included our observations related to these reports below.

Procedures

EY performed testing procedures as follows:

1. Reviewed the DERMS and dynamic and demand flexibility rates reports.
2. Obtained and read additional reports on pilots and programs identified in the DERMS and dynamic and demand flexibility rates reports.
3. Discussed with PG&E stakeholders involved with each report.
4. Documented observations related to energization activities.

Observations

DERMS

PG&E DERMS is a technology platform that facilitates various use cases related to Distributed Energy Resource ("DER") management. Currently, three primary use cases are enabled through the DERMS platform.

- Customer-Owned Telemetry for Large Generators
- Flexible Service/Generation Connection Pilot ("Flex Connect")
- Operation of the Distribution Investment Deferral Framework ("DIDF")

Funding for DERMs, as approved in PG&E's 2023 GRC, is allocated to further develop and enhance the platform's capabilities.

PG&E does not currently operate DERMS use cases that directly reduce the need for distribution capacity. Instead, Flex Connect acts as a bridging solution intended to accelerate customer energization rather than eliminating the need for capacity upgrades, while the DIDF program helps defer capacity upgrades. To manage situations where distribution capacity is insufficient for energization requests, PG&E has implemented standardized bridging solutions, primarily consisting of load limit letters and flexible service connections.

Load limit letters are used for projects that are subject to temporary load limits as a condition of initial energization until capacity upgrades are completed. The program incorporates an automated audit process to review customer loading against these limits and offers varying load limits depending on the nature of the grid constraint.

The Flex Connect program provides additional capacity for load-limited sites under specific capacity constraint conditions. It utilizes dynamic operating limits based on day-ahead forecasted grid conditions as a bridge solution while PG&E constructs the infrastructure necessary to meet full customer demand. This program is available to commercial, industrial, and wholesale distribution customers, enabling accelerated customer energization and supporting beneficial load growth. PG&E has incorporated Flex Connect at two customer sites, including a 6MW battery energy storage system (BESS) and a 4.5 MW EV charging station. PG&E have managed to load both sites using local control systems and IEEE 2030.5 hourly day-ahead limit schedules of up to 72 hours.

PG&E DERMS platform also facilitates the operation of DIDF grid service sites, which enables PG&E to postpone costly infrastructure investments by leveraging grid services from DER providers.

Dynamic and Demand Flexibility Rates

PG&E refers to the Dynamic and Demand Flexibility Rates as Hourly Flex Pricing ("HFP") rates. As of June 2025, there are three HFP pilot initiatives in PG&E's service area that have either been completed or are currently active that include a shadow-billed hourly HFP rate:

- Valley Clean Energy Agricultural Flexible Irrigation Technology (VCE AgFIT) Pilot
- PG&E Expanded Pilots
- Phase 2 of the Vehicle to Grid Integration (VGI) Pilots

These initiatives are expected to generate insights that will support PG&E in further understanding strategies to reduce expenditures on unnecessary capacity upgrades while continuing to meet customer needs.

I. Other metrics to support thorough evaluation of energization performance

Overview

SB 410 states the auditor shall assess "any other metrics deemed relevant by the commission or third-party auditor to support a thorough evaluation of the electrical corporation's energization performance, including to identify and correct past flaws and to identify future best practices."

In addition, EY and the Energy Division collaborated in the design of this scope of work for EY's audit. During this process, EY and the Energy Division agreed that EY should evaluate 31 additional metrics related to PG&E's energization activities, to the extent possible.

Approach

EY outlined the additional metrics, gathered related context and data from process owners, and documented conclusions. For instances in which data was not available to evaluate a given metric, EY indicated this accordingly.

Procedures

EY performed testing procedures as follows:

1. Held discussions with PG&E stakeholders to discuss data availability, identify data sources, and understand key inputs and assumptions for 31 metrics.
2. Reviewed the provided data for alignment with the metric definition.
3. Documented key observations for the metrics.

Observations

#	Metric description	Description of data	Observations
1	Total labor and material costs on a per site/project basis	NB/WRO: PG&E provided its September 2025 Data Reporting Template, for projects with successful application intake dates from January 31, 2023 to June 30, 2025. The data included "total labor and material costs on a per site/project basis." Capacity: PG&E provided a list of completed MWC 06 and 46 projects in SB 410-eligible MAT	Across SB 410-eligible MWCs, PG&E tracks data related to total labor and materials on a per-project basis.

		codes with completion dates from January 1, 2024 to June 30, 2025. The data set included a cost element breakdown for each project consisting of "consulting," "contract," "labor internal," "materials," "other," and "staff aug" charges since inception of the project. A PG&E stakeholder validated that labor consists of consulting, contract, and labor internal.	
2	Site/project specific costs for the following spending categories broken out by all equipment defined as the utility responsibility for PG&E to cover under each upstream capacity projects, and Electric Rule 15, Electric Rule 16, and Electric Rule 29.	PG&E does not separately track the data related to this metric. PG&E provided EY with project site-specific costs related to materials for upstream capacity or Electric Rules 15, 16, or 29. A PG&E stakeholder indicated that equipment will not be available beyond what can be identified for materials.	PG&E indicated that the Company and other large IOUs are presenting a definition to that Energy Division, and that definition is awaiting finalization. In future reports, EY will take the outcome of that discussion into consideration.
3	Site-specific/project-specific costs for anything else PG&E covers.	NB/WRO: PG&E provided its September 2025 Energization Data Reporting Template, for projects with successful application intake dates from January 31, 2023 to June 30, 2025. The data included "site-specific/ project-specific costs for anything else PG&E covers" (i.e., field name from report). Capacity: PG&E provided a list of completed MWC 06 and 46 projects in SB410 eligible MAT codes with completion dates from January 1, 2024 to June 30, 2025. The data set includes a cost element breakdown for each project consisting of "consulting," "contract," "labor internal," "materials," "other," and "staff aug" charges since inception of the project.	Within the Energization Data Reporting Data Set, PG&E tracks "anything else PG&E covers" (i.e., field name from report). For work in the Capacity program, the Company tracks "other" costs, which are primarily overheads. EY is continuing to review data provided to assess site-specific costs.
4	The total number of charging ports and supporting cabinet power level deployed at each site as included in the customer's application.	PG&E generated application data from its SAP system for all the completed projects assessed in the energization timeline section of this report. The data included a summary tab with the "# of port from Application." Per inquiry with PG&E stakeholders, this data is pulled directly from the customer's application and is not verified for accuracy prior to application intake. Additionally,	PG&E tracks the total number of charging ports by application. The ports are tracked by total maximum loading. However, the Company does not capture supporting cabinet power levels within the customer's application.

		the stakeholder indicated that supporting cabinet power level data is not tracked in the application.	
5	The total capacity (kW) at the time of installation for each site.	NB/WRO: PG&E provided a list of completed construction projects from January 31, 2023 to June 30, 2025, in alignment with its September 2025 Data Reporting Template. For each project with an issued transformer, the data tracks the total installed capacity, reported in kVA. Capacity: PG&E provided capacity in kW before and after for completed orders in MATs 06A, 06B, 06D,06E, 06H, 46A, and 46H. The data is specifically for orders completed between January 1, 2024 and July 31, 2025. In some instances, the data provides multiple values in a cell (e.g., 75/15 or 50/50/50/50), which a PG&E stakeholder indicates represents more than one transformer is present (the "/" serves as a delimiter).	For NB/WRO, PG&E did not provide total capacity at the time of installation in kW but does have transformer data in kVA. The company indicated that it assumes a power factor of 1, meaning that transformer kVA is equivalent to kW for these purposes. For the orders in MWCs 06 and 46, capacity before and after data was not available for all orders with "N/A" data points being input for orders. PG&E clarified that because each stand-alone project does not necessarily increase the capacity of a distribution circuit or add capacity to a substation transformer; for example, reconductoring of overloaded circuit branches can allow additional load to be added to each branch without increasing circuit or bank capacity of the substation. PG&E also noted that projects for projects with multiple components, the capacity of the projects cannot be fully calculated until all project components are completed.
6	On a per-site/project basis, how much, if any, additional capacity (kW) was installed for future electric load deployment.	NB/WRO: PG&E indicated that customer applications are based on requested capacity at a point in time. Future electric load deployment information is not requested in the customer application. Capacity: PG&E provided a write-up explaining that while it provides capacity before and after for 2024 completed projects recorded to the ECNBIMA (MAT 06B and 06H), capacity values for bank and feeder projects are only provided once projects have been completed and additional capacity is available. The total new capacity is listed as a full aggregate. This total capacity includes all customer applications, including those customers served by the same bank and/or feeder project.	NB/WRO: In the current customer application process, PG&E does not track additional capacity for future electric load deployment, and there are no plans to track this in the future. Capacity: PG&E provides an aggregate value of total installed kW capacity for its Capacity Program.
7	Total construction and overhead costs for each site/project.	NB/WRO: PG&E provided its September 2025 Data Reporting Template, for projects with	PG&E tracks total construction and overhead costs for each site/project for NB/WRO work. For Capacity program work, the Company reports that

		successful application intake dates from January 31, 2023 to June 30, 2025. The data included "total construction and overhead costs for each site/project." Capacity: PG&E provided a list of completed MWC 06 and 46 projects in SB 410-eligible MAT codes with completion dates from January 1, 2024 to June 30, 2025. The data set includes a cost element breakdown for each project consisting of "consulting," "contract," "labor internal," "materials," "other," and "staff aug" charges since inception of the project. Per a PG&E stakeholder, overhead is part of the "other" category, while construction costs are not independently reported.	the "other" category is primarily for overhead, and construction costs are not tracked separately. Instead, elements related to construction costs can fall under "contract," "labor internal," and "materials."
8	Difference between the forecast construction and overhead costs for each site/project and the actual costs at the time of energization.	NB/WRO: PG&E provided its September 2025 Data Reporting Template, for projects with successful application intake dates from January 31, 2023 to June 30, 2025. The data included the difference between total estimated project costs and actual project costs at the time of energization. Estimates include all costs from project initiation through final closeout. Capacity: PG&E provided estimated cost and total project costs (as of May 2025) for orders in MATs 06H and 06B as published in its AET filing for 2024. PG&E indicated that estimated costs are for the full job through closeout.	Project estimates are for the full project costs. However, the metric requests comparison to costs at the time of energization, which are subject to change until a job is financially closed.
9	Total number of sites that received energization service annually.	PG&E provided an SAP export of all of the projects with a complete CN24 date, representing "construction complete." The data set reports all MWC 16 projects with a CN24 date between 2020 and July 2025.[25] PG&E provided an export reporting on all SB 410 eligible	The closed CN24 data represents the number of jobs that are "construction complete," but does not include meter set, which is a part of the energization process.

25 Since the Energization Reporting Data Set reports projects completed in 2024 and because the population begins with applications submitted after January 31, 2023, the number of jobs reported complete does not necessarily align with the data set provided for Metric 9 energization projects.

		projects for the Capacity Program that were completed between 2024 and July 2025. The data tracks completed projects in the column "Completion (Operational) Date."	
10	Total number of sites receiving energization service through Electric Rules 16, 29, and 15/16 or 15/29.	PG&E provided an SAP export of all of the projects with a "CN24" date, representing construction complete in its system. The data includes the applicable electric tariff.	The data provided aligns with the metric description.
11	The cost associated with completing each site's/project's energization service via Electric Rules 15, 16, and 29.	PG&E provided an SAP export of all of the projects with a CN24 date representing construction complete in its system. The data includes the applicable electric tariff and total costs since project inception.	The data provided aligns with the metric description.
12	Total number of upstream distribution capacity projects completed annually.	The Company provided data for total projects with a completed operational date from January 1, 2024 to June 30, 2025. Additional information on completed MAT 06H and 06B projects is published in PG&E's AET filing for 2024.	The data provided aligns with the metric description.
13	Total number of upstream distribution capacity projects completed annually by project type (e.g., upgraded circuit, new circuit, upgraded feeder, new feeder, upgraded substation, new substation).	PG&E provided an export reporting all SB 410 eligible projects for the Capacity Programs that were completed between 2024 and July 2025. The data tracks completed projects in the column "Completion (Operational) Date." This data set did not track by project type outside of MAT code. An additional data set, limited to the upstream capacity upgrades related to energization and MAT codes booked to the ECNBIMA in 2024, indicated project type by the following: "Bank," "Feeder," "Bank & Feeder," and "Substation."	PG&E noted that its current systems and data do not have a field that can be queried to determine if the project is for a "new" or "upgraded" feeder; instead, the existing MAT codes differentiate projects by driver, not scope. Collecting "new" vs. "upgraded" circuit data, according to PG&E, would be a manual and administratively burdensome task.
14	The cost associated with completing each site's or project's upstream distribution capacity project.	PG&E provided a list of completed upstream distribution capacity projects by SAP operative date, with total costs accounted for since inception (through June 2025).	PG&E provided point-in-time data detailing costs associated with completing each site's or project's upstream distribution capacity project. However, additional costs may be incurred, as not all projects are financially closed at this time.
15	Total cost associated with completing all energization requests (Electric Rules and	See Metrics 11 and 14, which discuss cost data for the Electric Rules and upstream distribution	See Metrics 11 and 14.

