Application: 23-02-
(U 39 E)
Exhibit No.:
Date: February 28, 2023
Witness(es): Various

# PACIFIC GAS AND ELECTRIC COMPANY

# APPLICATION FOR COMPLIANCE REVIEW OF UTILITY-OWNED GENERATION OPERATIONS, PORTFOLIO ALLOCATION BALANCING ACCOUNT ENTRIES, ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES, CONTRACT ADMINISTRATION, ECONOMIC DISPATCH OF ELECTRIC RESOURCES, UTILITY-OWNED GENERATION FUEL PROCUREMENT, AND OTHER ACTIVITIES FOR THE PERIOD JANUARY 1 THROUGH DECEMBER 31, 2022

## PREPARED TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
APPLICATION FOR COMPLIANCE REVIEW OF UTILITY-OWNED GENERATION OPERATIONS, PORTFOLIO ALLOCATION BALANCING ACCOUNT ENTRIES, ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES, CONTRACT ADMINISTRATION, ECONOMIC DISPATCH OF ELECTRIC RESOURCES, UTILITY-OWNED GENERATION FUEL PROCUREMENT, AND OTHER ACTIVITIES
FOR THE PERIOD JANUARY 1 THROUGH DECEMBER 31, 2022
PREPARED TESTIMONY

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
APPLICATION FOR COMPLIANCE REVIEW OF UTILITY-OWNED GENERATION OPERATIONS, PORTFOLIO ALLOCATION BALANCING ACCOUNT ENTRIES, ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES, CONTRACT ADMINISTRATION, ECONOMIC DISPATCH OF ELECTRIC RESOURCES, UTILITY-OWNED GENERATION FUEL PROCUREMENT, AND OTHER ACTIVITIES
FOR THE PERIOD JANUARY 1 THROUGH DECEMBER 31, 2022
PREPARED TESTIMONY

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
APPLICATION FOR COMPLIANCE REVIEW OF UTILITY-OWNED GENERATION OPERATIONS, PORTFOLIO ALLOCATION BALANCING ACCOUNT ENTRIES, ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES, CONTRACT ADMINISTRATION, ECONOMIC DISPATCH OF ELECTRIC RESOURCES, UTILITY-OWNED GENERATION FUEL PROCUREMENT, AND OTHER ACTIVITIES
FOR THE PERIOD JANUARY 1 THROUGH DECEMBER 31, 2022
PREPARED TESTIMONY

TABLE OF CONTENTS
(CONTINUED)

TABLE OF CONTENTS
(CONTINUED)

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 1

# LEAST-COST DISPATCH AND ECONOMICALLY-TRIGGERED DEMAND RESPONSE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
LEAST-COST DISPATCH AND ECONOMICALLY-TRIGGERED DEMAND RESPONSE

TABLE OF CONTENTS

TABLE OF CONTENTS
(CONTINUED)

TABLE OF CONTENTS
(CONTINUED)

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 1
# LEAST-COST DISPATCH AND ECONOMICALLY-TRIGGERED DEMAND RESPONSE

## A. Introduction

This chapter describes the Least-Cost Dispatch (LCD) practices and procedures Pacific Gas and Electric Company (PG&E or the Utility) employed during the January 1 through December 31, 2022 record period. The testimony and workpapers, taken together, provide a qualitative and quantitative demonstration of LCD for each day during the record period.

During the record period, PG&E complied with the California Public Utilities Commission's (CPUC or Commission) Standard of Conduct 4 (SOC4), relevant Commission decisions, and PG&E's conformed Bundled Procurement Plan (BPP).[1] SOC4 and the related CPUC decisions mandate that:

> [T]he utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner.[2]

The format of this chapter and the associated workpapers is intended to conform with the requirements in Decision (D.) 15-05-006, as modified by D.15-12-015, which adopted a methodology for making an LCD showing in Energy Resource Recovery Account (ERRA) Compliance proceedings (LCD Decisions).

In addition, pursuant to the 2014 and 2015 ERRA Settlement Agreements between PG&E and the Public Advocates Office at the California Public Utilities Commission (Cal Advocates),[3] this chapter also addresses agreed-upon

---

1 D.15-10-031 adopted the investor-owned utilities' proposed BPPs, with modifications, and required PG&E to submit a conformed copy of its BPP, which was approved June 15, 2016. Since then, PG&E has updated the BPP as needed when market conditions or electric portfolio changes necessitate modifying the BPP.

2 See D.02-10-062, p. 74. This responsibility was clarified in D.14-05-023, Finding of Fact (FOF) 15, stating that while the regulated utilities are responsible for bidding and scheduling its generation resources in a least-cost manner, it is the California Independent System Operator (CAISO) who performs actual generation dispatch. (D.14-05-023, p. 19).

3 PG&E entered into these settlement agreements with the Office of Ratepayer Advocates (ORA). Subsequently, ORA changed its name to the Public Advocates Office at the California Public Utilities Commission (Cal Advocates).

additions to the testimony and workpapers.[4] These agreed upon additions are the following:

**TABLE 1-1**

| Line No. | Testimony/ Workpaper Section | 2014 and 2015 ERRA Settlement Requirements for LCD |
|---|---|---|
| 1 | B.3.b.1.d.; Workpaper 6 | An evaluation of PG&E's price forecast accuracy for all days during the record period |
| 2 | B.3.b.4.; Workpaper 1 | A description of the decision-making process that PG&E performs to determine whether proxy or registered costs are selected for resources |
| 3 | B.3.b.8.; Workpaper 2 | Explanations of instances in which bids were not submitted for thermal resources |
| 4 | B.3.b.12. Bid Sheets | Explanation of renewable resource opportunity costs and curtailments |
| 5 | C | Inclusion of PG&E's dispatch of Demand Response (DR) programs that have an economic trigger and evaluation of metrics |

Section B of this chapter addresses LCD, and Section C addresses economically-triggered DR.

## B. Least-Cost Dispatch

### 1. Structure of LCD Section

PG&E will demonstrate in this section and in the accompanying workpapers that during the record period it correctly performed LCD. The format of PG&E's testimony and workpapers is based on the LCD Decisions and consists of the following:

---

4 See D.16-12-045, *Decision on PG&E 2014 ERRA Compliance Review* (Issued December 20, 2016) and D.17-03-021, *Decision Addressing Settlement Between PG&E and ORA* (Issued March 28, 2017).

**TABLE 1-2**

| Line No. | Section | Subject |
|---|---|---|
| 1 | B.2. | Overview of LCD in the CAISO markets |
| 2 | B.3. | PG&E's Bidding and Scheduling Processes |
| 3 | B.4. | Summary Reports/Tables – Annual Exception Rates |
| 4 | B.5. | LCD Bidding and Scheduling Cost Impacts |
| 5 | B.6. | Background Summary Table |
| 6 | B.7. | 2022 Market and Business Process Changes |
| 7 | B.8. | LCD Summary |

PG&E is also providing detailed workpapers that are formatted consistent with, and provide the information required by, the LCD Decisions.

### 2. Overview of LCD in the CAISO Markets

During the record period, PG&E managed its portfolio of contracted and utility-owned resources consistent with SOC4, relevant Commission decisions, and its BPP.

SOC4 was initially adopted by the Commission in 2002. At that time, all CAISO generation resource schedules were either directly matched by the utilities to their customer loads or energy was procured and matched to forecast customer loads via bilateral trades. However, as the Commission explained in D.11-10-002, FOF 1:

> On April 1, 2009, the CAISO began implementation of the Market Redesign and Technology Upgrade, which substantially changed the [LCD] processes of SCE and other utilities.

As the Commission has noted, since 2009:

> [T]he regulated energy utility is responsible for scheduling and bidding its generation to the CAISO, but once that is done, it is the CAISO's responsibility to dispatch the generation.[5]

Since April 1, 2009, the CAISO has operated the day-ahead market (DAM) and real-time markets (RTM), enabling market participants to offer or procure energy and Ancillary Services (A/S) in the CAISO control area. The CAISO markets perform optimization (i.e., LCD) for all resources bid or

[5] D.14-05-023, FOF 15.

self-scheduled[6] into the markets based on information provided by market participants, CAISO transmission information, and information regarding system conditions that is not available to market participants. The Full Network Model (FNM) used in the CAISO markets contains approximately 19,000 pricing nodes. The FNM is used to identify potential local area reliability concerns and resolve them day-ahead in the Integrated Forward Market (IFM) and Residual Unit Commitment (RUC) processes (further detail below), as well as in the RTMs.

The CAISO's optimization by each of its markets results in supply clearing against demand at least cost. The results are based on the submitted hourly bids and the costs of getting energy from supply nodes to demand nodes in the CAISO grid. Market prices at each node are determined on a day-ahead basis for each hour of the day, and in real-time for each 15- and 5-minute interval, and indicate the incremental cost of an additional unit of energy at each location in the CAISO grid (Locational Marginal Price (LMP)).[7]

The structure and design of each of the CAISO markets, day-ahead and real-time, are described in more detail below.

**a. Day-Ahead Market**

The CAISO DAM process, the IFM, provides market participants with the opportunity to buy and sell energy for the following day. In the IFM, the CAISO clears the offers to buy and sell energy based on the physical characteristics and locations of available resources and bid-in demand, for each of the 24 hours of the following day, and establishes LMPs for each of the approximately 19,000 nodes within the CAISO system. The CAISO also uses the IFM to procure A/S

---

6 Self-schedules are interpreted by the CAISO markets as price-taking supply or demand. Price-taking supply is supply that is willing to accept any price to inject energy into the grid. Price-taking demand self-schedules, which can only be submitted by Load Serving Entities (LSE) in the day-ahead market, indicate a willingness to pay any price to clear demand in that market.

7 The LMP is the marginal cost of supplying, at least cost, the next increment of electric demand at a specific node on the electric power network. This takes into account supply (generation/import) bids, demand (load/export) offers and the physical network of the transmission system.

(regulation up, regulation down, spinning reserve and non-spinning reserve) to ensure system reliability for the next day. Energy and A/S procurement are performed simultaneously using the CAISO's Security Constrained Unit Commitment algorithm, which minimizes total costs based on submitted bids, the CAISO's A/S requirements, and the constraints on power flows imposed by the control area's large and complex transmission network.

The CAISO's market model recognizes load pockets that may be exposed to local market power. The CAISO performs a Local Market Power Mitigation (LMPM) process that identifies suppliers with local market power and mitigates their supply bids to competitive default bid levels.

Because not all forecast load will necessarily clear in the IFM, the CAISO performs a second phase of the DAM process, RUC, after the IFM to ensure that sufficient capacity has an obligation to bid into Real Time to meet the CAISO's own forecast of CAISO area load.

LCD requires PG&E to bid or schedule its generation portfolio such that it is generally dispatched to serve load if the variable operating costs of the resources are lower than the alternative CAISO market cost of energy. PG&E meets this requirement by offering PG&E owned and contracted resources into the DAM at incremental cost,[8] with the resulting awards of schedules determined by the CAISO without regard to whether the scheduled resources are PG&E controlled or from the other market participants.

The CAISO should dispatch resources such that those with lowest incremental costs are scheduled to meet loads at least cost.[9]

**b. Real-Time Markets**

The RTM is comprised of several overlapping market processes, producing financially and/or physically binding awards and prices that are used for energy and A/S settlements.

---

**8** Incremental cost refers to the variable costs of providing energy (which includes opportunity cost) but does not include fixed costs.

**9** The CAISO ultimately clears all control area demand physically in the RTMs: This is fundamental to its mandate to serve California's electricity needs reliably.

The Hour-Ahead Scheduling Process is an hour-ahead, non-binding process that runs every hour to yield feasible block schedules for imports and exports (permitting "tagging," i.e., scheduling of supporting transmission capacity across multiple balancing authorities) and advisory (non-binding) price and schedule results.

The Fifteen-Minute Market (FMM) process was introduced with Federal Energy Regulatory Commission (FERC) Order 764 implementation in 2014. The FMM process runs for successive 15-minute intervals with updated CAISO forecasts of system load and intermittent resource generation and yields schedules and financially binding prices for all CAISO products. As in the DAM, the LMPM process is run prior to each FMM run. Differences between the day-ahead awards and FMM awards are settled at the FMM prices.

Finally, the 5-minute Real-Time Dispatch (RTD) process runs with updated CAISO 5-minute load and intermittent resource forecasts, to yield 5-minute prices and physically binding energy dispatches for all resources internal to the CAISO's Balancing Authority Area. Differences between the FMM awards and RTD awards are settled at the RTD prices. Imbalances between RTD awards and actual deliveries are priced at the RTD prices in each 5-minute interval.

### 3. PG&E's Bidding and Scheduling Processes

#### a. LCD Guidelines and Principles

##### 1) LCD Principles

Consistent with the Commission-approved BPP in effect during the record period, PG&E adopted the following seven principles to guide its procurement and LCD activities:[10]

1) PG&E aims to minimize the total cost of energy required to meet load and A/S requirements, subject to regulatory, legal, operational, contractual, and financial requirements;
2) PG&E's scheduling and bidding process considers all regulatory, legal, safety, operational, contractual and

[10] See also BPP, Appendix K.

financial requirements. Subject to these requirements, the scheduling and bidding process aims to provide the CAISO flexibility in dispatching the resources across the DAM and RTM;

3) PG&E supports LCD by explicitly considering the incremental costs of all resources available to it in scheduling or bidding decisions;

4) PG&E integrates any local area reliability requirements, day-ahead scheduling requirements, and deliverability requirements into its scheduling or bidding decisions;

5) The CAISO markets perform LCD for all resources bid/scheduled into the markets based on information provided by all market participants, transmission information that is solely available to the CAISO, and information regarding system conditions that is solely available to the CAISO;

6) The parameters and forecasts that PG&E uses as inputs to the CAISO LCD process include: PG&E and CAISO load forecasts; market price forecasts; incremental heat rates; and Master File parameters. These parameters and forecasts are used in the calculation of submitted bids and/or schedules; and

7) LCD results are subject to forecast and market uncertainties, including those associated with actual customer loads, behavior of other market participants, actual energy deliveries from non-dispatchable and intermittent resources, non-public transmission constraints, and CAISO reliability-based discretionary decisions.

PG&E followed the principles described above during the record period. The principles described above remain essential for achieving LCD and meeting all safety, regulatory, legal, operational, and financial requirements associated with PG&E's portfolio.

PG&E bids resources with bidding rights into the CAISO markets based on their incremental costs or opportunity costs.[11] By bidding its resources into the CAISO markets at their incremental or opportunity costs, PG&E enables total procurement to meet customer demand in the CAISO markets at least cost. Resources with contractual or physical constraints that limit their ability to be bid may be fully or partially self-scheduled into the CAISO markets.

**2) Incremental Costs**

PG&E schedules[12] or bids resources that have dispatch flexibility into the CAISO markets at the incremental cost of providing energy, considering the variable resource operating cost and the most current market price forecast. Resource costs that increase or decrease with resource output are properly treated as incremental costs. Fixed costs that are not affected by how resources are dispatched, such as past capital investment costs or contract capacity payments, are treated as sunk costs and therefore not incorporated into energy bids. For resources with energy or starts constraints, incremental costs may also include the opportunity cost of not having use of the resource in the future.

Incremental costs are categorized as: (1) start-up costs; (2) minimum load costs; and (3) incremental energy costs. Start-up costs are the costs to start a resource and bring it to its minimum operating level; for Multi-Stage Generation (MSG)[13] resources, "state transition costs" are similar to startup costs and represent the start-up of resource sub-units. An additional opportunity cost component may be added to start-up costs when a limit on cycling

---

11 For those resources with energy, curtailment, or starts limitations, the opportunity cost reflects the value of not being able to use the resource's flexibility in a future time period.

12 Schedules commonly refer to self-schedules whereas bids refer to price-quantity offers to sell or buy in the CAISO markets.

13 MSG resources are described in further detail in the "Thermal Resource Bidding and Scheduling" section of this chapter.

(starts and shutdowns) is expected to be binding over a period of months or years.

Minimum load cost is the cost to operate a resource at its minimum operating level for one hour.

Minimum load, start-up, and transition costs may include fuel costs and Greenhouse Gas (GHG) costs as well as variable operations and maintenance (VOM) costs, and documented Major Maintenance Adder costs of inspections and overhauls that are incurred, or other contract provisions, based on run hours or cycles.

Incremental energy bid costs include those incremental or opportunity costs that vary directly with the generation of each additional megawatt-hour (MWh) above the minimum operating point. For example, fuel costs, GHG costs, and VOM costs vary directly with energy output.

Bids for resources with no explicit fuel cost, such as hydroelectric plants, are based on their opportunity costs, which are equivalent to fuel costs in their effect on bids. For Hydroelectric Generation (Hydro) resources, the opportunity cost is the future value of water. It may be more prudent and lower cost in the long run to defer hydro generation to higher value future periods, rather than using it in the current day and receiving a price below its opportunity cost.

In addition to its large (in number, total capacity, and total energy) portfolio of utility-owned resources, PG&E also bids and schedules resources under various types of contracts. Incremental costs of contracts are based on contract terms, reflecting the actual costs or opportunity cost of dispatch. Incremental costs of these different resource types are further discussed below.

### 3) Self-Scheduling

A portion of PG&E's supply portfolio is must-take[14] or must-run,[15] due to safety, environmental and license constraints, regulatory requirements, contract terms (e.g., certain renewable resources and Qualifying Facility (QF) resources) or because it is inherently non-dispatchable (e.g., run-of-river hydro with no reservoir controls). Because such generation is inflexible, PG&E self-schedules must-take supply in the DAM based on PG&E's forecast of their generation, and then modifies these self-schedules in real-time if the forecast of generation changes.

The Puget Exchange has dispatch flexibility on an earlier contractual timeline from the CAISO markets and therefore cannot be bid into the CAISO market and must be self-scheduled by PG&E. The best price forecast available at the time of the scheduling decision is used in PG&E optimization program runs to determine the highest value self-schedules.

In addition to must-take and must-run resources and bilateral contracts which are self-scheduled, other resources are periodically or partially self-scheduled when circumstances require. For example, self-schedules may be used when testing is to be performed on resources, or when resources such as hydro plants

---

14 Regulatory Must-Take Generation is defined as generation from the following resources that the relevant Scheduling Coordinator (SC) schedules directly with the CAISO as Regulatory Must-Take Generation: (1) Generation from Generating Units subject to (a) an Existing QF Contract or an Amended QF Contract, or (b) a QF Power Purchase Agreement (PPA) for a QF 20 megawatts (MW) or smaller, pursuant to a mandatory purchase obligation as defined by federal law; (2) Generation delivered from a Combined Heat and Power (CHP) Resource needed to serve its host thermal requirements up to RMTMax in any hour; and (3) Generation from nuclear units. See CAISO Conformed Tariff, November 29, 2022.

15 Regulatory Must-Run Generation is defined as Hydro Spill Generation and Generation which is required to run by applicable federal or California laws, regulations, or other governing jurisdictional authority. See CAISO Conformed Tariff, November 20, 2022. Such requirements include, but are not limited to, hydrological flow requirements, environmental requirements, such as minimum fish releases, fish pulse releases and water quality requirements, irrigation and water supply requirements, or the requirements of solid waste Generation, or other Generation contracts specified or designated by the jurisdictional regulatory authority as it existed on December 20, 1995, or as revised by federal or California law or Local Regulatory Authority.

need to be run above their minimum operating limits to ensure that water is used according to operating constraints. Resources may also be "self-committed," which refers to instances in which a resource is self-scheduled at minimum, and its remaining available capacity is bid economically into the markets.

#### 4) Operational Constraints

In addition to meeting load obligations at minimum cost, PG&E incorporates safety, operational, physical, legal, regulatory, and environmental constraints into bidding and scheduling decisions.

Operational constraints include those imposed by FERC licenses on the operations of PG&E's hydroelectric system. For example, FERC licenses may include requirements for fish and wildlife maintenance (e.g., flows for fish habitat and water quality that bypass generators and thus produce no electricity), recreation (e.g., seasonal minimum reservoir water levels), and safety (e.g., constraints on reservoir drawdowns). These considerations may not be readily apparent in a cost-only analysis of PG&E's bidding and scheduling decisions.

### b. 2022 LCD Business Process Overview

PG&E's daily LCD business processes use forecasts of loads and prices to perform LCD via the bidding of customer demand and PG&E supply. After the market run, PG&E performs routine validation and analysis of market results. PG&E's processes are described in the following sections.

#### 1) Load and Price Forecasts

In this section we describe PG&E's load and price forecasts.

##### a) Load Forecast Process

The short-term area load forecast utilized in PG&E's LCD process is provided by a vendor, Enverus.[16] The inputs to the short-term load forecast include actual historical loads for the

---

[16] For many years, PG&E relied on Pattern Recognition Technologies (PRT) for its load forecasts. PRT was acquired by Enverus in 2017.

PG&E system based on PG&E's Supervisory Control and Data Acquisition system, and actual and forecast temperatures for six representative weather stations in the PG&E service territory, provided by external weather forecast vendors to PRT. PG&E reviews data provided to the vendor and, on rare occasions, modifies inputs to the vendor model to correct for data quality problems.

The "7-day" hourly PG&E area load forecast provided by the vendor is adjusted to produce a forecast of PG&E's bundled customer load. During the record period, PG&E evaluated load forecast adjustments and assessed potential process enhancements that utilize additional data sources. The PG&E area load forecast is adjusted by subtracting estimates of transmission losses, municipal loads, and forecasts of Direct Access and Community Choice Aggregation loads in the PG&E area. PG&E uses this 7-day short-term forecast of bundled customer load in creating load bids for each of the next six days. PG&E may further modify the vendor forecast under special circumstances (e.g., holiday periods) that are not modelled adequately by the forecast model.

**b) Evaluation of Load Forecast Accuracy**

The most common metric used to evaluate the relative quality of load forecasts in the Utility industry is Mean Absolute percentage Error (MAPE). This metric measures both the magnitude and frequency of errors, and is similar to the Root Mean Square Error metric except that it puts a higher weight on larger errors. The metric is expressed as a percentage of actual hourly load.

Average daily MAPE of the short-term area load forecast was less than three percent during the record period. PG&E analyzes the short-term area load forecast on a daily basis and contacts the vendor when necessary (e.g., data quality problems).

#### c) Price Forecast Process

PG&E uses an hourly next-day price forecast and a long-term price forecast to inform bidding and scheduling in the DAM.

The short-term price forecast is used for load bids and for resources where a daily price forecast is used to optimize bids. During the 2022 record period, PG&E utilized a neural-network-based price short-term forecast model provided by Enverus. PG&E regularly reviews the reasonableness of the daily forecasts produced by the vendor.

A longer-term price forecast produced by PG&E's Market & Credit and Risk Management Department, ranging from several days up to two years, is used for resources with potential opportunity costs beyond the next day. The longer-term price forecast is needed to estimate the relative value of dispatching the resources next day versus at later points in time.

#### d) Evaluation of Price Forecast Accuracy

PG&E reviews the accuracy of the Enverus price forecast. The day-ahead PG&E Default Load Aggregation Point price forecast error during the record period using the metric of mean average percentage error, or MAPE, was 12.3 percent.[17] This MAPE value and Workpaper 6 offer PG&E's evaluation of its day-ahead price forecast accuracy, as requested by Cal Advocates in the 2014 ERRA Settlement.

### 2) Load Bidding

The CAISO DAM offers LSEs, such as PG&E, the capability to bid some or all of their forecast loads into the DAM.

PG&E evaluates the relative costs of serving customer loads in the DAM versus the RTM, based on actual past market outcomes. [redacted]

---

**17** Daily MAPE = $\frac{1}{24} * \sum_{t=1}^{24} \frac{|\text{Forecasted Price}_t - \text{Cleared Price}_t|}{\text{Daily Average Cleared Price}}$.

[redacted]

**3) Thermal Resource Bidding and Scheduling**

The portfolio of dispatchable thermal power plants for which PG&E creates bids (all using natural gas as their primary, if not exclusive, fuel) are either owned by PG&E or contracted from counterparties through tolling agreements.

D.02-12-069 provides that:

> [P]rohibited utility conduct under this standard includes any action that results in preference to utility-retained generation resources or the Utility's own negotiated contracts.[18]

PG&E makes no distinction between its own resources and contracted resources in its bidding practices: All resources are bid or self-scheduled into the CAISO markets based on their incremental costs, recognizing safety, regulatory, legal, operational, and financial requirements.

PG&E-owned plants and tolling agreement plants that can be bid into the CAISO markets are bid at incremental cost consistent with operational and contractual constraints, as described in Section 3.a.2. The incremental cost of energy consists of incremental fuel costs and any other costs that vary with output between the minimum and maximum points of a plant's operating range.

The incremental cost of minimum load is similarly estimated as the minimum load fuel cost and any other costs that are incurred in every hour that the plant runs (for example, hourly operating charges included or imputed in plant long-term service agreements).

The incremental cost of starting a plant (or in the case of a multi-unit plant, starting a unit at the plant) is estimated as the fuel and other inputs required for a start along with other costs incurred

---

18 D.02-12-069, pp. 62-63.

for every start (such as start charges included or imputed in plant long-term service agreements).

In its portfolio, PG&E has a number of MSG resources, which are resources that have multiple operating configurations that can be characterized as having distinct operating parameters. Often these resources require time and/or incur costs to move from one configuration operating range to another. For example, combined cycle gas turbine (CCGT) plants consist of a steam turbine (ST) and multiple gas turbines (GT) run in combination so that GT waste heat can be used to power the ST. Dispatch of CCGT plants therefore requires consideration of the cycling (startup and shutdown) of individual turbines. The CAISO has developed the MSG resource model to better represent dispatch of MSGs.

**4) Description of Proxy/Registered Cost Determination for Thermal Resources**

In the 2014 ERRA settlement, PG&E agreed to provide documentation for evaluating the proxy versus registered cost determination for thermal resources.

Starting April 1, 2019, CAISO retired the registered cost option with an exception only for the resources that have less than 12 months of 15-minute LMP data. Since none of the thermal resources in the PG&E's portfolio was eligible for the exception, all were required to use the proxy cost option starting April 1, 2019. Because of this CAISO rule change, PG&E did not perform any proxy/registered cost determinations for thermal resources during the record period for 2022.

**5) Hydro Resource Bidding and Scheduling**

In this section we describe PG&E's hydro resource bidding and scheduling processes. PG&E manages its hydro fleet through bidding and scheduling practices that depend on the constraints of each particular hydro facility and amount of water available.

In general, hydro generation is energy-limited due to the limited availability of water. While water in reservoirs from natural inflows may be considered a zero-cost fuel (except in the case of pumped storage hydro, which is further discussed below), the availability of this zero-cost water may be limited.

Hydro resources have their highest value to customers when this limited amount of water is utilized during high market prices. To the extent that the availability of water can be controlled, it is prudent to store water to generate when the power is most valuable (i.e., those times with the highest prices in the CAISO's DAM and RTM). Thus, in order to perform least-cost hydroelectric dispatch and target high market prices, PG&E bids and schedules hydro resources based on their estimated opportunity costs (which reflect their energy limitations and forecasts of the future value of water).

Opportunity costs are evaluated based on comparison to historical periods or forecasts of future periods to estimate the risk of high-market prices or capacity shortage. In addition, the energy and capacity markets provide short-term price signals, in the form of high energy or A/S prices, that also help identify high-risk, high-value periods. Prudent dispatch of PG&E's hydroelectric resources necessitates that uncertainties in future hydrological system conditions (stream flows, precipitation, temperatures, etc.) and uncertainties in the future value of energy and A/S be incorporated into planning models.

PG&E's operation of energy-limited resources, such as hydro, involves decisions that may span multiple months and years. Hydro conditions, reservoir target levels, market conditions, and scheduled plant outages affect the optimization of hydro operations in the "short term," meaning two years or less. For watersheds with sufficient storage, a two-year optimization cycle is used because using either too much or too little water from the large reservoirs in PG&E's hydro system may leave the system vulnerable to either drought or storm conditions in the following year.

In general, PG&E bids dispatchable hydro by submitting limits for each resource on total energy available for dispatch in the DAM. CAISO allows hydro resources to submit limits on total energy dispatched in a single day. PG&E sets hydro limits based on a resource's opportunity cost with bid prices that enable the CAISO to optimize the resource's dispatch over an operating day.

In addition to those resources with bid limits that reflect opportunity costs, depending on operating constraints (such as safety, FERC license requirements, recreational use requirements, or environmental restrictions), some hydro generation may be self-scheduled or bid at a price close to zero to indicate that some flow through the watersheds is not controllable, except possibly by diverting it from particular plants ("spilling" the water) and thus losing any opportunity to generate with it at these plants.

**a) Hydro Modeling**

Mid-term hydro planning models generate forecasts of optimal water plans for each of PG&E's watersheds using assumptions about forward prices, considering safety, physical, operational, and license constraints. The models produce target reservoir storages and end-of-month water values over the entire water planning horizon, as well as nominal hydro generation schedules at each PG&E powerhouse. The most recently generated water plans provide guidance in planning the storage and drafting of reservoirs, maintenance of hydro powerhouses, and assumptions about availability of hydro generation and A/S over the model's horizon.

The inputs to PG&E's mid-term hydro planning models include:

- Static characteristics of generators, reservoirs and canals and the network configurations of the watersheds;
- Energy and A/S price forecasts;
- Reservoir inflow forecasts;
- Outage schedules of generators (and at Helms Pumped Storage Plant (Helms), the pumps);

- Reservoir storage initial volumes; and
- Other reservoir operational constraints.

The nearest term outputs of the mid-term hydro planning models are their end-of-month target reservoir storage levels and marginal water values for the current and following months of the model's optimization horizon. Outputs of the mid-term hydro planning model include:

- Hourly MW schedules for all represented plants;
- Hourly A/S schedules for A/S capable plants;
- Forecast energy and A/S revenues;
- Forecast water releases from reservoirs and resulting storage levels;
- Flows on all canals/waterways; and
- Forecasted water values.

**b) Implementation and Use of Modeling Results**

The outputs of the mid-term hydro planning model are used as starting points in shorter-term hydro optimization. PG&E uses a combination of network optimization models and water balance spreadsheet models to forecast week-ahead powerhouse operations at each dispatchable powerhouse.

Multi-day hydro operations forecasts are translated into next-day preferred operating schedules and/or total energy available for each powerhouse.

Per the 2015 ERRA Settlement, PG&E contracted for an independent review of PG&E's hydro resource bidding and scheduling processes. The independent reviewer's conclusions were as follows:

> The hydropower modelling system I observed at PG&E does as well or better at meeting PG&E's needs when compared to other utilities with complicated hydropower systems. The use of a (sic) hourly time-step within the so-called "monthly" PLEXOS provides a good description of likely reserve resources given forecasted mean monthly

flows and mean hourly energy and regulation reserve prices.[19]

6) **Hydro Self-Scheduling Decisions**

In this section, PG&E includes a description of the rationales for hydro self-schedules during the record period to provide additional information on the operational constraints in the hydro LCD process as requested by Cal Advocates in the ERRA 2014 Settlement. Self-scheduling is done for one of the following three reasons:

a) **Self-Scheduling Required During and After Storms**

Under certain storm conditions, much or all of PG&E's hydroelectric system can become effectively "run of river" hydro, meaning that it cannot be controlled by dispatch decisions. Under such conditions, PG&E's hydro is self-scheduled.

b) **Self-Scheduling in Other Conditions with Limited Operating Flexibility**

Constraints on the hydroelectric system for irrigation, recreation, environmental, or safety reasons may be expressed in terms of minimum flows or minimum releases from reservoirs. Such constraints may require flows through powerhouses that exceed the rated minimum flows, thus requiring self-schedules at levels above minimum generating level for specific hydro resources. Additionally, limited capacities of small forebay reservoirs may require minimum guaranteed powerhouse flows, implemented as self-schedules, to ensure the safe operation of those small reservoirs.

c) **Self-Commitment to Indicate Preferred Ancillary Service Providing Resources**

Hydroelectric resources supply a significant amount of PG&E's supply of A/S, including regulation and spinning reserves. In cases where experience shows that price signals alone may result in excessive cycling of resources to provide

---

19 See Exhibit (PG&E-2), Attachment A, p. 1-AtchA-4, in PG&E's 2017 ERRA Compliance Application (Application 18-02-015).

A/S, PG&E may elect to self-schedule particular hydro resources to ensure that A/S are provided in the most efficient and effective way.

**7) Helms Pumped Storage Plant Bidding and Scheduling**

Helms is located on the Kings River watershed, situated between an upper reservoir, Courtright Lake, and lower reservoir, Lake Wishon. Helms has three generators that can be reversed to act as pumps. Like any other PG&E hydro resource, Helms is subject to physical operating constraints and hydrological uncertainties.[20] Unlike other hydro resources, Helms can increase its forebay reservoir storage (Courtright) by pumping water from Lake Wishon uphill to Courtright. Pumping water uphill requires purchase of electricity from the CAISO markets and serves as a future fuel source in addition to natural inflows (limited by the cycling capability and reservoir capacities of the plant).

LCD of Helms requires evaluation of the opportunity cost of stored water and, in addition, requires that pumping be evaluated based on the benefits of incremental generation and reduced downstream spill. LCD of Helms also requires evaluation of how best to use the generating capacity of the plant, which can provide A/S as well as energy. Because A/S generally have highest value in the same periods that energy has highest value, total costs to customers are minimized when the Helms schedule has maximum value considering both energy and A/S. The plant may therefore not be dispatched to its maximum generation output in the market, so that its remaining capacity may provide high value A/S.