	upstream distribution capacity projects) annually.	capacity projects completed annually.	
16	Total amount of new charging (number of charge ports and number of sites) that the EV Infrastructure Rules annually, including an aggregation of which power levels of EVSE were deployed, and confirmation of reporting of any publicly available charging to the relevant public databases.	PG&E provided a static report on the Company's charging port data. The report represents the total number of charging ports. The ports data is tracked by application. PG&E does not track the total amount of new charging ports (number of charge ports and number of sites) under the EV Infrastructure Rules annually.	The Company tracks this data manually within individual order details and, therefore, it is not readily accessible.
17	Total per site/project cost for every energization upgrade (Electric Rules and upstream distribution capacity).	PG&E provided its September 2025 Data Reporting Template, for projects with successful application intake dates from January 31, 2023, to June 30, 2025. The data tracks the "total upstream capacity project cost ($$$)" for projects that triggered upstream capacity projects.	For the 16 projects that triggered an upstream capacity project that was completed as of September 22, 2025, 15 of the projects lack data for "total upstream capacity project cost ($$$)."
18	Dollar per additional kW of capacity installed on a per site basis.	A PG&E stakeholder provided a write-up, as well as an illustrative example, to explain why it does not directly track Metric 18. According to the write-up, projects with similar amounts of additional capacity can vary significantly in total cost.	PG&E captures before and after kW capacity for its Capacity Programs. However, the Company does not directly track Metric 18, in part "due to the wide variation in scope, cost, materials, dependencies (e.g., permitting), etc., across projects."
19	The type of site that received service (single-family residential, multi-unit dwelling residential, small commercial, large commercial, light-duty transportation electrification, medium-heavy-duty transportation electrification, etc.) as listed on the customer's application.	PG&E provided its September 2025 Data Reporting Template, for projects with successful application intake dates from January 31, 2023 to June 30, 2025. PG&E tracks "Business Class (requested end use)" by "new agricultural," "new commercial," "new residential multi-family/subdivision," "new residential single-family," "new public facilities," "new industrial", and "relocation/rearrangement/ upgrade." PG&E provided its annual EV Infrastructure report as support for light-duty and medium- heavy-duty transportation electrification.	PG&E has begun tracking "Business Class" categories in more granular detail for new business projects. The provided EV Infrastructure report did not include the application data.
20	Site/project specific costs for the spending	See Metric 2.	See Metric 2.

	categories broken out by all equipment defined as the utility responsibility for PG&E to cover under each upstream capacity projects, and Electric Rule 15, Electric Rule 16, and Electric Rule 29.		
21	Site-specific/project-specific costs for anything else PG&E covers to complete the energization request.	See Metric 3.	See Metric 3.
22	Per-site data on sites that choose to install additional capacity to support the applicant's anticipated future load growth, the timing for when they anticipate to utilize the additional capacity, the total additional kW capacity of the upgrade, all as listed on the customer's application, and follow-up customer survey data on when the customer actually started utilizing the additional capacity after the initial energization was complete.	See Metric 6.	See Metric 6.
23	Per site costs for the total utility-side investments made under for each site/project, identifying the costs that the IOU/ratepayers cover and that the applicant covers.	PG&E provided an SAP export for the 8,923 completed jobs reported in its September 2025 Data Reporting Template provided for this report. The data provided illustrated the IOU/ratepayer costs (interpreted as total costs incurred to PG&E after applicant paid costs) and applicant costs (interpreted as billing credits). PG&E indicated that since Capacity Programs work does not have an applicant contribution, this metric is not applicable to upstream capacity work.	The total utility-side investment is calculated as PG&E costs less applicant payments (or billing credits).
24	On a per site/project basis, the average amount of ratepayer costs on the utility-side of the meter.	See Metric 23 for a description of the relevant data. An average of the total amounts provided can be calculated.	Take an average of the total utility-side investment as calculated in metric 23.

25	Estimated annual customer bill impact resulting from the total completed energization projects.	PG&E provided a model illustrating the calculated customer bill impact from its 2024 SB 410-eligible projects.	The data provided aligns with the metric requirement.
26	If full energization of the applicant's site is not feasible in a timely manner, the load management or flexible service options on which were installed or utilized to provide the applicant with timely service.	PG&E provided information on its Flex Connect program, as well as load limiting letters related to unique projects. The data indicates customer capacity requested, and customer load connected in kW. An anticipated or known full energization date is also provided.	PG&E tracks the requested data, as well as estimates for when full service will be provided to the applicant.
27	On a per-site/project basis, if load management or flexible service was utilized to provide service, the amount of load (kW) provided to the applicant, the remaining load requested by the applicant, and an estimate for when full service will be provided to the applicant.	See Metric 26.	See Metric 26.
28	For each site, whether it is located in a disadvantaged community, another designated underserved community location (if so, which), or neither.	NB/WRO: PG&E provided its September 2025 Data Reporting Template, for projects with successful application intake dates from January 1, 2023 to June 30, 2025. For each customer application, PG&E tracks community type by "Disadvantaged Community DAC," "Tribal Community," and "Underserved Community," if applicable. Capacity: PG&E indicated that it does not track or report this information on a project-level basis, though such designations are available at the feeder level.	PG&E tracks the requested data in addition to the field "Tribal Community" for NB work.
29	Number of applications that did not result in viable utility-side energization infrastructure deployments and why (description of why does not need to be per application, but a list of all reasons why in a given year).	PG&E provided its September 2025 Data Reporting Template, for projects with successful application intake dates from January 1, 2023 to June 30, 2025. PG&E indicated canceled orders and provided reasons for why the order was terminated, including but not limited to "inactive order," "customer	The data indicating the reason for a project not resulting in a viable utility-side energization deployment represents a process improvement to the Energization Data Reporting Data Set and was not available in previous iterations of EY's report.

		request," and "no response from customer."	
30	Identification of any constraints to infrastructure deployment including, but not limited to, materials, staffing, permitting, etc.	EY inquired with PG&E on any new constraints and obstacles to infrastructure deployment.	PG&E identified the same constraints as from its March 2025 report. PG&E cited the constraints listed in its September 2025 report which are materials availability, staffing challenges, permitting delays, upstream distribution capacity upgrades, and IT and Systems.
31	On a per site/project basis, the total number of business days between a customer's service request and when the facility is energized, and the total number of business days for each step of the energization process as adopted in R.24-01-018, including description or the days in which the IOU is waiting for the AHJ, customer, or other non-utility responsibility.	PG&E provided its September 2025 Data Reporting Template, for projects with successful application intake dates from January 1, 2023 to June 30, 2025. The data provided includes end-to-end energization time and has considerations for customer dependencies and agency time.	The following metric is related to EY's assessment of energization timelines and PG&E's calculation methodology. Please see the Section A, "Timeline calculations," in this report for additional reference.

II. Financial assessment

Overview

SB 410 does not contain a requirement for the auditor to assess energization costs. However, this became an updated requirement following the issuance of D.24-07-008 in the A.21-06-021 proceeding. On July 11, 2024, the CPUC issued D.24-07-008, authorizing a ratemaking mechanism for energization projects pursuant to SB 410. D.24-07-008 states the auditor shall assess the following:

- Ordering Paragraph 14: "All energization costs allowed under the annual cap in this decision shall also be verified by the required audit …"
- Ordering Paragraph 26: "PG&E's annual expended costs for energization authorized in D.23-11-069 …"
- Ordering Paragraph 9, which references section 10.7: "Evaluate the relevancy, reasonableness and prudency of any expense relating to the planning, construction or operation of the corporation's plant"; "Assessing relevancy and allowability of MAT"; and "Assess whether a project is energization related and needed".D.24-07-008 also requires an analysis of costs tracked in the ECNBIMA for energization costs that exceed the costs authorized in D.23-11-069.

Approach

We applied a statistical sampling methodology to the total gross population of $1.8B costs from July 1, 2024, through June 30, 2025, and identified a sample of orders totaling $181M to test in more detail. The purpose of designing a stratified sample is to increase efficiency and precision through a smaller sample compared to a simple random sample. During this process, the population of $1.8B is converted into the sampling population and then divided into groups called "strata." The samples selected are weighed to reflect the sampling rates for each of the different strata.

Our testing approach included analyzing a sample of orders to assess energization projects from project initiation to closeout to determine whether orders were reasonably and prudently incurred and related to energization activities, as defined by SB 410 and proceeding R.24-01-018. We also selected a sample of transactions to test actual order costs against invoices, contracts, purchase orders, and other potentially relevant contemporaneous information.

Table 7: Energization population from July 1, 2024–June 30, 2025

Major Work Category ("MWC")	Population total	Selection amount
06	$265,753,031	$9,630,239
10	$216,357,134	$3,826,520
16	$1,248,027,876	$166,481,682
46	$108,622,902	$1,336,849
EV	$13,297,761	$115,831
Total	**$1,852,058,704**	**$181,391,121**
Population adjustments[26]	**($161,115,677)**	**($3,215,048)**
Total adjusted population[27]	**$1,690,943,027**	**$178,176,073**

Analytics

We analyzed the population of costs and performed the following analytics to identify activities that appear unusual, unreasonable, or unrelated to energization activities, as defined by SB 410, as follows:

1. Analyzed description fields within the SAP data, such as "CE Desc" and "Order Desc," to identify activities that appear unusual, unrelated, or ineligible to energization activities, consistent with the directives from D.24-07-008.
2. Analyzed the distribution of costs per MWC and MAT to identify trends for analysis.
3. Analyzed the average costs per order within each MAT to identify potential outliers.

Based on the results of our analytics, we identified 6,370 orders in MWC 10 that are not energization-related and should be adjusted out of our starting population, totaling $161M, as of the date of this report.[28] The $161M identified to date is not recommended as an accounting exclusion.

Procedures

We tested a statistical sample of orders totaling $181M to assess whether appropriate project management policies and procedures are being followed during the project lifecycle, from project initiation to closeout, including specified outputs and management approvals at each stage.

EY performed the following testing steps for orders:

1. Discussed inquiries with key stakeholders to understand the project lifecycle and project management procedures and controls in place.
2. Requested supporting documentation for sample of orders selected.
3. Analyzed project plans, designs, and estimation summaries obtained from SAP to assess whether orders were sufficiently documented prior to execution.
4. Analyzed supporting documentation to determine whether projects were sufficiently documented and executed in accordance with plans. This included:
    a. Evaluating whether assets constructed were defined and sufficiently documented.
    b. Assessing documentation of any changes to planned procedures and estimates, as well as assessing the reason for those changes.

26 PG&E's starting population was overinclusive. During the course of our testing and data analytics, we identified costs totaling $161m that should be adjusted out of the starting population, as of this report date. These findings are not recommended accounting exclusions; rather, this detail is reported so that users can reconcile to the starting population collected from SAP.
27 PG&E's starting population for the financial analysis excluded MAT 164.
28 Refer to the population adjustments in Table 7 above.

5. Analyzed AsBuilts and Construction Completion packages, which are comprehensive records detailing the purpose, design, and execution of construction work, to determine whether projects were related to energization activities, as defined by SB 410.
6. Evaluated project details to understand the type of work that was performed and assets that were constructed to assess whether projects were related to energization activities:
    a. Evaluated project purpose, type (commercial, residential, etc.), capacity requirements, permitting requirements, third-party involvement, locations and timing.

From our statistical sample of orders totaling $181M, we made transaction selections to test whether costs related to the orders were reasonably and prudently incurred and related to energization. To test costs at the transactional level, we developed testing criteria, discussed below. Results of the procedures performed, relevant observations, and suggested exclusions were recorded in the case files for each transaction.

EY detailed testing steps for order expenditures were as follows:

1. Reconciliation of SAP data to supporting documentation:
    a. Analyzed the underlying documentation to determine whether an invoice from a third party was provided.
    b. Compared the invoice amount, vendor name, and other relevant identifiers to the relevant fields of SAP data to test whether vendor names were consistent and dollar amounts agreed.
    c. If an invoice or the underlying support was lacking sufficient information or was illegible, noted that additional documents or confirmations were needed to support the transaction amount.

1. Reasonableness testing:
    a. Performed analysis to determine if a transaction was reasonably and prudently incurred for the services provided by recalculating unit prices under each cost category (e.g., labor, equipment, materials, per diem, reimbursable expenses) and comparing those unit prices to prices charged by other vendors performing similar services. Where we did not have benchmarking data from other vendors performing similar services, other publicly available information, including GSA schedules, publications, and public rate filings, etc., was considered. Where outliers were identified, additional documentation was requested. Additional procedures were performed, and the results of those procedures were documented within the relevant case files.
    b. Analyzed invoices, receipts, and other third-party support to determine whether vendors billed for items that are prohibited by PG&E's employee expense policy, such as alcohol, tobacco, or personal products and services.

2. Accuracy of recording:
    a. We compared transaction detail to order-level details, including locations, project descriptions, dates, etc., to determine whether the invoice is appropriately charged to the correct order:
        - Analyzed the date range for services provided within invoices, receipts, and other support and documented whether services took place during the project scope period.
        - Analyzed the location of services within invoices, contracts, and other support and documented whether services occurred in locations specified in the order packets.

3. Relevancy of transaction to SB 410:
    a. Analyzed the information provided in the invoice, contract, and other support to determine whether the activity recorded appears to be related to energization activity, as defined by SB 410 and D.24-07-008. We relied on Company policies and other guidance from PG&E described below to help identify the nature and timing of energization activities in addition to guidance detailed in the related proceeding, R. 24-01-018:
        - The ratemaking mechanism decision, D.24-07-008, provided guidance around what activities were eligible for recovery in the memorandum account and what activities were not.
4. For observations requiring further consideration, additional procedures were performed. In some instances, transactions can be either partially or fully unsupported. On a case-by-case basis, the dollar amount that did not fully meet the testing requirements was calculated and recommended for exclusion.

Observations

As of the date of this report and as a result of the procedures described above, we have identified approximately $8.1K within the sampled orders that is recommended for exclusion. This amount was then extrapolated to the entire population to arrive at a total recommended exclusion of approximately $319K. See Appendix B for more information on the extrapolation methodology.

We have identified four instances of costs within our sample population that do not appear reasonable and prudent, such as vendor billing errors, improper vendor billing of premium or double-time before hitting minimum straight time hours, and vendor labor billed in excess of timesheet records. Identified amounts total $8.1k.

Table 8: Exclusions to date

Observation reason	Identified amounts	Total extrapolated amount
Not reasonable and/or prudent	$8,088	$318,783
Total exclusions	$8,088	$318,783

We will continue to test energization costs (from July 2025 on) and update this list with any additional exclusions identified in subsequent reports.

III. Appendix A: Mapping of auditor requirements to EY report

#	Required metrics	Reference	In current report?	Location discussed in report	Page
1	Energization requests for previous three years	SB 410 938 (a)(3)(A)	Yes	Refer to Appendix C – EY June 2025 Report	54
2	Customer demand growth projections in distribution plan	SB 410 938 (a)(3)(B)	Yes	Customer demand growth forecast	13
3	Qualified staffing levels	SB 410 938 (a)(3)(C)	Yes	Qualified staffing levels and future staffing projections	15
4	Future anticipated staffing needs	SB 410 938 (a)(3)(C)	Yes	Qualified staffing levels and future staffing projections	15
5	Energization funding requests for previous three years	SB 410 938 (a)(3)(D)	Yes	Refer to Appendix C – EY June 2025 Report	60
6	Commission-authorized funding for energization from previous three years and authorized changes to improve energization business practices and structures	SB 410 938 (a)(3)(E)	Yes	Refer to Appendix C – EY June 2025 Report	60
7	Future authorized energization funding	SB 410 938 (a)(3)(E)	Yes	Forecast and authorized funding	17
8	Performance in meeting CPUC-established energization time periods	SB 410 938 (a)(3)(F)	Yes	Timeline calculations	5
9	Performance in meeting internal energization time periods	SB 410 938 (a)(3)(G)	Yes	Refer to Appendix C – EY June 2025 Report	55
10	Other metrics to support thorough evaluation of energization performances	Specific metrics provided by the Energy Division 938 (a)(3)(H)	Yes	Other metrics to support thorough evaluation of energization performance	23
11	Evaluation of current energization performance	SB 410 938 (a)(4)	Yes	Operational assessment	5
12	Evaluation of future energization performance	SB 410 938 (a)(4)	Partial	Operational assessment	5
13	Training and retaining an adequate workforce	SB 410 938 (a)(4)	Yes	Training and retaining an adequate workforce	16

14	Biannual reports to the Commission	SB 410 938 (a)(5)	Yes	Executive summary	All
15	Financial analysis of base costs	D.24-07-008 Ordering Paragraph 14	Yes	Financial assessment	32
16	Financial analysis specific to memorandum account costs	D.24-07-008 Ordering Paragraph 26	Yes	Financial assessment	32
17	Verify and report number and scope of energization projects	D.24-07-008 Ordering Paragraph 21	Yes	Verification of number and scope of energization projects	19
18	Recommendation to which types of projects are similar enough for meaningful average costs or costs correlated with known data	D.24-07-008 Ordering Paragraph 21	Yes	Recommendation to which types of projects are similar enough for meaningful average costs or costs correlated with known data	20
19	Distributed Energy Resource Management Systems (DERMS) Report to be sent to auditor no later than January 1 and July 1 of each year and in its next GRC	D.24-07-008 Ordering Paragraph 24	Yes	Distributed Energy Resource Management (DERMS) considerations	21
20	Dynamic and demand flexibility rates report to be sent to auditor no later than January 1 and July 1 of each year	D.24-07-008 Ordering Paragraph 25	Yes	Dynamic and demand flexibility rates report	21

Pacific Gas and Electric Company

2025 Energization sampling and estimation report

Prepared by
Siyu Qing and Ryan Petska

Ernst & Young LLP
1101 New York Avenue, NW
Washington, DC 20005

August 25, 2025

Introduction

The purpose of the Pacific Gas and Electric Company ("PG&E") 2025 energization order sampling study was to estimate the total error amount for the PG&E energization order population related to the total order cost in fiscal year 2025. This report focuses exclusively on the statistical sampling and estimation methodology of the study. Decisions about the review process and the sample determinations are not part of this report.

Questions regarding the sampling and estimation methodology can be directed to Siyu Qing at +1 202 327 7210 or Ryan Petska at +1 202 327 7245.

I: Executive summary

A stratified sample of 131 energization orders (orders) was selected from a sampling population of 42,859 orders. Based on the results of the sample, it was estimated that the total error amount was $318,783, with margins of error of $377,283 and $453,364 at 90% and 95% confidence levels, respectively.

Table 1 summarizes the estimation results.

Table 1. Estimation summary

Estimation Category	Estimated Amount	Margin of Error at 90% Confidence Level	Margin of Error at 95% Confidence Level
Total Error Amount	$ 318,783	$ 377,283	$ 453,364

II: Population

Population

The original population contained 50,059 orders totaling $1,852,058,704 in order cost (cost). After removing orders with zero costs, the final population consisted of 49,345 orders totaling $1,852,058,704 in cost. The final population also contained -$285,572,811 in negative orders (credits), which were set aside during sample design and adjusted for during estimation via credit adjustment. Therefore, the resulting sampling population contained 42,859 orders totaling $2,137,631,515 in cost.

A summary of the population is provided in Table 2.

Table 2. Population summary

	Total Net		Positives (Debits)		Negatives (Credits)	
	Amount	Number of Records	Amount	Number of Records	Amount	Number of Records
Original Data	**$ 1,852,058,704**	**50,059**	**$ 2,137,631,515**	**43,452**	**$ (285,572,811)**	**6,607**
- Zero	$ -	714	$ -	593	$ -	121
Final Population	**$ 1,852,058,704**	**49,345**	**$ 2,137,631,515**	**42,859**	**$ (285,572,811)**	**6,486**
Sampling Population	**$ 2,137,631,515**	**42,859**	**$ 2,137,631,515**	**42,859**	**$ -**	**-**

Sampling unit

The sampling unit was an individual order.

Sampling frame

The sampling frame consisted of 42,859 orders totaling $2,137,631,515 in cost.

III: Sample design

Stratification

A stratified random sample design was used for the study. Stratified sample designs are highly efficient designs that often allow confidence and precision goals to be obtained with smaller samples than would be required with simple random samples. The population data was divided into groups, or strata, and each stratum was sampled separately, with different sampling rates to increase the efficiency of the design. During estimation, the sampled records were appropriately weighted to reflect the sampling rates for the different strata. In this study, the individual order's cost amount was used as the basis for stratification.

A certainty or take-all stratum was defined for orders with large costs relative to the rest of the data (greater than or equal to $10,000,000). Orders in this stratum (stratum 5) were sampled at a rate of 100% in an effort to improve the stability of the estimate. The remaining non-certainty stratum boundaries were determined to approximately equalize the population size (*Nh*) multiplied by the estimated standard deviation (*Sh*) across the non-certainty strata.

The sample design is shown below in Table 3.

Table 3. Sample design summary

Stratum Number	Stratum Definition	Population Size	Population Cost	Sample Size	Sample Cost
1	$0 to $46,899.99	36,499	$ 334,632,522	30	$ 248,596
2	$46,900 to $224,999.99	5,026	$ 471,470,962	30	$ 2,720,970
3	$225,000 to $1,030,999.99	1,149	$ 479,972,846	30	$ 11,429,354
4	$1,031,000 to $9,999,999.99	174	$ 429,847,869	30	$ 82,233,269
5	$10,000,000 and above	11	$ 421,707,315	11	$ 421,707,315
Total		**42,859**	**$ 2,137,631,515**	**131**	**$ 518,339,505**

IV: Sample selection and results

Source and seed of random numbers

The function RANUNI in the statistical software, SAS, was used to generate the random numbers for sample selection. The seed used to generate random numbers was 185205870.

Method of associating random numbers to the frame

Using the RANUNI function in SAS and the random seed mentioned above, a random number was directly assigned to each record in the original population.

Serialization of frame

Prior to generating random numbers in SAS, the population was sorted by the field "Order." The purpose of this sort was to place the file in a reproducible and verifiable order, so the random number assignment was independent of an arbitrary frame sequence.

Method of selection

To select the sample, the sampling frame was sorted by stratum and the random numbers described above. Thus, the entire file was put into random order within a stratum. Then the required number of orders per stratum was selected according to this random order. For example, the first 30 orders in this random order were selected for stratum 1.

Sample results

The results of the sample review are available upon request. Table 4 provides a summary of the results by stratum.

Table 4. Sample results summary

Stratum Number	Stratum Definition	Population Size	Population Cost	Sample Size	Sample Cost	Sample Error Amount
1	$0 to $46,899.99	36,499	$ 334,632,522	30	$ 248,596	$ -
2	$46,900 to $224,999.99	5,026	$ 471,470,962	30	$ 2,720,970	$ 450
3	$225,000 to $1,030,999.99	1,149	$ 479,972,846	30	$ 11,429,354	$ 7,638
4	$1,031,000 to $9,999,999.99	174	$ 429,847,869	30	$ 82,233,269	$ -
5	$10,000,000 and above	11	$ 421,707,315	11	$ 421,707,315	$ -
Total		**42,859**	**$ 2,137,631,515**	**131**	**$ 518,339,505**	**$ 8,088**

V: Estimation

Standard statistical methods were used to produce the estimates from the stratified sample. Differences in the probabilities of selection among strata were properly accounted for by statistical weighting. The mean per unit ("MPU") estimator[29] was used to compute the estimated total error amount.

The MPU estimator

The MPU estimator is the weighted sum of the sample means of error amount over all strata. In stratified sampling with *L* strata, this can be represented as:

$$\hat{Y}_{mpu} = \sum N_h \bar{y}_h,$$

Where:

N_h is the number of orders in stratum *h*.
$\bar{y}_h$ is the sample mean of error amount.
h = 1 to *L*, the number of strata.

The standard error of the MPU estimate is given by.

$$\hat{S}(\hat{Y}_{mpu}) = \sqrt{\sum N_h (N_h - n_h) S_{yh}^2 / n_h},$$

Where:

$S_{yh}^2 = \sum \frac{(y_{hi} - \bar{y}_h)^2}{n_h - 1}$ is the sample variance of error amount in stratum *h*.

Confidence limits were calculated from the estimate plus or minus its margin of error, where the margin of error is computed as the standard error times the student's t-value with a 90% or 95% two-sided confidence.

29 Roberts, D. M. (1978) Statistical Auditing, American Institute of Certified Public Accounts, Inc., New York.

The degrees of freedom for the t-value were approximated using the Satterthwaite formula as follows:

$$n_e = \left(\sum g_h s_{yh}^2\right)^2 \Big/ \sum \frac{g_h^2 s_{yh}^4}{n_h - 1},$$

Where:

$$g_h = N_h(N_h - n_h)/n_h.$$

As a result of the Satterthwaite adjustment, the t-value used in estimation was 1.691 and 2.032 for a 90% and 95% confidence level, respectively.

Table 5 shows the estimated total error amount and its associated precision measures.

Table 5. Estimation results summary

			90% Two-sided Confidence Level			95% Two-sided Confidence Level		
	Estimated Amount	Standard Error	Margin of Error	Lower Bound	Upper Bound	Margin of Error	Lower Bound	Upper Bound
Total Error Amount	$ 318,783	$ 223,112	$ 377,283	$ (58,499)	$ 696,066	$ 453,364	$ (134,581)	$ 772,148

Credit adjustments

The estimated total error amount was adjusted to account for the -$285,572,811 remaining credits. The overall estimated total error amount, determined from the sample (positive amounts only), was adjusted by applying the estimated error percentage of 0.017% to the unmatched credits (-$285,572,811). Therefore, the adjusted estimated total error amount was calculated as follows:

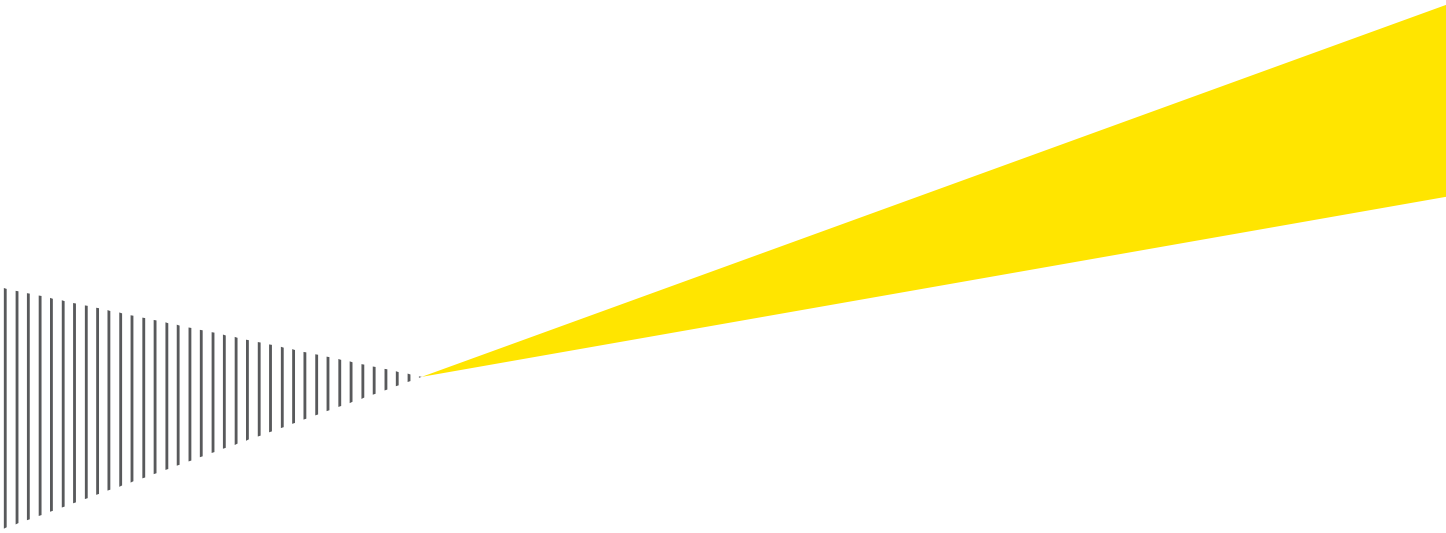
$367,937 + (0.017% * (-$285,572,811)) = $318,783.