The mid-term hydro planning optimization model is used to determine reservoir storage targets and water values for Courtright (forebay) and Wishon (afterbay) reservoirs on a monthly basis through the end of the year following the current year. Reservoir planning for Helms differs from that on other watersheds in that

---

[20] For more information on Helms in the context of PG&E's Hydroelectric System and PG&E's Portfolio Management, see "Chapter 2: Utility-Owned Generation: Hydroelectric."

inflows to the afterbay can be pumped to the forebay for later use; and mid-term planning model outputs therefore include a pumping plan over the horizon of the model.

Short-term hydro planning for Helms is based on the mid-term month-end reservoir targets and water values, as it is for other watersheds. Adjustments within the month are made based on realized inflows and operations as well as short-term price forecasting. The resulting preferred operating schedules for Helms may include some pumping and some combination of generation and A/S. Additional pumping may be economic in the short term if additional generation and A/S (above the forecast/preferred schedule) is valuable enough; likewise, additional generation and/or A/S may be economic in the short term if additional pumping is at low enough cost (the LMP paid for pumping energy). This incremental ability to pump and generate or provide A/S is included in the bids submitted for Helms to the CAISO markets.

**8) Battery Storage Bidding and Scheduling**

PG&E's Elkhorn Battery Energy Storage System (BESS) is a utility-owned 182.5MW lithium-ion battery project developed by Tesla which reached its commercial operation date (COD) on April 7, 2022. PG&E began bidding the Elkhorn BESS into the CAISO's DAM and RTM on the same date and first received DAM awards for trade date of April 8, 2022. Having previously operated two relatively small batteries in the CAISO markets (Yerba Buena and Vaca-Dixon, with 4.8 MW and 2.4 MW of power output respectively), PG&E identified the need for a more robust bidding and optimization platform to prepare for the Elkhorn BESS project. Prior to COD, PG&E prepared for bidding this asset into energy markets by (1) incorporating recent CAISO market rules into PG&E's bidding strategy; and (2) procuring and assisting in implementation of a Bidding Optimization Platform (BOP) from Fluence (formerly Advanced Microgrid Solutions or AMS).

PG&E bid the Elkhorn BESS under Least Cost Dispatch principles by considering both charging costs and the Variable

Storage Operations Cost (VSOC), which represents degradation costs (in $/MWh) incurred by a battery due to discharge. Discharge costs accumulate as total "throughput" over time, which are addressed in service agreements and result in maintenance costs due to "normal" operations or cycling, as well as potential higher costs due to excessive cycling. The VSOC is included in the default energy bid (DEB) calculation to capture cycling costs when a battery is exposed to market power mitigation. Prior to the COD of Elkhorn BESS, PG&E registered a VSOC with the CAISO based [redacted].

As stated previously, PG&E relies on the Fluence BOP to produce optimized bids in both the DAM and RTM for the Elkhorn BESS based on a given trading strategy. [redacted]

[redacted][21] [redacted]

[redacted]

---

21 [redacted]

[redacted]

9) **Thermal Resource Bid Non-Submission**

In this section, PG&E provides a description of the thermal resource bid non-submissions during the record period. "Thermal resource bid non-submission" here means non-submission of bids in periods when a resource is available, i.e., not explicitly limited by a clearance in the CAISO's Outage Management System (OMS). Resources on outage are not included here. Workpaper 2 provides additional detailed explanations for instances in which bids were not submitted for thermal resources. Taken together, this section and the workpapers offer complete documentation of thermal bid non-submission decisions as requested by Cal Advocates in the 2014 ERRA Settlement.

Gas-fired and other fossil fuel thermal plants are in general subject to limits (e.g., emissions limits) that translate into limits on startups and shutdowns over each year and over sub-periods, potentially even daily sub-periods, of the year. To stay within the limits and to guarantee the availability of some thermal resources to serve customers in the periods of the year with expected highest need, PG&E may not bid some or all of the resource capacity in other periods of the year, subject to meeting all Resource Adequacy (RA) and other contractual or reliability constraints on the resource.

**10) Bilateral Market Transactions**

Bilateral transactions in the CAISO DAMs take two forms: (1) financial bilateral transactions, known as "inter-SC trades" or "bi-lateral swaps," which trade the difference between a fixed price and the CAISO's day-ahead IFM prices at a given location without involving any delivery of energy to the grid; and (2) bilateral physical transactions at the intertie points (also known as scheduling points), which require physical scheduling of an import or export and are settled in the CAISO DAM just as other supplies or demands are settled.

Day-ahead financial bilateral transactions (i.e., within the CAISO balancing area) and bilateral physical transactions (i.e., at CAISO interties) were used to settle existing energy procurement contracts. During the record period, PG&E closed its financial and physical positions through in the CAISO markets, with the important exceptions of imports from, and exports to, outside of the CAISO control area.

Imports and exports require physical scheduling into the CAISO markets, "tagging" to match schedules across balancing authority control areas, and a separate bilateral financial settlement with counterparties outside of the CAISO control area. PG&E imports included energy associated with renewable contracts, energy required to meet RA targets, and the long-term Puget Exchange contract.

**11) Must-Take Resources and Contracts**

Must-take resources, unlike dispatchable resources, have no economic flexibility in the delivery of energy; whatever energy they produce must be taken by the transmission grid. Must-take resources include:

1) QFs: PG&E's QF PPAs allow QFs to decide what level of generation to provide;
2) CHP: Contracts allow certain CHP resources to determine the level of supply they will provide;

3) Renewable energy contracts and resources without bidding rights for economic dispatch;

4) Diablo Canyon Power Plant;

5) Existing/Legacy Contracts: PG&E had obligations to purchase or exchange power under existing contracts. These purchases and exchanges were settled as financial bilateral transactions (inter-SC trades); and

6) Must-Run Hydro Generation: Certain power plants have environmental, licensing or physical requirements that require continuous operations.

**12) Economic Bidding of Renewable Resources**

During the record period, PG&E's portfolio included utility owned and contracted renewable resources with dispatch capabilities and economic bidding rights. Economic bidding of these resources captures the incremental and opportunity costs associated with the contractual and operational constraints of these resources. [redacted]

In all cases of economic bidding of renewable resources, [redacted]

Economic curtailment of renewables occurs when market prices fall to, or below, [redacted]. Thus, the market, not PG&E, ultimately determines when these resources are economically curtailed.

**13) Bid/Award Validation**

PG&E reviews the results of each day's CAISO DAM. Market results in the form of resource schedules are evaluated for reasonableness based on expected outcomes of PG&E's forecast of generation. PG&E investigates any unexpected market results and follows-up with the CAISO when necessary.

Forecasts inherently do not perfectly match actual results. PG&E reviews the performance of its forecasts to assess the potential to increase the quality of forecast results.

If day-ahead schedules are not physically deliverable, PG&E adjusts them in real-time and performs an analysis to determine the reason for any infeasibility. In addition to correcting infeasible schedules (i.e., re-scheduling or rebidding in the RTMs), corrective action is taken when possible, with respect to future days' bidding and scheduling.

When total market revenues earned over the course of a day based on the awards by the CAISO do not cover the generating unit's bid in costs, units are eligible to receive Bid Cost Recovery (BCR) payments. PG&E validates that expected BCR is received in these cases, or if not, that PG&E communicates its concerns and/or disputes of BCR calculations to CAISO.

When issues with market results are identified, whether immediately after publication of DAM results or at any later point in time, management is informed and, when appropriate, a ticket is registered with the CAISO's Issues Management System (also known as Customer Inquiry, Dispute and Information (CIDI)) for resolution. Persistent issues not remedied through normal CIDI ticket resolution or settlement dispute resolution may be identified for resolution either by changes in bidding and scheduling strategy or through CAISO market design or regulatory channels.

### 4. Summary Reports/Tables Annual Exception Rates

Table 1-3 below is an index which maps LCD data requirements with PG&E's demonstration.

**TABLE 1-3**
**INDEX OF LCD DATA REQUIREMENTS[a] AND PG&E'S RESPONSES**

| Line No. | CPUC/Cal Advocates Metric | PG&E's Response |
|---|---|---|
| 1 | Commitment Cost Decisions | Testimony: Section B.3.b.4.; B.4.c.<br>Workpaper: 1 |
| 2 | Bid Cost Calculations | Testimony: Section B.3.a.2.; B.4.a.<br>Workpaper: 2 |
| 3 | Self-Commitment | Testimony: Section B.4.b.<br>Workpaper: 3 |
| 4 | Dispatchable Hydro Resources | Testimony: Section B.3.b.5.<br>Workpaper: 4 |
| 5 | Background Summary | Testimony: Section B.5.<br>Workpaper: 5 |
| 6 | Highest Energy Value Days | Workpaper: 6 |
| 7 | Load Bid | Testimony: Section B.3.b.2.<br>Workpaper: 7 |
| 8 | Business Processes and Software Documentation | Workpaper: 8 |
| 9 | Evaluation of PG&E's Price Forecast Accuracy | Testimony: Section B.3.b.1<br>Workpaper: 6 |
| 10 | Decision Making Process for Proxy vs. Registered Costs | Testimony: Section B.3.b.4; B.4.c.<br>Workpaper: 1 |
| 11 | Explanation of Thermal Bids Not Submitted | Testimony: Section B.3.b.9.<br>Workpaper: 2 |

(a) Per the LCD Decisions and the 2014 ERRA Settlement.

Additionally, consistent with the LCD Decisions, PG&E is providing the tables below which summarize exception rates for incremental cost bid calculations, self-commitment decisions, and Master File data changes. Tables 1-4 and 1-5 include exceptions for the record period. PG&E has work procedures and systems intended to detect and prevent internal errors before the fact. These procedures and systems are subject to continuous improvement (e.g., implementation of additional validation checks, and updates to bidding tools).

**a. Incremental Bid Cost Calculation Exceptions**

All bids submitted to the CAISO are reported in PG&E's confidential workpapers for Chapter 1 under the folder "Bid Sheets." There are individual files for each resource with a tab for Energy, A/S, and RUC bids. In the Workpaper 2 folder for dispatchable thermal resources, the actual incremental bid cost submitted to the CAISO is compared against the calculated cost, using incremental heat rates, VOM cost adders, GHG costs, and natural gas prices. In 2022, 480,327 bids were submitted to the CAISO for gas-fired dispatchable resources, with no bid price variance greater than $0.10/MWh (Workpaper 2).

Table 1-4 below summarizes the variances for dispatchable thermal resources during the record period.

**TABLE 1-4**
**INCREMENTAL BID COST CALCULATION VARIANCE – ANNUAL SUMMARY**

| Line No. | Description | No. of Significant Variances (in Hours) > $0.10 | % of Total Bid Hour Count | Potential Cost Impact $ |
|---|---|---|---|---|
| 1 | User Error | 0 | 0% | $0 |
| 2 | External to PG&E | – | – | – |
| 3 | Total | 0 | 0% | $0 |

Note: Reference – Workpaper 2: Bid Cost Calculation: Table 2.1 – Annual Bid Cost Calculation Variance – Annual 2022.

See Workpaper 2, Bid Cost Calculation, for additional details.

**b. Self-Commitment Decision Exceptions**

The reasons for self-commitment during the record period are described in Section B.3. above, "PG&E's Bidding and Scheduling Processes."

Table 1-5 below summarizes exceptions associated with daily self-commitment decisions for dispatchable thermal resources for the record period. During the record period, PG&E did not submit any Day Ahead self-schedules for dispatchable thermal resources.

**TABLE 1-5**
**SELF-COMMITMENT DECISION VARIANCE – ANNUAL SUMMARY**

| Line No. | Reason Code | Description | Total Count (Hour) | Total MWh Energy Self-Committed |
|---|---|---|---|---|
| 1 | N/A | N/A | 0 | 0 |
| 2 | Total | | 0 | 0 |

Note: Reference – Workpaper 3: Self Commitment: Table 3.1 – Self Commitment – Annual Report.

Refer to Workpaper 3: Self Commitment for additional details.

### c. Master File Data Change Exceptions

The Master File describes the detailed characteristics of resources. This section has historically summarized exceptions on proxy versus registered costs. As described in Workpaper 1 Commitment Cost Decisions, CAISO policies have evolved such that all units were required to use the Proxy cost option for the record period. PG&E did not perform any proxy/registered cost determinations for thermal resources during the record period for 2022.

**TABLE 1-6**
**PROXY VS. REGISTERED COST EXCEPTIONS – ANNUAL SUMMARY**

| Line No. | | No. of Times Proxy Used | No. of Times Registered Used | No. of Incorrect Submissions | Potential Cost Impact |
|---|---|---|---|---|---|
| 1 | Startup | – | – | – | – |
| 2 | Min Load | – | – | – | – |
| 3 | Total | – | – | – | – |
| 4 | Percent of Total Startup and Min Load Submissions | – | – | – | – |

Note: Reference: Workpaper 1: Commitment Cost Decisions (xlsx); Table 1.1 – Annual Summary.

## 5. LCD Bidding, and Scheduling Cost Impacts

The dynamic management of LCD for an increasingly complex supply portfolio creates inevitable challenges to perfect execution. The Commission has made clear that the Utility is not to be held to a “perfection” standard with respect to LCD. PG&E bids and schedules a large portfolio of over 300 resources, each of which may have individual operational and contract parameters. PG&E demonstrates in this testimony and the supporting workpapers that it bids and schedules resources and procures energy for customers to LCD standards. During the record period, PG&E submitted over 2,063,000 hourly Day-Ahead bids and self-schedules for CAISO day-ahead revenues of over $3.9 billion. The potential cost impact of scheduling errors described below in this testimony totaled $4,587 or 0.0001 percent of day-ahead revenue. The total affected bids of scheduling errors with cost impact totaled 207 hours, or 0.01 percent of total day-ahead bids. PG&E considers this error rate and cost impacts described in this testimony to demonstrate that PG&E was a prudent and reasonable manager, especially seen in the context of the overall gains to customers of its LCD processes. In addition, PG&E has instituted rigorous checks to monitor errors and has subjected our internal processes to continuous scrutiny.

During the record period, there were four bidding and scheduling events with estimated cost impacts as outlined below:

**TABLE 1-7**
**BIDDING, AND SCHEDULING EVENTS WITH IMPACT**

| Event No. | [redacted] | Estimated Cost Impact |
|---|---|---|
| 1 | | $2,144 |
| 2 | | $112 |
| 3 | | $2,278 |
| 4 | | $53 |

- [redacted]
- [redacted]

[redacted]

- [redacted]
- [redacted] In response to these events, PG&E improved processes/tools and conducted training to help prevent similar events from occurring again. These improvements that mitigate reoccurrence of similar scheduling errors included: implementation of additional validation checks, and updates to scheduling tools.

### 6. Background Summary Table

Table 1-8 below provides a summary of schedule and dispatch data for the record period, corresponding to the requirement in the LCD Decisions. The table reflects an annual summary by resource type (and divided into dispatchable and non-dispatchable resources) for capacity, day-ahead self-schedule awards and DAM awards.

**TABLE 1-8**
**BACKGROUND SUMMARY – ANNUAL REPORT**

| Line No. | Dispatchable | |
|---|---|---|
| 1 | CHP | [redacted] |
| 2 | HYDRO | |
| 3 | PDR | |
| 4 | RENEWABLE | |
| 5 | SOLAR | |
| 6 | STORAGE | |
| 7 | THERMAL | |
| 8 | WIND | |
| 9 | Dispatchable Total | |

(a) Capacity (MWh) for non-PDR resources is calculated using the resources' P-Max MW multiplied by the number of hours in a day during the applicable time period.

Capacity (MWh) for PDR resources is calculated using the resources' P-Max MW multiplied by the number of hours bid during the applicable time period.

(b) Total Unavailable Capacity for non-PDR resources represents the total capacity unavailable due to planned or forced outages reported in OMS.

(c) The renewable category consists mainly of biomass, biogas, and geothermal resources.

Reference: Workpaper 5: Background Summary (xlsx); Table 5.1 – Annual Report.

**TABLE 1-8**
**BACKGROUND SUMMARY – ANNUAL REPORT**
**(CONTINUED)**

| Line No. | Non-Dispatchable | [redacted] |
|---|---|---|
| 10 | CHP | |
| 11 | FIT | |
| 12 | Hydro | |
| 13 | Nuclear | |
| 14 | QF | |
| 15 | Renewable | |
| 16 | Solar | |
| 17 | Wind | |
| 18 | Non-Dispatchable Total | |
| 19 | Grand Total | |

(a) Capacity (MWh) for non-PDR resources is calculated using the resources' P-Max MW multiplied by the number of hours in a day during the applicable time period.

Capacity (MWh) for PDR resources is calculated using the resources' P-Max MW multiplied by the number of hours bid during the applicable time period.

(b) Total Unavailable Capacity for non-PDR resources represents the total capacity unavailable due to planned or forced outages reported in OMS.

### 7. 2022 Market and Business Process Changes

PG&E participates in CPUC proceedings and CAISO initiatives on changes to market design and implementation and then integrates any changes into internal processes. During the record period, PG&E participated in market initiatives that potentially impact LCD related business processes.

Two CAISO Stakeholder initiatives relevant to energy storage resources were implemented during 2021. The first was Phase 1 of the Resource Adequacy (RA) Enhancements Initiative,[22] which created the Minimum State of Charge (MSOC) constraint for Non-Generator Resources (NGRs[23]), such as storage. The purpose of the MSOC is to preserve

[22] http://www.caiso.com/InitiativeDocuments/ResourceAdequacyEnhancementsPhase1Apr21-2021.pdf.

[23] "Resources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to (1) generate Energy, (2) curtail the consumption of Energy in the case of demand response, or (3) consume Energy." CAISO Tariff Appendix A: Conformed-Tariff-as-of-Nov29-2022.pdf (caiso.com).

enough state-of-charge in the energy storage fleet to meet their respective DAM awards in the RTM. The CAISO also implemented energy storage and distributed storage resources phase 4 (ESDER4) initiative in October of 2021. In preparation for bidding and scheduling of future energy storage resources, PG&E updated bidding software to be able to process new ESDER4 storage bid parameters (i.e., end-of-hour state of charge bid parameter and variable storage operations costs).

As discussed in Section B.3.b.4), the CAISO's Commitment Cost Enhancements Phase 3 initiative implemented on April 1, 2019 eliminated the need for PG&E to make a Proxy/Registered cost determination for thermal resources during the record period. The market change eliminates the need for Workpaper 1 – Commitment Cost Decisions.

## C. Economically-Triggered DR Programs

### 1. Introduction

This section addresses PG&E's dispatch of DR programs with an economic trigger during the record period, as directed by the LCD Decisions. Specifically, these decisions require PG&E to include in this application metrics proposed by Cal Advocates concerning the dispatch of DR programs with economic triggers. For purposes of this section, the term "dispatch" refers to times when PG&E activates a DR program to reduce load.

PG&E utilized its DR portfolio during the record period to provide load reductions that enhanced reliability and reduced peak demand and associated prices. Economically-triggered DR programs were represented as Proxy Demand Response (PDR) resources in PG&E's portfolio and bid into the CAISO DAM based on calculated availabilities and dispatch trigger prices. In cases where forecast prices indicated that a PDR resource would exceed its maximum call days in a given month, an opportunity cost was added to the dispatch trigger price with the aim of maximizing the realized value of call days. Because PG&E's economically-triggered DR programs cannot be dispatched in the RTMs, all PDR resources were registered as "day-ahead only" in the Master File and received no further dispatch instructions in the RTMs.

During the record period, a total of 60 PDR resources were bid into the CAISO markets between May 1 through October 31, 2022 (the period when PDR was active). These resources represented subsets of customers enrolled in the Capacity Bidding Program (CBP) and SmartAC™[24] DR programs that were determined capable to respond when directed to do so.

For the record period, dispatch of DR resources was well-aligned with periods of high load and high prices. Instances in which either bidding procedures were not followed, or resources were not dispatched when awarded, can be attributed to resources reaching their maximum monthly event limits or operational challenges.

The remainder of this section consists of the following subsections:

- A description of the CBP and a summary of its dispatch during the record period. This section describes the program parameters and includes information about when the program's trigger conditions were met and resources dispatched. Also included is an explanation of non-dispatch decisions, including the instances when CBP triggers were met but resources were not dispatched, and a description of PG&E's opportunity cost methodology; and
- A description of the SmartAC Program and a summary of its dispatch during the record period. This section discusses SmartAC Program changes, including bidding strategy, information about the program's trigger conditions and forecasts, and when the programs were dispatched. There were no instances when SmartAC trigger conditions were met but resources were not dispatched. Further details can be found in section three.

### 2. Economically-Dispatched DR Summary

Table 1-9 below provides specific references to testimony or attachments to this chapter that address Cal Advocates' metrics.

---

[24] The name SmartAC is a registered trademark of PG&E. All further references to the program in PG&E's testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

**TABLE 1-9**
**INDEX OF CAL ADVOCATES' METRICS AND PG&E'S RESPONSES**

| Line No. | Cal Advocates' Metric | PG&E's Response |
|---|---|---|
| 1 | 1A | Section 2.b.1)., Attachment 1A |
| 2 | 1B | Attachment 1A |
| 3 | 1C | Section 2.b.3)., Attachment 1A |
| 4 | 2 | Section 2.b.2)., Attachment 1B |
| 5 | 3A | Attachment 1C |
| 6 | 3B | Attachment 1C |
| 7 | 3C | Attachment 1C |
| 8 | 4 | Section 2.b.3)., Attachment 1A |
| 9 | 5 | Section 2.b.3). |
| 10 | 6A | Section 2.b.4). |
| 11 | 6B | Section 2.b.4). |
| 12 | 6C | Section 2.b.4). |
| 13 | 7 | Section 2.b.3). |

## 3. Capacity Bidding Program

### a. Description

The CBP is a voluntary DR program that offers customers capacity and energy payments for being on standby to reduce energy consumption when requested by PG&E. Since 2018, CBP resources have been integrated into the CAISO DAM as PDRs. The PDR models the physical characteristics of a resource supplied to the CAISO and is the basis for bidding, awards, dispatch, outages, and settlements. Customers enroll through a third-party aggregator for participation in a Day-Ahead notification product. CBP operates from May through October.

CBP offers three program options: (1) Prescribed, (2) Elect, and (3) Elect Plus.

The *Prescribed option* program hours are 1-9 p.m., Monday through Friday, with a maximum of six events and 30 hours per month.

PG&E may trigger a CBP Prescribed Event for one or more Sub-Load Aggregation Points (Sub-LAP) when: (1) the CAISO DAM price exceeds $95/MWh; (2) PG&E receives a market award or dispatch instruction from the CAISO for a PDR sourced from CBP; (3) when PG&E, in its sole opinion, forecasts that generation resources or electric system capacity may not be adequate; or (4) forecasted temperature for a Sub-LAP exceeds the temperature threshold for the Sub-LAP.

The *Elect option* program hours are 1-9 p.m., Monday through Friday, with a maximum of six events and 30 hours per month, though Elect participants can choose to participate in additional events or hours at their discretion. The Elect option also gives aggregators the ability to choose the price at which their PDRs are bid into the DAM.

The *Elect Plus option* allows participation in the CAISO market for additional hours outside the standard program hours, and like the Elect option, gives aggregators the ability to choose the price at which their PDRs are bid into the DAM.

The maximum number of hours a customer may be dispatched under any of these options is 30 hours per month.

Starting in 2021, the Elect option and the Elect Plus option allow optional weekend participation. Weekend events count toward the maximum number of consecutive event days, maximum number of events per month, and maximum event hours per operating month for resources nominated for weekend participation.

**b. Annual Summary of Results**

All CBP events during the record period were dispatched as the result of PDR market awards, except for 5 test events. PDRs enrolled in the CBP are subject to a test event when they have not received a market award in a given month and the DAM price exceeds the tariff trigger price of $95 per MWh.

**1) Times and Duration of Program Dispatches**

During the record period, PG&E dispatched CBP resources on 24 occasions for a total of 70 event hours compared to 52 occasions and 112 event hours in 2021. The decrease in dispatch frequency and dispatch duration between 2021 and 2022 is due to a decrease in the number resources dispatched under the Prescribed option. There were no resources nominated under the Prescribed option in 2022.

Table 1-10 below provides additional detail and a comparison of CBP event count and frequency for 2013 through 2021.

**TABLE 1-10**
**CBP DR PROGRAM DISPATCH**

| | | CBP | |
|---|---|---|---|
| Line No. | Year | Day-Ahead Total Events/Hours | Day-Of Total Events/Hours |
| 1 | 2013 | 5/20 | 5/19 |
| 2 | 2014 | 11/41 | 15/60 |
| 3 | 2015 | 16/63 | 18/72 |
| 4 | 2016 | 16/58 | 19/69 |
| 5 | 2017 | 22/67 | 25/71 |
| 6 | 2018 | 47/114 | 0/0 |
| 7 | 2019 | 13/20 | 0/0 |
| 8 | 2020 | 28/60 | 0/0 |
| 9 | 2021 | 52/112 | 0/0 |
| 10 | 2022 | 24/70 | 0/0 |

Attachment 1A provides a summary of: (a) the times and duration that all programs were dispatched; (b) all cases where CBP trigger conditions were forecast to be met and all cases where these trigger conditions were actually met; and (c) a list of occurrences when DR resources met program triggers, but were not dispatched, along with an explanation of the reason for non-dispatch.

**2) Satisfaction of DR Program Trigger Conditions**

Table 11 below summarizes the annual number of hours CBP was dispatched in each Sub-LAP, compared to the annual number of hours that CBP was available. Also included is the annual number of events dispatched compared to the maximum number of events allowed.[25]

---

[25] The maximum number of events was established in Resolution E-4819 and implemented on June 1, 2017.

**TABLE 1-11**
**ANNUAL CBP HOURS DISPATCHED**

| Line No. | Load Zone | Number of Hours Day-Ahead Trigger Was Met | Total Day-Ahead Event Hours Dispatched | Number of Day-Ahead Events | Maximum Allowable Number of Events/Year |
|---|---|---|---|---|---|
| 1 | PGCC | 16 | 23 | 9 | 30 |
| 2 | PGEB | 28 | 35 | 16 | 30 |
| 3 | PGF1 | 16 | 23 | 8 | 30 |
| 4 | PGFG | 25 | 25 | 9 | 30 |
| 5 | PGHB | 8 | 10 | 5 | 30 |
| 6 | PGKN | 21 | 28 | 11 | 30 |
| 7 | PGNB | 18 | 27 | 12 | 30 |
| 8 | PGNC | 0 | 0 | 0 | 30 |
| 9 | PGNP | 15 | 24 | 9 | 30 |
| 10 | PGP2 | 32 | 32 | 13 | 30 |
| 11 | PGSB | 34 | 34 | 14 | 30 |
| 12 | PGSF | 30 | 29 | 12 | 30 |
| 13 | PGSI | 31 | 34 | 15 | 30 |
| 14 | PGST | 16 | 21 | 8 | 30 |
| 15 | PGZP | 14 | 20 | 7 | 30 |

Attachment 1B provides monthly tables showing the number of hours when PG&E forecasted that trigger criteria would be reached, hours in which trigger conditions were reached in the same time period, actual hours dispatched, and the number of events dispatched.

### 3) Non-Dispatch Occurrences

#### a) Summary

The number of hours when triggers were met but resources were not dispatched were minimal during the record period. As a result of the integration of CBP resources as PDRs in the CAISO day-ahead energy market, bidding strategies incorporated operational constraints and opportunity costs. Additionally, the Elect and Elect Plus Program options allow CBP aggregators to make resources available beyond the limits on number of events hours, and consecutive days. The details are discussed below.

**TABLE 1-12**
**CBP HOURS IN WHICH TRIGGER MET,**
**BUT RESOURCE NOT DISPATCHED**

| Line No. | Load Zone | Day-Ahead Hours |
|---|---|---|
| 1 | PGCC | 1 |
| 2 | PGEB | 3 |
| 3 | PGF1 | 1 |
| 4 | PGFG | 2 |
| 5 | PGHB | 0 |
| 6 | PGKN | 1 |
| 7 | PGNB | 1 |
| 8 | PGNC | 0 |
| 9 | PGNP | 1 |
| 10 | PGP2 | 8 |
| 11 | PGSB | 10 |
| 12 | PGSF | 7 |
| 13 | PGSI | 7 |
| 14 | PGST | 1 |
| 15 | PGZP | 0 |

Attachment 1C provides a detailed summary of total energy actually dispatched as a proportion of maximum available energy for each DR program. This comparison provides both percentage and nominal MWh terms.

**b) Explanation of the Basis for a Decision Not to Dispatch**

The integration of CBP as PDR in the DAM resulted in program dispatches triggered by market awards (5 dispatches were test events). Operational constraints and opportunity cost are incorporated into the PDR bidding strategy for the Prescribed option. For example, PG&E monitors the dispatches for each PDR to ensure the 6-event and 30-hour monthly maximums, as well as the three consecutive event days, are observed. When the limits are reached, the PDR is not bid into the market unless it is nominated in the Elect or Elect+ option and the aggregator opts to voluntarily exceed the limits. Similarly, when forecast prices indicate that a PDR resource would exceed its maximum in a given month, an opportunity cost was added to the dispatch trigger price to maximize the value of call days. The result of considering operational constraints and opportunity cost in the bidding strategy is a significant reduction of instances when the program trigger was met, but the program was not dispatched.

The Elect and Elect Plus participation options reduce the number of dispatch exceptions. These options provide CBP aggregators the ability to decide what operational constraints and opportunity cost considerations apply to their portfolio. The aggregators determine how many hours per month, events per month, and consecutive days their resources are available. They develop their bidding strategy and PG&E submits the bids as provided. When the bids result in a market award, PG&E dispatches the resources accordingly.

In the 2014 ERRA Settlement, PG&E agreed to provide definitions of “operational constraints” and “opportunity cost” which are used as reasons for not dispatching DR programs when economic triggers are met.[26] These definitions are provided in Sections 3.C.c and 3.C.d below, respectively. PG&E also agreed to provide guidelines for situations in which “customer fatigue” may occur. This is included in Section 3.C.d.

On 9 occasions totaling 23 hours, CBP resources received market awards but were not dispatched due to resources having already reached either the maximum number of events per month or the maximum number of consecutive event days. There were no occasions where hours were not dispatched due to technical difficulties.

**c) Operational Constraints Related to DR Dispatch**

PG&E defines a DR “operational constraint” as a constraint based on limitations included in the DR tariff(s). These include the monthly “total hour” and “number of events,” and the hour per-call basis. For example, the CBP Prescribed option is

---

[26] 2014 ERRA Settlement, 3.2, 3.6.

limited to 30 hours per month and six events per month.[27] As mentioned above, PG&E accounts for these constraints in the bidding strategy.

**d) Opportunity Costs as Related to DR Dispatch**

Generally, "opportunity cost" is the potential lost future value associated with calling a DR program at a certain point in time and, therefore, eliminating the option to use it at a future time. Opportunity costs arise from two issues.

First, there are maximum hour limits and number of times a PDR participating in the Prescribed option may be called in the DR program season, so dispatching a resource today may result in the resource not being available during a future time of need.

The second issue that creates opportunity cost is "customer fatigue," which is a reduction in participation rates after multiple calls due to the customer perceiving the costs of participating exceeding the benefits of participating.

Some of PG&E's largest DR customers have provided consistent feedback to PG&E that dispatch frequency has seriously impacted their business operations and requested that dispatch only occur if necessary. As a result, PG&E generally does not dispatch DR events for more than three days in a row, which was agreed to in the 2014 ERRA Settlement and included in the CBP tariff.

**4) Dispatch Day Selection**

For the record period, PG&E's CBP event dispatch helped to minimize its overall portfolio costs. As demonstrated in Table 1-13 below, PG&E employed its DR resources during highly valuable hours.

---

**27** The CBP tariff specifies that the program is only available during the summer (May-October) DR season. This also would be considered an operational constraint when compared to year-round DR programs.

**TABLE 1-13**
**AVERAGE LMP FOR FORECASTED TRIGGER EVENT DAYS AND ACTUAL DISPATCH DAYS**

| Line No. | Average Hourly Price During Actual Dispatch Events ($/MWh) (A) | Average Hourly Potential Price During All Times When Trigger Conditions Were Forecasted (Dispatched or Not) ($/MWh) (B) | $ (A) – (B) | (A)/(B) (%) |
|---|---|---|---|---|
| 1 | [redacted] | | | |

As indicated in Table 1-13, the average hourly LMP for CBP events actually dispatched in the record period was [redacted], whereas the average hourly potential LMP from all time periods when CBP triggers were forecasted to be met by PG&E was [redacted]. The variability between the two price figures can in part be attributed to instances where the trigger for an event was met, but was not ultimately dispatched due to resources having already reached either the maximum number of events per month or the maximum number of consecutive event days.

### 4. SmartAC

#### a. Description

PG&E's SmartAC Program is a voluntary DR program available to residential customers. PG&E installs a load control device at a customer's premises that can temporarily disengage the customer's primary central Air Conditioning (A/C) unit or raise the temperature at the thermostat when the device is remotely activated. SmartAC is both a reliability program used during emergencies and an economic program based on wholesale energy prices. It can be dispatched by: (1) order of the CAISO a) after the dispatch of Condition 2 Reliability Must-Run units and prior to canvasing other entities and Balancing Authorities for available Manual Dispatch Energy/Capacity on interties, or b) otherwise based on its forecasted system conditions and operating procedures; or c) during emergency or near-emergency situations; (2) at the discretion of PG&E's energy operations center in response to a CAISO economic award in the wholesale market or high wholesale energy prices; or (3) during program testing.