The associated precision measures (standard error, margin of error, etc.) were adjusted in a similar fashion.

V. Appendix C: Pacific Gas & Electric SB410 Powering Up Californians Act Assessment, filed on June 13, 2025.

Pacific Gas & Electric
SB 410 Powering Up Californians Act Assessment

June 13, 2025



Building a better working world

Building a better working world

June 13, 2025

Pacific Gas & Electric

To Narbir Hothi of Pacific Gas & Electric:

We have completed our first biannual report assessing Pacific Gas and Electric's ("PG&E" or "the Company") energization processes, timelines and costs, as described in Senate Bill 410 Powering Up Californians Act ("SB 410"). Our engagement was performed in accordance with our engagement letter ("Contract") dated June 7, 2024 and change order executed on July 3, 2024, and our procedures were limited to those described in that letter. After our Contract was executed, the CPUC issued Decision 24-07-008 and Decision 24-09-020, which contained several tasks and requirements that are inconsistent with the Contract currently executed with EY. As such, EY and PG&E are working closely on a change order to validate the scope of our work aligns with the additional requirements included in D.24-07-008 and D.24-09-020 for future reports.

Our findings and observations resulting from our procedures are limited to those identified as of this report date and provided throughout the report. Additional information received will be updated in the subsequent 2025 report.

As noted in our statement of work, the engagement is performed under standards promulgated by the American Institute of Certified Public Accountants ("AICPA").

This report is intended solely for the information and use of the Company's management. The Company may disclose this assessment report, or discuss information relating to the Services, with any governmental authority, agency or regulator ("Regulator") with jurisdiction over the Company; provided that the Company provides EY with advanced written notice of such disclosure. The Company acknowledges and agrees that: (i) EY's Services were not performed, and our report was not prepared, for any Regulator, and (ii) any such disclosure to a Regulator is for informational purposes only and not for any third party's use and/or benefit.

Very truly yours,

Ernst & Young LLP

Table of Contents

I. Executive summary

Background

In February 2024, a request for proposal was issued seeking a consultant to assess PG&E's energization projects in accordance with the SB 410 Powering Up Californians Act ("SB 410"), as codified in the California Public Utilities Code Sections 930-939.5. Ernst and Young LLC ("EY" or "we") was selected as the third-party consultant to provide these services. The contract was executed on June 7, 2024, and a change order was executed on July 3, 2024.

SB 410, signed into law on October 7, 2023, and related Rulemaking (R.) 24-01-018[1], aim to streamline the process for customer energization requests, addressing delays faced by customers of large electric investor-owned utilities (IOUs) when seeking new or upgraded electric service. SB 410 mandates the California Public Utilities Commission ("CPUC") to establish average and maximum target energization timelines and create a reporting mechanism for customers when these targets are not met to expedite California's electrification efforts to help achieve the state's carbon neutrality goals by 2045.

EY assessed PG&E's business practices and procedures for energizing new customers, as well as PG&E's timeline calculations, list of energization projects, and costs associated with energization projects to determine if they were reasonably and prudently incurred.

- **Operational Assessment -** Within this section, we describe the current population of energization projects identified by PG&E, including our assessment of PG&E's timeline calculations for obtaining such information. We analyzed PG&E's customer demand growth calculations for its energization program for 2025 and 2026. Additionally, we reviewed PG&E's historical funding forecasts and authorized funding related to energization projects in the General Rate Case (GRC) and provided insights into funding trends and their impacts for meeting future growth.
- **Financial Assessment -** Within this section, we describe the population of energization projects from January 2021 – June 2024 as captured in PG&E's books and records. We performed analytical procedures on this population in addition to a statistical sample of orders. Each order is intended to represent an energization project (with some variation). As a result, we are testing a statistically valid sample of orders to understand the nature of the work. We further selected expenditures within those orders to understand if the financial information is accurate, prudent and reasonable.

Limitations and assumptions of the assessment

Our work was performed based on the information provided to us by the Company and statements made by Company personnel as of this report date. EY performed factual analyses and procedures and documented the findings and results from such analyses and procedures.

Our procedures do not constitute an "audit," "review" or "compilation" of the Company's financial statements, as those terms are defined by the AICPA for financial statement audits, nor do we provide any form of assurance on the financial statements as a whole.[2] Additionally, our engagement cannot be relied upon to disclose errors, irregularities, or illegal acts including fraud or defalcations that may exist.

[1] On January 30, 2024, The CPUC issued Order Instituting Rulemaking (R.) 24-01-018, to serve as a venue for the Commission to implement certain provisions of Senate Bill (SB) 410 and Assembly Bill (AB) 50.

[2] AICPA, AU §508

EY performed the assessment in accordance with the consulting professional standards in the Statement on Standards for Consulting Services ("SSCS") established by the AICPA. Furthermore, our approach is designed to achieve the principles of the National Association of Regulatory Utility Commissioners' ("NARUC") Rate Case and Audit Manual (2003) in an effective and efficient manner. As noted in the manual, we relied on the commonly understood concepts of "prudence" and "reasonableness" when reviewing expenses and corresponding adjustments proposed. The manual states the purpose of applying these concepts is to "determine a revenue requirement and customer rates that are just, fair, reasonable, and sufficient."

The Company may disclose this assessment report, or discuss information relating to the Services, with any governmental authority, agency or regulator ("Regulator") with jurisdiction over the Company; provided that the Company provides EY with advanced written notice of such disclosure. The Company acknowledges and agrees that: (i) EY's Services were not performed, and our report was not prepared, for any Regulator, and (ii) any such disclosure to a Regulator is for informational purposes only and not for any third party's use and/or benefit.

Our procedures were limited as a result of the following factors:

- In July 2024, the CPUC issued Ratemaking Decision (D.24-07-008) and in September 2024, the CPUC issued the Energization Time Periods Decision (D.24-09-020). These decisions contained several tasks and requirements that are inconsistent with the contract and scope of work currently executed with EY. EY has been in discussion with PG&E to accommodate these items. EY, PG&E and the Energy Division subsequently aligned on the requirements to be addressed in the draft April 30, 2025, report.
- In addition, certain information is not available at the time of this report to complete all of our planned procedures. Our assessment is multi-year, and we will continue to update our observations in future reports, as more information becomes available. Consequently, this report does not cover all the tasks included in the decisions, and we are unable to provide finalized observations or conclusions at this time. Further details regarding the reconciliation of regulatory decision tasks and the EY report are provided in Appendix A below.

II. Operational assessment

Timeline calculations

PG&E's Biannual Energization Report

Overview

As stated in SB 410, the third-party auditor shall assess "the electrical corporation's performance in meeting energization time periods established by the commission pursuant to this article." R.24-01-018, established by the CPUC to implement SB 410 requirements, requires PG&E to adopt energization targets and timelines and track utilities compliance with those requirements. On September 12, 2024, the CPUC issued a decision, D.24-09-020, establishing target energization time periods and a reporting template for the large investor-owned utilities in California to report their progress on a biannual basis, with the first report to be submitted on March 31, 2025.

On March 31, 2025, PG&E filed its first Biannual Energization Report pursuant to Decision 24-09-020 (referred to as "the March 2025 Biannual Report" or "the Report"). The Report provided data for customer energization requests submitted from January 31, 2023, to December 31, 2024.

Approach

EY leveraged PG&E's March 2025 Biannual Report to assess the timelines for Electric Rule 16, Electric Rule 29 and Electric Rule 15/16, as well as the accuracy of the information within the Report,

according to the methodology established by the Company[3]. Using the project level detail in the Energization Data Reporting Template[4], we reperformed calculations of the reported average energization metrics and selected a sample of completed projects to analyze. From our sample of completed projects, we established start and end dates for each energization phase by extracting data from the Company's SAP and Salesforce data. Then, we recalculated the timeline for each energization phase, and recalculated the Customer Calendar Days, PG&E Calendar Days, and the End-to-End Energization Cycle Calendar Days, using the Company's defined methodology.

Procedures

EY performed testing procedures as follows:

1. Obtain the March 2025 Biannual Report and the supporting Energization Data Reporting Template.
2. Perform a mathematical recalculation of the Electric Rule 16, Electric Rule 29 and Electric Rule 15/16 energization metrics disclosed in the March 2025 Biannual Report using the Energization Data Reporting Template.
3. Using the Energization Data Reporting Template,
    1. Identify completed projects that have start and end dates for each energization phase.
    2. Identify completed projects that have zero total PG&E calendar days.
    3. Compare, by project, calendar days in Phases 7 and 8 to the total PG&E calendar days to identify unusual patterns, such as, projects with total PG&E calendar days that are less than the calendar days stated for Phase 7 and Phase 8.
    4. Follow up on items identified and document observations.
4. Select a judgement sample of 25 completed projects from the Energization Data Reporting Template and perform the following for each project:
    a. Agree start date and end date of each energization phase to the Company's query of SAP and Salesforce. Agree a selection of the start dates and end dates in the query to SAP and/or Salesforce.
    b. Recalculate the timeline for each energization phase.
    c. Recalculate the Customer Calendar Days, PG&E Calendar Days, and the End-to-End Energization Cycle Calendar Days, based on the Company's defined methodology.
    d. Identify and report any outliers and/or discrepancies.

Observations to date

The following information summarizes our understanding of the data contained within PG&E's Report and methodology for obtaining such data:

- Table 1 below is a summary of the average energization timelines for completed projects included in the Report, which the Company defines as new business applications submitted between January 31, 2023, and December 31, 2024 that were completed by March 20, 2025. The average timelines do not include projects that were not completed by March 20, 2025, or applications that were cancelled or rejected. Based on the data received, approximately 41%[5] of the applications submitted between January 31, 2023, and December 31, 2024 were completed by March 20, 2025; therefore, the timelines presented in Table 1 below represent less than half of the applications submitted between January 31, 2023 and December 31, 2024.

[3] Please note: EY did not review design effectiveness of the methodology for this reporting period, and we make no comment on appropriateness of this methodology.

[4] The Energization Data Reporting Template is an Excel attachment filed with their March 2025 Biannual Report.

[5] PG&E Biannual Energization Report Pursuant to Decision 24-09-020, dated March 31, 2025, pdf page 6.

Table 1 - PG&E's energization metrics reported*

Description	Electric Rule 16	Electric Rule 29	Electric Rule 15/16	Main Panel Upgrades**
Total Projects Submitted 1/31/23 - 12/31/24 and Completed Through 3/20/25	5,882	56	3,104	21,632
Average Energization PG&E Calendar Days***	122.45	119.79	119.14	50.99
Average End-to-End Energization Calendar Days****	306.97	466.66	320.59	61.38
Percent of Completed Jobs Under Maximum Energization Days	97.90%	96.40%	96.40%	59.00%

** PG&E's Biannual Energization Report Pursuant to Decision 24-09-020, dated March 31, 2025, pdf pages 6 and 7.*
*** Main Panel Upgrade projects are captured under annual blanket orders making it difficult to delineate the required energization phase structure. See Section 3C of the March 2025 Biannual Report for more details.*
**** Average number of days it takes PG&E to complete the steps in the energization process under its control.*
***** Average number of days from the start date of an energization request (date the customer's application is deemed complete) to the date the customer's request is energized.*

- The Company utilized the following methodology for capturing and reporting the energization metrics in Table 1:
    1. Phase Responsibility:
        - PG&E Time is attributed to the following operational phases:
            - Phase 2: Engineering & Design
            - Phase 4: Utility Dependencies
            - Phase 6: IOU Site Readiness
            - Phase 7: Construction
            - Phase 8: Service Energization
        - Customer Time is limited to the following phases:
            - Phase 1: Customer Intake[6]
            - Phase 3: Customer Dependencies
            - Phase 5: Customer Site Readiness
    2. PG&E's methodology principles:
        - Customer Overlap in Phases: When a customer phase coincides with a PG&E phase (e.g., a customer-related process occurs simultaneously with a PG&E process) that overlapping time is exclusively categorized as customer time and not attributed to PG&E time. The result is that shared time is not double counted. As mentioned above, we make no comment regarding whether this methodology is appropriate.
        - Concurrent PG&E Phase Work: In cases where PG&E undertakes multiple overlapping phases concurrently (e.g., two PG&E processes happen at the same time), those overlapping days are not counted multiple times. Instead, they are aggregated as a single day within the total PG&E time count. The result is that overlapping time is not double counted. As mentioned above, we make no comment regarding whether this methodology is appropriate.
- The Company reported a total of 8,919 completed projects. The Company recognizes that its current systems of record (SAP and Salesforce) did not track all the required start and end dates needed for the energization timelines. In addition, the Company identified data gaps and outlier data that impacted the energization timelines. Below are data gaps and outlier data[7] that impacted the metrics in Table 1:

[6] While PG&E attributed Phase 1 as Customer Time, Phase 1 days are not included in the calculation of Customer Calendar Days or Customer Business Days.

[7] For a complete list and description of reporting gaps, see Section 3 to the PG&E Biannual Energization Report Pursuant to Decision 24-09-020, dated March 31,2025.

1. IOU Site Readiness (Phase 6) is measured by the time between the Requested Inspection Date and the actual First Inspection Date. The Company has stated that IOU Site Readiness was not a data point it required Company personnel to capture in its systems of record prior to Decision 24-09-020, dated September 12, 2024. The Company stated that it cannot recreate the missing historical IOU Site Readiness data. As a result, IOU Site Readiness data was only available for 21[8] of 8,919 completed projects included in the metrics in Table 1. The Company has stated it has developed and launched a new Salesforce tool to track this time.[9] The Company stated that as Company personnel are trained and the utilization of this new tool grows, the availability of Site Readiness data for energization projects will increase. Design and operating effectiveness of the newly implemented process, controls and tools will be assessed as part of future reports.
2. The Service Energization phase (Phase 8) is measured by the time between construction complete and meter set. Because of the format differences, the Company stated it is unable to consistently pull meter set data into the project timeline data. In addition, the Company indicated that there were instances where meter set data was not maintained in an electronic format, i.e., it was only available in manual documentation. The Company has stated that it cannot recreate the missing historical meter set data. As a result, meter set data was only available for 3,339[10] of 8,919 completed projects included in the metrics in Table 1. For projects where a meter set date was not retrievable, the Company substituted the construction completion date to signal project completion.

   The Company indicated that it is working to develop an automated process to merge meter data and project timeline data. In addition, the Company stated it is evaluating the need to issue guidance to internal job owners on accurate and timely capture of meter set data. The Company anticipates that these enhancements will allow for more complete meter set data for projects that require a meter to be installed. The Company stated that future enhancements to meter set data may result in an increase to total PG&E responsible time. Enhancement status will be reassessed as part of future reports.

   It is important to recognize that not all new business projects will require the installation of a new meter; therefore, there will continue to be projects that have no meter set date. Examples include a customer requesting additional load, a main panel upgrade, or an electric vehicle charging project where a meter already exists. In this situation, the construction completion date is used to signal project completion. In addition, the Company stated that there could be projects with meter set dates that occur much later than the completion of the energization construction phase. For example, the Company stated that the meter set dates for an energization project related to a new strip mall could be substantially later than the completion of the energization construction phase because tenants will move into the newly constructed strip mall over an extended period. In this instance, the set date of the first meter in the strip mall is used to signal project completion.

3. Main Panel Upgrade (MPU) projects are reported separately from the standard tariff projects because they do not follow the typical energization process from intake to

[8] PG&E Biannual Energization Report Pursuant to Decision 24-09-020, dated March 31, 2025, pdf page 9.

[9] EY has not assessed the new salesforce tool at the time of this report.

[10] PG&E Biannual Energization Report Pursuant to Decision 24-09-020, dated March 31, 2025, pdf page 9.

meter set via a PG&E order. At this time PG&E captures these projects under annual blanket orders and as such cannot provide detailed energization timelines. Additionally, these orders may include other work in support of an MPU, for example: weather heads, new meters, or relocation. PG&E's MPU reporting does not include the vast majority of the required reportable fields due to the internal order and notification structure they use to track Main Panel projects. The timelines reported represent total PG&E calendar days without detailed accounting of customer time. PG&E expects that future reporting will include more robust and accurate timelines with detailed phase information for both Customer, PG&E, and when applicable, Agency time.

4. The Company removed outlier data. Outlier data includes items such as data entry errors, measurement anomalies, and extreme deviations from typical values. Below are the outliers identified in the Report:
    - Customer Site Readiness (Phase 5): In instances where negative day aging[11] occurred within the site readiness phase, PG&E removed those data points to avoid skewing averages. Negative aging within the site readiness phase could occur due to data entry errors or other anomalies within the job process.
    - Completed Jobs Without Task Data: PG&E identified and excluded a subset of jobs from its reporting and analysis processes. The Company stated that those jobs, although marked as complete in its system, lack meaningful task-specific data necessary for accurate and comprehensive evaluation. Sixty-nine (69)[12] jobs were excluded from the population of completed projects used to determine the metrics in Table 1.
    - Residential EV Upgrades: Residential electric vehicle upgrades are captured under MATs 161 and 162 at PG&E. The Company has excluded them from the Report because the typical energization process from Intake through Energization does not take place for the vast majority of these projects. Most EV upgrade projects only encounter the Design phase and are considered complete once a design review has been completed.[13]
    - Streetlights: Streetlights are categorized under MAT 160 at PG&E. Per a joint agreement with the other Investor-Owned Utilities (IOUs) in California, work involving streetlights has been excluded from the Report.[14]

Below are our observations identified as a result of the procedures performed:

1. As identified in the March 2025 Biannual Report, the Company's systems of record (SAP and Salesforce) did not allow for tracking of all start and end dates for each of the energization phases. We observed that 7 of the 8,919 completed projects listed in the Energization Data Reporting Template had start and end dates for all 8 of the energization phases. The Company has stated that it cannot capture or recreate the missing start and end dates. Because start and end dates are not available for all completed projects, the energization metrics in the March 2025 Biannual Report do not represent a baseline measurement of PG&E's energization timelines. The Company has stated that it is designing process enhancements and technological improvements that, when fully implemented, will allow it to capture more complete and accurate timeline data. For new projects requested after the full implementation of the process and technological improvements, PG&E expects the timeline data to get better. However, there are projects that were started before the issuance of Decision 24-09-020 that were not completed by March 20, 2025, the date the Company compiled the March 2025 Biannual

[11] Negative day aging occurs when the start date of a phase is after the end date of the phase. The Company indicated that negative aging within a phase could be caused by data entry errors or other anomalies within the job process.

[12] PG&E Biannual Energization Report Pursuant to Decision 24-09-020, dated March 31, 2025, pdf page 25.

[13] Although these MATs were excluded from the Report, MATs 161 and 162 are still eligible for SB 410 funding.

[14] Although this MAT was excluded from the Report, MAT 160 is still eligible for SB 410 funding.

Report. Therefore, there may be completed projects included in subsequent biannual reports that do not have start and end dates for each of the energization phases.

2. We observed that 156 of the 8,919 completed projects were initiated by customers after the adoption of Decision 24-09-020 on September 12, 2024. None of the 156 projects had start and end dates for all 8 of the energization phases. As indicated above, the Company stated it is currently designing processes and technological improvements that, when fully implemented, will allow it to capture more complete and accurate timeline data.
3. We observed that the energization metrics in the March 2025 Biannual Report (summarized in Table 1 above) differed[15] from the Energization Data Reporting Template. The Company explained that the energization metrics in the Main March 2025 Biannual Report were compiled as of March 20, 2025, and the Energization Data Reporting Template was compiled as of March 28, 2025. Because the underlying projects are moving through the energization phases, data is constantly changing. Therefore, we would expect data to change each time it is pulled from the source systems. The Company is working to create a static report for the biannual reporting process.
4. As described in the March 2025 Biannual Report, when a customer phase coincides with a PG&E phase (e.g., a customer-related process occurs simultaneously with a PG&E process) that overlapping time is exclusively categorized as customer time and not attributed to PG&E time. During our testing, we also identified that the Company excludes overlapping Agency time[16] and overlapping customer-initiated re-design time from PG&E time. Both of these overlapping criteria reduce PG&E's time in their Report.
5. As described in the March 2025 Biannual Report, in instances where negative day aging occurred within the customer site readiness phase[17] (Phase 5), PG&E removed those data points to avoid skewing averages that otherwise would have artificially lowered PG&E's timelines, which means an energization phase with negative aging is counted as zero days in the timeline calculation. 935 of the 8,919 completed projects had instances of negative day aging.
6. We identified two completed projects that had zero total PG&E Calendar Days. These two projects demonstrate that the assumptions used in PG&E's calculation may total days that are not representative of actual PG&E effort. For one of these two completed projects, both the total Customer Calendar Days and the total PG&E Calendar Days were zero. This is the result of customer phases overlapping with PG&E phases and/or missing dates. In addition, Customer Calendar Days exclude Phase 1.
7. We identified 11 of the 8,919 completed projects that had total PG&E Calendar Days less than PG&E Calendar Days for Phase 8 – Service Energization. Four of these projects were captured in our sample testing. For those 4 projects, total PG&E Calendar Days were less than the PG&E Calendar Days for Phase 8 because Customer Phase 5 dates overlapped PG&E Phase 8 dates.
8. We identified 643 of the 8,919 completed projects that had total PG&E Calendar Days less than the PG&E Calendar Days for Phase 7 – Construction. Eleven of those projects were captured in our sample testing. For those 11 projects, the Company explained that total PG&E Calendar Days were less that PG&E Calendar Days for Phase 7 for a variety reasons, including:
    a) The Company included incorrect total PG&E Calendar Days in the Energization Data Reporting Template due to a program logic error. PG&E has also stated they have corrected the program logic, which we will test in future reports.
    b) Overlapping Agency time reduced total PG&E Calendar Days.

[15] Electric Rule 16 total project count was different by 79 (1% difference). Electric Rule 15/16 total project count was different by 44 (1% difference). Electric Rule 16 Average End to End Energization Calendar Days were different by .15 days (less than 1%). Electric Rule 15/16 Average End to End Energization Calendar Days were different by 1.56 days (less than 1%).

[16] Agency time is third party activities. Activities include joint pole intent, land services, environmental services, encroachment permit, and Federal Aviation Administration (FAA).

[17] During EY's sample testing, we also observed negative days in the customer intake phase (Phase 1) and the construction phase (Phase 7). The Company removed the negative days.

c) Customer Phase 5 dates overlapped PG&E Phase 7 dates.

9. We noted that for eight projects in our sample, when the end date for an energization activity was erroneously recorded as a date later than the meter set date, that later date was captured as the project end date for purposes of calculating the End-to-End Energization Calendar Days. Using the later date as the project end date overstates the End-to-End Energization Calendar Days. PG&E has stated they have corrected this error, and we will analyze that in future reports.
10. We noted that for eight projects in our sample, the Company determined that the dates were entered into SAP incorrectly. The Company stated that they will be issuing additional guidance to internal job owners on accurate and timely capture of job task dates to improve the data entry process.
11. We identified errors in the calculation of PG&E Calendar Days and End to End Calendar Days for two projects that were related to housing subdivisions during our sample testing. In instances when the request for service is a housing subdivision, building permitting data can cause errors in the timeline calculations due to energization phase overlaps. The Company stated that it is working to develop a process to resolve this error.
12. We identified five projects within our sample where PG&E Calendar Days for a completed project reported in the Energization Data Reporting Template was incorrect. The Company stated that in early April 2025, it identified errors in the program logic used to calculate PG&E Calendar Days and has since updated the program to correct the errors. The Company has stated that 155 completed projects in the March 2025 Biannual Report were impacted by the logic error.
13. The Company continues to gather support and answer requests related to our testing of the energization timelines. We will provide any updates and additional findings in our next report.

Energization requests from prior three years

Overview

As stated in SB 410, the third-party auditor shall assess the "electrical corporation's customer energization requests for the previous three years." R.24-01-018 requires PG&E to adopt energization targets and timelines and track a utility's compliance with those requirements. As part of the proceeding, the CPUC requested historical information from each of the three electric IOUs to determine statewide energization targets. On September 12, 2024, the CPUC issued decision D.24-09-020, establishing target energization time periods. Please note, the CPUC target energization time periods were not established during the historical period assessed in this section (2021-2023); however, D.24-09-020 definitions and requirements were used as guidance for assessing historical numbers in this section.

Approach

EY obtained energization requests from the last 3 years (2021-2023) to assess the timelines for Electric Rule 16, Electric Rule 29 and Electric Rule 15/16, as well as the accuracy of the information within the workpaper, according to the methodology established by the Company.

Procedures

EY performed testing procedures as follows:

1. Obtain the supporting workpapers containing energization project timelines from 2021 to 2023.
2. Assess the integrity of the data provided to us.
3. Perform walkthroughs with stakeholders to understand the overall calculation logic and methodology for identifying energization projects.

4. Perform a mathematical recalculation of the Electric Rule 16, Electric Rule 29 and Electric Rule 15/16 energization projects provided in the workpaper support based on the methodology defined by PG&E.

Observations to date

1. From 2021-2023, PG&E did not have a defined process and system to consistently track and monitor all relevant Energization timeline data fields. As stated in PG&E's March 2025 Biannual Report, PG&E recognizes that its current systems of record (SAP and Salesforce) do not track all required fields needed to perform timeline calculations, which means there are data gaps, especially within historical data. PG&E acknowledged past inefficiencies and started implementing process improvements to comply with the requirements from the Energization Time Periods Decision, D.24-09-020. Some improvements noted to date in PG&E's rebuttal testimony[18]:
    a. In late 2023, PG&E identified that more than half of customer applications did not result in a completed project due to customers cancelling the project. In response, PG&E improved the application portal's screening tools and required customers to submit documents prior to application submission.
    b. PG&E is continuing to redesign the collection of project information and documents, as well as PG&E-customer engagement, prior to customers completing their application.
    c. When new business customers submit their applications, PG&E's engineers create internal orders, job packages, and estimates for the work. PG&E is continuing to work on improved visual management and operating reviews to reduce the wait time for designs and estimates. PG&E started improving its job-package-preparation and estimating processes in 2024, which included creating job-package checklists and enhancing training for engineers.
    d. In 2023, the New Business team initiated a customer-outreach campaign to address delayed applications. Active applications were rerouted to PG&E's Service Planning organization to initiate the next steps. If PG&E was unable to reach a customer within 90 days, the application was cancelled, which freed up resources to focus on active applications.
    e. In 2024, PG&E established the New Business Project Management Office (NB PMO) to provide oversight over the New Business program and execution of the New Business workplan.
2. PG&E pulled the data of energization projects from 2021-2023 using the same logic and methodology as their March 31, 2025 report. Please refer to "Observations to date" in "PG&E's Biannual Energization Report" section for additional information on data gaps identified to date.

PG&E has indicated that they will continue to refine and update their processes and systems to capture and calculate timelines going forward. EY will provide additional information in future Energization reports.