SmartAC is available for dispatch from May 1 through October 31, consistent with times of high A/C usage. It is available for emergencies seven days a week and economic dispatch is targeted for Monday through Friday. The program was originally designed to permit a maximum of 100 hours of cycling per customer per year. Historically, however, few emergency events happened, and with CAISO wholesale market integration in 2018, economic dispatch has been targeted at 20 hours per service account annually. This target number of hours was identified based on PG&E's own testing, and information shared by Southern California Edison Company and their experience with their A/C cycling program. Both sources indicated that cycling in excess of 20-25 hours leads to higher customer attrition rates.

As mentioned above, SmartAC continued to be integrated as a PDR in the CAISO DAM in 2022. The SmartAC bidding strategy reflects the dual nature of the program as both a reliability program and an economic program.

A/C usage and potential load reduction is highly dependent on temperature, so determining resource availability is based on regional temperature forecast. The Sub-LAP temperature thresholds in Table 1-14 below were developed by the PG&E Measurement and Evaluation team based on analysis of SmartAC Program testing over several years. In order to make SmartAC PDRs available for emergency dispatch, the PDR resources are generally bid at $1,000 per MWh during intervals when Sub-LAP temperature thresholds are not forecast to be met.

**TABLE 1-14**
**SMART AC SUB-LAP TEMPERATURE THRESHOLDS**

| Line No. | Load Zone | Forecast High Temperature |
|---|---|---|
| 1 | PGCC | 99 |
| 2 | PGEB | 106 |
| 3 | PGF1 | 110 |
| 4 | PGFG | 103 |
| 5 | PGHB | 108 |
| 6 | PGKN | 109 |
| 7 | PGNB | 99 |
| 8 | PGNC | 108 |
| 9 | PGNP | 111 |
| 10 | PGP2 | 99 |
| 11 | PGSB | 99 |
| 12 | PGSF | 95 |
| 13 | PGSI | 108 |
| 14 | PGST | 108 |
| 15 | PGZP | 109 |

If the Sub-LAP temperature was forecast to exceed the temperature threshold in a Sub-LAP, then the resource was deemed to have significant load reduction potential and the economic trigger was forecast to be met. When this condition was met, the bid price was lowered from the $1,000 per MWh emergency price to the level of the Net Benefit Test, the CAISO-determined price above which DR resource bids are cost effective.

**b. Annual Summary of Results**

**1) Times and Duration of Program Dispatches**

During the record period, PG&E dispatched SmartAC resources on 16 occasions on 14 days. All events were dispatched as a result of market awards, a program system serial test event, or a CAISO emergency.

**TABLE 1-15**
**SMARTAC PROGRAM DISPATCH**

| Line No. | Year | Day-Ahead Total Events/Hours |
|---|---|---|
| 1 | 2018 | 9/32 |
| 2 | 2019 | 10/32 |
| 3 | 2020 | 15/40.367 |
| 4 | 2021 | 8/25.183 |
| 5 | 2022 | 17/46.5 |

Attachment 1A provides a summary of: (a) the times and duration that programs were dispatched; (b) all cases where trigger conditions were forecast to be met and all cases where these trigger conditions were actually met; and (c) a list of occurrences when DR resources met program triggers, but were not dispatched, along with an explanation of the reason for non-dispatch.

### 2) Satisfaction of DR Program Trigger Conditions

Table 1-16 summarizes the annual number of hours SmartAC was dispatched in each Sub-LAP, compared to the annual number of hours that it was available.

**TABLE 1-16**
**ANNUAL SMARTAC PROGRAM HOURS DISPATCHED**

| Line No. | Load Zone | Hours Trigger Was Forecast to be Met | Hours Day-Ahead Trigger Was Met | Hours Day-Ahead Event Dispatched | Number of Day-Ahead Events | Maximum Allowable Event Hours/Year |
|---|---|---|---|---|---|---|
| 1 | PGCC | 0 | 0 | 15.4 | 5 | 100 |
| 2 | PGEB | 10 | 10 | 17.4 | 6 | 100 |
| 3 | PGF1 | 19 | 19 | 26.4 | 10 | 100 |
| 4 | PGFG | 0 | 0 | 11.4 | 5 | 100 |
| 5 | PGHB | 0 | 0 | 0.0 | 0 | 100 |
| 6 | PGKN | 20 | 20 | 27.4 | 11 | 100 |
| 7 | PGNB | 10 | 10 | 17.4 | 6 | 100 |
| 8 | PGNC | 19 | 19 | 26.4 | 10 | 100 |
| 9 | PGNP | 18 | 18 | 25.4 | 10 | 100 |
| 10 | PGP2 | 12 | 12 | 18.4 | 6 | 100 |
| 11 | PGSB | 11 | 11 | 18.4 | 6 | 100 |
| 12 | PGSF | 0 | 0 | 0.0 | 0 | 100 |
| 13 | PGSI | 19 | 19 | 26.4 | 10 | 100 |
| 14 | PGST | 15 | 15 | 21.4 | 8 | 100 |
| 15 | PGZP | 21 | 21 | 26.4 | 11 | 100 |

Attachment 1B provides monthly tables showing the number of hours when PG&E forecasted that trigger criteria would be reached, hours in which trigger conditions were reached in the same time period, actual hours dispatched, and the number of events dispatched.

**3) Non-Dispatch Occurrences**

There were few instances when SmartAC resources received a market award but resources were not dispatched because the SmartAC program was not instructed by front office to dispatch. There were no instances when the high temperature threshold trigger for the SmartAC Program was met and the bid price was not lowered from the $1,000 per MWh emergency price to the level of the Net Benefit Test.

Commonly, PG&E will lower bids for days that are still forecasted as middle or low trigger temperature days in order to reach a 20-hour event goal per enrolled service agreement for the season. There were instances in 2022 where the middle or low forecasted temperature trigger was met but PG&E did not lower bid prices to receive market awards. Overall, this did not significantly impact the 20-event hour goal per customer as the average number of hours per customer was 19 for the 2022 summer season across the territory. The most a customer would have participated in event hours was 26.47 hours and the least a customer would have participated in event hours was 11.47 hours, which was for PGFG, historically a much cooler load zone and was still the case in 2022. Also in 2022, a dispatch error occurred in which roughly half the population of 2-way load control switches did not dispatch for events throughout the season related to the head end device management system and the demand response management system.

**TABLE 1-17**
**SMARTAC PROGRAM HOURS IN WHICH TRIGGER MET**
**BUT RESOURCE NOT DISPATCHED**

| Line No. | Load Zone | Day-Ahead Hours |
|---|---|---|
| 1 | PGCC | 0 |
| 2 | PGEB | 0 |
| 3 | PGF1 | 0 |
| 4 | PGFG | 0 |
| 5 | PGHB | 0 |
| 6 | PGKN | 0 |
| 7 | PGNB | 0 |
| 8 | PGNC | 0 |
| 9 | PGNP | 0 |
| 10 | PGP2 | 1 |
| 11 | PGSB | 0 |
| 12 | PGSF | 0 |
| 13 | PGSI | 1 |
| 14 | PGST | 1 |
| 15 | PGZP | 2 |

#### 4) Dispatch Day Selection

For the record period, PG&E's SmartAC Program event dispatches helped to minimize its overall portfolio costs. As demonstrated in Table 1-18 below, PG&E employed its DR resources during highly-valuable hours.

**TABLE 1-18**
**AVERAGE LMP FOR**
**SMARTAC FORECASTED TRIGGER EVENT DAYS**
**AND ACTUAL DISPATCH DAYS**

| Line No. | Average Hourly Price During Actual Dispatch Events ($/MWh) (A) | Average Hourly Potential Price During All Times When Trigger Conditions Were Forecasted (Dispatched or Not) ($/MWh) (B) | $ (A) – (B) | (A)/(B) (%) |
|---|---|---|---|---|
| 1 | [redacted] | | | |

As indicated in Table 1-18, the average hourly LMP for SmartAC events actually dispatched in the record period was [redacted]. The average hourly potential LMP from all time periods when SmartAC triggers were forecasted to be met was [redacted]. The difference in prices in mainly attributed to the dispatch hours where SmartAC resources did not receive market awards and still dispatched for emergency events, test events, or retail dispatches. Additionally, there were a few instances when SmartAC was awarded market awards but did not dispatch which impact the difference in prices.

#### 5. Economically-Dispatched DR Summary

PG&E utilized CBP and SmartAC to provide load reductions that enhanced reliability and reduced peak demand and associated prices. DR resources were well-aligned with high load and price time periods. While PG&E did not dispatch its DR resources each time an economic trigger was met, instances of non-dispatch were due to operational constraints of the programs or due to opportunity costs associated with customer impact as outlined earlier. Additionally, in rare instances, the temperature threshold for lowering SmartAC bids was not met even during periods of high load and price.

### D. Conclusion

In compliance with the LCD Decisions and 2014 and 2015 ERRA Settlements, this chapter and the associated work papers have demonstrated that PG&E:

- Achieved LCD during the record period; and
- Reasonably utilized, integrated, and improved the dispatch for economic DR resources during the record period.

PG&E has fully complied with the Commission decisions addressing LCD practices during the record period and has provided testimony and workpapers that are consistent with the LCD Decisions to satisfy PG&E's burden to demonstrate that it achieved LCD. This testimony and the confidential workpapers for Chapter 1 demonstrate that PG&E dispatched its resources in a manner consistent with LCD requirements during the record period.

PG&E also utilized its DR portfolio during the record period to provide load reductions that enhanced reliability and reduced peak demand and associated prices. In addition, PG&E has provided the information and metrics required by the LCD Decisions for LCD and its economically-triggered DR Programs. Finally, where applicable, the Chapter 1 testimony and workpapers satisfy the requirements of the 2014 and 2015 ERRA Settlements.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 1

# ATTACHMENT A

# SUMMARY OF TRIGGERED DISPATCH FROM DEMAND RESPONSE PROGRAMS

## Attachment A - Triggers Met - DR Program Dispatched

| Date Trigger Condition Was Forecast to be Met | Type of Trigger | Program | Location | Forecast Start Time | Forecast End Time | Dispatch Start Time | Dispatch End Time | Forecast Event Hours | Trigger Was Met? | Resource Dispatched? | If No, Explain | Was Program Not Dispatched Because PG&E Resources Would Be More Economic? | Hours Dispatched/Hours Non-dispatched Should Be Reported | Total Capacity of Program Available for Dispatch | Forecasted Available Load For the Program Being Dispatched | Actual Load Achieved | Duration of Dispatch |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5/20/2022 | Test Event | Capacity Bidding Program | PGCC, PGEB, PGF1, PGFG, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST, PGZP | 19:00 | 21:00 | 19:00 | 21:00 | 2 | N | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 5/25/2022 | Market Award | Capacity Bidding Program | PGSB | 14:00 | 16:00 | 14:00 | 16:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 5/25/2022 | Market Award | Capacity Bidding Program | PGEB, PGFG | 19:00 | 21:00 | 19:00 | 21:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 5/25/2022 | Market Award | Capacity Bidding Program | Combined Market Award dispatch | 14:00 | 21:00 | 14:00 | 21:00 | 7 | Y | Y | | | 7 | [redacted] | [redacted] | [redacted] | 7.00 |
| 6/8/2022 | Market Award | Capacity Bidding Program | PGP2, PGSF | 14:00 | 15:00 | 14:00 | 15:00 | 1 | Y | Y | | | 1 | [redacted] | [redacted] | [redacted] | |
| 6/8/2022 | Market Award | Capacity Bidding Program | PGKN | 19:00 | 21:00 | 19:00 | 21:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 6/8/2022 | Market Award | Capacity Bidding Program | Combined Market Award dispatch | 14:00 | 21:00 | 14:00 | 21:00 | 7 | Y | Y | | | 7 | [redacted] | [redacted] | [redacted] | 7.00 |
| 6/9/2022 | Market Award | Capacity Bidding Program | PGKN | 19:00 | 21:00 | 19:00 | 21:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 6/10/2022 | Market Award | Capacity Bidding Program | PGEB, PGFG, PGKN, PGNB, PGP2, PGSF | 13:00 | 21:00 | 13:00 | 21:00 | 8 | Y | Y | | | 8 | [redacted] | [redacted] | [redacted] | 8.00 |
| 6/21/2022 | Market Award | Capacity Bidding Program | PGSF | 15:00 | 16:00 | 15:00 | 16:00 | 1 | Y | Y | | | 1 | [redacted] | [redacted] | [redacted] | |
| 6/21/2022 | Market Award | Capacity Bidding Program | PGEB, PGP2, PGSB | 17:00 | 20:00 | 17:00 | 20:00 | 3 | Y | Y | | | 3 | [redacted] | [redacted] | [redacted] | |
| 6/21/2022 | Market Award | Capacity Bidding Program | Combined Market Award dispatch | 15:00 | 20:00 | 15:00 | 20:00 | 5 | Y | Y | | | 5 | [redacted] | [redacted] | [redacted] | 5.00 |
| 6/22/2022 | Market Award | Capacity Bidding Program | PGSB | 14:00 | 15:00 | 14:00 | 15:00 | 1 | Y | Y | | | 1 | [redacted] | [redacted] | [redacted] | |
| 6/22/2022 | Market Award | Capacity Bidding Program | PGEB | 17:00 | 18:00 | 17:00 | 18:00 | 1 | Y | Y | | | 1 | [redacted] | [redacted] | [redacted] | |
| 6/22/2022 | Market Award | Capacity Bidding Program | Combined Market Award dispatch | 14:00 | 18:00 | 14:00 | 18:00 | 4 | Y | Y | | | 4 | [redacted] | [redacted] | [redacted] | 4.00 |
| 6/23/2022 | Market Award | Capacity Bidding Program | PGEB, PGFG, PGNB, PGP2, PGSB | 14:00 | 20:00 | 14:00 | 20:00 | 6 | Y | Y | | | 6 | [redacted] | [redacted] | [redacted] | 6.00 |
| 6/24/2022 | Market Award | Capacity Bidding Program | PGSF | 15:00 | 17:00 | 15:00 | 17:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 6/28/2022 | Test Event | Capacity Bidding Program | PGCC, PGEB, PGKN, PGNB, PGNP, PGSB, PGSI | 19:00 | 21:00 | 19:00 | 21:00 | 2 | N | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 7/22/2022 | Test Event | Capacity Bidding Program | PGCC, PGEB, PGF1, PGHB, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST, PGZP | 18:00 | 21:00 | 18:00 | 21:00 | 3 | N | Y | | | 3 | [redacted] | [redacted] | [redacted] | 3.00 |
| 8/1/2022 | Market Award | Capacity Bidding Program | PGSI | 19:00 | 20:00 | 19:00 | 20:00 | 1 | Y | Y | | | 1 | [redacted] | [redacted] | [redacted] | 1.00 |
| 8/4/2022 | Market Award | Capacity Bidding Program | PGEB | 15:00 | 16:00 | 15:00 | 16:00 | 1 | Y | Y | | | 1 | [redacted] | [redacted] | [redacted] | 1.00 |
| 8/16/2022 | Market Award | Capacity Bidding Program | PGSI | 19:00 | 20:00 | 19:00 | 20:00 | 1 | Y | Y | | | 1 | [redacted] | [redacted] | [redacted] | 1.00 |
| 8/26/2022 | Test Event | Capacity Bidding Program | PGCC, PGEB, PGF1, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST, PGZP | 18:00 | 20:00 | 18:00 | 20:00 | 2 | N | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 9/1/2022 | Market Award | Capacity Bidding Program | PGCC, PGEB, PGF1, PGFG, PGHB, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST | 17:00 | 21:00 | 17:00 | 21:00 | 4 | Y | Y | | | 4 | [redacted] | [redacted] | [redacted] | 4.00 |
| 9/2/2022 | Market Award | Capacity Bidding Program | PGCC, PGEB, PGFG, PGNB, PGP2, PGSB, PGSF, PGSI, PGST | 17:00 | 20:00 | 17:00 | 20:00 | 3 | Y | Y | | | 3 | [redacted] | [redacted] | [redacted] | 3.00 |
| 9/4/2022 | Market Award | Capacity Bidding Program | PGSI | 18:00 | 19:00 | 18:00 | 19:00 | 1 | Y | Y | | | 1 | [redacted] | [redacted] | [redacted] | 1.00 |
| 9/6/2022 | Market Award | Capacity Bidding Program | PGCC, PGEB, PGF1, PGFG, PGHB, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST | 16:00 | 21:00 | 16:00 | 21:00 | 5 | Y | Y | | | 5 | [redacted] | [redacted] | [redacted] | 5.00 |
| 9/7/2022 | Market Award | Capacity Bidding Program | PGCC, PGEB, PGF1, PGFG, PGHB, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST | 17:00 | 21:00 | 17:00 | 21:00 | 4 | Y | Y | | | 4 | [redacted] | [redacted] | [redacted] | 4.00 |
| 9/8/2022 | Market Award | Capacity Bidding Program | PGCC, PGEB, PGF1, PGFG, PGHB, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST | 16:00 | 21:00 | 16:00 | 21:00 | 5 | Y | Y | | | 5 | [redacted] | [redacted] | [redacted] | 5.00 |
| 10/6/2022 | Market Award | Capacity Bidding Program | PGSI | 18:00 | 19:00 | 18:00 | 19:00 | 1 | Y | Y | | | 1 | [redacted] | [redacted] | [redacted] | 1.00 |
| 10/19/2022 | Market Award | Capacity Bidding Program | PGSI | 18:00 | 19:00 | 18:00 | 19:00 | 1 | Y | Y | | | 1 | [redacted] | [redacted] | [redacted] | 1.00 |
| 10/20/2022 | Test Event | Capacity Bidding Program | PGEB, PGF1, PGNB, PGNP, PGP2, PGSB, PGSI | 17:00 | 20:00 | 17:00 | 20:00 | 3 | N | Y | | | 3 | [redacted] | [redacted] | [redacted] | 3.00 |
| 7/11/2022 | Market Award | SmartAC | PGKN, PGNC, PGNP, PGSI, PGZP | 17:00 | 19:00 | 17:00 | 19:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 7/16/2022 | Market Award | SmartAC | PGF1, PGKN, PGSI, PGST, PGZP | 16:00 | 18:00 | 16:00 | 18:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 7/16/2022 | Market Award | SmartAC | PGNP | 17:00 | 19:00 | 17:00 | 19:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 7/16/2022 | Market Award | SmartAC | Combined Market Award dispatch | 16:00 | 19:00 | 16:00 | 19:00 | 3 | Y | Y | | | 3 | [redacted] | [redacted] | [redacted] | 3.00 |
| 7/17/2022 | Market Award | SmartAC | PGF1 | 15:00 | 17:00 | 15:00 | 17:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 7/17/2022 | Market Award | SmartAC | PGKN, PGZP | 16:00 | 18:00 | 16:00 | 18:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 7/17/2022 | Market Award | SmartAC | Combined Market Award dispatch | 15:00 | 18:00 | 15:00 | 18:00 | 3 | Y | Y | | | 3 | [redacted] | [redacted] | [redacted] | 3.00 |
| 7/24/2022 | Market Award | SmartAC | PGNC | 18:00 | 20:00 | 18:00 | 20:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 7/29/2022 | Market Award | SmartAC | PGF1, PGKN, PGNC, PGZP | 17:00 | 19:00 | 17:00 | 19:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 7/29/2022 | Market Award | SmartAC | PGNP | 18:00 | 20:00 | 18:00 | 20:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 7/29/2022 | Market Award | SmartAC | Combined Market Award dispatch | 17:00 | 20:00 | 18:00 | 20:00 | 3 | Y | Y | | | 3 | [redacted] | [redacted] | [redacted] | 3.00 |
| 8/16/2022 | Market Award | SmartAC | PGEB, PGP2, PGSB | 17:00 | 19:00 | 17:00 | 19:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 8/16/2022 | Market Award | SmartAC | PGF1, PGKN, PGNB, PGNC | 18:00 | 20:00 | 18:00 | 20:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 8/16/2022 | Market Award | SmartAC | PGNP, PGST | 19:00 | 21:00 | 19:00 | 21:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 8/16/2022 | Market Award | SmartAC | PGSI | 20:00 | 22:00 | 20:00 | 22:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 8/16/2022 | Market Award | SmartAC | Combined Market Award dispatch | 17:00 | 22:00 | 17:00 | 22:00 | 5 | Y | Y | | | 5 | [redacted] | [redacted] | [redacted] | 5.00 |
| 8/17/2022 | Test Event | SmartAC | PGNP, PGSI, PGST, PGKN, PGF1, PGZP, PGNC, PGFG, PGNB, PGEB, PGSB, PGP2, PGCC | 16:30 | 19:00 | 16:30 | 19:00 | 2.5 | N | Y | | | 2.5 | [redacted] | [redacted] | [redacted] | 2.50 |
| 8/19/2022 | Market Award | SmartAC | PGSI | 17:00 | 19:00 | 17:00 | 19:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 9/2/2022 | Market Award | SmartAC | PGF1, PGKN, PGZP | 17:00 | 19:00 | 17:00 | 19:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 9/5/2022 | Market Award | SmartAC | PGEB, PGF1, PGKN, PGNB, PGNC, PGNP, PGP2, PGSB, PGSI, PGST, PGZP | 18:00 | 20:00 | 18:00 | 20:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 9/5/2022 | Retail Event | SmartAC | PGCC, PGFG | 18:00 | 20:00 | 18:00 | 20:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 9/5/2022 | Transmission Emergency | SmartAC | PGEB, PGF1, PGKN, PGNB, PGNC, PGNP, PGP2, PGSB, PGSI, PGST, PGZP, PGCC, PGFG | 20:00 | 21:18 | 20:00 | 21:18 | 1.3 | N | Y | | | 1.3 | [redacted] | [redacted] | [redacted] | 1.30 |
| 9/6/2022 | Test Event | SmartAC | PGEB, PGF1, PGKN, PGNB, PGNC, PGNP, PGP2, PGSB, PGSI, PGST, PGZP, PGCC, PGFG | 17:00 | 20:00 | 17:00 | 20:00 | 3 | N | Y | | | 3 | [redacted] | [redacted] | [redacted] | 3.00 |
| 9/6/2022 | Transmission Emergency | SmartAC | PGEB, PGF1, PGKN, PGNB, PGNC, PGNP, PGP2, PGSB, PGSI, PGST, PGZP, PGCC, PGFG | 20:00 | 20:38 | 20:00 | 20:38 | 0.633333 | N | Y | | | 0.6 | [redacted] | [redacted] | [redacted] | 0.63 |
| 9/7/2022 | Market Award | SmartAC | PGEB, PGF1, PGKN, PGNB, PGNC, PGNP, PGP2, PGSB, PGSI, PGST, PGZP | 16:00 | 20:00 | 16:00 | 20:00 | 4 | Y | Y | | | 4 | [redacted] | [redacted] | [redacted] | 4.00 |
| 9/7/2022 | Retail Event | SmartAC | PGCC, PGFG | 16:00 | 20:00 | 16:00 | 20:00 | 4 | Y | Y | | | 4 | [redacted] | [redacted] | [redacted] | 4.00 |
| 9/8/2022 | Market Award | SmartAC | PGEB, PGKN, PGNB, PGNP, PGST | 17:00 | 19:00 | 17:00 | 19:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | |
| 9/8/2022 | Market Award | SmartAC | PGF1, PGNC, PGP2, PGSB, PGSI, PGZP | 17:00 | 20:00 | 17:00 | 20:00 | 3 | Y | Y | | | 3 | [redacted] | [redacted] | [redacted] | |
| 9/8/2022 | Market Award | SmartAC | Combined Market Award dispatch | 17:00 | 20:00 | 17:00 | 20:00 | 3 | Y | Y | | | 3 | [redacted] | [redacted] | [redacted] | 3.00 |
| 9/8/2022 | Retail Event | SmartAC | PGCC, PGFG | 17:00 | 19:00 | 17:00 | 19:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |
| 9/9/2022 | Market Award | SmartAC | PGNC, PGNP, PGSI, PGST | 16:00 | 18:00 | 16:00 | 18:00 | 2 | Y | Y | | | 2 | [redacted] | [redacted] | [redacted] | 2.00 |

## Attachment A - Triggers Met - DR Program Dispatched

| Date Trigger Condition Was Forecast to be Met | Type of Trigger | Program | Location | Forecast Start Time | Forecast End Time | Dispatch Start Time | Dispatch End Time | Forecast Event Hours | Trigger Was Met? | Resource Dispatched? | If No, Explain | Was Program Not Dispatched Because PG&E Resources Would Be More Economic? | Hours Dispatched/Hours Non-dispatched Should Be Reported | Total Capacity of Program Available for Dispatch | Forecasted Available Load For the Program Being Dispatched | Actual Load Achieved | Duration of Dispatch |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5/25/2022 | Market Award | Capacity Bidding Program | PGEB, PGFG | 16:00 | 18:00 | | | 2 | Y | N | exceeds tariff max event calls per day | Y | 2 | [redacted] | | | 0 |
| 6/10/2022 | Market Award | Capacity Bidding Program | PGP2, PGSF | 18:00 | 20:00 | | | 2 | Y | N | exceeds tariff max event calls per day | Y | 2 | | | | 0 |
| 6/21/2022 | Market Award | Capacity Bidding Program | PGP2, PGSB | 15:00 | 16:00 | | | 1 | Y | N | exceeds tariff max event calls per day | Y | 1 | | | | 0 |
| 6/21/2022 | Market Award | Capacity Bidding Program | PGSF | 17:00 | 19:00 | | | 2 | Y | N | exceeds tariff max event calls per day | Y | 2 | | | | 0 |
| 6/23/2022 | Market Award | Capacity Bidding Program | PGP2 | 14:00 | 16:00 | | | 2 | Y | N | exceeds tariff max event calls per day | Y | 2 | | | | 0 |
| 6/23/2022 | Market Award | Capacity Bidding Program | PGSB | 18:00 | 19:00 | | | 1 | Y | N | exceeds tariff max event hours per day | Y | 1 | | | | 0 |
| 6/24/2022 | Market Award | Capacity Bidding Program | PGEB, PGSB | 16:00 | 18:00 | | | 2 | Y | N | exceeds tariff max consecutive event days | Y | 2 | | | | 0 |
| 9/4/2022 | Market Award | Capacity Bidding Program | PGF1 | 18:00 | 19:00 | | | 1 | Y | N | Imp did not exceed bid price | Y | 1 | | | | 0 |
| 9/6/2022 | Market Award | Capacity Bidding Program | PGSB, PGSF, PGSI | 14:00 | 17:00 | | | 3 | Y | N | exceeds tariff max event hours per day | Y | 3 | | | | 0 |
| 9/6/2022 | Market Award | Capacity Bidding Program | PGSF | 20:00 | 21:00 | | | 1 | Y | N | exceeds tariff max event hours per day | Y | 1 | | | | 0 |
| 9/7/2022 | Market Award | Capacity Bidding Program | PGP2, PGSB, PGSI | 14:00 | 17:00 | | | 3 | Y | N | exceeds tariff max event hours per day | Y | 3 | | | | 0 |
| 9/8/2022 | Market Award | Capacity Bidding Program | PGCC, PGEB, PGKN, PGNB, PGNP, PGP2, PGSF, PGSI, PGST | 15:00 | 17:00 | | | 2 | Y | N | exceeds tariff max event hours per day | Y | 2 | | | | 0 |
| 9/8/2022 | Market Award | Capacity Bidding Program | PGFG, PGSB | 20:00 | 21:00 | | | 1 | Y | N | exceeds tariff max event hours per day | Y | 1 | | | | 0 |
| 8/16/2022 | Market Award | SmartAC | PGZP | 19:00 | 21:00 | | | 2 | Y | N | instructed by front office not to dispatch | Y | 2 | | | | 0 |
| 9/7/2022 | Market Award | SmartAC | PGSI | 20:00 | 21:00 | | | 1 | Y | N | instructed by front office not to dispatch | Y | 1 | | | | 0 |
| 9/8/2022 | Market Award | SmartAC | PGP2 | 15:00 | 16:00 | | | 1 | Y | N | Imp did not exceed bid price | Y | 1 | | | | 0 |
| 9/8/2022 | Market Award | SmartAC | PGST | 19:00 | 20:00 | | | 1 | Y | N | Imp did not exceed bid price | Y | 1 | | | | 0 |

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 1

# ATTACHMENT B

# SUMMARY OF 2022 CAPACITY BIDDING PROGRAM EVENTS

Attachment B. Number of hours when PG&E forecasted that trigger criteria would be Met, actual hours Met, and actual hours dispatched

[redacted]

**May**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | | | |
| PGEB | | | | |
| PGF1 | | | | |
| PGFG | | | | |
| PGHB | | | | |
| PGKN | | | | |
| PGNB | | | | |
| PGNC | | | | |
| PGNP | | | | |
| PGP2 | | | | |
| PGSB | | | | |
| PGSF | | | | |
| PGSI | | | | |
| PGST | | | | |
| PGZP | | | | |

**June**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | | | |
| PGEB | | | | |
| PGF1 | | | | |
| PGFG | | | | |
| PGHB | | | | |
| PGKN | | | | |
| PGNB | | | | |
| PGNC | | | | |
| PGNP | | | | |
| PGP2 | | | | |
| PGSB | | | | |
| PGSF | | | | |
| PGSI | | | | |
| PGST | | | | |
| PGZP | | | | |

**July**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | | | |
| PGEB | | | | |
| PGF1 | | | | |
| PGFG | | | | |
| PGHB | | | | |
| PGKN | | | | |
| PGNB | | | | |
| PGNC | | | | |
| PGNP | | | | |
| PGP2 | | | | |
| PGSB | | | | |
| PGSF | | | | |
| PGSI | | | | |
| PGST | | | | |
| PGZP | | | | |

**August**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | | | |
| PGEB | | | | |
| PGF1 | | | | |
| PGFG | | | | |
| PGHB | | | | |
| PGKN | | | | |
| PGNB | | | | |
| PGNC | | | | |
| PGNP | | | | |
| PGP2 | | | | |
| PGSB | | | | |
| PGSF | | | | |
| PGSI | | | | |
| PGST | | | | |
| PGZP | | | | |

**September**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | | | |
| PGEB | | | | |
| PGF1 | | | | |
| PGFG | | | | |
| PGHB | | | | |
| PGKN | | | | |
| PGNB | | | | |
| PGNC | | | | |
| PGNP | | | | |
| PGP2 | | | | |
| PGSB | | | | |
| PGSF | | | | |
| PGSI | | | | |
| PGST | | | | |
| PGZP | | | | |

**October**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | | | |
| PGEB | | | | |
| PGF1 | | | | |
| PGFG | | | | |
| PGHB | | | | |
| PGKN | | | | |
| PGNB | | | | |
| PGNC | | | | |
| PGNP | | | | |
| PGP2 | | | | |
| PGSB | | | | |
| PGSF | | | | |
| PGSI | | | | |
| PGST | | | | |
| PGZP | | | | |

**Annual**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | | | |
| PGEB | | | | |
| PGF1 | | | | |
| PGFG | | | | |
| PGHB | | | | |
| PGKN | | | | |
| PGNB | | | | |
| PGNC | | | | |
| PGNP | | | | |
| PGP2 | | | | |
| PGSB | | | | |
| PGSF | | | | |
| PGSI | | | | |
| PGST | | | | |
| PGZP | | | | |

Attachment B. Number of hours when PG&E forecasted that trigger criteria would be Met, actual hours Met, and actual hours dispatched

[redacted]

**May**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGEB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGF1 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGFG | [redacted] | [redacted] | [redacted] | [redacted] |
| PGHB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGKN | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNP | [redacted] | [redacted] | [redacted] | [redacted] |
| PGP2 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSF | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSI | [redacted] | [redacted] | [redacted] | [redacted] |
| PGST | [redacted] | [redacted] | [redacted] | [redacted] |
| PGZP | [redacted] | [redacted] | [redacted] | [redacted] |

**June**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGEB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGF1 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGFG | [redacted] | [redacted] | [redacted] | [redacted] |
| PGHB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGKN | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNP | [redacted] | [redacted] | [redacted] | [redacted] |
| PGP2 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSF | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSI | [redacted] | [redacted] | [redacted] | [redacted] |
| PGST | [redacted] | [redacted] | [redacted] | [redacted] |
| PGZP | [redacted] | [redacted] | [redacted] | [redacted] |

**July**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGEB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGF1 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGFG | [redacted] | [redacted] | [redacted] | [redacted] |
| PGHB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGKN | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNP | [redacted] | [redacted] | [redacted] | [redacted] |
| PGP2 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSF | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSI | [redacted] | [redacted] | [redacted] | [redacted] |
| PGST | [redacted] | [redacted] | [redacted] | [redacted] |
| PGZP | [redacted] | [redacted] | [redacted] | [redacted] |

**August**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGEB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGF1 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGFG | [redacted] | [redacted] | [redacted] | [redacted] |
| PGHB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGKN | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNP | [redacted] | [redacted] | [redacted] | [redacted] |
| PGP2 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSF | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSI | [redacted] | [redacted] | [redacted] | [redacted] |
| PGST | [redacted] | [redacted] | [redacted] | [redacted] |
| PGZP | [redacted] | [redacted] | [redacted] | [redacted] |