Performance in meeting internal time periods

Overview

SB 410 states the third-party auditor shall assess the "electrical corporation's performance in meeting its internally established energization time periods over the prior 10 years or longer, as necessary."

[18] PG&E's rebuttal, "Pacific Gas and Electric Company's (U 39 E) Motion to Revise 2025 and 2026 Energization Cost Caps," in response to Rulemaking 24-01-018, dated October 4, 2024.

Approach

EY assessed whether the Company had established internal energization time periods over the last 10 years and assessed the Company's performance in meeting its internally established energization time periods, as applicable.

Procedures

EY performed testing procedures as follows:

1. Performed walkthroughs with key stakeholders to inquire about PG&E's policies and procedures and whether they had internal time goals for completing energization projects.
    a. During our walkthroughs with the Company, it came to our attention that PG&E did not have internally established energization time periods, which is why we were unable to perform the rest of our planned procedures for this requirement.

Observations to date

PG&E did not have defined internal energization time periods prior to the issuance of the September 2024 decision establishing target energization time periods, D.24-09-020.

In addition, as stated in PG&E's March 2025 Biannual Report, PG&E recognizes that its current systems of record (SAP and Salesforce) do not track all required fields needed to perform timeline calculations, which means there are data gaps, especially within historical data.

Customer demand growth forecast

Overview

SB 410 states the auditor shall assess "the electrical corporation's projections of customer demand growth included in the electrical corporation's distribution plan, including growth in new customers and growth in demand from existing customers." In addition, it states, "The third-party auditor shall evaluate the electrical corporation's current and future energization performance and make recommendations as to whether the electrical corporation is adequately meeting and anticipating customer demand."

EY requested insight from Energy Division on their interpretation of "current and future energization performance" and Energy Division responded with the following clarification: "Energy Division believes that this builds on the previous assessments that the CPUC and EY have done in A.21-06-021 and R.24-01-018, including timelines, customer demand, staffing, and funding levels."

Approach

EY assessed PG&E's key assumptions and inputs in their electrical projections of customer demand growth, including growth in new customers and growth in demand from existing customers. Customer demand growth is closely linked with Company staffing, "energization performance" and capital funding plans, which means EY will be assessing customer demand growth holistically with the other related sections within this report: timelines, staffing and funding levels. We will continue to update our assessment of customer demand growth and current and future performance in future reports.

Procedures

EY performed testing procedures as follows:

1. Obtain an understanding of the Company's process for developing the forecast.

2. Identify key factors/inputs upon which the forecast was developed.
3. Obtain sources of information that the Company used in formulating the forecast.
4. Trace key assumptions to the internal sources to determine whether the indicated source of information was used.
5. Perform a mathematical recalculation of the forecast.
6. Inquire about Company's process improvements for developing the forecast.

Observations to date

The Company estimates customer demand growth using the following:

- Known Work: This is the number of applications deemed complete ("ADC") and represents the number of energization applications from customers that have not been completed at the time of the forecast. The Company obtains this information from its SAP system, which is its system of record.
- Forecast of New Work (also called "Steady State ADC"): This is the forecast of new energization requests. The forecast is based on total historical ADC as obtained from the Company's SAP system. The Company uses a 4-year historical average of orders deemed complete and applies a 3-year historical average cancellation rate to arrive at the Forecast of New Work. The Company then makes assumptions of how much of the Steady State ADC will be completed in each forecast year; the Company does this by using historical service requests, which is obtained from SAP.

EY recalculated the Company's 2025 and 2026 customer demand growth forecast that was disclosed in the response to data request EstablishEnergizationTimelinesOIR_DR_TURN_008-Q008 using data sources provided by the Company. The total forecasted customer demand growth for 2025 and 2026 was 38,175 ADCs. This differs from the total forecasted customer demand growth of 39,477 ADCs that was reported in Winget Declaration Attachment C, Table C-4. The Company has stated that the forecast in Winget Declaration Attachment C, Table C-4, assumed that the Steady State ADC would be completed within the calendar year it was forecasted, meaning it did not account for customers requesting energization in a later year. The Steady State ADC in EstablishEnergizationTimelinesOIR_DR_TURN_008-Q008 considers customers requesting energization in a later year.

Observations noted to date:

- EY recommends that PG&E should assess the design effectiveness of its customer demand growth forecasting process (including the need to use a more granular forecast) for the following reasons:
    - As stated above, the Company uses total historical ADC to forecast Steady State ADC. At this time, it does not contemplate increased or decreased volumes based on legislation impacts.
    - PG&E's current forecast is not granular. The Company stated they are developing a new bottoms-up Steady State ADC forecasting process that utilizes historical ADC by MAT and job size. Because job size is a driver of unit cost, PG&E believes this new forecasting process will allow the Company to improve their forecast of energization costs. EY will review the new Steady State ADC forecasting process after it is implemented.
    - PG&E filed its 2027 rate case on May 15, 2025 which included the updated forecast for customer demand growth. EY will assess this forecast in the next Biannual report.

Additional considerations

When requesting recovery of energization costs in base rates, the Company forecasts customer demand growth because anticipated customer demand drives the energization costs the Company expects to incur. While the forecast of customer demand growth and the associated energization costs

is necessary for developing a test year in a rate case, the Company's method of recovering energization costs is designed to allow the Company to only recover actual energization costs incurred.

Specifically, the Company currently recovers only a portion of its eligible energization costs in base rates. Our understanding is that the Company has obtained CPUC approval in D.24-07-008 to record the difference between actual eligible energization costs and the amount of energization costs recovered in base rates in a memorandum account, up to the annual cap amount. At some point in the future, the Company will request recovery of energization costs recorded in the memorandum account through a mechanism outside of base rates. The Company's recovery of energization costs through the combination of base rates and the memorandum account is designed to allow the Company to recover the total actual energization costs incurred, subject to a reasonableness review.

Table 2 - Illustrative example of recovery of energization costs

Line #	Description	Amount
1	Total energization costs incurred in 2026	$ 10,000,000
2	Energization costs authorized in base rates in 2026	$ 4,000,000
3	Energization costs not recovered in base rates (Line 1 - Line 2). This amount is deferred to the memorandum account, if it's below the annual cap amount authorized in D.24-07-008.	$ 6,000,000
4	Under recovered energization costs deferred to the memorandum account are recovered through a rate mechanism outside of base rates.	$ 6,000,000
5	Net Recovery[19]	$ -

Qualified staffing levels and future staffing projections

Overview

SB 410 states that the auditor shall assess "the electrical corporation's qualified staffing levels and future anticipated staffing needs to meet projections for customer demand growth, including the ability of the electrical corporation to sufficiently build its workforce." In addition, it states that the third-party auditor shall evaluate the "electrical corporation's current and future energization performance and make recommendations as to whether the electrical corporation is … adequately training and retaining an adequate workforce."

EY requested insight from Energy Division on their interpretation of "current and future energization performance" and the Energy Division responded with the following clarification: "Energy Division believes that this builds on the previous assessments that the CPUC and EY have done in A.21-06-021 and R.24-01-018, including timelines, customer demand, staffing, and funding levels."

Approach

EY assessed PG&E's current energization practices and procedures related to staffing, as well as key assumptions and inputs for determining staffing projections. To reduce energization timelines in compliance with SB 410, PG&E is required to develop forecasts to meet current demand, address the backlog of projects and sufficiently plan for future demand growth within its energization program, all of which requires sufficient staffing.

Staffing is closely linked with customer demand growth and "energization performance", which means EY will be assessing staffing holistically with the other related sections within this report: timelines,

[19] For capital costs, interim revenue requirements will be recovered, but only up to the revenue requirements cap authorized in D.24-07-008. After 2027, energization related capital expenditures will be recovered through the GRC.

customer demand growth and funding levels. We will continue to update our assessment of staffing and current and future performance in future reports.

Procedures

EY performed testing procedures as follows:

1. Conduct walkthroughs with PG&E stakeholders on staffing procedures and projection methodologies.
2. Assess relevant policies.
3. Identify key inputs upon which the forecast was developed.
4. Obtain sources of information that the Company used in formulating the forecast.
5. Compare projection methodology to customer demand growth.

Observations to date

PG&E's current workforce planning process includes the HR Solutions and Services Department to work with each line of business (LOB) to develop their workforce plans. The LOBs determine the workforce they will need to perform the required work, balancing use of contractors and third parties with PG&E employees. These forecasts are adjusted and updated as new or changed work priorities and funding levels are established.

Our observations are as follows:

1. During the course of the proceeding, PG&E developed an updated plan to address immediate demand and eliminate the backlog before 2026. The current plan utilizes a mix of internal and external resources, with a heavier reliance on more expensive contractor resources. PG&E has indicated the following in their rebuttal testimony[20]:

    a. Energization projects are increasing in size, scope and complexity, requiring PG&E to build more system reinforcements and upgrades to serve new electric loads safely and reliably.
    b. Contractor resources are comprised of large crew sizes, which are better staffed and able to handle larger projects.
    c. Assigning larger projects to contract crews frees up internal crews to pivot to emergencies when needed.
    d. Hiring permanent staff to address a temporary backlog is not cost-effective over the long term, and it requires the purchase of additional vehicles, equipment, tools, etc.
    e. Onboarding and training internal resources will delay the completion of forecasted and backlog work.
2. To assess the sufficiency of PG&E's staffing plan in meeting forecasted demand and backlog of applications, we have assessed the most current timeline data in PG&E's first biannual report. As noted in that section, we have identified some observations within that subset of data. A large portion of those projects reported in PG&E's first biannual report were executed prior to the updated staffing plan. As we continue to test more projects in the future, we will update our observations on the sufficiency of PG&E's current staffing plan.
3. Utility staffing projections are closely tied to customer demand growth forecasts, which are expected to undergo updates. Please refer to our observations outlined in the "Customer demand growth" section above.
4. In addition, PG&E is still working on their staffing projections for the upcoming 2027 GRC. We will continue to assess the sufficiency of PG&E's staffing levels and projections as more information comes to light.

[20] PG&E's rebuttal, "Pacific Gas and Electric Company's (U 39 E) Motion to Revise 2025 and 2026 Energization Cost Caps," in response to Rulemaking 24-01-018, dated October 4, 2024.

Forecasted and authorized funding

Overview

SB 410 states the auditor shall assess:

- "Funding requested by the electrical corporation to support energization requests for the previous three years in the general rate case or any other proceeding, and the efficacy of those previous requests in meeting customer demand."
- "Commission authorized funding for the electrical corporation to support energization for the previous three years, future authorized funding, and authorized changes to the electrical corporation's business practices or structures to improve its ability to respond to changing customer demand."

In addition, it states that the third-party auditor shall evaluate the "electrical corporation's current and future energization performance and make recommendations as to whether the electrical corporation is … funded at sufficient levels to meet forecasted demand growth."

EY requested insight from the Energy Division on their interpretation of "future authorized funding". The Energy Division responded with the following statement, "ED interprets 'future authorized funding' to be funding that is already authorized but for future years (e.g., ECNBIMA 2025 and 2026 authorization) and upcoming funding requests in their GRC submission."

Approach

In addition to the analyses of customer demand growth projections, we analyzed PG&E's energization funding requests and commission authorized funding over the past three years (2021-2023) and compared funding requests and authorized numbers to actual PG&E spend during that period. This analysis highlights PG&E's historical forecasting and funding patterns and their alignment with SB 410 requirements.

SB 410 also requires a future funding assessment. For 2027 and beyond, that data is not available at this time to assess PG&E's projections. We will continue to update our assessment of funding and current and future performance in future reports.

Procedures

EY performed testing procedures as follows:

1. Review historical data on funding requests submitted by the electrical corporation through GRC to determine what funds are provided within the GRC and final decision for energization projects.
2. Conduct walkthroughs with PG&E stakeholders to understand the forecasting process.
3. Understand how GRC activities are budgeted, planned for and performed.
4. Analyze the funding levels in relation to actual spend using historical data (2021-2023).
    a. At the time of our report, we were not able to compare funding to actual spend for 2024, given our population cutoff was June 2024 and PG&E is still finalizing their books for year end.

Observations to date

Our understanding of PG&E's historical forecasting factors is provided below:

1. PG&E used current estimates and historical averages as key inputs for requested funding in the 2020 and 2023 GRC.

Table 3 – PG&E's 2020 GRC forecasting factors

MWC	PG&E's forecasting factors
06	• Based on projects and engineering estimates • Used a 3-year average
10	• Based on Rosen Consulting Group (RCG) Model
16	• Based on historical trends • Based on RCG Model
46	• Based on projects and engineering estimates

We have observed the following to date:

1. PG&E spent $1B more than forecasted and $1.2B more than authorized for energization-related MAT codes from 2021-2023. Due to the timing of the 2023 GRC, which included recorded amounts through 2020, the 2021 - 2023 overspend has not been recovered. The 2021-2023 overspend for O&M expenses (MWC EV in Table 5) has not and will not be recovered. For capital expenditures (MWC 06, 10, 16 and 46 in Table 5), the 2021-2023 overspend is included in the Company's 2027 GRC application, which includes recorded capital expenditures through 2024. See tables below.