**September**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGEB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGF1 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGFG | [redacted] | [redacted] | [redacted] | [redacted] |
| PGHB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGKN | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNP | [redacted] | [redacted] | [redacted] | [redacted] |
| PGP2 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSF | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSI | [redacted] | [redacted] | [redacted] | [redacted] |
| PGST | [redacted] | [redacted] | [redacted] | [redacted] |
| PGZP | [redacted] | [redacted] | [redacted] | [redacted] |

**October**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGEB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGF1 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGFG | [redacted] | [redacted] | [redacted] | [redacted] |
| PGHB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGKN | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNP | [redacted] | [redacted] | [redacted] | [redacted] |
| PGP2 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSF | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSI | [redacted] | [redacted] | [redacted] | [redacted] |
| PGST | [redacted] | [redacted] | [redacted] | [redacted] |
| PGZP | [redacted] | [redacted] | [redacted] | [redacted] |

**Annual**

| Load Zone | Forecasted | Met | Actual Hours Dispatched | Number of Events Dispatched |
|---|---|---|---|---|
| PGCC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGEB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGF1 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGFG | [redacted] | [redacted] | [redacted] | [redacted] |
| PGHB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGKN | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNC | [redacted] | [redacted] | [redacted] | [redacted] |
| PGNP | [redacted] | [redacted] | [redacted] | [redacted] |
| PGP2 | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSB | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSF | [redacted] | [redacted] | [redacted] | [redacted] |
| PGSI | [redacted] | [redacted] | [redacted] | [redacted] |
| PGST | [redacted] | [redacted] | [redacted] | [redacted] |
| PGZP | [redacted] | [redacted] | [redacted] | [redacted] |

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 1**

**ATTACHMENT C**

**SUMMARY OF TOTAL ENERGY DISPATCHED FROM DEMAND RESPONSE PROGRAMS**

**Attachment C.** Number of hours dispatched, energy dispatched and maximum energy available

[redacted]

**May**

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 30 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 2 | [redacted] | | 7% |
| PGEB | 4 | | | 8% |
| PGF1 | 2 | | | 7% |
| PGFG | 4 | | | 13% |
| PGHB* | 0 | | | 0% |
| PGKN | 2 | | | 7% |
| PGNB | 2 | | | 7% |
| PGNC* | 0 | | | 0% |
| PGNP | 2 | | | 7% |
| PGP2 | 2 | | | 7% |
| PGSB | 4 | | | 10% |
| PGSF | 2 | | | 7% |
| PGSI | 2 | | | 7% |
| PGST | 2 | | | 7% |
| PGZP | 2 | | | 7% |

* No participating customers

**June**

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 30 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 2 | [redacted] | | 5% |
| PGEB | 9 | | | 6% |
| PGF1 | 0 | | | 0% |
| PGFG | 6 | | | 20% |
| PGHB* | 0 | | | 0% |
| PGKN | 8 | | | 1% |
| PGNB | 4 | | | 7% |
| PGNC* | 0 | | | 0% |
| PGNP | 2 | | | 2% |
| PGP2 | 9 | | | 30% |
| PGSB | 9 | | | 9% |
| PGSF | 8 | | | 20% |
| PGSI | 2 | | | 7% |
| PGST | 0 | | | 0% |
| PGZP | 0 | | | 0% |

* No participating customers

**July**

| Load Zone | Actual Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 30 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 2 | [redacted] | | 6% |
| PGEB | 2 | | | 4% |
| PGF1 | 2 | | | 2% |
| PGFG | 0 | | | 0% |
| PGHB | 2 | | | 7% |
| PGKN | 2 | | | 1% |
| PGNB | 2 | | | 6% |
| PGNC* | 0 | | | 0% |
| PGNP | 2 | | | 2% |
| PGP2 | 2 | | | 3% |
| PGSB | 2 | | | 2% |
| PGSF | 2 | | | 5% |
| PGSI | 2 | | | 3% |
| PGST | 2 | | | 5% |
| PGZP | 2 | | | 1% |

* No participating customers

**August**

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 30 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 2 | [redacted] | | 7% |
| PGEB | 3 | | | 6% |
| PGF1 | 2 | | | 7% |
| PGFG | 0 | | | 0% |
| PGHB | 0 | | | 0% |
| PGKN | 2 | | | 6% |
| PGNB | 2 | | | 1% |
| PGNC* | 0 | | | 0% |
| PGNP | 2 | | | 5% |
| PGP2 | 2 | | | 5% |
| PGSB | 2 | | | 5% |
| PGSF | 2 | | | 6% |
| PGSI | 4 | | | 5% |
| PGST | 2 | | | 3% |
| PGZP | 2 | | | 6% |

* No participating customers

**September**

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 30 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 15 | [redacted] | | 47% |
| PGEB | 15 | | | 47% |
| PGF1 | 15 | | | 47% |
| PGFG | 15 | | | 50% |
| PGHB | 8 | | | 27% |
| PGKN | 14 | | | 47% |
| PGNB | 15 | | | 47% |
| PGNC* | 0 | | | 0% |
| PGNP | 14 | | | 47% |
| PGP2 | 15 | | | 48% |
| PGSB | 15 | | | 48% |
| PGSF | 15 | | | 48% |
| PGSI | 20 | | | 53% |
| PGST | 15 | | | 47% |
| PGZP | 14 | | | 47% |

* No participating customers

**October**

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 30 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 0 | [redacted] | | 0% |
| PGEB | 2 | | | 2% |
| PGF1 | 2 | | | 3% |
| PGFG | 0 | | | 0% |
| PGHB | 0 | | | 0% |
| PGKN | 0 | | | 0% |
| PGNB | 2 | | | 0% |
| PGNC* | 0 | | | 0% |
| PGNP | 2 | | | 3% |
| PGP2 | 2 | | | 3% |
| PGSB | 2 | | | 1% |
| PGSF | 0 | | | 0% |
| PGSI | 4 | | | 2% |
| PGST | 0 | | | 0% |
| PGZP | 0 | | | 0% |

* No participating customers

**Annual**

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 23 | [redacted] | | 12% |
| PGEB | 35 | | | 13% |
| PGF1 | 23 | | | 11% |
| PGFG | 25 | | | 15% |
| PGHB | 10 | | | 9% |
| PGKN | 28 | | | 10% |
| PGNB | 27 | | | 13% |
| PGNC* | 0 | | | 0% |
| PGNP | 24 | | | 12% |
| PGP2 | 32 | | | 14% |
| PGSB | 34 | | | 14% |
| PGSF | 29 | | | 13% |
| PGSI | 34 | | | 20% |
| PGST | 21 | | | 15% |
| PGZP | 20 | | | 11% |

* No participating customers

**Attachment C.** Number of hours dispatched, energy dispatched and maximum energy available

[redacted]

May

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 20 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 0 | [redacted] | | 0% |
| PGEB | 0 | | | 0% |
| PGF1 | 0 | | | 0% |
| PGFG | 0 | | | 0% |
| PGHB* | 0 | | | 0% |
| PGKN | 0 | | | 0% |
| PGNB | 0 | | | 0% |
| PGNC | 0 | | | 0% |
| PGNP | 0 | | | 0% |
| PGP2 | 0 | | | 0% |
| PGSB | 0 | | | 0% |
| PGSF* | 0 | | | 0% |
| PGSI | 0 | | | 0% |
| PGST | 0 | | | 0% |
| PGZP | 0 | | | 0% |

* No participating customers

June

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 20 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 0 | [redacted] | | 0% |
| PGEB | 0 | | | 0% |
| PGF1 | 0 | | | 0% |
| PGFG | 0 | | | 0% |
| PGHB* | 0 | | | 0% |
| PGKN | 0 | | | 0% |
| PGNB | 0 | | | 0% |
| PGNC | 0 | | | 0% |
| PGNP | 0 | | | 0% |
| PGP2 | 0 | | | 0% |
| PGSB | 0 | | | 0% |
| PGSF* | 0 | | | 0% |
| PGSI | 0 | | | 0% |
| PGST | 0 | | | 0% |
| PGZP | 0 | | | 0% |

* No participating customers

July

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 20 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 0 | [redacted] | | 0% |
| PGEB | 0 | | | 0% |
| PGF1 | 6 | | | 12% |
| PGFG | 0 | | | 0% |
| PGHB* | 0 | | | 0% |
| PGKN | 8 | | | 13% |
| PGNB | 0 | | | 0% |
| PGNC | 6 | | | 12% |
| PGNP | 6 | | | 9% |
| PGP2 | 0 | | | 0% |
| PGSB | 0 | | | 0% |
| PGSF* | 0 | | | 0% |
| PGSI | 4 | | | 7% |
| PGST | 2 | | | 3% |
| PGZP | 8 | | | 14% |

* No participating customers

August

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 20 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 2.5 | [redacted] | | 0% |
| PGEB | 4.5 | | | 11% |
| PGF1 | 4.5 | | | 14% |
| PGFG | 2.5 | | | 0% |
| PGHB* | 0 | | | 0% |
| PGKN | 4.5 | | | 14% |
| PGNB | 4.5 | | | 11% |
| PGNC | 4.5 | | | 12% |
| PGNP | 4.5 | | | 13% |
| PGP2 | 4.5 | | | 11% |
| PGSB | 4.5 | | | 10% |
| PGSF* | 0 | | | 0% |
| PGSI | 6.5 | | | 19% |
| PGST | 4.5 | | | 12% |
| PGZP | 2.5 | | | 6% |

* No participating customers

September

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 20 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 12.9 | [redacted] | | 0% |
| PGEB | 12.9 | | | 38% |
| PGF1 | 15.9 | | | 47% |
| PGFG | 8.9 | | | 0% |
| PGHB* | 0 | | | 0% |
| PGKN | 14.9 | | | 45% |
| PGNB | 12.9 | | | 38% |
| PGNC | 15.9 | | | 44% |
| PGNP | 14.9 | | | 50% |
| PGP2 | 13.9 | | | 40% |
| PGSB | 13.9 | | | 43% |
| PGSF* | 0 | | | 0% |
| PGSI | 15.9 | | | 54% |
| PGST | 14.9 | | | 41% |
| PGZP | 15.9 | | | 41% |

* No participating customers

October

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 20 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 0 | [redacted] | | 0% |
| PGEB | 0 | | | 0% |
| PGF1 | 0 | | | 0% |
| PGFG | 0 | | | 0% |
| PGHB* | 0 | | | 0% |
| PGKN | 0 | | | 0% |
| PGNB | 0 | | | 0% |
| PGNC | 0 | | | 0% |
| PGNP | 0 | | | 0% |
| PGP2 | 0 | | | 0% |
| PGSB | 0 | | | 0% |
| PGSF* | 0 | | | 0% |
| PGSI | 0 | | | 0% |
| PGST | 0 | | | 0% |
| PGZP | 0 | | | 0% |

* No participating customers

Annual

| Load Zone | Hours Dispatched | (a) Total Energy Dispatched (MWh) | (b) Maximum Energy Available (Avg MW X 20 hrs) | (c) = (a)/(b) % |
|---|---|---|---|---|
| PGCC | 15.4 | [redacted] | | 0% |
| PGEB | 17.4 | | | 7% |
| PGF1 | 26.4 | | | 13% |
| PGFG | 11.4 | | | 0% |
| PGHB* | 0.0 | | | 0% |
| PGKN | 27.4 | | | 12% |
| PGNB | 17.4 | | | 7% |
| PGNC | 26.4 | | | 14% |
| PGNP | 25.4 | | | 12% |
| PGP2 | 18.4 | | | 9% |
| PGSB | 18.4 | | | 8% |
| PGSF* | 0.0 | | | 0% |
| PGSI | 26.4 | | | 13% |
| PGST | 21.4 | | | 10% |
| PGZP | 26.4 | | | 10% |

* No participating customers

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 2

# UTILITY-OWNED GENERATION:  HYDROELECTRIC

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
UTILITY-OWNED GENERATION: HYDROELECTRIC

TABLE OF CONTENTS

TABLE OF CONTENTS
(CONTINUED)

TABLE OF CONTENTS
(CONTINUED)

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 2
# UTILITY-OWNED GENERATION: HYDROELECTRIC

## A. Introduction

In compliance with Decision (D.) 14-01-011, this chapter addresses the operation of Pacific Gas and Electric Company's (PG&E or the Company) utility-owned hydroelectric facilities, and outages that occurred at these facilities during the 2022 record year.

PG&E's utility-owned hydroelectric portfolio was operated in a reasonable manner during the record period. At year-end 2022 PG&E's hydro-generating portfolio consisted of 63 powerhouses with 102 generating units. The system operates under 22 Federal Energy Regulatory Commission (FERC) licenses, which govern the operation of 98 of the generating units at 61 powerhouses. Four generating units are at two non-FERC jurisdictional powerhouses. PG&E's hydro-generating portfolio has an aggregate nameplate capacity of 3,857.1 megawatts (MW) and produces an average of about 10 terawatt-hours of energy in a normal precipitation year.

PG&E's 63 hydro powerhouses are located on 13 rivers and four tributaries of the Sierra Nevada, Cascade and Coastal Mountain ranges. This is a unique set of facilities that was built between 1900 and 1986. Most of the dams and powerhouses have been in service for well over 50 years, and some of the water collection and transport systems were used for gold mining and consumptive water prior to the development of the hydro-generating facilities.

The system collectively includes the following ancillary support facilities: 97 reservoirs, 72 diversions, 167 dams, over 400 miles of water conveyance (canals, flumes, penstocks, siphons, tunnels, low head pipes, and natural waterways), and approximately 140,000 acres of fee-owned land. It also includes switchyards, switching centers that remotely control generation facilities, administrative buildings, fleet, multiple modes of communication, materials and supplies inventories, office equipment, and other miscellaneous instrumentation and monitoring equipment. PG&E's authority to divert and store water for power generation is based on 88 water right licenses or interim permits, and 151 Statements of Water Diversion and Use.

PG&E's hydro plants produce low cost and clean energy, high value ancillary services and peaking capacity to meet customers' needs. PG&E has demonstrated its ability to optimize these generation facilities through efficient use of water resources and continuing environmental stewardship.

PG&E's system of dams, reservoirs, and water collection facilities enables PG&E to store runoff and aquifer flows and then subsequently use the water to generate power when customers need it most. This "shaping" of the available generation is performed both seasonally (for example, by storing more water in the spring and releasing water from the reservoirs during high value hot summer days) and day-to-day (for example, generating more during hours of peak system demand—typically weekday late-afternoons and evenings—and less at night and on weekends). In general, the highest value of PG&E-owned generation is likely to be when demand is greatest and intermittent renewables are not available, and hydro generation can contribute significantly toward offsetting the cost of power purchased for PG&E bundled customers during higher priced hours.

Hydroelectric generating units typically start up quickly, have fast ramp rates, and can easily, quickly, and economically vary output in response to changing customer loads and system conditions. In addition, hydro-generating units can operate at no load or low load with much higher efficiency than the alternative fossil fueled peaking plants. Finally, because a large portion of California's non fossil-fueled electricity resources consist of non-dispatchable energy sources such as wind, solar, nuclear, and regulatory "must-take" generation, the California Independent System Operator (CAISO) relies on PG&E's hydro resources to satisfy a significant portion of its operating reserve requirements.

## B. Overview of PG&E's Hydroelectric System

### 1. Hydro System Characteristics

Hydroelectric generation converts the potential energy contained in falling water to electricity. In general, water from precipitation runoff and aquifer flows is collected at a high elevation and through various water collection, storage and conveyance systems is delivered to the powerhouse penstock where it drops to the powerhouse elevation. The water, under pressure from the elevation drop, is directed through or against the turbine runner causing the turbine and coupled generator to rotate and produce electricity. The major system components consist of:

- Water Collection Facilities – Reservoirs and dams including stream diversions;
- Water Conveyance Facilities – Tunnels, canals, flumes, natural waterways, conduits, and penstocks utilized to direct the water from collection points to the powerhouse;
- Powerhouses – Structures containing the turbines, generators and associated equipment used to produce electricity; and
- Auxiliary Equipment – Transmission lines and associated switchyard equipment to transmit the electricity to the grid.

PG&E's hydro-generation portfolio can be segregated into three categories based on the characteristics of the water supply to the powerhouse:

- Run-of-the-River Powerhouses – These powerhouses generally have little or no water storage facilities and rely on stream/river diversions, with small impoundments, to direct the water into the water conveyance system. The powerhouse is operated based on the flow available to be diverted from the river. Once diverted, the water travels through various water conveyance facilities, such as canals, flumes, tunnels, natural waterways, and conduits to the penstock.
- Reservoir Storage Powerhouses – Powerhouses that have significant water storage facilities are not limited to run based on the available river flow but can store runoff and aquifer flows and then subsequently use the water to generate power when customers need it most. Generally, these powerhouses have less water conveyance assets either because they are located close to the dams or have a single large tunnel delivering water to the penstock(s). Because of their large impoundments and hydro's ability to quickly come online and ramp up to full capacity, these powerhouses can be used for peaking during high demand power periods.
- Pumped Storage Powerhouse – PG&E has one pumped storage powerhouse, Helms Pumped Storage Facility (Helms). Helms is a

reservoir storage powerhouse, situated between an upper reservoir, Courtright Lake, and a lower reservoir, Lake Wishon, with three generators that can be reversed to act as pumps. During hours when energy prices are lower, the pumping mode is utilized to pump water back up to Courtright Lake to be reused during the next cycle. The ability to pump the water back up to the storage reservoir allows the water resource to be reused during peak demand hours. Helms also provides renewable integration benefits such as regulation up and down, load following, operating reserves (backup), shaping, and management of system over-generation conditions that result from excess renewables generation during off-peak and partial-peak periods.

### 2. Hydro Operations and Maintenance (O&M) Organization

PG&E's Power Generation organization is responsible for managing the hydro-generating portfolio. The Hydro O&M organization is responsible for facility O&M and works side by side with the other Power Generation and PG&E Energy Supply support organizations to provide safe, reliable, cost-effective, and environmentally responsible generation. Hydro O&M is organized geographically into six areas. These areas consist of logical groupings of facilities that enable efficient oversight, control, and management of O&M. The powerhouses are operated from seven switching centers located throughout the system. Six of the switching centers are located at powerhouses and one is in Fresno. A full listing of powerhouses and individual units is included in Attachment 2A.

The Hydro Areas (from North to South) and the Power Generation support organizations are described below, and the information is then summarized in Table 2-1.

#### a. Shasta Area

The Shasta Area manages 16 powerhouses with 27 generating units and has an installed capacity of 808.3 MW. The powerhouses have in-service dates spanning from 1903 to 1981. The facilities are situated on six different watersheds in Shasta and Tehama counties. There are two switching centers in Shasta, located at Pit 3 Powerhouse and Pit 5 Powerhouse. The Shasta Area headquarters is located in Burney with a satellite headquarters in Manton.

**b. DeSabla Area**

The DeSabla Area manages 15 powerhouses with 27 generating units and has an installed capacity of 785.7 MW. The powerhouses have in-service dates spanning from 1900 to 1985. The facilities are situated on five different watersheds in Plumas and Butte counties, and on one watershed located in Mendocino County. There is one switching center in DeSabla located at Rock Creek Powerhouse. The DeSabla Area headquarters is located at Rodgers Flat (near Oroville) with satellite headquarters at Camp One (near Paradise) and Potter Valley (near Ukiah).

**c. Drum Area**

The Drum Area manages 12 powerhouses with 15 generating units and has an installed capacity of 189.1 MW. The powerhouses have in-service dates spanning from 1902 to 1986. The facilities are situated on three different watersheds in Nevada, Placer, and El Dorado counties. There are two switching centers in the Drum Area located at Drum Powerhouse and Wise Powerhouse. The Drum Area headquarters is located in Auburn and satellite headquarters at Alta.

**d. Motherlode Area**

The Motherlode Area manages 7 powerhouses with 11 generating units and has an installed capacity of 314.5 MW. The powerhouses have in-service dates spanning from 1902 to 1986. The facilities are situated on three different watersheds in Amador, Tuolumne, and Merced counties. There is one switching center in the Motherlode Area located at Tiger Creek Powerhouse. The Motherlode Area has satellite headquarters Angels Camp, Tiger Creek (near Jackson), and Sonora.

**e. Kings-Crane Valley Area**

The Kings-Crane Valley Area manages 12 powerhouses with 19 generating units and has an installed capacity of 547.5 MW. The powerhouses have in-service dates spanning from 1910 to 1983. The facilities are situated on six different watersheds in Madera, Fresno, Tulare, and Kern counties. The Kings-Crane Valley switching center is located at the Fresno Operating Center. The Kings-Crane Valley Area headquarters is located in Auberry with a satellite headquarters at Balch Camp (east of Clovis).

**f. Helms Pumped Storage Facility**

This Area consists of the Helms facility with three pump-generator units and an installed capacity of 1,212 MW. Helms was placed in service in 1984. Helms is in Fresno County and has a headquarters facility at the project site.

**TABLE 2-1**
**HYDRO GENERATION AREA DETAILS**

| Line No. | Area | No. of Powerhouses | No. of Units | MW | No. of FERC Licenses | No. of Dams |
|---|---|---|---|---|---|---|
| 1 | Shasta | 16 | 27 | 808.3 | 6 | 44 |
| 2 | DeSabla | 15 | 27 | 785.7 | 6 | 32 |
| 3 | Drum | 12 | 15 | 189.1 | 1 | 45 |
| 4 | Motherlode | 7 | 11 | 314.5 | 3 | 24 |
| 5 | Kings Crane Valley | 12 | 19 | 547.5 | 5 | 16 |
| 6 | Helms | 1 | 3 | 1,212.0 | 1 | 6 |
| 7 | Total | 63 | 102 | 3,857.1 | 22 | 167 |

**g. Support Organizations**

The Hydro O&M organization works side-by-side with both Power Generation support organizations and centralized PG&E support organizations to provide safe, reliable, cost-effective generation to California in an environmentally responsible manner. These support organizations provide oversight, direction, and support to ensure that critical resources, personnel, and technical information and advice are available to support O&M for effective operations and maintenance of the hydro fleet.

**1) Portfolio Strategy**

The Power Generation Portfolio Strategy organization is led by a director and includes several functions:

- optimization of the composition of the generation fleet;

- compliance and commitments which includes FERC relicensing and licensing compliance as well as optimizing the cost and benefit to the State, public, and shareholders by working with regulatory agencies such as FERC, Division of Safety of Dams (DSOD);
- business planning and regulatory reporting which includes identifying, prioritizing, and planning Power Generation's work;
- monitoring customer value (costs and benefits) of PG&E's utility-owned generation to identify and recommend potential changes to the portfolio;
- implementing approved divestiture strategies on less economic Power Generation assets to reduce cost to PG&E's customers including overseeing regulatory approvals from the California Public Utilities Commission (CPUC or the Commission) and FERC;
- providing analysis and regulatory support for other potential portfolio optimization strategies, such as decommissioning and alternative ratemaking proposals;
- serving as a liaison for PG&E's Land Conservation Commitment efforts among various PG&E departments and the Stewardship Council;
- Managing the business operations function for Power Generation which combines several functions into an integrated department that provides strategic, and tactical (operational and financial) services; and
- regulatory reporting which includes preparation and filing of all required documentation for various regulatory proceedings which includes responding to data requests and preparing work papers and testimony.

**2) Geosciences**

The Geosciences organization is led by a director and is responsible for providing services company wide including the following Power Generation services:

- On-call emergency evaluations and mitigation for seismic events, landslide, erosion, and foundation issues for all company lines of business;
- Support for the Hydro Facility Safety Program including fault studies, penstock geotechnical assessments, dam seepage and liquefaction analysis, and spillway assessments;
- Support for the Company Emergency Response Program, Emergency Operations Center, earthquake exercises, post-event reconnaissance, and emergency training;
- Wildfire burn area debris flow hazard modeling and alerting;
- Geotechnical design and construction review; and
- Climate team research studies and planning support.

**3) Corrective Action Program (CAP)**

The CAP program is led by a manager and is responsible for the Electric Operations CAP program, which includes Power Generation. The Electric Operations CAP group is focused on continuously monitoring the performance of the organization and facilitating the timely and accurate use of CAP across the line of business. The team is responsible for monitoring declines in performance, addressing gaps to standards using evaluation tools (such as cause analysis) to support the safety of our employees and the public and the continued reliable operation of our assets. The CAP Program is further described under Section C.5.e.

**4) Asset Excellence**

The Asset Excellence department is led by a director and consists of an Asset Management (AM) program that is ISO 55001[1] certified. The department focuses on systemwide condition assessment of Power Generation system equipment and proposes projects and/or changes to operations and/or maintenance practices

---

[1] ISO 55000 is an internationally recognized Asset Management System standard that details out the requirements for a business to ensure it is maximizing the value of its assets and minimizing its risks. ISO 55000 standards are aligned with the concept of risk and data informed investment decision making and requires a significant improvement in the way Power Generation treats and maintains its data.

to ensure that Power Generation’s long-term investment plan reduces risk and maintains the safety and reliability of the hydro portfolio.

Power Generation met its commitment of achieving ISO 55001 certification of its Dams by 2022 and also achieved certification on its entire portfolio, which includes, Hydro Powerhouses, Civil Infrastructure, Fossil, Solar, Battery Storage, Physical Data, and Data assets.

The Asset Excellence department includes the Facility Safety Program for dams and water conveyance facilities to assure compliance with FERC and California Department of Water Resources DSOD regulations.

The Asset Excellence department is supported by a team that develops and implements analytical risk modeling processes and techniques to achieve effective risk management, reduction, and mitigation.

**5) Engineering and Technical Services**

Engineering and Technical Services department is led by a director and provides engineering technical services, and asset security to Power Generation operations, projects, and public safety work.

Engineering provides engineering services for projects and support of routine hydro O&M work. Engineering uses a number of contractors to augment its workforce, in order to execute on planned work. It ensures that Power Generation is focused on public and employee safety, continuously improving processes, delivering high quality work, and ensuring compliance with all standards and procedures that govern the Power Generation business.

PG&E’s Technical Services organization provides direct support to the O&M North and O&M South for the safe, reliable, compliant, efficient operation of PG&E’s hydro units. O&M Specialists in the Technical Services organization act as consultants offering expertise in methods and procedures to help assure compliance with operating and maintenance standards.

The department includes the Power Generation Security Program which ensures asset protection and public safety.

**6) Outage Management and Project Management**

Outage management and Project Management is led by a director and includes outage management, inspection services, and contract services. This team manages project work in addition to supporting routine O&M operations and uses a number of contractors to augment its workforce, particularly in the construction functions, in order to execute on planned work.

Outage Management coordinates outage work scope and schedules among various groups performing project and routine maintenance work. Inspection Services inspects contract construction and equipment installation associated with Power Generation projects.

Project Management provides project management services to Power Generation projects including the development, initial scoping, scheduling, resource planning, and cost estimating for all the major projects included in the long-term plan. Project Management ensures that resources are balanced to improve the implementation of the portfolio of projects in the plan. Project work includes both capital and expense projects. Project Management uses several contractors to augment its workforce, in order to execute on planned work.

Contract Services provides various procurement services including specification development, requests for proposal, bid evaluation, and contract administration support for hydro maintenance and project work.

**7) Hydro Construction**

Hydro Construction is a mobile construction organization led by a director that handles major maintenance and construction projects throughout the hydro system. With both a civil construction group and an electrical-mechanical group, this organization constructs and/or makes major repairs on a wide variety of hydro facilities.

## C. Hydro Portfolio Management

### 1. Overview

The PG&E hydro portfolio is a complex system composed of many facilities with interrelated operational parameters. Many powerhouses are in "river-chains" where the water is most optimally used sequentially through the powerhouses as it moves downriver. This requires coordinated operations to assure each powerhouse is online to utilize the water flow as it arrives, without spilling past the powerhouse. Operation of the hydro portfolio also must comply with FERC license conditions mandating minimum and maximum flows and ramping rates on the river. Management of this complex portfolio relies on the integration of information and expertise from multiple organizations.

PG&E is committed to providing safe utility service to its customers. As part of this commitment, PG&E reviews its operations, including operation of its hydro facilities, to identify and mitigate, to the extent possible, potential safety risks to the public, PG&E's workforce, and its contractors. As it operates and maintains its hydro generation facilities, PG&E follows internal controls to ensure public, workplace, and contractor safety. PG&E's Employee Code of Conduct specifies that the safety of the public, employees, and contractors are PG&E's highest priority. PG&E's commitment to a safety-first culture is reinforced with its Safety Principles, Safety Commitment, Personal Safety Commitment, and Keys to Life. These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E obtains all applicable regulatory approvals from governmental authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As part of PG&E's Safety Commitment, PG&E follows recognized best practices in the industry. PG&E operates each of its generation facilities in compliance with all local, state, and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration requirements and the CPUC's General Order 167. As discussed below, PG&E does this by using internal controls to help manage the O&M of its generation facilities.

Power Generation employees develop action plans each year related to key performance indicators in the areas of safety and reliability. The action plans focus on various items such as forced outage and planned outage performance, approaches to reduce or eliminate recordable injuries and motor vehicle incidents, and safe dam operations.

With regard to public safety, PG&E continues to develop and implement a comprehensive public safety program that includes: (1) public education, outreach, and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills, and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grassroots safety team that can act to encourage safe work practices among peers. Power Generation's grassroots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement changes that can improve safety performance.

### 2. Operational Planning

#### a. Environmental/Regulatory Considerations Affecting Operations

PG&E's operation of its hydro system is governed by the 22 Operating Licenses issued by FERC, which contain over 500 discrete operating conditions. PG&E safely and reliably operates the system in compliance with all FERC license conditions and all local, state, and federal regulations. In addition, operations are constrained by many conditions imposed by United States Forest Service agreements, DSOD regulations, contractual obligations, water diversion rights and other regulations. PG&E's hydro projects deliver water at over 50 locations for consumption by over 30 different user groups under water delivery agreements that contain additional constraints on how the projects are operated. There are defined minimum and maximum flow requirements in most river reaches below PG&E's reservoirs and powerhouses. Any changes in the flows must be performed in compliance with prescribed ramp rates. Reservoirs have both minimum and maximum storage requirements which vary depending upon the time of year.

**b. Management of Water Resources**

Water is the fuel for the hydro powerhouses and efficient management of water is a very important element of hydro generation operation. The Water Management (WM) organization forecasts runoff and provides guidance for scheduling hydroelectric resources consistent with all regulatory rules, agreements, contracts, environmental regulations, and recreational needs.

Water Management scheduling consultants employ sophisticated computer modeling programs to forecast runoff. These programs use inputs from the current hydrologic state of the watershed (snowpack, current runoff, and aquifer outflows), an updated 10-day weather forecast, and the long-range weather forecast, with appropriate probability factors, to compile the monthly and daily runoff forecasts used to develop optimized monthly water release schedules. The monthly water release schedules are used by PG&E's Short-Term Electric Supply (STES) organization and Hydro O&M to operate the reservoirs, water conveyance systems and powerhouses.

**c. Outage Planning**

PG&E has formal outage planning and scheduling processes for its generation assets. Management control over the planning and scheduling of outages is key to prudent management of PG&E's generation facilities. The planning and scheduling processes include management approval points for the base yearly outage schedule and for any changes to the schedule. Scheduled outages are classified as (1) Planned Outages (PO) and (2) Maintenance Outages (MO).

**1) Planned Outages**

PO are part of the normal course of maintaining a generating facility. Due to the age of PG&E's hydro portfolio assets and the complexity of the water collection and conveyance systems, and to assure that these generating facilities are reliable during periods of high electric demand, most hydro units are scheduled for one PO each year. These POs are typically scheduled during periods of lower electric demand when market prices are lower.

The purpose of the annual PO is to accomplish recurring routine maintenance work, equipment repairs that can only be performed during an outage, minor project work and condition assessment. Typical annual maintenance tasks include time-based equipment overhauls; time-based equipment inspections; North American Electric Reliability Corporation (NERC) compliance testing; turbine component lubrication, adjustment, and repairs; generator inspection and repairs; relay performance tests; annual auto tests; and condition assessment measurements and readings. The need for scheduled maintenance is well documented in PG&E's past general rate case applications. If major capital projects requiring an outage are planned, the annual outages are modified to accommodate that work.

Scheduling POs is an iterative process spanning several years with input from many stakeholders and quarterly submissions to the CAISO. As described in Section C.5.f., the processes for planning and scheduling annual POs ensure that POs are scheduled sufficiently in advance, have an adequate duration for planning and preparation, have controls in place to manage changes, and have reasonable management oversight to assure that units are promptly returned to service.

**2) Maintenance Outages**

MOs are taken in response to an emerging need for maintenance that can be deferred beyond the end of the next weekend but cannot be deferred until the next PO. Typical work performed during MOs include replacing generator brushes;

cleaning brush rigging; performing auto tests; troubleshooting tests; transmission line work; monthly routine minor maintenance; monthly gate travel tests; and out-of-tolerance equipment adjustments.

To assure proper planning and preparation, MOs for more routine activities are scheduled much further in advance to assure proper planning and preparation. Every attempt is made to include all maintenance items in the annual PO for each unit, but some systems and equipment must be serviced or tested more frequently.

### 3. Conventional Hydro Portfolio Operation

PG&E's 63 conventional powerhouses are operated from five around-the-clock switching centers. Four of the switching centers are at powerhouses and one is in Fresno. Switching center operators receive day-ahead dispatch instructions from PG&E's STES organization. Operators review the day-ahead schedules and verify that they are attainable. Any operational constraints that may interfere with running the unit to the dispatch schedule are reviewed with STES, and if necessary, the dispatch schedule is adjusted. The conventional hydro powerhouses are operated in accordance with the final dispatch directions provided by STES.

During daily operations, there is close communication between the operators and STES's real-time energy desk. Through the Supervisory Control and Data Acquisition (SCADA) system, operators remotely start, vary the loading, and stop units in accordance with dispatch instructions. They continuously monitor and adjust the operations of the units at the powerhouses, the canal flows and levels, the reservoir levels, the instream flow releases and other operating parameters. Any operational issues that require a unit to deviate from the dispatch schedule are communicated to the Real-Time Desk (RTD), and operators adjust operations in accordance with the directions received back from the RTD.

Roving operators visit remote, unmanned powerhouses to perform station reads and operational checks that cannot be performed through SCADA. They also perform minor maintenance and adjustments, such as lubricating equipment, checking oil reservoirs on equipment, and cleaning strainers. Roving operators are also dispatched to perform remote unit start-ups that cannot be handled through the SCADA system. At the four powerhouses housing switching centers, the switching center operators perform the duties of the roving operators for those local units.

Water system operators manage the water delivery systems that feed the powerhouses and adjust the reservoir and canal operations for instream flow releases and water deliveries to third parties. In concert with the switching center operators monitoring SCADA, the water system operators assure safe canal flows and reservoir levels while meeting dispatch requirements.

### 4. Helms Pumped Storage Operation

Helms is operated around-the-clock from a control room in the powerhouse. Similar to conventional powerhouse dispatch described above, the Helms operators receive day-ahead generating and pumping instructions from STES. Operators review the day-ahead schedules and verify that they are attainable. Any operational constraints that may interfere with running the unit to the dispatch schedule, either in generating or pumping mode, are reviewed with STES and if necessary, the dispatch instructions are adjusted. Helms is operated in accordance with the final dispatch directions provided by STES.

The CAISO relies on Helms for grid stability. As a result, the dispatch of Helms units may change many times throughout the day. Helms operators, the Fresno Operating Center, and the STES RTD stay in constant communication and operators adjust operations in accordance with instructions from the RTD.

Helms operators, similar to roving operators described in Section C.3., complete the system reads and operational checks that cannot be performed through SCADA and perform minor maintenance and adjustments in the powerhouse.

### 5. Internal Controls

PG&E directs, manages, and monitors its resources using internal controls—processes reflecting the organization’s structure, work and authority flows, people, and management information systems.

The internal controls in place to manage the O&M of the hydro facilities include: (1) guidance documents; (2) operating plans; (3) operations reviews; (4) an event reporting system; (5) a CAP; (6) outage planning and scheduling processes; (7) a project management process; and (8) a design change process. Each of these controls is discussed below.

**a. Guidance Documents**

The guidance documents applicable to hydro operations include PG&E Policy, PG&E Utility Standard Practices, PG&E Utility Procedures, and Power Generation-specific guidance documents. Power Generation-specific guidance documents include Standards, Procedures and Bulletins. These guidance documents cover virtually all aspects of safety, operations, maintenance, planning, environmental compliance, regulatory compliance, emergency response, work management, inspection, testing and other areas. Each guidance document describes the purpose of the document, the details of the actions and/or processes covered by the document, management roles and responsibilities, and the date the document became effective.

**b. Operating Plans**

The hydro switching centers have operating plans to assure that the powerhouses are operated in conformance with license conditions and all other local, state, and federal regulations. There are also specific operating plans developed for operating the powerhouses in the extreme conditions of summer and winter. The plans specify how operation of the facilities is adjusted to take into account the impacts of the seasons. For example, the summer plan addresses operational issues related to excessive heat and increased public recreation in, around and downstream of PG&E facilities. The winter plan addresses operational issues related to heavy rainfall, increased river and stream runoff and snow conditions.

**c. Operations Reviews**

Operations reviews are periodically performed at hydro powerhouses and switching centers by the Technical Services organization. The purpose of an operations review is to ensure PG&E's generation facilities are operated in a safe and efficient manner and that they are in compliance with standard operating and clearance procedures.

An operations review evaluates the overall operation of a powerhouse against a variety of Power Generation's guidance documents to assure that standard operating practices are being followed and the powerhouse is in full regulatory and environmental compliance. The results of the review are shared with management and any identified findings or issues require a response and correction.

**d. CAP**

The CAP is designed to document and track corrective actions (CA) and commitments. The CAP includes problem identification, cause determination, reporting, development of CAs and CA implementation tracking.

PG&E's Power Generation organization has implemented a CAP that utilizes SAP notifications and orders to track and document the following: actions that are necessary or have been taken in response to audit and/or inspection findings, deviations identified in incident reports, regulatory non-compliance issues, engineering deviations, and other systemwide issues.

**e. Outage Planning and Scheduling Processes**

The hydro outage schedule is developed to plan and communicate when various powerhouse units will be unavailable due to maintenance or project work. Shown on the schedule are Planned Outages (PO) consisting of maintenance tasks and project-specific outages and combination outages encompassing both project and maintenance tasks as described in section 2.c.1 above. The hydro outage schedule for a given outage year is developed through an iterative process, over several years, as projects and maintenance tasks are identified by field employees, management, project managers, and others. Except for outages with scopes of work demanding long durations or units that have little or no water to run, few outages are planned during the peak summer generation season. Also, every effort is made to limit the number and duration of outages in the off-peak shoulder months.

The yearly outage schedule is not a static document. The schedule is fluid and adaptable to changing requirements. PG&E's STES organization, the CAISO, and others use the schedule to make plans regarding resource allocation, replacement power and restrictions on the system. Therefore, changes in the schedule, particularly in the short term, are discouraged. Due to the dynamic nature of the system, changes will inevitably be required. Changes to the schedule may be required due to weather conditions, resource constraints, changes in project scope or schedule, and/or emergent work. Depending on the proximity to the outage start date, changes to the scope and schedule require different levels of management review and approval. Before outage changes are approved, consideration is given to the impacts of the change on equipment reliability, replacement power costs, water deliveries, possible by-pass spills, resources and impacts to other scheduled outages.

For an individual outage, an outage management plan is developed prior to the start of the outage. Depending on the size and duration of the outage, an outage management plan can be as simple as a list of work orders extracted from the SAP Work Management (SAP WM) system, or as complex as a critical path, resource-loaded work execution plan detailing each task for a project as well as preventative and corrective maintenance work orders. The development of an outage management plan can be broken down into three distinct, but interrelated, processes: (1) Planning and Scoping; (2) Scheduling; and (3) Outage Execution.

**1) Planning and Scoping**

The planning and scoping process determines the work to be executed during the outage. This includes preventative maintenance work orders, corrective work orders for repairs on equipment and/or facilities and project-specific asset replacements or major refurbishments. The required resources to execute the work and the duration of all work activities are identified during this process.

Power Generation manages preventative and corrective work utilizing SAP WM. Preventative maintenance work orders, sometimes referred to as recurring work, encompass routine maintenance work performed at established intervals. Corrective work orders, sometimes referred to as trouble tags, refer to work identified to correct an issue that is limiting the ability of the equipment or facility to efficiently perform its design function. The SAP WM system is the electronic repository where preventative and corrective work is identified, tracked, organized, and managed. The system utilizes maintenance libraries to generate recurring work orders against a piece of equipment at the appropriate frequency as specified by PG&E. Corrective work orders are created in the system by the crews or individuals identifying the problem.

The planning and scoping process begins two to three years prior to the outage and continues until outage execution.

**2) Scheduling**

The scheduling process determines the start and duration of the outage. Outage timing and durations are influenced by: capital and maintenance work to be performed, system operation constraints, powerhouse elevation, time of year, weather conditions, water storage requirements, downstream water user requirements, size of unit, labor resources available to perform work, configuration of hydro system (close coupled to dam or long water delivery system), effects on other powerhouses, CAISO constraints, transmission system issues, distribution system issues, and FERC license conditions.

Table 2-2 below provides the timeline for the outage scheduling process.

**TABLE 2-2**
**OUTAGE SCHEDULING PROCESS**

| Steps | Timing | Process Description |
|---|---|---|
| 1. | 3 to 5 Years Prior to Outage Year | A preliminary annual outage schedule for the outage year is prepared 3 to 5 years in advance. This preliminary schedule is created using outages identified from Power Generation's long term investment plan as well as historical outage durations and timing data for each watershed, powerhouse, and unit. There is no formal approval of this preliminary schedule. The local O&M supervisors review the preliminary schedule and recommend changes. |
| 2. | 1 to 2 Years Prior to Outage Year | Each annual outage on the schedule is adjusted/revised over the next 1 to 2 years as more information becomes available about routine maintenance tasks, non-routine maintenance requirements, and/or project work that must be performed during the outage. During this preliminary phase, requested changes are made to the schedule and reviewed by PG&E Generation Supervisors for powerhouses under their control. |
| 3. | 3 Months Prior to the Start of the Outage Year | On a quarterly basis, PG&E submits to the CAISO a PO schedule that details the outages planned for the following 15 months. In October of the year prior to the outage year, the PO schedule is submitted to the CAISO to set the base outage schedule. After this submission, any requests for changes to individual outages are submitted to the responsible Area Manager and/or Hydro O&M Director and/or Vice President for approval. The level of management approval is dictated by the proximity of the request to the outage start date. These internal approvals are required before the changes are submitted to the CAISO. |
| 4. | Changes During an Outage | Changes to the duration of an outage can occur during an outage due to emerging work, unforeseen problems, or other issues. Requests for outage extensions require the approval of the Hydro O&M Director. Outage extensions that occur during the outage require notification to the Power Generation Vice President or Hydro O&M Director. The level of management notification is dictated by the unit capacity. |

**3) Outage Execution**

The outage execution process includes performing the work planned for the outage, complying with the many sub-processes for notifications and approvals between the outage stakeholders, and lessons learned. Activities include:

- Notifications to and approvals from the CAISO to separate the unit(s) from the grid;
- Clearance procedures covering the steps required to electrically, hydraulically, and mechanically clear the units and facilities (i.e., put them in a safe condition) for the outage work to proceed;

- Notifications and approvals for any changes in the outage due to emerging work or changed conditions;
- Restoration procedures to restore the unit to service when the outage work is completed.  This includes complying with the steps in the switch log and any start-up procedure for new or refurbished equipment;
- Notifications to and approvals from the CAISO to restore the unit to service and connect to the grid at the completion of the outage; and
- Collection of lessons learned at the completion of the outage for incorporation into processes and procedures.

Table 2-3 provides the timeline for the outage execution process.

**TABLE 2-3**
**OUTAGE EXECUTION PROCESS**

| Steps | Timing | Process Description |
|---|---|---|
| 1. | Prior to Outage Start Date | An Application for Work (AFW) covering the PO is submitted to the STES organization's Outage Coordinator. Once the AFW has been reviewed and approved internally, it is submitted to the CAISO through the Outage Management System (OMS) for preliminary approval.<br><br>Switching Center Operators write detailed step-by-step switching logs for clearing the units. These logs detail all the clearance points for the outage and the tasks that need to be performed, and the order in which they must be performed, to make the unit or facility safe for outage work to begin. |
| 2. | Outage Start Date | The STES organization's RTD, working off the list of preliminary approved outages, contacts the CAISO for final approval that the unit can be separated from the grid and communicates that approval to the Switching Center Operators.<br><br>Once approval has been obtained, an operator, working in concert with the Switching Center, executes the steps in the Switching Log to clear the unit or facility. |
| 3. | During the Outage | PG&E employees and/or contractor resources are utilized to execute the prioritized maintenance work and any project work in accordance with the outage plan and in compliance with PG&E standards.<br><br>Emerging work that is identified during the outage is evaluated and prioritized against other ongoing work. If it is determined that the emerging work must be completed during the current outage, the work is added to the outage plan. Adding emergent work to the outage plan is often necessary to prevent a future forced outage. If emerging work requires an outage extension, approval of the Hydro O&M Director is required. Notification of an outage extension is communicated to the CAISO through the OMS.<br><br>Both the Switching Log for restoring the unit and a start-up procedure, covering all the requirements for testing newly installed equipment, are written. |
| 4. | Return to Service Date | When all outage work has been completed, the process of restoring the unit to service begins. This entails a series of standard unit tests that must be performed before the unit can be released for service and a start-up procedure if there is newly installed equipment. Once complete, an operator, working in concert with the Switching Center, executes the steps in the Switching Log to restore the unit to service.<br><br>The Switching Center Operators contact the RTD when the unit has been restored and the RTD notifies the CAISO through the OMS that the unit has been restored to service.<br><br>At the completion of the outage, the information gathered while performing the maintenance work during the outage is utilized to update maintenance libraries in SAP WM and refine the details and timing of future maintenance tasks. |

The three processes detailed above are highly interrelated. Outage scheduling is dependent on planning and scoping. As the defined outage scope changes, the outage schedule is continuously reviewed and updated based on that changed scope. Conversely, if outside influences require the outage timing or duration to change, the scope of work is reviewed and adjusted to fit the revised timeframe. During outage execution, emerging work may require an outage extension, which could, in turn, impact the planning and scheduling of outages on other units or facilities.

#### f. Project Management Process

Project work is controlled through the project management process. Each project has an assigned Project Manager who has responsibility for the project scope, cost, and schedule, and who coordinates and manages the project from inception to closeout. Project management procedures and tools are in place to provide Power Generation project managers and job leaders guidelines for successfully achieving the project objective of each project they manage. These procedures are intended to be applicable to all types, sizes, and phases of Power Generation projects, and are anticipated to improve the consistency and quality of project management throughout Power Generation. Project Managers report regularly to management.

#### g. Design Change Process

Design changes are controlled through the design change process. The design change process is the process for proposing, evaluating, and implementing changes to the design of structures, systems, and equipment at PG&E’s hydro-generating facilities. It includes the process for requesting design changes; reviewing and approving design change requests; implementing design changes; closing out design changes; and revising design change notices.

## D. Operational Results

PG&E operates its diverse hydro system as a portfolio. The following section discusses the operational results for the hydro portfolio. The operational results achieved by PG&E's hydro portfolio demonstrate that PG&E's hydro resources were operated in a reasonable manner during the record period.

### 1. Energy Production

The energy production at hydro generation facilities is dependent on the available water supplies in any given year. Just as natural gas is fuel for a fossil fuel generating station, water from precipitation, snowmelt, and aquifer outflows is the fuel for hydro-generating facilities. Water availability in any given year is dependent on several factors including meteorological conditions, snowpack, aquifer outflows, the amount of water storage carryover in reservoirs from the previous year, and FERC license conditions. The changing meteorological conditions each year and the ongoing changes in aquifer outflows result in a yearly variation in the fuel supply directly impacting energy output each year.

As FERC-jurisdictional hydro projects, many of PG&E's projects have strict and complex license requirements. To comply with these demands on water resources (such as stream flows for fish, frogs and other species, recreation (including white water rafting), consumptive water uses, and other purposes), some of the water bypasses the generating assets and is lost for the production of energy.

The primary drivers of energy production from hydro generation in any given year are the quality of the water year and the snowpack. PG&E's hydro generating assets total generation for the portfolio for 2022 record year was 5,269 gigawatt-hours of energy. This is significantly lower than historical long-term averages and primarily driven by drought.

### 2. Outages

PG&E's hydro generation facilities experienced scheduled outages and forced outages during the record period.

Scheduled outages include PO and MO as described in Section C.2.c above. Forced outages occur when equipment suddenly fails and the unit immediately trips offline, or when the repair need is so urgent that the unit must be forced out of service by an operator before the end of the next weekend. A forced outage is triggered in two ways: (1) the unit is forced out of service by the plant operator or (2) the unit is automatically tripped offline by a protective device.

Consistent with previous ERRA Compliance proceedings, PG&E presents general information regarding scheduled outages and specific information regarding each forced outage at facilities 25 MW or greater lasting longer than 24 hours.[2]

One of the key industry metrics used to gauge the operating performance of generating units is the Forced Outage Factor (FOF). FOF is a ratio of the hours a unit is forced out of operation to the total hours in the operation period (i.e., month or year). The hydro portfolio 2022 FOF was 3.47 percent which is better than the industry benchmark of 3.51 percent.[3] Table 2-4 includes the hydro portfolio FOF for the past five years compared to the industry benchmark.

**TABLE 2-4**
**HYDRO PORTFOLIO FOF**

| Line No. | Year | PG&E FOF (%) | Benchmark FOF (%) |
|---|---|---|---|
| 1 | 2018 | 3.22[(a)] | 2.91 |
| 2 | 2019 | 2.41 | 3.03 |
| 3 | 2020 | 2.06 | 3.22 |
| 4 | 2021 | 2.98[(b)] | 3.08 |
| 5 | 2022 | 3.47[(c)] | 3.51 |

(a) Excludes storm-related outages.
(b) Excludes storm and wildfire-related outages
(c) Excludes the planned outage time for Pit 7 transformer replacement (refer to subsection b)(2)(j) for more detail)

### a. Scheduled Outages

PG&E's hydro portfolio had 103 scheduled outages 24 hours or greater in duration on units greater than 25 MW during the record

2 PG&E has provided additional, detailed information concerning the outages that occurred during the record period to the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) at the CPUC in response to Cal Advocates' Master Data Request.

3 The industry benchmark for 2022 is the 2017-2021 NERC Generator Availability Data System Generating Unit Statistical Brochure 4. The brochure and derivation of the forced outage benchmark is included in PG&E's workpapers.

period. Of this total, 71 were POs and 32 were MOs.[4] This is an average of just over one scheduled outage per unit across the hydro portfolio.

### b. Forced Outages

The average age of PG&E's 102-unit hydro portfolio is approximately 81 years. 89 units are more than 50 years old, and 36 units are more than 100 years old, so it is reasonable to expect some forced outages of PG&E's hydro units. Some of these outages are related to unanticipated equipment malfunctions while others are related to external events such as lightning strikes, wildfire, storm-induced transmission line interruptions, or debris in the water.

During forced outages, PG&E's primary goal is to bring the unit back on-line safely. For outages resulting from equipment failure, PG&E examines components associated with the specific equipment that failed to determine whether modifications or repairs should be made to those components, either at the unit where the outage occurred or at other units with similar components. While this might extend the time before a unit is returned to service, it can potentially avoid a future forced outage.

During the record period, there were 26 forced outages with durations longer than 24 hours occurring at 20 different units with a powerhouse capacity of 25 MW or greater. PG&E has grouped these into two categories: (1) Forced Outages related to wildfires or storms and (2) Forced Outages Unrelated to wildfires or storms.

#### 1) Forced Outages Related to Wildfires or Storms

During the record period, there were 6 forced outages resulting from wildfires and no forced outages due to storms. All 6 forced outages were related to outages caused by the Electra Fire[5] where units were taken offline or forced out of service for the following reasons: (1) public and personnel safety; (2) minimize equipment

---

4 A description of the general nature and scope of PO and MO is provided in Section C.2.c. above.

5 The Electra Fire was a wildfire that burned northeast of Mokelumne Hill in Amador and Calaveras Counties, California that started on July 4, 2022 and fully contained on July 28, 2022

damage; (3) transmission lines in the area having to be de-energized due to the wildfire; and (4) water delivery downstream. Table 2-5 below lists these forced outage events.

**TABLE 2-5**
**2022 HYDRO FORCED OUTAGES – ELECTRA FIRE RELATED FORCED OUTAGES**

| Line No. | Unit Name | Actual Started | Actual Ended | Actual Duration (Days) |
|---|---|---|---|---|
| 1 | ELECTRA POWERHOUSE UNIT #2 | 7/4/22 18:48 | 7/6/22 15:43 | 1.87 |
| 2 | ELECTRA POWERHOUSE UNIT #1 | 7/4/22 19:00 | 7/5/22 19:28 | 1.02 |
| 3 | ELECTRA POWERHOUSE UNIT #3 | 7/4/22 16:59 | 7/5/22 19:03 | 1.09 |
| 4 | SALT SPRINGS PH UNIT #1 | 7/4/22 18:22 | 7/7/22 11:59 | 2.73 |
| 5 | SALT SPRINGS PH UNIT #2 | 7/4/22 18:31 | 7/6/22 1:06 | 1.27 |
| 6 | TIGER CREEK PH UNIT #1 | 7/4/22 18:22 | 7/7/22 8:57 | 2.61 |

**2) Forced Outages Unrelated to Wildfires or Storms**

During the record period, there were 20 forced outages unrelated wildfire or storms. Table 2-6 below summarizes the events followed by a detailed description of each event.

**TABLE 2-6**
**2022 HYDRO FORCED OUTAGES-UNRELATED TO WILDFIRES OR STORMS**

| Line No. | Unit Name | Actual Started | Actual Ended | Actual Duration (Days) |
|---|---|---|---|---|
| 1 | BALCH PH 1 UNIT 1 | 5/29/22 23:59 | 6/2/22 16:57 | 3.71 |
| 2 | BELDEN POWERHOUSE | 3/24/22 23:59 | 4/8/22 8:55 | 14.37 |
| 3 | CARIBOU #1 POWERHOUSE UNIT #1 | 10/13/22 8:32 | 10/18/22 14:12 | 5.24 |
| 4 | DRUM POWERHOUSE #1, UNIT #4 | 1/22/22 9:13 | 1/24/22 15:50 | 2.28 |
| 5 | ELECTRA POWERHOUSE UNIT #1 | 4/22/22 11:13 | 4/23/22 15:21 | 1.17 |
| 6 | ELECTRA POWERHOUSE UNIT #3 | 7/11/22 14:10 | 7/12/22 16:59 | 1.12 |
| 7 | HAAS PH UNIT 1 | 1/21/22 15:32 | 2/4/22 14:43 | 13.97 |
| 8 | PIT PH 1 UNIT 1 | 10/24/22 10:48 | – | – |
| 9 | PIT PH 3 UNIT 1 | 11/24/21 23:59 | 6/8/22 10:16 | 158.43 |
| 10 | PIT PH 3 UNIT 2 | 12/15/21 23:59 | 6/17/22 17:07 | 167.71 |
| 11 | PIT PH 3 UNIT 3 | 11/24/21 23:59 | 6/8/22 15:23 | 158.64 |
| 12 | PIT PH 4 UNIT 1 | 3/15/22 2:37 | 3/16/22 16:51 | 1.59 |
| 13 | PIT PH 4 UNIT 1 | 4/11/22 9:56 | 4/12/22 11:25 | 1.06 |
| 14 | PIT PH 4 UNIT 2 | 3/15/22 2:37 | 3/16/22 16:53 | 1.59 |
| 15 | PIT PH 4 UNIT 2 | 4/11/22 9:56 | 4/12/22 11:29 | 1.06 |
| 16 | PIT PH 7 UNIT 2 | 11/25/21 0:00 | 7/31/22 20:47 | 211.87 |
| 17 | POE POWERHOUSE UNIT #1 | 10/27/22 23:30 | 11/30/22 23:59 | 34.02 |
| 18 | SALT SPRINGS PH UNIT #1 | 12/1/22 15:31 | – | – |
| 19 | STANISLAUS POWERHOUSE UNIT #1 | 10/27/22 18:34 | 12/5/22 10:12 | 38.65 |
| 20 | TIGER CREEK PH UNIT #1 | 8/6/22 7:04 | 8/9/22 12:37 | 3.23 |

**a) Balch Powerhouse**

On May 29, 2022, at 11:59 p.m., Balch 2 Unit 1 tripped offline on neutral overvoltage relay protection during start-up testing at the end of a planned outage. The unit was inspected and tested, with no issues found. The relay protection data was also reviewed which determined that the bus feeding the 12kv distribution circuit caused the unit trip. The unit was returned to service with the 12kv distribution circuit de-energized since the 12kv distribution bus does not provide the normal station service power that is necessary to start the unit back up. Normal station service power for the plant comes through a separate source from Balch 2 Station Service that allows the unit to generate.

The Unit was tested and returned to service on June 2, 2022 at 4:57 p.m. Subsequently, PG&E performed tests and repairs of the circuit and restored the 12kv distribution circuit.

**b) Belden Powerhouse**

On March 24, 2022, at 11:59 p.m., Belden was transitioned to a forced outage from a planned outage due to a delay in testing on newly replaced 230kv Capacitor Voltage Transformers (CCVT). The 230kv CCVTs at Belden were being replaced during the planned outage. On March 24th, after the CCVTs were replaced, required testing was not able to be completed until the transmission Grid Control Center (GCC) operators and the substation technicians were able to support testing. The GCC operators and the substation technicians were working on a deadline commitment to change the protection setting for PG&E's Enhanced Powerline Safety Settings Program (EPSS)[6]. Management confirmed that water was being stored at Lake Almanor during this time of year, so Belden (downstream of Lake Almanor) was not scheduled to generate during this time. Since Belden was not scheduled to generate and given EPSS is critical for PG&E to mitigate wildfire risk, management determined it was prudent to not attempt to prioritize the CCVT testing over the EPSS work. Upon availability of the Grid Control Center (GCC) operators and the substation technicians, the CCVTs were tested, and the unit was returned to service on April 8, 2022 at 8:55 a.m.

**c) Caribou Powerhouse**

On October 13, 2022, at 8:21 p.m., Caribou Unit 1 tripped offline on generator stator ground relay protection. After extensive testing and troubleshooting it was found to be a third harmonic issue. The third harmonic issue occurred while the

---

**6** PG&E Enhance Powerline Safety Settings (EPSS) is a program where PG&E adjusts the sensitivity of our electric equipment on distribution circuits in high fire-risk areas to automatically turn off power faster when there is a hazard, like a tree branch falling into a line. The program provides greater customer protection from wildfire ignitions.

unit was generating through Unit 2 and Unit 3's transformer bank when Unit 1's bank was being replaced, which is an uncommon mode of operation for the unit. It was determined that the third harmonic settings were not reliable when all three units from Caribou powerhouse generate through the Unit 2 and Unit 3 bank. New relay settings were installed, and the third harmonic setting was disabled until the breaker configuration and third harmonic operation can be changed to avoid this type of trip from occurring when the Unit 2 and Unit 3 bank is being used for all three units. Caribou Unit 1 was tested and returned to service on October 18, 2022 at 2:12 pm and put into reserve shutdown.

**d) Drum Powerhouse**

On January 22, 2022, at 9:13 a.m., Drum 1 Unit 1 tripped offline on generator neutral overcurrent relay protection. The unit and protection relays were tested. The relay settings were adjusted, and the unit was tested and returned to service on January 24, 2022, at 3:50 p.m.

**e) Electra Powerhouse**

On April 22, 2022, at 7:05 a.m., Electra Unit 1 tripped offline on exciter relay protection. Upon investigation it was determined the main exciter control board had failed. A new board was installed. The unit was tested and returned to service the next day at 3:21 p.m.

On July 11, 2022, at 2:10 p.m., Electra Unit 3 was forced out of service when operators attempted to start up the unit. Upon investigation, it was determined that the 5-way valve on the Turbine Shutoff valve had failed. The 5-way valve was replaced, and the unit was tested and returned to service on July 12, 2022, at 4:10 p.m.

**f) Haas Powerhouse**

On January 21, 2022, at 8:35 p.m., Haas Unit 1 was transitioned to a forced outage from planned outage due to arcing being observed on the Main Transformer Bank Upper Disconnect switch when the unit was being returned to service from the planned outage. Upon investigation of the switch, a broken bushing was discovered. A new bushing was procured and installed; the switch enclosure was resealed. The unit was tested and returned to service on February 4, 2022, at 2:43 p.m.

**g) Pit 1 Powerhouse**

On October 24, 2022, at 5:42 a.m., Pit 1 Unit 1 was forced out of service due to lower guide bearing high temperature indication. Upon investigation, it was determined the lower guide bearing had wiped. [7] The lower guide bearing and upper guide bearing oil tubs were disassembled and cleaned. The associated oil piping was cleaned and flushed to remove any debris from the system. The lower guide bearing was sent to a third-party vendor for refurbishment. The bearing was still with the vendor for repair at the end of 2022. A cause evaluation is also underway for this event.

Given that the unit remains out of service at the end of 2022, PG&E seeks review of this outage in the 2023 ERRA Compliance proceeding.

**h) Pit 3 Powerhouse**

On November 25, 2021, at 12:00 a.m., Pit 3 Unit 1 and 3 were transitioned to forced outage at the end of their planned outages and on December 16, 2021, at 12:00 a.m., Pit 3 Unit 2 was transitioned to forced outage at the end of its planned outage due to transformer bank issues. Transformer bank maintenance and repair work was being performed while the transformer was open for the planned outage. The inspection revealed that numerous winding spacers were loose or laying at the bottom of the tank, allowing the top edge of the winding to lift from its desired position, which could result in transformer

---

7 A bearing wipe occurs when the temperature in the bearing becomes high enough that the overlay babbitt material is melted or displaced.

failure. There were no indications of the damage during operations and previous testing. An engineering evaluation determined that the units should not return to service until the transformer could be repaired. The bank was repaired and tested, and Unit 1 was returned to service on June 8, 2022, at 10:16 a.m., Unit 2 on June 17, 2022, at 5:07 p.m. and Unit 3 on June 8, 2022, at 3:23 p.m.

A cause evaluation (CE) was completed for this event. Three corrective actions were identified in the CE of which all three have been completed.

**i) Pit 4 Powerhouse**

On March 15, 2022, at 2:37 a.m., Pit 4 Unit 1 and 2 tripped offline due to communication failure to the valve house. Upon investigation, there was water intruding into the valve house building where the conduit penetrates the building wall. The water traveled into the Penstock butterfly valve control cabinet and damaged components of the Programmable Logic Controller (PLC). Repairs were made to prevent water intrusion into the valve house and the damaged PLC components were replaced. The units were tested and returned to service the next day at 4:51 and 4:53 pm.

On April 11, 2022, at 9:56 a.m., Pit 4 Unit 1 and 2 were forced out of service again for water intrusion damaging the PLC. The initial repair did not account for water pooling in the area under the roof overhang of the valve house. A second, more robust repair was completed. The units were tested and returned to service the next day at 11:25 am. and 11:29 a.m. respectively.

**j) Pit 7 Powerhouse**

On November 25, 2021, at 12:00 a.m., Pit 7 Unit 2 was transitioned to a forced outage from a planned outage due to the transformer bank showing abnormally high gas test results. The planned outage scope included advanced testing of the transformer bank before an upcoming planned outage in 2022 to replace the transformer bank. Electrical testing was performed but some of the gas values did not meet PG&E standards, requiring engineering evaluation. Additional engineering review determined that the risk posed by the gas values was a possible catastrophic failure of the transformer that could not be sufficiently mitigated or detected in advance of a failure. The risk of asset failure also raised safety risk to personnel regularly present at the facility or in the vicinity of the Pit River. Therefore, the decision was made to leave the unit out of service until the next planned outage between April 1 and July 31, 2022, for replacement of the transformer bank. The new transformer bank was installed and tested, and Pit 7 Unit 2 was returned to service on July 31 2022, 7:47 a.m.

**k) Poe Powerhouse**

On October 27, 2022, at 11:23 p.m., Poe Unit 1 was transitioned from a planned outage to a forced outage due to internal damage found in the transformer bank. North American Substation Services (NASS) was performing refurbishment project work on the transformer when the internal damage was discovered. Hitachi was brought on as a Subject Matter Expert to evaluate the health of the transformer and to proactively replace components showing signs of degradation. The transformer was repaired on site by NASS and the unit was tested and returned to service on November 30, 2022, at 11:59 p.m.

**l) Salt Springs Powerhouse**

On December 1, 2022, at 3:53 p.m., Salt Springs Unit 1 was forced out of service due to lack of water due to seasonal water constraints which are often a part of the normal operations of hydro plants. When sufficient water is available to run the unit, the unit will be returned to service. The unit was out of service at the end of 2022.

#### m) Stanislaus Powerhouse

On October 27, 2022, at 6:34 p.m., Stanislaus was forced out of service due to lack of water. Lack of water was driven by hydro facilities in the Tri-Dam Project[8] being offline which are upstream of Stanislaus powerhouse on the Middle Fork of the Stanislaus River in Tuolumne County. The unit was returned to service on December 5, 2022, at 8:12 p.m., when sufficient water was available.

#### n) Tiger Creek Powerhouse

On August 6, 2022, at 11:46 p.m., Tiger Creek Unit 1 was forced out of service due to an exciter field ground indication. Upon investigation, water and debris were discovered in the generator winding area. No leaks or openings were found upon inspection. Dehumidifiers were used to dry the unit out. The unit was tested and returned to service on August 9, 2022, at 1:43 p.m.

## E. Compliance Items

### 1. Transformer Inspection Program Standards

D.18-05-004, Ordering Paragraph (OP) 6 directed PG&E to include a report, in future ERRA Compliance applications, describing national industry standards of similar transformer inspection program tests, including standards for inspection periods. The following testimony and the workpapers supporting this chapter provide the required report.

PG&E instituted a transformer inspection program in December 2015. This program follows industry recommendations regarding specific inspection intervals from the International Council on Large Electric Systems (CIGRE) Working Group and associated feedback from the product of an AM partnership, Hydropower Asset Management Partnership (HydroAMP).[9]

---

8 Tri-Dam project is a partnership between the Oakdale Irrigation District and the South San Joaquin Irrigation District

9 In 2001, the Bureau of Reclamation, Hydro-Québec, the Army Corps of Engineers' Hydroelectric Design Center, and Bonneville Power Administration began collaborating on a hydroelectric equipment condition assessment technique that was later named HydroAMP.