Table 4 – Historical funding by MWC (in 1000s)

MWC	Total Forecast 2021-2023*	Total Actuals 2021-2023**	Total Variance
06	$288,110	$415,951	($127,841)
10	$435,324	$518,905	($83,581)
16	$1,684,965	$2,502,674	($817,709)
46	$139,862	$106,512	$33,349
EV	$13,878	$44,350	($30,471)
Total	**$2,562,139**	**$3,588,392**	**($1,026,253)**

Note: Totals in this table include eligible and partially eligible MAT codes as outlined in Ratemaking Decision (D.24-07-008) and assessed during financial analytics procedures.
**Forecasted amounts represent requested amounts in "reply brief with escalation update".*
*** Actuals are based on EY's starting population provided by PG&E at the beginning of the project and do not include MAT 46A.*

Table 5 – Authorized funding by MWC (in 1000s)

MWC	Total Authorized 2021-2023	Total Actuals 2021-2023*	Total Variance 2021-2023
06	$276,362	$415,951	($139,590)
10	$421,076	$518,905	($97,829)
16	$1,597,037	$2,502,674	($905,637)
46	$131,948	$106,512	$25,435
EV	$39,992	$44,350	($3,673)
Total	**$2,466,414**	**$3,588,392**	**($1,121,293)**

Note: Totals in this table include eligible and partially eligible MAT codes as outlined in Ratemaking Decision (D.24-07-008) and assessed during financial analytics procedures.
**Actuals are based on EY's starting population provided by PG&E at the beginning of the project and do not include MAT 46A.*

2. In the 2023 GRC, PG&E forecasted $3.9B in 2024-2026 for energization-related activity, and authorized amounts were $3.1B which is within $500K of actual spend from 2021-2023 of $3.6B.
    a. As evidenced by D.24-07-008, there is a general recognition that current funding is not sufficient to cover the backlog of projects. Therefore, the CPUC authorized PG&E to

establish the Electric Capacity and New Business Interim Memorandum Account (ECNBIMA) to record energization costs pursuant to SB 410, and to include revenue requirements resulting from capital additions recorded within the ECNBIMA in its Annual Electric True Up Advice letters that serve as the ratemaking mechanism for granting interim rate recovery for such costs, subject to a reasonableness review in PG&E's next GRC. Through the memorandum account, PG&E will track revenue requirements associated with incremental spend above amounts authorized in the last GRC, within the allowable maximum incremental revenue requirement stated in D.24-07-008. We will analyze actual spend in future reports.

Table 6 – Forecasted GRC spend by MWC (in 1000s)

MWC	Total Forecast 2024-2026*	Total Authorized 2024-2026	Actual Spend 2021-2023**
06	$527,031	$397,003	$415,951
10	$542,227	$444,490	$518,905
16	$2,632,994	$2,098,204	$2,502,674
46	$239,879	$191,179	$106,512
EV	$0	$44,961	$44,350
Total	**$3,942,131**	**$3,175,837**	**$3,588,392**

Note: Totals in this table include eligible and partially eligible MAT codes as outlined in Ratemaking Decision (D.24-07-008) and assessed during financial analytics procedures.
**Forecasted amounts represent requested amounts in "reply brief with escalation update". Totals in this table include eligible and partially eligible MAT codes as outlined in Ratemaking Decision (D.24-07-008) and assessed during financial analytics procedures.*
*** Actuals are based on EY's starting population provided by PG&E at the beginning of the project and do not include MAT 46A.*

3. As noted in other sections above (Refer to "Customer Demand Growth Projections" and "Staffing" sections), it is recognized that PG&E needs to refine its forecast methodology and assumptions for energization-related activities to meet future demand growth and reduce overspend. PG&E's projection methodologies rely heavily on historical data which does not address the unprecedented rise in energization requests. Additionally, PG&E should consider future legislation in its forecasts for the upcoming GRC proceeding. A new bottom-up approach to forecasting customer demand is currently under development. We will review this new forecasting process upon its completion and continue to evaluate the adequacy of the requests as further information becomes available.

III. Financial assessment

Analysis of energization costs

Overview

SB 410 does not contain a requirement for the auditor to assess energization costs. However, this became an updated requirement during proceeding R.24-01-018, which was established by the CPUC to implement SB 410 requirements. On July 11, 2024, the CPUC issued D.24-07-008, authorizing a ratemaking mechanism for energization projects pursuant to SB 410. D.24-07-008 states the auditor shall assess the following:

- Ordering Paragraph 14: "All energization costs allowed under the annual cap in this decision shall also be verified by the required audit…"
- Ordering Paragraph 26: "PG&E's annual expended costs for energization authorized in D.23-11-068…"
- Ordering Paragraph 9, which references section 10.7: "Evaluate the relevancy, reasonableness and prudency of any expense relating to the planning, construction or operation of the

corporation's plant"; "Assessing relevancy and allowability of MAT"; and "Assess whether a project is energization related and needed".

- D.24-07-008 also requires an analysis of costs tracked in the ECNBIMA for energization costs that exceed the costs authorized in D.23-11-069.[21]

Approach

We analyzed the gross population of approximately $4.5B of costs from January 1, 2021, to June 30, 2024.[22] We segregated the population into "projects" by order number and performed analytics across the population.

From the total gross population, we applied a statistical sampling methodology[23] and identified a sample of orders totaling $871M to test in more detail. The purpose of designing a stratified sample is to increase the efficiency and precision through a smaller sample compared to a simple random sample. During this process, the population of $4.5B is converted into the sampling population and then divided into groups called strata. The samples selected are weighted to reflect the sampling rates for each of the different strata.

Our testing approach included analyzing a sample of orders to assess energization projects from project initiation to close-out to determine whether orders were reasonably and prudently incurred and related to energization activities, as defined by SB 410 and proceeding R.24-01-018. We also selected a sample of transactions to test actual order costs against invoices, contracts, purchase orders and other potentially relevant contemporaneous information.

Table 7 - Energization population from January 2021 – June 2024

Major Work Category ("MWC")	Population Total	Selection Amount
06	$511,663,181	$103,807,788
10	$691,689,145	$32,010,552
16	$3,134,616,235	$701,241,765
46	$138,688,510	$17,742,274
EV	$50,843,984	$16,749,707
Total	**$4,527,501,055**	**$871,552,087**
Population adjustments[24]	**$1,278,171,186**	
Total adjusted population[25]	**$3,249,329,869**	**$871,552,087**

Analytics

We analyzed the population of costs and performed the following analytics to identify activities that appear unusual, unreasonable, or unrelated to energization activities, as defined by SB 410, as follows:

[21] We will assess memorandum account spend in future reports.

[22] Please note, this first report only analyzed base spend. We analyzed cost data by pulling specific time periods. As of June 2024, PG&E did not exceed authorized amounts. We will test memorandum account spend in the next report.

[23] Refer to Appendix B for more detail.

[24] PG&E's starting population was overinclusive, knowing the proceeding was still open and new guidance was coming out. During the course of our testing and data analytics, we identified costs totaling $1.3B that should be adjusted out of the starting population, as of this report date. These findings are not recommended accounting exclusions, rather, this detail is reported so that users can reconcile to the starting population collected from SAP.

[25] PG&E's starting population for the financial analysis inadvertently did not include MAT 46A.

1. Analyzed description fields within the SAP data, such as "CE Desc" and "Order Desc," to identify activities that appear unusual, unrelated or ineligible to energization activities, consistent with the directives from D.24-07-008.
2. Analyzed the distribution of costs per MWC and MAT to identify trends for analysis.
3. Analyzed the average costs per order within each MAT to identify potential outliers.

Based on the results of our analytics, we identified 3 MAT codes and 11,077 orders that should be adjusted out of our starting population, totaling $1.3B, as of the date of this report.[26] The $1.3B identified to date are not recommended accounting exclusions. Our starting population was overinclusive, knowing the proceeding was still open and new guidance was coming out, such as D.24-07-008.

Procedures

We tested a statistical sample of orders totaling $871M to assess whether appropriate project management policies and procedures are being followed during the project lifecycle, from project initiation to close-out, including specified outputs and management approvals at each stage.

EY performed the following testing steps for orders as follows:
1. Held walkthroughs with key stakeholders to understand the project lifecycle and project management procedures and controls in place.
2. Requested supporting documentation for sample of orders selected.
3. Analyzed project plans, designs and estimation summaries obtained from SAP to assess whether orders were sufficiently documented prior to execution.
4. Analyzed supporting documentation to assess whether projects were sufficiently documented and executed in accordance with plans. This included:
    a. Evaluating whether assets constructed were defined and sufficiently documented.
    b. Assessing documentation of any changes to planned procedures and estimates, as well as assessing the reason for those changes.
5. Analyzed AsBuilts and Construction Completion packages, which are comprehensive records detailing the purpose, design, and execution of construction work, to assess whether projects were related to energization activities, as defined by SB 410.
6. Evaluated project details to understand the type of work that was performed and assets that were constructed to assess whether projects were related to energization activities.
    a. Evaluated project purpose, type (commercial, residential, etc.), capacity requirements, permitting requirements, third party involvement, locations and timing.

From our statistical sample of orders totaling $871M, we made transaction selections to test whether costs related to the orders were reasonably and prudently incurred and related to energization. To test costs at the transactional level, we developed testing criteria, discussed below. Results of the procedures performed, relevant observations, and suggested exclusions were recorded in the case files for each transaction.

EY detailed testing steps for order expenditures were as follows:
1. Reconciliation of SAP data to supporting documentation:
    a. Analyzed the underlying documentation to determine whether an invoice from a third party was provided.
    b. Compared the invoice amount, vendor name, and other relevant identifiers to the relevant fields of SAP data to test whether vendor names were consistent, and dollar amounts agreed.

[26] Refer to the population adjustments in Table 7 above.

c. If an invoice or the underlying support was lacking sufficient information or was illegible, it was noted that additional documents or confirmations were needed to support the transaction amount.

2. Reasonableness testing:
    a. Performed analyses to determine if a transaction was reasonably and prudently incurred for the services provided by recalculating unit prices under each cost category (e.g., labor, equipment, materials, per diem, reimbursable expenses) and comparing those unit prices to prices charged by other vendors performing similar services. Where we did not have benchmarking data from other vendors performing similar services, other publicly available information including GSA Schedules, publications, public rate filings, etc. were considered. Where outliers were identified, additional documentation was requested. Additional procedures performed and the results of those procedures were documented within the relevant case files.
    b. Analyzed invoices, receipts, and other third-party support to determine whether vendors billed for items that are prohibited by PG&E's employee expense policy, such as alcohol, tobacco, or personal products and services.
3. Accuracy of recording
    a. We compared transaction detail to order level detail, including locations, project descriptions, dates, etc., to determine whether the invoice is appropriately charged to the correct order.
        i. Analyzed the date range for services provided within the invoices, receipts, and other support and documented whether the services took place during the project scope period.
        ii. Analyzed the location of services within the invoices, contracts, and other support and documented whether the services occurred in locations specified in the order packets.
4. Relevancy of transaction to SB 410:
    a. Analyzed the information provided in the invoice, contract, and other support to determine whether the activity recorded appears to be related to energization activity, as defined by SB 410 and D.24-07-008. We relied on Company policies and other guidance from PG&E described below to help identify the nature and timing of energization activities in addition to guidance detailed in the related proceeding, R. 24-01-018:
        i. The ratemaking mechanism decision, D.24-07-008, provided guidance around what activities were eligible for recovery in the memorandum account and what activities were not.
    5. For observations requiring further consideration, additional procedures were performed. In some instances, transactions can be either partially or fully unsupported. On a case-by-case basis, the dollar amount that did not fully meet the testing requirements was calculated and recommended for exclusion.

Observations to date

As of the date of this report and as a result of the procedures described above, we have identified approximately $24K within the sampled orders that is recommended for exclusion. This amount was then extrapolated to the entire population to arrive at a total recommended exclusion of $1.5M. See Appendix B for more information on the extrapolation methodology.

Below is a list of preliminary observations as of the date of this report:

1. Not related to SB 410: Identified one instance where an order for an in-kind replacement was incorrectly charged to an energization order, totaling $487.
2. Does not align to contract: We have identified eight instances of costs within our sample population where rates billed were higher than the agreed upon rates in the contract, totaling $3.9K.

3. Not reasonable/prudent: We have identified fourteen instances of costs within our sample population that do not appear reasonable or prudent, such as high rates, billing errors, improper billing of premium or double-time on non-holiday weekdays before hitting minimum straight time hours, unsupported subcontractor charges, and labor billed in excess of timesheet records. Identified amounts total $15K.
4. Canceled orders: We have identified three samples within our testing population that were canceled. These orders should be removed, totaling $4.8K.

Table 8 – Exclusions to date

Observation Reason	Identified Amounts	Total Extrapolated Amount
Not Related to SB 410	$487	$151,742
Does not align to contract	$3,912	$674,145
Not reasonable/prudent	$15,032	$520,570
Outside of order location	$89	$145,164
Canceled Order	$4,760	$4,760
Total exclusions to date	**$24,280**	$1,496,380

We will continue to test energization costs (from July 2024 on) consisting of both base and incremental spend and update this list with any additional exclusions identified in future reports.

IV. Appendix A – Mapping of auditor requirements to EY report

As noted in the executive summary, decisions within the energization proceeding dictated that the auditor should perform specific tasks. Many of these tasks were not contemplated in the current contract between PG&E and EY. EY is actively working with PG&E on a contract change order to include these additional requirements. Additionally, several of these tasks require data that is not available at this time. EY will continue to request and test more data as it becomes available. This assessment is a multi-year assessment where each report will build upon the last. Metrics not included in this report will be included in future reports.