This program also incorporates key findings from studies done by the Centre for Energy Advancement through Technological Innovation (CEATI) and CIGRE international workgroups. While CEATI and CIGRE have observed significant differences on maintenance activities and their intervals across the utility industry, PG&E has adopted best practices and recommendations to design and validate its transformer program. In 2018, in response to D.18-05-004, OP 6, PG&E worked with Doble, an industry leader in transformer assessment, to survey seven companies to understand if other power generation companies have coalesced around a specific set of standards. The transformer program inspections continue to be executed based on the results of the survey from 2019 and in line with industry best practices.

**2. Transformer Inspection Program Status**

D.18-05-004, OP 6 directed PG&E to report the dates and results of all inspections performed under the new transformer inspection program in its future ERRA Compliance filings, including descriptions of the results of all visual inspections. The following testimony and the workpapers supporting this chapter provide the required inspection results.

As discussed in Section E.1. above, PG&E instituted a transformer inspection program in December 2015 following industry recommendations from CIGRE and HydroAMP. Power Generation's guidance documents for its transformer inspection program include a High Voltage Transformer Condition Evaluation Standard and three procedures: (1) High Voltage Transformer Tier 1 Inspection and Measurement; (2) High Voltage Transformer Tier 2 Oil Test and Investigation; and (3) High Voltage Transformer Tier 3 Electrical Testing and Inspection.

PG&E has 108 transformers under this program as shown in Table 2-7 by hydro area and fossil plant.

**TABLE 2-7**
**NUMBER OF TRANSFORMERS IN THE TRANSFORMER INSPECTION PROGRAM**

| Line No. | Hydro Area or Fossil Facility | Number of Transformers |
|---|---|---|
| 1 | Central | 22 |
| 2 | DeSabla | 22 |
| 3 | Helms | 10 |
| 4 | Kings Crane | 16 |
| 5 | Shasta | 24 |
| 6 | Humboldt Bay GS | 3 |
| 7 | Colusa GS | 6 |
| 8 | Gateway GS | 5 |
| 9 | Total | 108 |

The transformer inspection program results are included in the workpapers supporting this chapter.

### 3. 2020 ERRA Settlement Agreement Report on February 2020 Pit 5 Unit 2 Forced Outage

Decision 22-04-041 adopted a settlement agreement between PG&E and Cal Advocates in PG&E’s 2020 ERRA Compliance Proceeding. PG&E agreed to provide a progress report on the two remaining corrective actions (as of the Settlement date) associated with the February 2020 Pit 5 Unit 2 forced outage. PG&E completed the two remaining corrective actions in 2021. The Table 2-8 below shows all nine corrective actions associated with this forced outage with their completion dates.

**TABLE 2-8**
**STATUS OF REMAINING CORRECTIVE ACTIONS – FEB 2020 PIT 5 UNIT 2 FORCED OUTAGE**

| Line No. | # | Corrective Action | Status | Completion Date |
|---|---|---|---|---|
| 1 | CA-1 | Create and disseminate Final Incident Communication to Hydro O&M, Engineering, and ATS employees, identifying potential for 3-part maintainable mini-ball valves to fail and release hazardous energy if internal bushing is removed under pressure. | Complete | 6/5/2020 |
| 2 | CA-2 | Use accountability processes per Human Resources and Labor Relations guidance to administer appropriate measures to reinforce expectations to the four employees involved in this event. | Complete | 6/4/2020 |
| 3 | CA-3 | Review and reinforce expectations for compliance and consequences for non-compliance to Power Gen personnel.<br>- Code of Safe Practices, Section 9<br>- PG-1404P-02, ‘Application for Work’<br>- PG-1025P-01, Job Safety Analysis<br>- PG-1404P-01, ‘Power Generation Clearance and Tagging – Lockout Tagout’ WBT | Complete | 8/27/2020 |
| 4 | CA-4 | Use PG-2498S, ‘Hydro Work Management Process’ to install dedicated oil sampling port(s) at Pit 5. | Complete | 11/8/2021 |
| 5 | CA-5a | Identify locations in Hydro powerhouses that need dedicated oil sampling ports. | Complete | 8/27/2020 |
| 6 | CA-5b | Create H1 or HA Notifications for installation of dedicated sampling ports. | Complete | 9/13/2021 |
| 7 | CA-5c | Where dedicated sample ports cannot be installed before next samples are required, O&M and AM collaboratively identify improvised sample locations. If hazardous energy is a factor (as determined by Authorized Person), write and approve Special Work Procedure per PG-1404P-01 for samples. | Complete | 11/30/2020 |
| 8 | CA-6 | Revise PG-1330P-01: ‘Oil Sampling of Mechanical Systems’ so that it requires a Journeyman Electrical Machinist to provide a powerhouse -specific orientation / walkdown for any persons performing oil sampling in Hydro powerhouses. | Complete | 6/30/2020 |

**TABLE 2-8**
**STATUS OF REMAINING CORRECTIVE ACTIONS – FEB 2020 PIT 5 UNIT 2 FORCED OUTAGE (CONTINUED)**

| Line No. | # | Corrective Action | Status | Completion Date |
|---|---|---|---|---|
| 9 | CA-7a | Align Power Gen Leadership on prioritization of<br>Lubricating Oil Program in relation to other preventative maintenance and corrective maintenance work given resource limitations. | Complete | 7/8/2020 |
| 10 | CA-7b | Upon alignment, communicate with a 5 - minute meeting to Asset Management and Operations & Maintenance teams, and ATS. | Complete | 7/8/2020 |
| 11 | CA-8a | Revise PG-1330P-01: ‘Oil Sampling of Mechanical Systems’ | Complete | 6/30/2020 |
| 12 | CA-8b | Develop and implement a process for assigning oil sampling from O&M to AM Engineering or ATS. | Complete | 8/31/2020 |
| 13 | CA-c | Develop and implement a Change Management plan to communicate changes PG-1330P-01: ‘Oil Sampling of Mechanical Systems’ | Complete | 6/30/2020 |
| 14 | CA-9 | Review and reinforce expectations with Asset Management employees on PG-2498S, ‘Hydro Work Management Process’ to ensure understanding of work initiation and prioritization processes. | Complete | 8/31/2020 |

## F. Conclusion

In compliance with D.14-01-011, this chapter addressed the operation of PG&E’s utility-owned hydroelectric facilities, and outages that occurred at these facilities during the 2022 record year. It demonstrates that PG&E’s utility-owned hydroelectric portfolio was operated in a reasonable manner during the record period.

PG&E has a comprehensive management structure, with numerous internal controls, to prudently oversee the operation of a large, geographically dispersed, and complex hydro system. Scheduled outages were planned sufficiently in advance to allow adequate preparation time and were efficiently executed to assure prompt return to service.

PG&E’s hydro resources were operated in a reasonable manner as demonstrated by the 2022 record year FOF results being better than the industry average when considering the total portfolio. Additionally, PG&E assets larger than 25 MW are significantly better than the industry average. PG&E acted reasonably in resolving forced outages in a timely manner.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 2

# ATTACHMENT A

# PG&E POWERHOUSES AND GENERATING UNITS

# PACIFIC GAS AND ELECTRIC COMPANY
## CHAPTER 2
## UTILITY OWNED GENERATION: HYDROELECTRIC
## Attachment A Table of Hydro Generating Units at 2022 End of Year

| Line No. | Powerhouse Name and Unit | Basic type and / or configuration | Management Area | Specific physical location | Capacity | Date in service |
|---|---|---|---|---|---|---|
| 1 | ALTA POWERHOUSE UNIT #1 | Conv Hydro | Central | Alta, CA | 1.0 | 11/7/1902 |
| 2 | BALCH PH 1 UNIT 1 | Conv Hydro | Kings Crane Valley | Balch Camp, CA | 31.0 | 2/20/1927 |
| 3 | BALCH PH 2 UNIT 2 | Conv Hydro | Kings Crane Valley | Balch Camp, CA | 52.5 | 11/26/1958 |
| 4 | BALCH PH 2 UNIT 3 | Conv Hydro | Kings Crane Valley | Balch Camp, CA | 52.5 | 11/26/1958 |
| 5 | BELDEN POWERHOUSE | Conv Hydro | DeSabla | Belden, CA | 125.0 | 9/14/1969 |
| 6 | BUCKS CREEK PH UNIT #1 | Conv Hydro | DeSabla | Storrie, CA | 33.0 | 3/4/1928 |
| 7 | BUCKS CREEK PH UNIT #2 | Conv Hydro | DeSabla | Storrie, CA | 32.0 | 3/4/1928 |
| 8 | BUTT VALLEY POWERHOUSE | Conv Hydro | DeSabla | Belden, CA | 41.0 | 12/31/1958 |
| 9 | CARIBOU #1 POWERHOUSE UNIT #1 | Conv Hydro | DeSabla | Belden, CA | 25.0 | 5/6/1921 |
| 10 | CARIBOU #1 POWERHOUSE UNIT #2 | Conv Hydro | DeSabla | Belden, CA | 25.0 | 5/6/1921 |
| 11 | CARIBOU #1 POWERHOUSE UNIT #3 | Conv Hydro | DeSabla | Belden, CA | 25.0 | 5/6/1921 |
| 12 | CARIBOU #2 POWERHOUSE UNIT #4 | Conv Hydro | DeSabla | Belden, CA | 60.0 | 11/9/1958 |
| 13 | CARIBOU #2 POWERHOUSE UNIT #5 | Conv Hydro | DeSabla | Belden, CA | 60.0 | 11/9/1958 |
| 14 | CENTERVILLE PH UNIT NO.1 | Conv Hydro | DeSabla | Chico, CA | 5.5 | 5/1/1900 |
| 15 | CENTERVILLE PH UNIT NO.2 | Conv Hydro | DeSabla | Chico, CA | 0.9 | 5/1/1900 |
| 16 | COLEMAN PH UNIT NO.1 | Conv Hydro | Shasta | Anderson, CA | 13.0 | 6/19/1979 |
| 17 | COW CREEK PH UNIT NO.1 | Conv Hydro | Shasta | Millville, CA | 0.9 | 1/1/1907 |
| 18 | COW CREEK PH UNIT NO.2 | Conv Hydro | Shasta | Millville, CA | 0.9 | 1/1/1907 |
| 19 | CRANE VALLEY PH UNIT 1 | Conv Hydro | Kings Crane Valley | North Fork, CA | 0.9 | 7/4/1919 |
| 20 | CRESTA POWERHOUSE UNIT #1 | Conv Hydro | DeSabla | Storrie, CA | 35.0 | 11/23/1949 |
| 21 | CRESTA POWERHOUSE UNIT #2 | Conv Hydro | DeSabla | Storrie, CA | 35.0 | 1/15/1950 |
| 22 | DE SABLA PH UNIT NO.1 | Conv Hydro | DeSabla | Magalia, CA | 18.5 | 2/28/1963 |
| 23 | DEER CREEK PH UNIT #1 | Conv Hydro | Central | Nevada City, CA | 5.7 | 5/6/1908 |
| 24 | DRUM POWERHOUSE #1, UNIT #1 | Conv Hydro | Central | Alta, CA | 13.2 | 11/26/1913 |
| 25 | DRUM POWERHOUSE #1, UNIT #2 | Conv Hydro | Central | Alta, CA | 13.2 | 11/26/1913 |
| 26 | DRUM POWERHOUSE #1, UNIT #3 | Conv Hydro | Central | Alta, CA | 13.1 | 11/26/1913 |
| 27 | DRUM POWERHOUSE #1, UNIT #4 | Conv Hydro | Central | Alta, CA | 14.5 | 11/26/1913 |
| 28 | DRUM POWERHOUSE #2, UNIT #5 | Conv Hydro | Central | Alta, CA | 49.5 | 12/18/1965 |
| 29 | DUTCH FLAT POWERHOUSE UNIT #1 | Conv Hydro | Central | Alta, CA | 22.0 | 3/29/1943 |
| 30 | ELECTRA POWERHOUSE UNIT #1 | Conv Hydro | Central | Jackson, CA | 31.0 | 6/29/1948 |
| 31 | ELECTRA POWERHOUSE UNIT #2 | Conv Hydro | Central | Jackson, CA | 31.0 | 6/29/1948 |
| 32 | ELECTRA POWERHOUSE UNIT #3 | Conv Hydro | Central | Jackson, CA | 36.0 | 6/29/1948 |
| 33 | HAAS PH UNIT 1 | Conv Hydro | Kings Crane Valley | Balch Camp, CA | 72.0 | 12/23/1958 |
| 34 | HAAS PH UNIT 2 | Conv Hydro | Kings Crane Valley | Balch Camp, CA | 72.0 | 12/23/1958 |
| 35 | HALSEY POWERHOUSE UNIT #1 | Conv Hydro | Central | Auburn, CA | 11.0 | 12/6/1916 |
| 36 | HAMILTON BRANCH PH UNIT #1 | Conv Hydro | DeSabla | Penninsula Village, CA | 2.4 | 1/1/1921 |
| 37 | HAMILTON BRANCH PH UNIT #2 | Conv Hydro | DeSabla | Penninsula Village, CA | 2.4 | 1/2/1921 |
| 38 | HAT CREEK PH 1 UNIT 1 | Conv Hydro | Shasta | Burney, CA | 8.5 | 8/22/1921 |
| 39 | HAT CREEK PH 2 UNIT 1 | Conv Hydro | Shasta | Burney, CA | 8.5 | 9/28/1921 |
| 40 | HELMS POWERHOUSE UNIT 1 | Pumped Storage | Helms | Shaver Lake, CA | 404.0 | 6/30/1984 |
| 41 | HELMS POWERHOUSE UNIT 2 | Pumped Storage | Helms | Shaver Lake, CA | 404.0 | 6/30/1984 |
| 42 | HELMS POWERHOUSE UNIT 3 | Pumped Storage | Helms | Shaver Lake, CA | 404.0 | 6/30/1984 |
| 43 | INSKIP PH UNIT NO.1 | Conv Hydro | Shasta | Manton, CA | 8.0 | 10/9/1979 |
| 44 | JAMES B. BLACK PH UNIT #1 | Conv Hydro | Shasta | Big Bend, CA | 86.0 | 2/17/1966 |
| 45 | JAMES B. BLACK PH UNIT #2 | Conv Hydro | Shasta | Big Bend, CA | 86.0 | 12/17/1965 |
| 46 | KERCKHOFF PH 1 UNIT 1 | Conv Hydro | Kings Crane Valley | Auberry, CA | 12.6 | 8/6/1920 |
| 47 | KERCKHOFF PH 1 UNIT 3 | Conv Hydro | Kings Crane Valley | Auberry, CA | 12.8 | 8/6/1920 |
| 48 | KERCKHOFF PH 2 UNIT 1 | Conv Hydro | Kings Crane Valley | Auberry, CA | 155.0 | 5/6/1983 |
| 49 | KILARC PH UNIT NO.1 | Conv Hydro | Shasta | Whitmore, CA | 1.6 | 10/1/1903 |
| 50 | KINGS RIVER PH UNIT 1 | Conv Hydro | Kings Crane Valley | Balch Camp, CA | 52.0 | 3/7/1962 |

# PACIFIC GAS AND ELECTRIC COMPANY
## CHAPTER 2
## UTILITY OWNED GENERATION: HYDROELECTRIC
## Attachment A Table of Hydro Generating Units at 2022 End of Year

| Line No. | Powerhouse Name and Unit | Basic type and / or configuration | Management Area | Specific physical location | Capacity | Date in service |
|---|---|---|---|---|---|---|
| 51 | LIME SADDLE PH UNIT NO.1 | Conv Hydro | DeSabla | Oroville, CA | 1.0 | 8/1/1906 |
| 52 | LIME SADDLE PH UNIT NO.2 | Conv Hydro | DeSabla | Oroville, CA | 1.0 | 8/1/1906 |
| 53 | NEWCASTLE POWERHOUSE UNIT #1 | Conv Hydro | Central | Auburn, CA | 11.5 | 10/28/1986 |
| 54 | OAK FLAT POWERHOUSE UNIT #1 | Conv Hydro | DeSabla | Belden, CA | 1.3 | 11/2/1985 |
| 55 | PHOENIX POWERHOUSE UNIT #1 | Conv Hydro | Central | Sonora, CA | 2.0 | 2/20/1940 |
| 56 | PIT PH 1 UNIT 1 | Conv Hydro | Shasta | Burney, CA | 30.5 | 2/28/1922 |
| 57 | PIT PH 1 UNIT 2 | Conv Hydro | Shasta | Burney, CA | 30.5 | 2/28/1922 |
| 58 | PIT PH 3 UNIT 1 | Conv Hydro | Shasta | Burney, CA | 23.3 | 7/15/1925 |
| 59 | PIT PH 3 UNIT 2 | Conv Hydro | Shasta | Burney, CA | 23.3 | 7/15/1925 |
| 60 | PIT PH 3 UNIT 3 | Conv Hydro | Shasta | Burney, CA | 23.4 | 7/15/1925 |
| 61 | PIT PH 4 UNIT 1 | Conv Hydro | Shasta | Big Bend, CA | 47.5 | 10/1/1955 |
| 62 | PIT PH 4 UNIT 2 | Conv Hydro | Shasta | Big Bend, CA | 47.5 | 10/1/1955 |
| 63 | PIT PH 5 UNIT 1 | Conv Hydro | Shasta | Big Bend, CA | 40.0 | 4/29/1944 |
| 64 | PIT PH 5 UNIT 2 | Conv Hydro | Shasta | Big Bend, CA | 40.0 | 4/29/1944 |
| 65 | PIT PH 5 UNIT 3 | Conv Hydro | Shasta | Big Bend, CA | 40.0 | 4/29/1944 |
| 66 | PIT PH 5 UNIT 4 | Conv Hydro | Shasta | Big Bend, CA | 40.0 | 4/29/1944 |
| 67 | PIT PH 6 UNIT 1 | Conv Hydro | Shasta | Montgomery Creek, CA | 40.0 | 8/14/1965 |
| 68 | PIT PH 6 UNIT 2 | Conv Hydro | Shasta | Montgomery Creek, CA | 40.0 | 8/14/1965 |
| 69 | PIT PH 7 UNIT 1 | Conv Hydro | Shasta | Montgomery Creek, CA | 56.0 | 9/10/1965 |
| 70 | PIT PH 7 UNIT 2 | Conv Hydro | Shasta | Montgomery Creek, CA | 56.0 | 9/10/1965 |
| 71 | POE POWERHOUSE UNIT #1 | Conv Hydro | DeSabla | Storrie, CA | 60.0 | 10/26/1958 |
| 72 | POE POWERHOUSE UNIT #2 | Conv Hydro | DeSabla | Storrie, CA | 60.0 | 10/26/1958 |
| 73 | POTTER VALLEY UNIT 1 | Conv Hydro | DeSabla | Potter Valley, CA | 4.5 | 4/1/1908 |
| 74 | POTTER VALLEY UNIT 3 | Conv Hydro | DeSabla | Potter Valley, CA | 2.0 | 4/1/1908 |
| 75 | POTTER VALLEY UNIT 4 | Conv Hydro | DeSabla | Potter Valley, CA | 2.7 | 4/1/1908 |
| 76 | ROCK CREEK POWERHOUSE UNIT #1 | Conv Hydro | DeSabla | Storrie, CA | 63.0 | 3/1/1950 |
| 77 | ROCK CREEK POWERHOUSE UNIT #2 | Conv Hydro | DeSabla | Storrie, CA | 63.0 | 3/16/1950 |
| 78 | SALT SPRINGS PH UNIT #1 | Conv Hydro | Central | Pioneer, CA | 11.0 | 6/15/1931 |
| 79 | SALT SPRINGS PH UNIT #2 | Conv Hydro | Central | Pioneer, CA | 33.0 | 4/24/1953 |
| 80 | SAN JOAQUIN 1A PH UNIT 1 | Conv Hydro | Kings Crane Valley | North Fork, CA | 0.4 | 3/12/1919 |
| 81 | SAN JOAQUIN 2 PH UNIT 1 | Conv Hydro | Kings Crane Valley | North Fork, CA | 3.2 | 9/29/1917 |
| 82 | SAN JOAQUIN 3 PH UNIT 1 | Conv Hydro | Kings Crane Valley | North Fork, CA | 4.2 | 8/17/1923 |
| 83 | SOUTH PH UNIT NO.1 | Conv Hydro | Shasta | Manton, CA | 7.0 | 12/8/1979 |
| 84 | SPAULDING PH #1, UNIT #1 | Conv Hydro | Central | Emigrant Gap, CA | 7.0 | 5/8/1928 |
| 85 | SPAULDING PH #2, UNIT #1 | Conv Hydro | Central | Emigrant Gap, CA | 4.4 | 7/16/1928 |
| 86 | SPAULDING PH #3, UNIT #1 | Conv Hydro | Central | Emigrant Gap, CA | 5.8 | 2/21/1929 |
| 87 | SPRING GAP POWERHOUSE UNIT #1 | Conv Hydro | Central | Long Barn, CA | 7.0 | 9/16/1921 |
| 88 | STANISLAUS POWERHOUSE UNIT #1 | Conv Hydro | Central | Vallecito, CA | 91.0 | 3/11/1963 |
| 89 | TIGER CREEK PH UNIT #1 | Conv Hydro | Central | Pioneer, CA | 29.0 | 8/1/1931 |
| 90 | TIGER CREEK PH UNIT #2 | Conv Hydro | Central | Pioneer, CA | 29.0 | 8/1/1931 |
| 91 | TOADTOWN PH UNIT NO.1 | Conv Hydro | DeSabla | Mogalia, CA | 1.5 | 4/22/1986 |
| 92 | TULE RIVER PH UNIT 1 | Conv Hydro | Kings Crane Valley | Springville, CA | 3.2 | 1/21/1914 |
| 93 | TULE RIVER PH UNIT 2 | Conv Hydro | Kings Crane Valley | Springville, CA | 3.2 | 1/21/1914 |
| 94 | VOLTA 1 PH UNIT NO.1 | Conv Hydro | Shasta | Manton, CA | 9.0 | 4/4/1980 |
| 95 | VOLTA 2 PH UNIT NO.2 | Conv Hydro | Shasta | Manton, CA | 0.9 | 10/30/1981 |
| 96 | WEST POINT PH UNIT #1 | Conv Hydro | Central | Pioneer, CA | 14.5 | 11/21/1948 |
| 97 | WISE POWERHOUSE #1, UNIT #1 | Conv Hydro | Central | Auburn, CA | 14.0 | 3/4/1917 |
| 98 | WISE POWERHOUSE #2, UNIT #1 | Conv Hydro | Central | Auburn, CA | 3.2 | 12/12/1986 |
| 99 | WISHON PH 1 UNIT 1 | Conv Hydro | Kings Crane Valley | North Fork, CA | 5.0 | 9/20/1910 |
| 100 | WISHON PH 1 UNIT 2 | Conv Hydro | Kings Crane Valley | North Fork, CA | 5.0 | 9/20/1910 |
| 101 | WISHON PH 1 UNIT 3 | Conv Hydro | Kings Crane Valley | North Fork, CA | 5.0 | 9/20/1910 |
| 102 | WISHON PH 1 UNIT 4 | Conv Hydro | Kings Crane Valley | North Fork, CA | 5.0 | 9/20/1910 |
| | | | | | 3,857.1 | |

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 3

# UTILITY-OWNED GENERATION:

# FOSSIL AND OTHER GENERATION

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
UTILITY-OWNED GENERATION:
FOSSIL AND OTHER GENERATION

TABLE OF CONTENTS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
UTILITY-OWNED GENERATION:
FOSSIL AND OTHER GENERATION

TABLE OF CONTENTS
(CONTINUED)

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 3
# UTILITY-OWNED GENERATION: FOSSIL AND OTHER GENERATION

## A. Introduction

In compliance with Decision (D.) 14-01-011, this chapter addresses the operation of Pacific Gas and Electric Company's (PG&E or the Company) utility-owned fossil-fuel, battery energy storage, and photovoltaic (PV) facilities during the 2022 record year. PG&E's utility-owned fossil-fuel, battery energy storage, and PV portfolio was operated in a reasonable manner during the record period.

During the record period, PG&E owned, operated, and maintained three fossil-fuel generating stations, one battery energy storage project, and 10 ground-mounted PV solar stations.[1] The three fossil-fuel generating stations are Gateway Generating Station, Colusa Generating Station, and Humboldt Bay Generating Station (HBGS). These three generating facilities have a combined maximum normal operating capacity of 1,400 megawatts (MW).

PG&E received approval in Resolution (Res.) E-4949 to design, permit, construct, and maintain the Elkhorn Battery Energy Storage System (Elkhorn BESS), a lithium-ion battery installation that delivers 182.5 MWs of power at the Moss Landing Substation in Monterey County. The project began operation on April 7, 2022.

The 10 ground-mounted PV generating stations are Vaca Dixon, Westside, Stroud, Five Points, Huron, Cantua, Giffen, Gates, West Gates, and Guernsey Solar Stations. These facilities were built as part of the Utility-Owned Generation (UOG) portion of PG&E's 5-year solar PV Program approved in D.10-04-052.

---

[1] PG&E also owns three small PV facilities in San Francisco that entered commercial operations in 2007. Because these facilities total less than 300 kilowatts (kW), PG&E has not addressed them in this testimony.

## 1. Fossil-Fuel Generating Stations

### a. Gateway Generating Station

Gateway is a 530 MW combined cycle power plant consisting of two General Electric (GE) Frame 7FA combustion turbine (CT)-generators, each with its own Vogt-NEM heat recovery steam generator (HRSG), and a single GE steam turbine (ST)-generator. In this standard 2 × 1 configuration, each CT generates power and exhausts directly into its own HRSG where the exhaust heat is captured and generates steam for use in the ST. The exhaust steam leaves the turbine and is condensed for reuse in an air-cooled condenser. Air emissions are controlled with Dry Low Nitrogen Oxide ($NO_x$) combustion coupled with Selective Catalytic Reduction (SCR) systems. For each HRSG, two catalyst systems are used to reduce $NO_x$, carbon monoxide (CO), and Volatile Organic Compound (VOC) production. Additionally, Gateway is equipped with a capacity enhancing technology to improve output during peak generation periods. Duct burners are used to increase steam production in the HRSGs resulting in increased ST output. The duct burners allow Gateway to increase its output by approximately 50 MW above the 530 MW nominal capacity.

### b. Colusa Generating Station

Colusa is a 530 MW combined cycle power plant consisting of two GE Frame 7FA CTs, each with its own HRSG, and a single GE ST. In this standard 2 × 1 configuration, each CT generates power and exhausts directly into its own HRSG where the exhaust heat is captured and generates steam for use in the ST. The exhaust steam leaves the turbine and is condensed for reuse in an air-cooled condenser. Air emissions are controlled with Dry Low $NO_x$ combustion coupled with SCR systems. For each HRSG, two catalyst systems are used to reduce $NO_x$, CO, and VOC production. Additionally, Colusa is equipped with a capacity enhancing technology to improve output during peak generation periods. Duct burners are used to increase steam production in the HRSGs resulting in increased ST output. The duct burners allow Colusa to increase its output by approximately 127 MW above the 530 MW nominal capacity.

**c. Humboldt Bay Generating Station**

Humboldt is a 163 MW reciprocating engine power plant consisting of 10 Wartsila 18V50 Dual Fuel (DF) natural gas-fired reciprocating units.[2] Each unit has 18 cylinders, each with a bore of 50 centimeters, and operates at 514 revolutions per minute. Each unit is designed to run on natural gas with 1 percent of total fuel input provided by low sulfur distillate as the pilot fuel. The units are also designed to run on low sulfur distillate or biodiesel. Each unit is equipped with a separate independent closed loop cooling system. Emission control is accomplished with SCR. Similar to Gateway and Colusa, two catalyst systems are used to reduce $NO_X$, CO, and VOC production.

## 2. Battery Energy Storage

**a. Elkhorn**

The Elkhorn BESS is a lithium-ion battery installation that delivers 182.5 MWs of power at the Moss Landing Substation in Monterey County.

The project includes the installation of 256 Tesla Megapack battery units on 33 concrete slabs. Each unit houses batteries and associated equipment in a steel cabinet. Transformers and switchgears connect energy stored in the batteries with the 115-kilovolt (kV) transmission system. It has the capacity to store and dispatch up to 730 megawatt-hours (MWh) of energy to the electrical grid at a maximum of 182.5 MWs for up to four hours during periods of high demand.

Non-Generating Resources (NGR) such as the Elkhorn BESS are important to the grid due to their flexibility and ability to respond to regulation signals. They have the capability to serve as both generation and load and can be dispatched to any operating level within their entire capacity range. Elkhorn BESS also enhances reliability by addressing

---

[2] For HBGS, each engine is also referred to as a unit.

capacity deficiencies resulting from local load growth, without adding new fossil fuel resources to the grid. The system participates in the California Independent System Operator (CAISO) markets, providing energy and ancillary services, such as serving as an operating reserve that can quickly be dispatched to facilitate sufficient capacity to the CAISO-controlled grid. The system's ability to serve as a load during the times of the day and throughout the year are integral to helping the state integrate renewable resources, such as wind and solar, which are intermittent or have a generation profile that does not match with customer demand.

### 3. Solar Stations

#### a. Vaca Dixon Solar Station

Vaca Dixon is a 2 MW PV solar station located in Vacaville, California, on a 16-acre site. The solar station includes 9,672 solar modules that provide Direct Current (DC) energy; five inverters that convert the DC energy to Alternating Current (AC); one transformer that increases the voltage from 480 volts (V) to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

#### b. Westside Solar Station

Westside is a 15 MW PV solar station located near Five Points, California, on a 200-acre site. The solar station includes over 66,000 solar modules that provide DC energy; 30 inverters that convert the DC energy to AC; 15 transformers that increase the voltage from 440 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

#### c. Stroud Solar Station

Stroud is a 20 MW PV solar station located near Helm, California, on a 201-acre site. The solar station includes 88,000 solar modules that provide DC energy; 40 inverters that convert the DC energy to AC; 20 transformers that increase the voltage from 440 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

**d. Five Points Solar Station**

Five Points is a 15 MW PV solar station located near Five Points, California, on a 162-acre site. The solar station includes over 75,000 solar modules that provide DC energy; 24 inverters that convert the DC energy to AC; 12 transformers that increase the voltage from 320 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

**e. Huron Solar Station (HSS)**

Huron is a 20 MW PV solar station located near Huron, California, on a 145-acre site. The solar station includes over 90,000 solar modules that provide DC energy; 40 inverters that convert the DC energy to AC; 10 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

**f. Cantua Solar Station**

Cantua is a 20 MW PV solar station located near Cantua Creek, California, on a 171-acre site. The solar station includes approximately 110,000 solar modules that provide DC energy; 32 inverters that convert the DC energy to AC; 16 transformers that increase the voltage from 320 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

**g. Giffen Solar Station**

Giffen is a 10 MW PV solar station located near Cantua Creek, California, on a 97-acre site. The solar station includes close to 55,000 solar modules that provide DC energy; 16 inverters that convert the DC energy to AC; 8 transformers that increase the voltage from 320 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

**h. Gates Solar Station**

Gates is a 20 MW PV solar station located on a 120-acre site, adjacent to the HSS near Huron, California. The solar station includes 91,490 solar modules that provide DC energy; 28 inverters that convert the DC energy to AC; 31 transformers that increase the voltage from

420 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

**i. West Gates Solar Station**

West Gates is a 10 MW PV solar station located on a 60-acre site, near Huron, California. The solar station includes over 45,752 solar modules that provide DC energy; 14 inverters that convert the DC energy to AC; 14 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment, such as a communications enclosure, two weather stations, and electrical switchgear.

**j. Guernsey Solar Station**

Guernsey is a 20 MW PV solar station located on a 120-acre site, near Hanford, California. The solar station includes: 89,400 solar modules that provide DC energy; 40 inverters that convert the DC energy to AC; 11 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear. Guernsey also includes single axis trackers that move the solar modules to optimize their position with the sun.

## B. Fossil and Other Operations and Maintenance Organization

The Fossil and Other Operations and Maintenance (O&M) organization is responsible for managing PG&E's fossil, BESS, and solar PV generating assets to provide safe, reliable, cost-effective, and environmentally responsible generation. The fossil portion of the O&M organization is located at the three generating stations. The PV and Elkhorn BESS portion of the organization is located at two separate locations—Caruthers and Moss Landing.

PG&E primarily utilizes contract services to perform major maintenance work at its fossil-fuel generating stations, PV, and BESS facilities. For Gateway and Colusa, Long-Term Service Agreements (LTSA)[3] for the CTs and STs are provided by GE, their Original Equipment Manufacturer (OEM). For Elkhorn BESS, PG&E also entered into a maintenance agreement and performance guarantee with the OEM, Tesla.

---

3 LTSAs are also known as Contractual Services Agreements.

PG&E is committed to providing safe utility service to its customers. As part of this commitment, PG&E reviews its operations, including operation of its fossil and other generation facilities, to identify and mitigate, to the extent possible, potential safety risks to the public, PG&E's workforce, and its contractors. As it operates and maintains its fossil and other generation facilities, PG&E follows internal controls to ensure public, workplace, and contractor safety. PG&E's Employee Code of Conduct specifies that the safety of the public, employees, and contractors are PG&E's highest priority. PG&E's commitment to a safety-first culture is reinforced with its Safety Principles, Safety Commitment, Personal Safety Commitment, and Keys to Life. These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E obtains all applicable regulatory approvals from governmental authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As part of PG&E's Safety Commitment, PG&E follows recognized best practices in the industry. PG&E operates each of its generation facilities in compliance with all local, state, and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration requirements and the California Public Utilities Commission's (CPUC) General Order (GO) 167. As discussed below, PG&E does this by using internal controls to help manage the O&M of its generation facilities.

Power Generation (PG) employees develop action plans each year related to key performance indicators in the areas of safety and reliability. The action plans focus on various items such as forced outage and planned outage performance and approaches to reduce or eliminate recordable injuries and motor vehicle incidents.

With regard to public safety, PG&E continues to develop and implement a comprehensive public safety program that includes public education, outreach, and partnership with key agencies, and enhanced emergency response preparedness, training, drills, and coordination with emergency response organizations.

Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grassroots safety team that can act to encourage safe work practices among peers. PG's grassroots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement changes that can improve safety performance.

The Fossil O&M organization works side-by-side with PG support organizations to provide safe, reliable, cost-effective generation to California in an environmentally responsible manner.

Support organizations consist of centralized departments within PG. The centralized departments within PG work closely with the Fossil and Other O&M organization. These support organizations provide oversight, direction, and support to ensure that critical resources, personnel, and technical information and advice are available to support O&M for effective O&M of the fossil, solar and BESS fleet.

### 1. Portfolio Strategy

The PG Portfolio Strategy organization is led by a director and includes several functions:

- optimization of the composition of the generation fleet;
- compliance and commitments which includes Federal Energy Regulatory Commission (FERC) relicensing and licensing compliance as well as optimizing the cost and benefit to the State, public and shareholders by working with regulatory agencies such as FERC, Division of Safety of Dams (DSOD);
- business planning and regulatory reporting which includes identifying, prioritizing, and planning PG's work;
- monitoring customer value (costs and benefits) of PG&E's utility-owned generation to identify and recommend potential changes to the portfolio;
- implementing approved divestiture strategies including overseeing regulatory approvals from the CPUC and FERC;

- providing analysis and regulatory support for other potential portfolio optimization strategies, such as decommissioning and alternative ratemaking proposals;
- serving as a liaison for PG&E's Land Conservation Commitment efforts among various PG&E departments and the Stewardship Council;
- managing the business operations function for PG which combines several functions into an integrated department that provides strategic and tactical (operational and financial) services; and
- regulatory reporting, preparation, and filing of all required documentation for various regulatory proceedings which includes responding to data requests and preparing work papers and testimony.

### 2. Geosciences

The Geosciences organization is led by a director and is responsible for providing services company wide including the following PG services:

- On-call emergency evaluations and mitigation for seismic events, landslide, erosion, and foundation issues for all company functional areas;
- Support for the Hydro Facility Safety Program including fault studies, penstock geotechnical assessments, dam seepage and liquefaction analysis, spillway assessments;
- Support for the Company Emergency Response Program, Emergency Operations Center, earthquake exercises, post-event reconnaissance, and emergency training;
- Wildfire burn area debris flow hazard modeling and alerting;
- Geotechnical design and construction review; and
- Climate team research studies and planning support.

### 3. Process Improvement and Corrective Action Program (CAP)

The CAP program is led by a manager and is responsible for Electric Operations CAP program, which includes PG. The Electric CAP group is focused on continuously monitoring the performance of the organization and facilitating the timely and accurate use of CAP. The team is responsible for monitoring declines in performance, addressing gaps to standards using evaluation tools (such as cause analysis) to support the safety of our employees and the public and the continued reliable operation of our assets. The CAP Program is further described under Section D.4.

### 4. Asset Excellence

The Asset Excellence department is led by a director and consists of an Asset Management (AM) program that is International Standards Organization (ISO) 55001[4] certified. The department focuses on systemwide condition assessment of PG system equipment and proposes projects and/or changes to operations and/or maintenance practices to ensure that PG's long-term investment plan reduces risk and maintains the safety and reliability of PG.

PG met its commitment to achieve ISO 55001 certification of all PG&E dams by 2022. PG also achieved certification for the entire portfolio, which includes, hydro powerhouses, fossil generators, solar power plants, battery storage, and associated items such as civil Infrastructure, physical data, and data assets.

The Asset Excellence department is supported by a team that develops and implements analytical risk modeling processes and techniques to achieve effective risk management, reduction, and mitigation.

### 5. Engineering and Technical Services

Engineering and Technical Services department is led by a director and provides engineering technical services, and asset security to PG operations, projects, and public safety work.

Engineering provides engineering services for projects and support of routine hydro O&M work. Engineering uses a number of contractors to augment its workforce in order to execute on planned work. It ensures that PG is focused on public and employee safety, continuously improving processes, delivering high quality work, and ensuring compliance with all standards and procedures that govern the PG business.

---

4 ISO 55000 is an internationally recognized Asset Management System standard that details out the requirements for a business to ensure it is maximizing the value of its assets and minimizing its risks. ISO 55000 standards are aligned with the concept of risk and data informed investment decision making and requires a significant improvement in the way PG treats and maintains its data.

PG&E's Technical Services organization provides direct support to the O&M North and O&M South for the safe, reliable, compliant, efficient operation of PG&E's hydro units. O&M Specialists in the Technical Services organization act as consultants offering expertise in methods and procedures to help assure compliance with operating and maintenance standards.

The department includes the PG Security Program which ensures asset protection and public safety.

## C. Other Support Organizations

PG&E's Environmental Services organization also provides direct support to the Fossil and Other O&M organization, with a focus on regulatory compliance. Environmental consultants are located at each of the fossil-fuel generating stations and at or near the Elkhorn BESS and PV facilities and support the facility staff.

## D. Internal Controls

PG&E directs, monitors, and measures its resources using processes that take into consideration the organization's structure, work and authority flows, people, and management information systems. Internal controls help PG&E comply with GO 167.

GO 167 sets forth standards that govern the O&M of power plants. The purpose of GO 167 is:

> …to implement and enforce standards for the maintenance and operation of electric generating facilities and power plants so as to maintain and protect the public health and safety of California residents and businesses, to ensure that electric generating facilities are effectively and appropriately maintained and efficiently operated, and to ensure electrical service reliability and adequacy.[5]

The standards set forth in GO 167 include operation standards, maintenance standards, and logbook standards. PG&E accomplishes compliance with GO 167 through the use of various internal controls, and through audits by the CPUC. GO 167 was set in place post energy crisis by the CPUC as a way to enforce prudent practices in the availability of the fossil fleet for California.

---

**5** CPUC, GO 167, Section 1.0 Purpose.

PG&E has many internal controls in place to manage the O&M of its generation assets, including: (1) guidance documents; (2) operations reviews; (3) an event reporting system; (4) a CAP; (5) an outage planning and scheduling process; and (6) a design change process. Each of these controls is discussed below.

**1. Guidance Documents**

The guidance documents applicable to PG&E's fossil and solar operations include PG&E Policy, PG&E Utility Standard Practices, PG&E Utility Procedures, and PG-specific guidance documents. PG-specific guidance documents include Standards, Procedures, and Bulletins. In addition, the fossil-fuel generating stations PV facilities and BESS facility have site-specific procedures. These guidance documents cover virtually all aspects of safety, operations, maintenance, planning, environmental compliance, regulatory compliance, emergency response, work management, inspection, testing, and other areas. Each guidance document describes the purpose of the document, the details of the actions and/or processes covered by the document, management's roles and responsibilities, and the date the document became effective.

**2. Operations Reviews**

Operations reviews are performed by the Technical Services organization at the three fossil-fuel generating stations each year and periodically at remote facilities such as Elkhorn BESS and the solar stations. The purpose of an operations review is to ensure PG&E's generation facilities are operated in a safe and efficient manner and that they comply with standard operating and clearance procedures.

By thoroughly reviewing fossil, solar and battery storage operations, PG&E can identify possible precursors to more serious problems. Plant managers are provided a report on the overall operational health of their generating stations, with recommendations based on safety, best operating practices, latest operating technologies, training, and reducing the overall cost of production. The recommendations are then implemented on a priority basis within a reasonable time frame. This control enhances PG&E's ability to improve operations by promoting safe operating practices and verifying compliance with emergency and standard operating and clearance procedures.

### 3. Event Reporting System

The event reporting system documents and resolves problems related to forced outages or curtailments to generating units. By thoroughly analyzing significant problem events that occur in the O&M of PG&E's facilities, PG&E can report to various regulatory agencies as required, identify possible precursors to repetitive or more serious problems, identify, understand, and correct causal factors, and communicate lessons learned to other facilities and personnel.

### 4. Corrective Action Program

The CAP documents and tracks corrective actions and commitments. The CAP includes problem identification, cause determination, reporting, development of corrective actions, and corrective action implementation tracking.

The CAP for PG&E's PG organization utilizes SAP notifications and orders to track and document actions that are necessary or have been taken in response to audit and/or inspection findings, deviations identified in incident reports, regulatory non-compliance issues, engineering deviations, and other systemwide issues.

### 5. Outage Planning and Scheduling Processes

The outage schedule is developed to plan and communicate when various generating stations will be unavailable due to maintenance or project work. Shown on the schedule are Planned Outages consisting of maintenance tasks and project-specific outages and combination outages encompassing both project and maintenance tasks. The outage schedule for a given outage year is developed through an iterative process, over several years, as projects and maintenance tasks are identified by field employees, management, project managers and others. Typically, no outages are planned during the peak summer generation season. Also, every effort is made to limit the number and duration of outages in the off-peak shoulder months.

The yearly outage schedule is not a static document. The schedule is fluid and adaptable to changing requirements. PG&E's Energy Policy and Procurement organization, the CAISO and others use the schedule to make plans regarding resource allocation, replacement power and restrictions on the system. Therefore, changes in the schedule, particularly in the short term, are discouraged. Due to the dynamic nature of the system, changes inevitably will be required. Changes to the schedule may be required due to: (1) weather conditions; (2) resource constraints; (3) changes in project scope or schedule; and (4) and/or emergent work. Depending on the proximity to the outage start date, changes to the scope and schedule require different levels of review and approval. Before outage changes are approved, consideration is given to the impacts of the change on: (1) equipment reliability; (2) replacement power costs; and (3) resources and other scheduled outages.

An outage plan is developed prior to the start of the outage. Depending on the size and duration of the outage, an outage plan can be as simple as a list of work orders extracted from the SAP Work Management System (SAP/WMS), or as complex as a critical path, resource-loaded work execution plan detailing each task for a project as well as preventative and corrective maintenance work orders. The development of an outage plan can be broken down into three distinct, but interrelated, processes: (1) planning and scoping; (2) scheduling; and (3) outage execution.

**a. Planning and Scoping**

The planning and scoping process determines the work to be executed during the outage. This includes preventative maintenance work orders, corrective work orders for repairs on equipment and/or facilities and project-specific asset replacements or major refurbishments. The required resources to execute the work and the durations of all work activities are identified during this process.

PG&E manages preventative and maintenance work using SAP/WMS. Preventative maintenance work orders, sometimes referred to as recurring work, encompass routine maintenance work performed at established intervals. Corrective work orders, sometimes referred to as trouble tags, refer to work identified to correct an issue that is limiting the ability of the equipment or facility to efficiently perform its design function. The SAP/WMS is the electronic repository where preventative and corrective work is identified, tracked, organized, and managed. The system utilizes maintenance libraries to generate recurring work orders against a piece of equipment at the appropriate frequency as specified by PG&E. Corrective work orders are created in the system by the crews or individuals identifying the problem.

The planning and scoping process occurs over a 2- to 3-year period leading up to the outage start date.

**b. Scheduling**

The scheduling process determines the start and duration of an outage. Outage timing and durations are influenced by: (1) capital and maintenance work to be performed; (2) system operation constraints; (3) time of year; (4) labor resources available to perform work; (5) CAISO constraints, and transmission system issues.

The scheduling process occurs in conjunction with the scoping and planning process over a 2- to 3-year timeframe. A base preliminary outage schedule is developed from historical outage durations and timing, and OEM recommended frequency based on service hours and/or the number of equipment starts/stops. This schedule is refined over time as the scoping and planning process provides updated information regarding the work to be performed during the outages.

In October of the year prior to the outage year, the planned outage schedule is submitted to the CAISO to set the base outage schedule. After this submission, any requests for changes to individual outages are submitted to the responsible plant manager and/or fossil O&M director for approval. The level of management approval is dictated by the proximity of the request to the outage start date. These internal approvals are required before the changes are submitted to the CAISO.

**c. Outage Execution**

The outage execution process includes performing the work planned for the outage, following many sub-processes for notifications to and approvals by stakeholders and lessons learned. Activities include:

- Notifications to and approvals from the CAISO to separate the unit(s) from the grid;
- Energy isolation procedures covering the steps required to electrically, hydraulically, and mechanically, clear the units and facilities (i.e., put them in a safe condition) for the outage work to proceed;
- Notifications and approvals for any changes in the outage due to emerging work or changed conditions;
- Restoration procedures to restore the unit to service when the outage work is completed. This includes complying with the steps in the energy isolation procedure and any start-up procedure for new or re-furbished equipment; and
- Notifications to and approvals from the CAISO to restore the unit to service and connect to the grid at the completion of the outage.

The three processes detailed above are highly interrelated. Outage scheduling is dependent on planning and scoping. As the defined outage scope changes, the outage schedule is continuously reviewed and updated based on that changed scope. Conversely, if outside influences require the outage timing or duration to change, the scope of work is reviewed to determine if it can be adjusted to fit the revised timeframe, or if the outage scheduling needs to be moved. During outage execution, emerging work may require an outage extension, which could, in turn, impact the planning and scheduling of outages on other units or facilities.

### 6. Design Change Process

Design changes are controlled through the design change process. The design change process is the process for proposing, evaluating, obtaining approval, and implementing changes to the design of structures, systems, and equipment at PG&E’s generating facilities. It includes the process for requesting design changes; reviewing and approving design change requests; implementing design changes; closing out design changes; and revising design change notices.

## E. Operational Results

This section examines the operational results during the 2022 record period by reviewing the energy production, fuel usage, and reliability of the fossil-fuel generating stations and the energy production and fuel usage of Elkhorn BESS and the PV facilities. For facilities greater than 25 MW and longer than 24 hours, 2022 outages are also presented.

### 1. Energy Production

The output of Gateway, Colusa, and Humboldt varies throughout the day in response to CAISO market awards and dispatch instructions.

PG&E's fossil fuel generating stations provided approximately 5,457 gigawatt hours (GWh) of energy during the 2022 record period. To generate this amount of energy, the fossil fuel generating stations burned 40,100,858 millions of British Thermal Units (MMBtu) of natural gas and 16,302 MMBtu of distillate fuel. The resulting net plant heat rate for the fossil fuel generating stations in 2022 was 7,357 British thermal units per kilowatt-hour (Btu/kWh) as shown in Table 3-1 below.[6]

**TABLE 3-1**
**FOSSIL GENERATION 2022 ENERGY PRODUCTION**

| Line No. | Station | Net Generation (GWh) | Fuel Usage (MMBtu) | Average Net Heat Rate (Btu/kWh) |
|---|---|---|---|---|
| 1 | Colusa | 2,564 | 18,512,261 | 7,218 |
| 2 | Gateway | 2,439 | 17,625,791 | 7,228 |
| 3 | Humboldt | 454 | 3,979,108 | 8,765 |
| 4 | Total | 5,457 | 40,117,160 | 7,352 |

During 2022, PG&E's PV generating facilities were included in the CAISO market in accordance with the appropriate CAISO tariff provisions relating to these types of intermittent renewable facilities, and as a result were typically operated at maximum production.[7] PG&E's PV generating

6 Net plant heat rate is equal to the amount of fuel consumed (British Thermal Units) divided by the net generation (kWh).

7 Nine of PG&E's PV generation facilities are capable of being curtailed for economic dispatch purposes.

facilities provided approximately 231 GWh of energy during the 2022 record period.

D.10-04-052 approving PG&E's 5-year solar PV Program links recovery of O&M costs for PG&E-owned PV facilities to the performance of the PV facilities. If the average performance of PG&E's PV UOG systems falls below 80 percent of expected output, it will weigh heavily in favor of disallowing or refunding some of the O&M costs to ratepayers.[8] The PV facilities operated at 72.2 percent of expected output during the 2022 record period. PG&E reduced power output on (curtailed) many of its PV generation facilities during 2022 (at the request of the CAISO and for economic dispatch purposes). Had PG&E not reduced output as directed, PG&E's PV facilities would have operated at 82.8 percent of the expected output during the 2022 record period.

The net result of Elkhorn BESS operations (generation plus storage) resulted in 12,127MWHs being removed off the grid for the 2022 record period. Additionally, the Elkhorn BESS provided Resource Adequacy capacity (both System and Flex), Energy and Ancillary Services such as Regulation (Up & Down) and Spinning Reserves that directly supported grid reliability.

**2. Outages**

PG&E's fossil-fuel generating stations and BESS experienced scheduled outages and forced outages during the record period.

Scheduled outages include planned outages and maintenance outages. Planned outages are typically scheduled prior to the start of the year. PG&E's combined cycle plants, Gateway and Colusa, and Elkhorn BESS typically schedule planned outages in the spring of each year to address preventive and corrective maintenance issues. Maintenance outages are scheduled when needed throughout the year to perform testing or routine maintenance, or to perform non-emergency repairs when an outage can be deferred beyond the end of the next weekend but cannot be performed while the unit is operational and must be performed before the next planned outage. Humboldt schedules planned outages for larger scope and duration

---

[8] D.10-04-052, Ordering Paragraph 7.

routine unit maintenance based on service hours. Humboldt schedules maintenance outages for smaller scope and duration routine unit maintenance based on service hours as well.

Forced outages occur when equipment suddenly fails and the unit immediately trips offline, or when the repair need is so urgent that the unit must be forced out of service by an operator before the end of the next weekend. A forced outage is triggered in two ways: (1) the unit is forced out of service by the plant operator or (2) the unit is automatically tripped offline by a protective device.

Consistent with previous Energy Resource Recovery Account compliance proceedings, PG&E is providing general information regarding scheduled outages that were 24 hours or more in duration, and specific information regarding each forced outage that was longer than 24 hours in duration for facilities that are 25 MW or greater in size.[9]

During forced outages, PG&E's primary goal is to bring the unit back on-line safely and expediently. For forced outages due to equipment failure, PG&E also examines components associated with the specific equipment failure. This examination helps inform whether modifications or repairs should be made to those components, either at the unit where the outage occurred, and/or at other units with similar components. While this may extend the time before a unit is returned to service, it can potentially avoid a future forced outage.

One of the key industry metrics used to gauge the operating performance of generating units is the Forced Outage Factor (FOF). FOF is a ratio of the hours a unit is forced out of operation to the total hours in the operation period (i.e., month or year). The fossil portfolio 2022 FOF was 1.79 percent, 0.11 percent better than the industry benchmark of 1.96 percent.[10] Table 3-2 includes the fossil portfolio FOF for the past five years compared to the industry benchmark.

---

9 PG&E has provided additional, detailed information concerning the outages that occurred during the record period to the Public Advocates Office at the California Public Utilities Commission in response to Cal Advocates' Master Data Request.

10 The 2022 industry benchmark is the 2017-2021 North American Electric Reliability Corporation Generating Availability Data System Generating Unit Statistical Brochure. It is included in PG&E's workpapers.

**TABLE 3-2**
**FOSSIL PORTFOLIO FOF**

| Line No. | Year | FOF (%) | Benchmark FOF (%) |
|---|---|---|---|
| 1 | 2018 | 1.21 | 1.72 |
| 2 | 2019 | 1.63 | 1.70 |
| 3 | 2020 | 0.46 | 1.73 |
| 4 | 2021 | 1.06 | 1.85 |
| 5 | 2022 | 1.79 | 1.96 |

### a. Gateway Generating Station

#### 1) Scheduled Outages

Gateway executed two planned outages and no maintenance outages in 2022 lasting 24 hours or more in duration.

#### 2) Forced Outages

Gateway experienced two forced outages in 2022 lasting longer than 24 hours.

On April 23, 2022, at 10:37 p.m., Gateway was forced out of service during a plant start up due to a non-responsive steam turbine intercept valve. Plant staff worked with the OEM (GE) to diagnose and repair the non-responsive valve. The hydraulic shut off valve and high-speed solenoid on the left-hand valve were replaced and a hydraulic actuator flush on both intercept valves was performed. Valve stroke tests were conducted to ensure reliable and repeatable operation and the plant was returned to service on April 27, 2022, at 12:37 p.m.

On June 15, 2022, at 12:50 p.m., Gateway was forced out of service when the steam turbine rotor stopped rotating during a plant restart. Initial observation determined that the main steam turbine turning gear motor had failed and there was damage to the upper drive coupling. Repeated attempts to get the steam turbine back on gear were unsuccessful. Upon further investigation, plant staff determined that the steam turbine rotor was above the OEM shutdown requirement of 500 degrees Fahrenheit. The emergency ratchet drive was utilized to keep the steam turbine rotor from locking up during the cool down period to allow the rotor to cool.

Once the steam turbine rotor had cooled to below 500 degrees Fahrenheit plant staff replaced the main turning gear motor and upper drive coupling with plant spares. The plant staff also inspected and greased the lower turning gear motor drive coupling and checked settings in motor soft start controller. The turning gear system was returned to service on June 18, 2022, at 7:30 p.m.

**b. Colusa Generating Station**

**1) Scheduled Outages**

Colusa executed one planned outage and no maintenance outages in 2022 lasting 24 hours or more in duration.

**2) Forced Outages**

Colusa experienced one forced outage in 2022 lasting longer than 24 hours.

On April 23, 2022, at 11:03 p.m., Colusa was forced out of service due to an inability to establish sufficient vacuum in the condenser during plant start-up. Upon investigation it was determined that the nozzle liberated on the vacuum (hogging) system. The nozzle was replaced and tested for functionality. The plant was returned to service on April 26, 2022, at 9:18 a.m.

**c. Humboldt Bay Generating Station**

**1) Scheduled Outages**

The preventative maintenance schedule at HBGS is based on service hours of each unit. Maintenance is necessary for each unit at: 1,000, 2,000, 4,000, 6,000, 8,000, 12,000, 18,000, and 24,000-hour intervals. The 18,000 (and associated multiples thereafter) hour overhauls are the most extensive and take the most time to plan for and complete. As mentioned earlier, Humboldt schedules planned outages for larger scope and duration unit maintenance, and schedules maintenance outages for smaller scope and duration unit maintenance. Since Humboldt is a 10-unit facility, another unit is typically available to back up a unit that is out of service for an outage.

Humboldt experienced three planned outages and 49 maintenance outages lasting longer than 24 hours in 2022.

**2) Forced Outages**

Humboldt experienced 12 forced outages lasting longer than 24 hours in 2022. Seven of the 12 forced outages were caused by an earthquake in Eureka, CA that took several units offline.as shown in Table 3-3 below.[11] The remaining five forced outages are shown in Table 3-4.

**TABLE 3-3**
**2022 HUMBODLT FORCED OUTAGES – CAUSED BY EARTHQUAKE**

| Line No. | | Start | End | Duration (Days) |
|---|---|---|---|---|
| 1 | Humboldt Bay GS Unit 02 | 12/20/22 2:39 | 12/22/22 9:03 | 3.27 |
| 2 | Humboldt Bay GS Unit 03 | 12/20/22 2:39 | 12/30/22 7:24 | 11.20 |
| 3 | Humboldt Bay GS Unit 04 | 12/20/22 2:39 | 12/21/22 15:04 | 2.52 |
| 4 | Humboldt Bay GS Unit 05 | 12/20/22 2:39 | 12/24/22 9:00 | 5.26 |
| 5 | Humboldt Bay GS Unit 06 | 12/20/22 2:39 | 12/21/22 15:28 | 2.53 |
| 6 | Humboldt Bay GS Unit 07 | 12/20/22 2:39 | 12/23/22 7:23 | 4.20 |
| 7 | Humboldt Bay GS Unit 10 | 12/20/22 2:39 | 12/23/22 7:42 | 4.21 |

**TABLE 3-4**
**2022 HUMBODLT FORCED OUTAGES**

| Line No. | | Start | End | Duration (Days) |
|---|---|---|---|---|
| 1 | Humboldt Bay GS Unit 01 | 9/4/22 12:57 | 9/6/22 9:48 | 1.87 |
| 2 | Humboldt Bay GS Unit 05 | 7/30/22 12:21 | 8/1/22 12:50 | 2.02 |
| 3 | Humboldt Bay GS Unit 05 | 11/12/22 3:27 | 11/14/22 9:35 | 2.26 |
| 4 | Humboldt Bay GS Unit 09 | 9/1/22 5:38 | 9/20/22 17:51 | 19.51 |
| 5 | Humboldt Bay GS Unit 10 | 5/11/22 21:31 | 5/13/22 13:17 | 1.66 |

[11] A 6.4 magnitude earthquake struck Northern California's Eureka area on December 20th, 2022. The epicenter of the quake struck at 2:34 a.m., pacific time.

**a) Unit 1**

On September 4, 2022, at 12:57 p.m., Unit 1 was forced out of service due to low lube oil pressure. Upon further inspection it was found that the lube oil cooler inlet valve was partially closed. This condition was the cause of the low lube oil pressure. Once the valve was opened, the lube oil pressure increased and the unit was released for service. Investigation determined that the valve partially closed due to a failed locking clip allowing vibration to partially close the valve due to the weight of the handle. As an interim solution to allow the unit to be returned to service safely, the handle was reconfigured so the handle is in the down position and the weight of the handle can't cause the valve to move to the closed position. The valve clip is scheduled to be replaced during the next planned outage. The unit was tested and returned to service on September 6, 2022, at 9:48 a.m.

**b) Unit 5**

On July 30, 2022, at 12:21 p.m., Unit 5 was forced out of service due to a failed rupture disc located on top of the Selective Catalytic Reducer (SCR). The HBGS Maintenance staff and Stephens Mechanical staff removed and replaced the failed rupture disc. The unit was returned to service on August 1, 2022, at 12:50 p.m.

On November 12, 2022, at 3:27 a.m., Unit 5 was forced out of service due to an engine rupture disc failure.[12] The failed rupture disc was replaced and was returned to service on November 14, 2022, at 9:35 a.m.

---

[12] A rupture disk, also known as a pressure safety disc, is a non-reclosing pressure relief safety device that protects equipment or system from over-pressurization or potentially damaging vacuum conditions. A rupture disk is a type of sacrificial part because it has a one-time-use membrane that fails at a predetermined differential pressure, either positive or vacuum.

**c) Unit 9**

On September 1, 2022, at 5:38 a.m., Unit 9 was forced out of service due to the loss of pilot pressure while operating. Upon investigation of the engine cylinders, it was discovered that one of the valves had failed causing damage to several components of the engine including the head, piston, and bearing components. The damaged components were replaced, and new lube oil was installed. Once all components were replaced, the unit was tested and returned to service on September 20, 2022, at 5:51 p.m.

**d) Unit 10**

On May 11, 2022, at 9:31 p.m., Unit 10 was forced out of service due to high emissions while attempting to shut the unit down. Upon inspection it was discovered that the governor had failed and needed to be replaced. HBGS maintenance staff replaced the governor with a spare governor on site and the unit was tested and returned to service on May 13, 2022, at 1:17 p.m.

**d. Elkhorn BESS**

**1) Scheduled Outages**

Elkhorn experienced no planned outages or maintenance outages lasting longer than 24 hours in 2022.

**2) Forced Outages**

Elkhorn BESS experienced a forced outage lasting longer than 24 hours in 2022. On Tuesday, September 20, 2022, at 1:06 am, the site was forced out of service due to a thermal event on a Megapack causing it to catch fire. The fire involved a single Megapack designated as unit T101-MP2. Consistent with Tesla's Lithium-Ion Battery Emergency Response Guide1 (ERG), which was incorporated into the PG&E Pre-Fire Plan, the Megapack was allowed to burn and consume itself while being monitored by first responders at a safe distance.[13] Damage was primarily limited to the loss of a single Megapack out of the 256 that occupy the site, i.e., less than 0.5 percent of the facility's battery energy storage capacity. Tesla removed Unit T101-MP2 and transferred the Megapack to a Tesla Facility in Hayward, California. The system remained off-line to perform site clean-up, allow Tesla to conduct a complete inspection of site Megapacks, complete repairs related to the deflagration vents, and perform a root cause analysis (RCA). The system was restored to service on December 30, 2022 at 2:55 pm except for unit T101-MP2 which remains out of service at the end of 2022.

A technical review of the fire event is underway by Energy Safety Response Group, an independent energy storage fire safety consulting firm. This review summarizes the investigations and analyses from all the entities involved. This review also summarizes the findings of RCA conducted by Tesla and included the mitigations proposed by Tesla.

The technical review and Tesla RCA were still in progress at the time of the ERRA 2022 Compliance Filing. PG&E recommends this outage be reviewed in the ERRA 2023 proceeding.

## F. Conclusion

In compliance with D.14-01-011, this chapter addresses the operation of PG&E's utility-owned fossil-fuel, BESS, and PV facilities, and outages that occurred at these facilities during the 2022 record year. It demonstrates that PG&E's utility-owned fossil-fuel, BESS, and PV portfolio was operated in a reasonable manner during the record period.

PG&E has in place a comprehensive management structure, with adequate internal controls, to prudently oversee the operation of its fossil-fuel generating stations, PV facilities, and BESS. PG&E's compliance with the operations

---

[13] If experiencing a catastrophic failure, the Megapack is designed to burn in a controlled manner with no overpressure events (e.g., explosions). The design intends the Megapack to consume itself in the process without propagating beyond a single cabinet, also minimizing the risk to personnel from dangerous stranded electrical energy. This was the case at this fire. Importantly, no site personnel, workers, emergency responders, or others (i.e., the public) were injured.

standards, maintenance standards, and logbook standards set forth in GO 167 are further evidence that PG&E's fossil, BESS, and solar portfolio was operated in a reasonable manner. In addition, scheduled outages were planned sufficiently in advance to allow adequate preparation time and were executed efficiently to assure prompt return to service.

PG&E's fossil portfolio was operated in a reasonable manner as demonstrated by the 2022 record year FOF results being better than the industry average and by the minimal number of forced outages. PG&E acted reasonably in resolving forced outages in a timely manner.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 4

# UTILITY-OWNED GENERATION: NUCLEAR

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
UTILITY-OWNED GENERATION: NUCLEAR

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 4
# UTILITY-OWNED GENERATION: NUCLEAR

## A. Introduction

In compliance with Decision (D.) 14-01-011, this chapter addresses the operation of Pacific Gas and Electric Company's (PG&E) utility-owned nuclear facility, and outages that occurred at this facility during the 2022 record year.

PG&E's utility-owned nuclear facility was operated in a reasonable manner during the record period. During the record period, PG&E owned, operated, and maintained one nuclear generating facility, the Diablo Canyon Power Plant (DCPP), located nine miles northwest of Avila Beach in San Luis Obispo County. DCPP consists of twin pressurized water reactors, Units 1 and 2, rated at a nominal 1,122 megawatts (MW) and 1,118 MW, respectively. Unit 1 operated safely and reliably in 2022. Unit 1 experienced both planned and forced outages in 2022. Unit 2, while also operating safely, experienced a planned refueling outage in 2022.

All nuclear activities are regulated and overseen daily by the Nuclear Regulatory Commission (NRC) to ensure that the facility is operated within federal regulations.

## B. DCPP's Operations Organization

PG&E's Nuclear Generation (NG) organization, led by the Senior Vice President (SVP), Chief Nuclear Officer, has responsibility for all activities necessary for safe operation of Nuclear Operations. The Site VP of Diablo Canyon Power Plant, VP Business and Technical Services, Senior Manager of Quality Verification (QV), Director of Strategy and Policy, and the Manager of Employee Concerns Program (ECP) report to the SVP, Chief Nuclear Officer. The Station Director, Senior Director Organizational Effectiveness and Training, Senior Director Nuclear Technology, Emergency Services, and Director of Nuclear Projects License Renewal report to the Site VP of Diablo Canyon Power Plant.

The Station Director is responsible for operations, maintenance, and nuclear work management. Operations Services, Maintenance Services, Nuclear Work Management, Project Management, Chemistry and Radiation Protection report to the Station Director. The Director Engineering is responsible for providing engineering and design services. Senior Director Organizational Effectiveness and Training is responsible for site security, learning and performance improvement. Regulatory and risk programs, site emergency services and business planning report to the VP, Business and Technical Services. The Director of QV is responsible for independent oversight of nuclear activities. Finally, the Manager of ECP administers the ECP required by NRC regulations.

## C. DCPP System Management

Plant safety is essential to the successful operation of a nuclear power station. Nuclear plants that focus on cost and production at the expense of safety may be required by the NRC to shut down for extended periods of time to correct safety problems. PG&E has remained focused on plant safety and equipment reliability by pursuing critical projects in expense and capital, even as it pursues cost control efforts. Due to PG&E's effective balancing of plant safety, reliability, and cost, DCPP has performed safely with reliability maintained to the benefit of PG&E's customers.

PG&E has many internal controls in place to manage the operations and maintenance of DCPP. These controls include: (1) procedures; (2) a Corrective Action Program (CAP); (3) an outage planning and scheduling process; (4) a project management process; and (5) a Quality Assurance (QA) Program. Each of these controls is discussed below.

### 1. Procedures

Procedures cover virtually all aspects of safety, operations, maintenance, planning, environmental compliance, regulatory compliance, emergency planning, work management, inspection, testing, and other areas. Each procedure describes the purpose of the document, the details of the actions and/or processes covered by the document, management's roles and responsibilities, and the date the document became effective.

### 2. Corrective Action Program

The CAP is the main process that DCPP uses to identify, analyze, and resolve plant problems and is required by the regulations of the NRC.[1]

---

[1] See 10 Code of Federal Regulations (CFR) 50, Appendix B.