#	Required Metrics	Reference	In current report?	Location Discussed in Report	Page
1	Energization Requests for Previous Three Years	SB 410 938 (a)(3)(A)	Yes	Energization requests from prior three years	53
2	Customer Demand Growth Projections in Distribution Plan	SB 410 938 (a)(3)(B)	Yes	Customer demand growth forecast	13
3	Qualified Staffing Levels	SB 410 938 (a)(3)(C)	Partial	Qualified staffing levels and future staffing projections To assess sufficiency of staffing levels, the most current timeline data assessed from PG&E's first biannual report included projects that were completed before the implementation of the updated staffing plan. As we continue to test more projects in the future, we will update our observations on the sufficiency of the current staffing plan.	15
4	Future Anticipated Staffing Needs	SB 410 938 (a)(3)(C)	Partial	Qualified staffing levels and future staffing projections PG&E's staffing projections are closely tied to customer demand growth forecasts, which are expected to undergo updates. In addition, PG&E is currently working on their staffing projections for the upcoming 2027 GRC. We will continue to evaluate as additional information becomes available.	15
5	Energization Funding Requests for Previous Three Years	SB 410 938 (a)(3)(D)	Yes	Forecasted and authorized funding	17
6	Commission Authorized Funding for Energization from Previous Three Years and Authorized Changes to Improve Energization Business Practices and Structures	SB 410 938 (a)(3)(E)	Yes	Forecasted and authorized funding	17

7	Future Authorized Energization Funding	SB 410 938 (a)(3)(E)	Partial	Forecasted and authorized funding For 2024-2026, we assessed forecasted and authorized amounts and compared to historical actuals. The cost data is not available at this time to compare to true actuals for that time period. PG&E is still developing and/or updating their forecasts for their upcoming 2027 GRC. Therefore, that data is not currently available for assessment.	17
8	Performance in Meeting CPUC-Established Energization Time Periods	SB 410 938 (a)(3)(F)	Yes	Timeline calculations	47
9	Performance in Meeting Internal Energization Time Periods	SB 410 938 (a)(3)(G)	Yes	Performance in meeting internal time periods	54
10	Other Metrics to Support Thorough Evaluation of Energization Performances (31)	Specific metrics provided by Energy Division. 938 (a)(3)(H)	No	Not a requirement of SB 410 or D.24-07-008. EY and PG&E are working on a contract change order, and we will plan to address these metrics, to the extent the data is available, in future reports.	n/a
11	Evaluation of Current Energization Performance	SB 410 938 (a)(4)	Yes	Operational assessment (All sections)	5
12	Evaluation of Future Energization Performance	SB 410 938 (a)(4)	No	Customer demand growth forecast PG&E is still developing and/or updating their forecasts for their upcoming 2027 GRC. Therefore, that data is not currently available for assessment.	n/a
13	Training and Retaining an Adequate Workforce	SB 410 938 (a)(4)	No	Not included in our Contract. Our quality standards do not permit us to report anything not included in our Contract. EY and PG&E are working on a contract change order.	n/a
14	Biannual Reports to the Commission	SB 410 938 (a)(5)	Yes	Executive summary All sections of this report.	All
15	Financial Analysis of base costs	D.24-07-008 Ordering Paragraph No. 14	Yes	Financial assessment	32

16	Financial Analysis Specific to Memorandum Account costs	D.24-07-008 Ordering Paragraph No. 26	No	We analyzed cost data by pulling specific time periods. As of June 2024, PG&E did not exceed authorized amounts. We will test memorandum account spend in the next report.	n/a
17	Verify and Report Number and Scope of Energization Projects	D.24-07-008 Ordering Paragraph No. 21	Partial	Requirement was issued in July 2024 after EY's Contract was signed; therefore, this requirement was not included in our Contract. However, certain procedures already performed in other sections address this topic. <u>PG&E's Biannual Energization Report</u> <u>Financial assessment</u> - As part of our financial analysis, we performed data analytics across the population and identified costs not related to SB 410. Additional analyses and/or metrics will require a contract change order.	47, 32 (Table 7 footnote and analytics section)
18	Recommendation to Which Types of Projects Are Similar Enough for Meaningful Average Costs or Costs Correlated with Known Data	D.24-07-008 Ordering Paragraph No. 21	No	Requirement was issued in July 2024 after EY's Contract was signed; therefore, this requirement was not included in our Contract. Our quality standards do not permit us to report anything not included in our Contract. EY and PG&E are working on a contract change order.	n/a
19	Distributed Energy Resource Management Systems (DERMS) Report to be sent to auditor no later than January 1 and July 1 of each year and in its next GRC	D.24-07-008 Ordering Paragraph No. 24	No	Requirement was issued in July 2024 after EY's Contract was signed; therefore, this requirement was not included in our Contract. Our quality standards do not permit us to report anything not included in our Contract. EY and PG&E are working on a contract change order.	n/a
20	Dynamic and Demand Flexibility Rates Report to be sent to auditor no later than January 1 and July 1 of each year	D.24-07-008 Ordering Paragraph No. 25	No	Requirement was issued in July 2024 after EY's Contract was signed; therefore, this requirement was not included in our Contract. Our quality standards do not permit us to report anything not included in our Contract. EY and PG&E are working on a contract change order.	n/a

V. Appendix B – Statistical report

Pacific Gas and Electric Company

2024

Energization order

Sampling and estimation report

Prepared by
Huantong Wu, Siyu Qing and Ryan Petska

Ernst & Young LLP
1101 New York Avenue, NW
Washington, DC 20005

April 28, 2025

Introduction

The purpose of the Pacific Gas and Electric Company (PG&E) 2024 energization order sampling study was to estimate the total error amount for the PG&E energization order population related to the total order cost from fiscal year (FY) 2021 through 2024. This report focuses exclusively on the statistical sampling and estimation methodology of the study. Decisions about the review process and the sample determinations are not part of this report.

Questions regarding the sampling and estimation methodology can be directed to Siyu Qing at (202) 327-7210 or Ryan Petska at (202) 327-7245.

Section I: Executive summary

A stratified sample of 157 energization orders (orders) was selected from a sampling population of 66,243 orders. Based on the results of the sample, it was estimated that the total error amount was $1,491,621 with margins of error of $677,453 and $811,160 at 90 and 95 percent confidence levels, respectively.

Table 1 summarizes the estimation results.

Table 1. Estimation summary

Estimation Category	Estimated Amount	Margin of Error at 90% Confidence Level	Margin of Error at 95% Confidence Level
Total Error Amount	$1,491,621	$ 677,453	$ 811,160

Section II: Population

Population

The original population contained 83,018 orders totaling $4,527,501,055 in order cost (cost) from FY2021 through FY2024. After removing orders with zero costs, the final population consisted of 78,000 orders totaling $4,527,501,055 in cost. The final population also contained -$248,722,476 in negative orders (credits) which were set aside during sample design and adjusted for during estimation via a credit adjustment. Therefore, the resulting sampling population contained 66,243 orders totaling $4,776,223,532 in cost.

A summary of the population is provided in Table 2.

Table 2. Population summary

	Total Net		Positives (Debits)		Negatives (Credits)	
	Amount	Number of Records	Amount	Number of Records	Amount	Number of Records
Original Data	**$ 4,527,501,055**	**83,018**	**$ 4,776,223,532**	**70,433**	**$ (248,722,476)**	**12,585**
- Zero	$ -	5,018	$ -	4,190	$ -	828
Final Population	**$ 4,527,501,055**	**78,000**	**$ 4,776,223,532**	**66,243**	**$ (248,722,476)**	**11,757**
Sampling Population	**$ 4,776,223,532**	**66,243**	**$ 4,776,223,532**	**66,243**	**$ -**	**-**

Sampling unit

The sampling unit was an individual order.

Sampling frame

The sampling frame consisted of 66,243 orders totaling $4,776,223,532 in cost.

Section III: Sample design

Stratification

A stratified random sample design was used for the study. Stratified sample designs are highly efficient designs that often allow confidence and precision goals to be obtained with smaller samples than would be required with simple random samples. The population data was divided into groups, or *strata*, and each stratum was sampled separately, with different sampling rates to increase the efficiency of the design. During estimation, the sampled records were appropriately weighted to reflect the sampling rates for the different strata. In this study, the individual order's cost amount was used as the basis for stratification.

A certainty or take-all stratum was defined for orders with large costs relative to the rest of the data (greater than or equal to $12,000,000). Orders in this stratum (stratum 6) were sampled at a rate of 100 percent in an effort to improve the stability of the estimate. The remaining non-certainty stratum boundaries were determined to approximately equalize the population size (*Nh*) multiplied by the estimated standard deviation (*Sh*) across the non-certainty strata.

The sample design is shown below in Table 3.

Table 3. Sample design summary

Stratum Number	Stratum Definition	Population Size	Population Cost	Sample Size	Sample Cost
1	$0 to $49,659.99	51,503	$ 631,384,908	30	$ 372,391
2	$49,660 to $161,515.99	9,854	$ 871,774,694	30	$ 2,724,419
3	$161,516 to $448,896.99	3,438	$ 894,974,113	30	$ 8,022,406
4	$448,897 to $1,590,881.99	1,238	$ 915,432,028	30	$ 23,715,999
5	$1,590,882 to $11,999,999.99	203	$ 730,494,725	30	$ 104,553,809
6	$12,000,000 and above	7	$ 732,163,063	7	$ 732,163,063
Total		**66,243**	**$ 4,776,223,532**	**157**	**$ 871,552,087**

Section IV: Sample selection and results

Source and seed of random numbers

The function RANUNI in the statistical software, SAS, was used to generate the random numbers for sample selection. The seed used to generate the random numbers was 8301800.

Method of associating random numbers to the frame

Using the RANUNI function in SAS and the random seed mentioned above, a random number was directly assigned to each record in the original population.

Serialization of frame

Prior to generating random numbers in SAS, the population was sorted by the field, Order. The purpose of this sort was to place the file in a reproducible and verifiable order so the random number assignment was independent of an arbitrary frame sequence.

Method of selection

To select the sample, the sampling frame was sorted by stratum and the random numbers described above. Thus, the entire file was put into random order within a stratum. Then, the required number of orders per stratum was selected according to this random order. For example, the first 30 orders in this random order were selected for stratum one.

Sample results

The results of the sample review are available upon request. Table 4 provides a summary of the results by stratum.

Table 4. Sample results summary

Stratum Number	Stratum Definition	Population Size	Population Cost	Sample Size	Sample Cost	Sample Error Amount
1	$0 to $49,659.99	51,503	$ 631,384,908	30	$ 372,391	$ 122
2	$49,660 to $161,515.99	9,854	$ 871,774,694	30	$ 2,724,419	$ 2,675
3	$161,516 to $448,896.99	3,438	$ 894,974,113	30	$ 8,022,406	$ 2,165
4	$448,897 to $1,590,881.99	1,238	$ 915,432,028	30	$ 23,715,999	$ 5,034
5	$1,590,882 to $11,999,999.99	203	$ 730,494,725	30	$ 104,553,809	$ 3,644
6	$12,000,000 and above	7	$ 732,163,063	7	$ 732,163,063	$ 5,881
Total		**66,243**	**$ 4,776,223,532**	**157**	**$ 871,552,087**	**$ 19,521**

Section V: Estimation

Standard statistical methods were used to produce the estimates from the stratified sample. Differences in the probabilities of selection among strata were properly accounted for by statistical weighting. The mean per unit (MPU) estimator[27] was used to compute the estimated total error amount.

The MPU estimator

The MPU estimator is the weighted sum of the sample means of error amount over all strata. In stratified sampling with *L* strata, this can be represented as

$$\hat{Y}_{mpu} = \sum N_h \bar{y}_h,$$

where

N_h is the number of orders in stratum *h*,
$\bar{y}_h$ is the sample mean of error amount and
h = 1 to *L*, the number of strata.

The standard error of the MPU estimate is given by

$$\hat{S}(\hat{Y}_{mpu}) = \sqrt{\sum N_h(N_h - n_h)S_{yh}^2/n_h},$$

where

$S_{yh}^2 = \sum \frac{(y_{hi}-\bar{y}_h)^2}{n_h-1}$ is the sample variance of error amount in stratum *h*.

Confidence limits were calculated from the estimate plus or minus its margin of error, where the margin of error is computed as the standard error times the Student's t-value with a 90 or 95 percent two-sided confidence.

The degrees of freedom for the t-value were approximated using the Satterthwaite formula as follows:

$$n_e = \left(\sum g_h s_{yh}^2\right)^2 \Big/ \sum \frac{g_h^2 s_{yh}^4}{n_h - 1},$$

[27] Roberts, D. M. (1978) *Statistical Auditing*, American Institute of Certified Public Accounts, Inc., New York.

where

$$g_h = N_h(N_h - n_h)/n_h.$$

As a result of the Satterthwaite adjustment, the t-value used in estimation was 1.672 and 2.002 for a 90 and 95 percent confidence level, respectively.

Table 5 shows the estimated total error amount and its associated precision measures.

Table 5. Estimation results summary

			90% Two-sided Confidence Level			95% Two-sided Confidence Level		
	Estimated Amount	Standard Error	Margin of Error	Lower Bound	Upper Bound	Margin of Error	Lower Bound	Upper Bound
Total Error Amount	$1,491,621	$405,175	$677,453	$814,168	$2,169,073	$811,160	$680,460	$2,302,781

Credit adjustments

The estimated total error amount was adjusted to account for the -$248,722,476 remaining credits. The overall estimated total error amount, determined from the sample (positive amounts only), was adjusted by applying the estimated error percentage of 0.03 percent to the unmatched credits (-$248,722,476). Therefore, the adjusted estimated total error amount was calculated as follows:

$1,573,564 + (0.03% * (-$248,722,476)) = $1,491,621.

The associated precision measures (standard error, margin of error, etc.) were adjusted in a similar fashion.

EY | Building a better working world

EY is building a better working world by creating new value for clients, people, society and the planet, while building trust in capital markets.

Enabled by data, AI and advanced technology, EY teams help clients shape the future with confidence and develop answers for the most pressing issues of today and tomorrow.

EY teams work across a full spectrum of services in assurance, consulting, tax, strategy and transactions. Fueled by sector insights, a globally connected, multidisciplinary network and diverse ecosystem partners, EY teams can provide services in more than 150 countries and territories.

All in to shape the future with confidence.

2511-10159
None.

ey.com