Elements of the program include: issue identification, issue significance reviews, various levels of cause analysis up to root cause analysis, corrective action development and implementation, and performance trending and monitoring. The program is used to develop corrective action to prevent recurrence of problems.

### 3. Outage Planning and Scheduling Process

As discussed in Section D.2 below, nuclear generating units must be shut down periodically to be refueled. Planning the duration of each refueling outage is a complex task. Every refueling outage has work activities that are similar in scope and length including: (1) shutdown and cool down of the reactor; (2) disassembly of the reactor vessel; (3) fuel replacement; and (4) re-assembly of the reactor vessel, followed by heatup and startup of the plant. During these refueling periods, scheduled maintenance is conducted, surveillance tests[2] are performed, and plant modifications are completed. Because DCPP Units 1 and 2 do not routinely shut down at other times, a great deal of maintenance is planned for these refueling outages.

The DCPP refueling outage planning process is governed by a system of milestones. The outage is broken down into individual steps to allow a logical process for developing a schedule and monitoring outage preparation activities. Each outage has a set of milestones and due dates. The milestones are consistent from outage to outage. Nuclear Work Management and senior leadership monitor completion of the milestones to ensure the organization is prepared for the upcoming outage.

The outage preparation milestones begin with a review of the long-range outage plan by Nuclear Work Management, approximately 24 months prior to the outage start date. Other significant milestones include outage scope freeze at approximately 10 months prior to outage start and issuance of the initial schedule at approximately 11 months prior to outage start. The initial schedule undergoes two additional revisions prior to the outage start to incorporate activity logic ties and resource availability. An additional review of the outage safety plan and the outage safety schedule is performed by

2 Surveillance tests are tests required by the NRC-approved technical specifications.

the Plant Staff Review Committee prior to outage start. The final schedule is normally issued two weeks prior to the outage start.

The initial start time for future outages is developed years in advance of the outage start through a coordinated effort between Nuclear Work Management and Engineering Services. Outage start dates are typically in the spring or fall to support operation during the summer months and are coordinated with reactor fuel core cycle length (currently from 18-20 months on each unit). This planning minimizes fuel cost for the remaining operating years on both Units 1 and 2. The outage initial start date is then coordinated through PG&E’s Energy Policy and Procurement organization, in advance of the actual outage start date.

All key steps necessary to determine the duration of a refueling outage are developed through the milestone process discussed above. In the outage schedule, some “float” hours are included to accommodate any minor issues that arise during the outage. The float hours are intended to assure that the unit is returned to service as planned in the outage schedule.

Nuclear Work Management, through the milestone structure, identifies most of the outage design scope (including both major and minor items) approximately 22 months prior to the outage start. This scope is reviewed and approved by station leadership and is finalized 20 months prior to the outage start. Required preventive maintenance items are identified and approved by Engineering Services 12 months prior to the outage start. Preventive maintenance items are items that are needed on a recurring frequency to ensure a safe and reliable plant. Examples of preventive maintenance include motor overhauls, valve refurbishments and instrument calibrations.

Once the outage scope milestone is completed, there is a process for incorporating late scope additions and scope deletions. For significant scope items or challenges to the scope, approval of the changes escalates to increasing senior leadership levels, dependent on the magnitude of the change. These items are presented and either approved as scope addition or rejected. This process is utilized for all refueling outages at DCPP.

### 4. Project Management

Project work is controlled through the project management process. Projects are assigned a Project Manager who has responsibility for the project scope, cost, and schedule, and coordinates and manages the project from inception to closeout. Project management procedures and tools are in place to provide NG Project Managers with guidelines for successfully achieving the objective of each project they manage. These procedures are intended to be applicable to all project types, sizes, and phases, and are anticipated to improve the consistency and quality of project management throughout NG. Project Managers are responsible for regular project reporting to management.

### 5. QA Program

QA audits, assessments, reviews, and inspections are required by the NRC. These processes evaluate plant activities to ensure they are being performed in accordance with NRC QA program requirements and other recognized industry standards. Quality oversight activities at DCPP are performed in accordance with the following regulations: 10 CFR 50, Appendix B; NRC Regulatory Guide 1.33 (that endorses American National Standards Institute (ANSI) N18.7); NRC Regulatory Guide 1.44 (that endorses ANSI N45.2.12); NRC Regulatory Guide 1.58 (that endorses ANSI N45.2.6); and NRC Regulatory Guide 1.123 (that endorses ANSI N45.2.13).

QV has overall responsibility for independent quality oversight of DCPP: plant operations, maintenance, radiation protection, chemistry, emergency planning, environmental protection plan, fitness for duty, engineering, design, procurement, outage management, work control, and strategic projects. The work performed by the QV section includes: independent QA audits, assessments, reviews, quality control inspections, welding non-destructive examinations, source assessments, and supplier audits.

## D. Operational Results

### 1. Capacity Factor and Energy Production

DCPP is consistently operated at 100 percent (or full) power level. Regular cycling of DCPP is not performed. This is consistent with the operation of most nuclear power plants in the United States, which are operated as baseload units. When a plant is taken off-line for any reason, regulatory-required testing must be performed before the plant can be returned to service, which extends the time period to return to service beyond the time required to conduct repairs.

There are a number of factors that can affect the megawatt-hour (MWh) output of a nuclear facility, such as: scheduled refueling outages, routine turbine generator valve testing, ocean cooling water temperature, ocean cooling water system tunnel cleaning, curtailments, and forced outages. The capacity factor[3] and net generation[4] for the 2022 record period for DCPP Units 1 and 2 are shown below in Table 4-1.

**TABLE 4-1**
**NG 2022 ENERGY PRODUCTION**

| Line No. | DCPP Unit | Capacity Factor | Net Generation (MWh)[(a)] |
|---|---|---|---|
| 1 | 1 | 90.7% | 8,915,482 |
| 2 | 2 | 88.9% | 8,704,450 |

(a) Net generation values include preliminary California Independent System Operator (CAISO) data for October, November, and December. Final 2022 generation values will be available in April 2023.

Electric power industry generation unit performance calculations are based on "Maximum Dependable Capacity" (MDC). This value is determined for each generating unit based on extensive unit operational testing and engineering analysis by the plant staff. MDC is the maximum amount of power a unit can produce during average worst case natural operating conditions.[5]

---

3 Capacity factor is a measure of actual generation compared to potential generation (based on operating a unit 24 hours a day every day of the reporting period and established Net MDC values of 1,122 MW for Unit 1 and 1,118 MW for Unit 2).

4 Net generation (MWh) is equal to gross generation minus the amount of energy consumed by the plant, as reported by PG&E to the CAISO.

5 The NRC's definition of MDC can be found at: https://www.nrc.gov/reading-rm/basic-ref/glossary/maximum-dependable-capacity-gross.html.

The MDC values for DCPP Units 1 and 2 are 1,122 MW and 1,118 MW, respectively. As shown in Table 4-1 above, the 2022 capacity factors for Unit 1 and Unit 2 were 90.7 percent and 88.9 percent, respectively. In 2022, Unit 1 was taken off-line one time to perform equipment repairs. Additionally, Unit 1 and Unit 2 had planned Refueling Outages (1R23 and 2R23, respectively). The 2022 Unit 1 forced outage is discussed below.

Combined, DCPP Units 1 and 2 generated 17,619,931 MWh of energy with an average capacity factor of 89.8 percent (for the record period) against a planned target of 89.1 percent.[6] The 2021 industry average annual capacity factor was 92.7 percent (2022 industry results are not yet available).[7] DCPP's performance reflects completion of the planned Unit 1 1R23 Refueling Outage and a unit maintenance shutdown and the planned Unit 2 2R23 Refueling Outage.

As demonstrated above, DCPP's performance resulted in safe and reliable generation for PG&E's customers, with high levels of safety and availability. In addition, completion of the Unit 1 1R23 and Unit 2 2R23 Refueling Outages significantly contributed to the overall safety and performance results.

**2. Outages**

Nuclear generating facilities can experience generation losses due to: (1) refueling (planned) outages; (2) maintenance outages; (3) forced outages; and (4) curtailments. Refueling outages and maintenance outages are both classified as scheduled outages. Each of these types of outages are discussed below.

Nuclear generating units are unique in that they must be shut down periodically to be refueled. The consumption of this set amount of fuel is what establishes the operating duration of a fuel cycle and scheduling of a refueling outage. Nuclear units schedule necessary maintenance and projects within the refueling outages. After a nuclear unit is refueled it can

---

**6** The 89.1 percent planned target capacity factor accounted for the scheduled Unit 1 1R23 and Unit 2 2R23 Refueling Outages.

**7** Industry capacity factor from the U.S. Energy Information Administration, Electric Power Monthly (with data for October 2021), Table 6.7.B https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b.

then be operated until the next refueling outage. The planned duration of a refueling outage is established based on the duration required to refuel the reactor, the scope of maintenance required for the specific outage, and the scope of projects required to be implemented for regulatory or plant improvement activities.

Maintenance outages are scheduled when needed throughout the year to perform testing, routine maintenance, or non-emergency repairs when the repairs can be deferred beyond the end of the next weekend but require a capacity reduction before the next scheduled refueling outage.

Forced outages are generally the result of equipment malfunctions or unexpected ocean conditions that restrict the plant's ocean cooling water intake system. When a forced outage occurs, the primary objective is to repair the item that led to the outage or protect plant equipment from damage resulting from restricted ocean cooling water flow. While minimizing the outage period is important, a certain amount of work is required for every forced shutdown. This includes surveillance testing, as well as complying with all regulatory requirements and emergent maintenance requirements that cannot be deferred to a later period.

A curtailment is when a unit is not operating at 100 percent capacity. A curtailment could be the result of required surveillance testing that must be performed at a power level less than 100 percent, routine maintenance that requires a unit to be at less than 100 percent, such as cleaning of the ocean cooling water system to remove biological growth, emergent maintenance items that require the unit to be at a reduced power level, or an operational decision to reduce power due to external influences such as significant swells that could impact the ability of a unit to remain operational.

Further detail concerning refueling outages and forced outages that occurred during the record period for DCPP Units 1 and 2 are discussed below. Consistent with previous Energy Resource Recovery Account compliance proceedings, PG&E is providing general information regarding scheduled outages that were 24 hours or more in duration, and specific information regarding each forced outage that was longer than 24 hours in duration. PG&E has provided additional, detailed information concerning the outages that occurred during the record period to the Public Advocates Office at the California Public Utilities Commission Master Data Request.

**a. Unit 1**

During 2022, Unit 1 operated safely and reliably, remaining online with one planned refueling outage and one unplanned maintenance outage.

PG&E conducted the planned Unit 1 1R23 Refueling Outage from March 26, 2022 at 21:00 until April 22, 2022 at 03:47. The Unit 1 refueling outage included: 10-year inspection of Special Lifting Device (SLD), Refueling Cavity fuel movement equipment maintenance, Auxiliary Saltwater Pump replacement, Vital Bus major maintenance, major overhaul of three travelling screen systems, power factor testing of Start-Up Transformers, Non-Vital bus maintenance and Safety System integrated testing.

The dates and times Unit 1 was taken offline and returned to service for forced outages are as shown below in Table 4-2.

**TABLE 4-2**
**DIABLO CANYON UNIT 1 2022 OFFLINE TIMES**

| Line No. | Event | Date-Time Offline | Date-Time Online | 2022 Days Offline |
|---|---|---|---|---|
| 1 | 1 | 4/23/22 00:03 | 4/26/22 17:36 | 3.7 |

**b. Outage Due to Steam Generator Blowdown**

On April 23, 2022 at 00:03, the unit was ramping up in power after paralleling to the grid from 1R23 Refueling outage. The unit experienced failure of a non-safety pressure controller that caused actuation of relief valves in the Steam Generator Blowdown system. Subsequent air in leakage from the relief valves caused the condenser vacuum to degrade, requiring unit shut down to perform repairs. Operators ramped the unit down in power and disconnected from the grid to perform repairs. The repairs were performed, and the unit was ramped up in power after being offline for 3.7 days.

**c. Unit 2**

During 2022, Unit 2 operated safely and reliably, remaining online with one planned refueling outage and no unplanned outages.

PG&E conducted the planned Unit 2 2R23 Refueling Outage from October 15, 2022 at 21:00 until November 24, 2022 at 17:28. The Unit 2 outage included: Replacement of the Main Condenser Expansion joints, Feedwater heater inspection and repairs, Turbine Valve inspections, Auxiliary Saltwater Pump motor and pump replacement, Condensate Polisher Computer Replacement project, Overhaul and maintenance of three Travelling Screens, Main Generator crawl through inspection, Circulating Water Pump motor overhaul, Non-Vital bus maintenance and Safety System integrated testing.

**d. Violations From the NRC**

There were no NRC violations in 2022 that resulted in an outage extension or unplanned outage. PG&E was issued 7 green non-cited violations (NCV) in 2022. A green violation is defined as being very low safety significance and is accordingly not cited. The green NCV requires PG&E to enter the violation into the corrective action program and resolve the problem.

A summary of the violation and actions taken are listed in the table below:

## TABLE 4-3
## SUMMARY OF NRC VIOLATIONS

| Line No. | Inspection Report | Violation Description/Summary | Corrective Actions |
|---|---|---|---|
| 1 | 2022-001 | Green NCV. DCPP failed to promptly identify and correct moisture and debris buildup on the ASW pump 1-1 motor internal windings, which resulted in a challenge to the operability of the ASW motor. | Motor was replaced, monitoring program for pump was revised, revision of engineering and work maintenance procedures and preventative maintenance plan revised. |
| 2 | 2022-001 | Green NCV. Failure to adequately scope maintenance verification testing for retune of the diesel generator 2-3 fuel system resulted in a low steady state frequency during a start in isochronous mode | Revision to maintenance procedures and acceptance criteria, training for governor control valve, event communications and organizational learning. |
| 3 | 2022-001 | Green NCV. DCPP Annunciator Response Procedure AR PK 10-16 contained inadequate guidance that could have led to delays in actions taken by control room personnel in response to an identified feedwater tube leak. | Feedwater heater inspections and preventative tube plugging, monitoring program revised, revision of heat exchanger maintenance program, revision of operating procedures. |
| 4 | 2022-002 | Green NCV. DCPP failed to adequately control the tightening of banjo bolts on Diesel Generator 2-3 to prevent a bolt coming loose, resulting in a fuel oil leak. | Equipment was repaired to specifications, maintenance procedure to specific equipment was revised and preventative maintenance action was created. |
| 5 | 2022-002 | Green NCV. Failure to adequately secure items, i.a.w. CP M-16 and AD4.ID4, in the 500 kilovolt switchyard prior to a high wind event. | All items were secured or removed from area, temporary storage procedure process was revised, and housekeeping procedures were revised. |
| 6 | 2022-002 | Green NCV. Failure to secure poly bottles in the RHR pump room i.a.w. the SISI program requirements. | Equipment was secured, operations outage hose hanging guidance was revised, additional seismic training given. |
| 7 | 2022-004 | Green NCV. Failure to implement and maintain all provisions for fire protection program due to not implementing annual air flow testing of incipient fire detection system. | Recurring maintenance plan was created for annual flow test of fire detection system. |
| 8 | 2022-010 | Green NCV. Failure to generate timely notification for fuel line bolt torquing of emergency diesel generator 2-1 and 2-2. | Re-enforce and hold accountable station personnel on station procedures for timely reporting requirements.<br>Further corrective actions are in development. |
| 9 | 2022-010 | Severity Level IV, NCV. Failure to adopt procedure for evaluating deviations and failures to comply to 10 CFR 21. | Revise evaluation and reporting guidance to comply with 10 CFR 21. |
| 10 | 2022-011 | Green NCV. Failure to include the equipment in the 480 volt Vital Switchgear room in the EQ program | Electrical load calculations revised, testing procedure and operating procedure revised. |

## E. Conclusion

In compliance with D.14-01-011, this chapter addresses the operation of PG&E's utility-owned nuclear facility, and outages that occurred at this facility during the 2022 record year. It demonstrates that DCPP was operated in a reasonable manner during the record period.

PG&E has a comprehensive management structure, with numerous internal controls, to prudently oversee the operation of DCPP. The 2022 year-end DCPP total plant capacity factor of 89.8 percent was above the 2022 target of 89.1 percent. The Unit 1 and Unit 2 planned Refueling Outages were planned sufficiently in advance to allow adequate preparation and was safely executed.

In summary, DCPP was operated in a reasonable manner in 2022 as demonstrated by PG&E's on-line operation of Unit 1 and Unit 2 for all 2022 and the absence of forced outages that could have been foreseen and prevented by testing and monitoring practiced by the NG industry.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 5

# REVIEW ENTRIES RECORDED IN THE DISADVANTAGED COMMUNITY – GREEN TARIFF BALANCING ACCOUNT AND THE COMMUNITY SOLAR GREEN TARIFF BALANCING ACCOUNT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
REVIEW ENTRIES RECORDED IN THE DISADVANTAGED COMMUNITY – GREEN TARIFF BALANCING ACCOUNT AND THE COMMUNITY SOLAR GREEN TARIFF BALANCING ACCOUNT

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 5
# REVIEW ENTRIES RECORDED IN THE DISADVANTAGED COMMUNITY – GREEN TARIFF BALANCING ACCOUNT AND THE COMMUNITY SOLAR GREEN TARIFF BALANCING ACCOUNT

## A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents for review its funding and administrative costs recorded to the Disadvantaged Community – Green Tariff (DAC-GT) subaccount and Community Solar – Green Tariff (CS-GT) subaccount of the Public Policy Charge Balancing Account (PPCBA) during 2022, the record period, as directed by the California Public Utilities Commission (CPUC or Commission) in Decision (D.) 18-06-027, the *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*. D.18-06-027 implements Assembly Bill 327, which required the Commission to develop alternatives to increase the adoption and growth of renewable generation in Disadvantaged Communities (DAC).

## B. Disadvantaged Community – Green Tariff Balancing Account

### 1. Overview

The DAC-GT Program is available to residential customers who live in a DAC and meet the income eligibility requirements for the California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs. DAC-GT provides customers a 20 percent discount on electricity bills on top of applicable CARE or FERA discounts. The DAC-GT Program allows eligible customers to choose clean energy options without the need to own their home and without the cost of installing their own distributed renewable generation. PG&E's DAC-GT has a program generating resource cap of 52.32 megawatts (MW).[1] The program is funded through greenhouse gas (GHG) allowance proceeds. If GHG allowance proceeds

---

[1] Per Resolution (Res.) E-4999, PG&E's DAC-GT program cap of 70 MW was modified to 54.82 MW (see p. 13) and further modified to 52.32 MW per PG&E's AL 6075-E-A, and Peninsula Clean Energy's (PCE) AL 15-E. This transition was finalized in joint PG&E/PCE AL 6785-E filed in December 2022.

are exhausted, the programs will then be funded through Public Purpose Program (PPP) funds.[2] PG&E's procurement team holds semi-annual DAC Request for Offers to procure the full program capacity, as is required by CPUC Res.E-4999.[3] The DAC-GT program is fully subscribed with the program funds already providing discounts to participants. PG&E is also providing renewable energy to these customers, in the interim, with eligible resources from its Renewable Portfolio Standard (RPS) or other existing PG&E solar resources until a series of dedicated PG&E DAC-GT solar resources come online.[4]

### 2. Balancing Account Implementation

In accordance with D.18-06-027, PG&E filed Advice Letter (AL) 5351-E establishing two additional subaccounts within the PPCBA: DAC-GT and CS-GT programs balancing accounts, which track the costs and revenues associated with these programs.[5] Subsequently, PG&E's filed AL 5763-E and AL 5763-E-A, modified the DAC-GT Balancing Account and addressed changes requested by Energy Division (ED) of the CPUC to reconcile accounting treatment for the DAC-GT and CS-GT programs among the three Investor-Owned Utilities (IOU).[6]

### 3. Funding of the DAC-GT Program and Transfer to Balancing Account

Pursuant to Ordering Paragraph (OP) 14 of D.18-06-027, the DAC-GT program is funded first through GHG allowance proceeds. If GHG allowance funds are exhausted, the program is funded through the Public Purpose Charge component of the PPP funds. As described in AL 6308-E,

---

**2** Res.E-4999, p. 14, Table 1.

**3** Res.E-4999, OP 8, p. 69.

**4** D.20-07-008 directed PG&E to auto-enroll eligible DAC-GT customers that were at highest risk of disconnection.

**5** Hereafter the two subaccounts are interchangeably referred to as balancing accounts as follows: DAC-GT subaccount of the PPCBA may be referred to as the DAC-GT Balancing Account, the CS-GT subaccount of the PPCBA may be referred to as the CS-GT Balancing Account, or CSGTBA.

**6** Changes include a harmonization of incremental renewable generation and generation-related program costs used to support the DAC-GT and CS-GT tariffs with the approach Southern California Edison Company and San Diego Gas & Electric Company had implemented.

given the California Air Resources Board's (CARB) prohibition on the use of GHG auction revenues from allowance allocations to fund volumetric discounts, these funds are effectively exhausted for purposes of funding any cost except renewable resource costs for the DAC-GT and CS-GT programs. Consequently, PG&E uses PPP funds for the 20 percent electric bill discount, and administration and marketing expenses.

The DAC-GT program receives a portion of the monthly Public Policy Charge Program (PPCBA) revenues based on the revenue requirement (RRQ) from the 2022 ERRA Forecast.[7] The allocation of PPCBA revenues began in March 2022. DAC-GT recorded a total of $3.5M in PPCBA revenues allocated to the program for 2022.

In the 2022 Energy Resource Recovery Account (ERRA) Forecast Proceeding (Application (A.) 21-06-001), PG&E presented a set aside of $4.8 million from GHG allowance proceeds for use in the DAC-GT Program for the 2022 record period. In February 2022, the Commission approved this use of GHG allowance proceeds for the DAC-GT Program. Accordingly, $4.8 million was transferred from the GHG Revenue Balancing Account to the DACGTBA during 2022, as approved by D.22-02-002.

### 4. DAC-GT Program Expenses and Other Activity Recorded to the Balancing Account

An overview of the various program activities – revenue shortfalls, procurement, California Independent System Operator (CAISO) market activity, and program expenses and balancing account interest—recorded in 2022 to the DAC-GT are shown in Table 5-1 below. Each category of activity is further described below.

---

7 Based on the RRQ Electric Rate filing from the ERRA Forecast multiplied by the rate from Electric Preliminary Statement Part I. A description of PPCBA revenue information can be found in PPCBA's Preliminary HM.

**TABLE 5-1**
**DAC GT EXPENSE ACTIVITY**

| Line No. | Tariff Line Item | Description | 2022 Amount |
|---|---|---|---|
| 1 | 5.A.c. | Renewable Resource Costs | 2,153,987 |
| 2 | 5.A.h. | Revenue Shortfall Based on 20 percent Discount | 5,589,389 |
| 3 | 5.A.k. | Administrative Costs | |
| | | DAC-GT Information Technology (IT) (IT/Billing System) | 325,854 |
| | | Program Management | 150,052 |
| | | Contact Center Operations | 3,724 |
| | | Energy Procurement | 85,860 |
| | | Subtotal of Administrative Costs (b) | 565,490 |
| 4 | 5.A.l. | Marketing | 26,152 |
| 5 | | Total DAC GT Expense Activity(a) | 8,335,018 |

a) Includes all administrative, marketing, and other program expenses excluding balancing account interest.
b) Tariff line 5.A.k. excludes a prior period adjustment of $77,920 from 2021.

### a. Revenue Shortfalls Based on 20 percent Discount

As mentioned in Section B.1 above, the DAC-GT Program provides a 20 percent discount to CARE or FERA-eligible residential customers located in DACs which is applied to their total electric bill. The 20 percent discount provided to the customer in support of the program will be shown on the customers' bills and the revenue shortfall associated with the discount is recorded as an expense to the DAC-GT subsidiary account in the PPCBA. During 2022 the DAC-GT Balancing Account recorded $5.6 million in revenue shortfalls.

### b. Energy Procurement and CAISO Market Activity

As mentioned in Section B.2 above, PG&E filed AL 5763-E and AL 5763-E-A to address changes requested by ED to reconcile accounting treatment for the DAC-GT and CS-GT programs among the three IOUs. Included in this update was identification of three interim pool resources selected to support the DAC-GT program because they met all relevant requirements[8] and the clarification of accounting procedure 5.A.c., which separately records the interim pool renewable

8 The resources are RPS eligible, located in a disadvantaged community, are less than 20 MW, and are Green-e certified.

resource costs net of CAISO energy revenues and ancillary service revenues (if any) used to support the DAC-GT Program subscription level, as transferred from Portfolio Allocation Balancing Account (PABA). PG&E implemented this AL in April 2021, including all necessary interim resource costs transferred from PABA back to the beginning of the program in March 2020. During 2022, PG&E recorded $2.2 million in renewable resource costs net of market revenues to the DAC-GT balancing account. PG&E notes market revenues in 2022 were substantially higher than in 2021 resulting in a substantially lower renewable resource cost.

#### c. Other Program Expenses and Balancing Account Interest

PG&E incurred $592,000 in expenses to the DACGTBA during 2022.[9] Activities associated with these expenses included:

- Administrative expenses associated with implementation and operation which may include costs associated, but not limited to include:
  - IT-related system modifications;
  - Customer Communications Center training and job aids;
  - Program Management;
  - Enrollment process; and
- Marketing expenses for the program.

In addition, PG&E recorded approximately $17,500 in balancing account interest during the record period, which represents the 3-month commercial paper rate for the prior month as found on Statistical Release H-15.

#### d. Other Program Activity

Per Res.E-5124, OP 3, PG&E disburses program funding to community choice aggregators (CCA) quarterly in amounts approved by the most recent ERRA Forecast decision. These funds are recorded in CCA DAC-GT balancing accounts and therefore are not included within PG&E's ERRA Compliance Filing.

---

9 The $592,000 in administrative and marketing expenses excludes a prior period adjustment from 2021 for $77,920.

### C. Community Solar – Green Tariff Balancing Account

#### 1. Overview

The CS-GT Program is structured similarly to the DAC-GT Program, but is intended to drive more local engagement with community-developed solar projects. To achieve this goal, there are customer eligibility and program rules intended to create a closer relationship between the customer and the solar project which do not exist within DAC-GT. Specifically, the solar generation project supporting the program must be located within five miles of the participating customers' community (or within 40 miles if the participant lives in a San Joaquin Valley pilot community), and the program requires demonstration of community involvement and interest, facilitated through a local "sponsor." Participation in the CS-GT Program is limited to CARE or FERA eligible customers (also referred to as income-qualified) for the first 50 percent of the project capacity.[10] Once 50 percent of the project is subscribed to by income-qualified customers, CS-GT projects may allow non-CARE or FERA eligible customers and/or the "sponsor" to participate in the program discount. The CS-GT program offers the same 20 percent discount to participating customers as the DAC-GT Program and has a program cap of 14.2 MW for PG&E.[11]

Due to CS-GT project development delays no customers were enrolled in the CS-GT Program in 2022, and customers are not expected to be enrolled until the first CS-GT projects come online in 2023.

#### 2. Funding of the CS-GT Program and Transfer to Balancing Account

Pursuant to OP 14 of D.18-06-027, the CS-GT program is funded first through GHG allowance proceeds. If GHG allowance funds are exhausted, the program is funded through the Public Purpose Charge component of the PPP funds. As described in AL 6308-E, given the CARB's prohibition on the use of GHG auction revenues from allowance allocations to fund volumetric discounts, these funds are effectively exhausted for purposes of funding any cost except renewable resource costs for the DAC-GT and CS-GT

---

10 D.18-06-027, p. 57-59 and refers to Alternate Proposed Decision OP 15.

11 Res.E-4999, p. 14, Table 1. Per Res.E-4999, PG&E's CS-GT Program cap of 18 MW was modified to 14.20 MW.

programs. Consequently, PG&E uses PPP funds for the 20 percent electric bill discount, and administration and marketing expenses.

The CS-GT program receives a portion of the monthly PPCBA revenues based on the RRQ from the 2022 ERRA Forecast.[7] The allocation of PPCBA revenues began in March 2022. The CS-GT records a total of $1 million in PPCBA revenues allocated the program.

In the 2022 ERRA Forecast Proceeding (A.21-06-001), PG&E presented that $2.24 million in unspent CS-GT GHG funds were rolled over from 2020 while the 2022 forecasted spend on renewable resources (the only GHG-eligible cost) was only $0.12 million, yielding a net excess GHG carryover of $2.12 million. Accordingly, PG&E transferred $2.12 million back to the GHG Revenue Balancing Account from the CSGTBA during 2022.

### 3. Expenses of the CS-GT Program Recorded to the Balancing Account

An overview of the expenses recorded in 2022 to the CS-GT are shown in Table 5-2 below.

**TABLE 5-2**
**CS-GT EXPENSE ACTIVITY**

| Line No. | Tariff Line Item | Description | 2022 Amount |
|---|---|---|---|
| 1 | 5.B.i. | Administrative Costs | |
| | | CS GT IT (IT/Billing System) | 55,161 |
| | | Program Management | 28,423 |
| | | Energy Procurement | 14,014 |
| | | Subtotal of Administrative Costs | 97,598 a |
| 2 | 5.B.j. | Marketing | 4,643 |
| | | Total DAC GT Expense Activity(a) | 102,241 |

a) Includes all administrative, marketing, and other program expenses excluding balancing account interest.

PG&E incurred $102,241 in administrative expenses to the CSGTBA during 2022. Activities associated with these expenses included:

- Administrative expenses associated with implementation and operation which may include costs associated but not limited to include:
  - IT-related system modifications;
  - Customer Communications Center training and job aids;
  - Program Management;
  - Enrollment process; and
- Marketing expenses for the program.

In addition, PG&E recorded approximately $87,000 in balancing account interest income during the record period, which represents the 3-month commercial paper rate for the prior month as found on Statistical Release H-15.

Separately, PG&E did not incur any renewable resource costs in 2022 for the CS-GT program. There were no CS-GT resources online during this time, and the program does not leverage interim resources like DAC-GT. Therefore, these are not included in Table 5-2 above.

#### 4. Other Program Activity

Per Res.E-5124, OP 3, PG&E disburses program funding to CCAs quarterly in amounts approved by the most recent ERRA Forecast decision. These funds are recorded in CCA CS-GT balancing accounts and therefore are not included within PG&E's ERRA Compliance Filing.

### D. Conclusion

In this chapter, PG&E described its funding and recorded expenses for the DAC-GT and CS-GT programs. PG&E requests the Commission find the amounts recorded to the DACGTBA and CSGTBA accounts during the 2022 record period were in compliance with the Commission's directives.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 6

# GENERATION FUEL COSTS AND

# ELECTRIC PORTFOLIO HEDGING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
GENERATION FUEL COSTS AND
ELECTRIC PORTFOLIO HEDGING

TABLE OF CONTENTS

TABLE OF CONTENTS
(CONTINUED)

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 6
# GENERATION FUEL COSTS AND ELECTRIC PORTFOLIO HEDGING

## A. Introduction

This chapter reviews actions taken by Pacific Gas and Electric Company (PG&E) regarding generation fuel procurement for:

- PG&E-owned conventional generation;
- PG&E tolling agreements;
- Hydroelectric; and
- Diablo Canyon Power Plant (DCPP).

PG&E engaged in fuel procurement activities in a manner consistent with: its California Public Utilities Commission (CPUC or Commission)-approved procurement plans; Nuclear Fuel Procurement Plan; and Commission decisions addressing procurement.

In addition, consistent with Decision (D.) 12-05-010, Ordering Paragraph (OP) 3, PG&E is also providing in this chapter a report concerning its activities and operating costs associated with the STARS Alliance, LLC (STARS Alliance).

Finally, this chapter reviews PG&E's implementation of its Commission-approved Electric Portfolio Hedging Plan (Hedging Plan) during the record period from January 1 to December 31, 2022. Consistent with D.11-07-039, OP 3, PG&E is also providing in this chapter a high-level discussion of its internal procedures and controls for ensuring compliance with its Hedging Plan.

## B. Gas Procurement

### 1. Portfolio Overview

PG&E manages natural gas procurement for its portfolio of gas-fired generators, including power plants owned by PG&E and generators contracted to PG&E under tolling agreements. PG&E describes its gas procurement activities in the section below.

### 2. Natural Gas Procurement

#### a. PG&E Generation

PG&E owned three generating facilities in commercial operation during the record period that primarily use natural gas as a fuel source: Humboldt Bay Generating Station (Humboldt), Gateway Generating Station (Gateway), and Colusa Generating Station (Colusa). Humboldt primarily burns natural gas[1] and is capable of burning distillate fuel oil during gas curtailments or emergencies. These facilities are listed in Table 6-1 below.

**TABLE 6-1**
**PG&E-OWNED GENERATION FACILITIES**

| Line No. | Name | Location | Capacity (megawatts (MW)) | Technology | Heat Rate (Millions of British Thermal Units (MMBtu)/ megawatt-hours (MWh)) |
|---|---|---|---|---|---|
| 1 | Gateway | Antioch, CA | 530 | Combined Cycle Gas Turbine | 7.2 |
| 2 | Colusa | Maxwell, CA | 530 | Combined Cycle Gas Turbine | 7.2 |
| 3 | Humboldt | Eureka, CA | 163 | Reciprocating Engines | 8.7 |

#### b. PG&E Tolling Agreements

In addition to the gas-fired generating facilities it owns, PG&E's electric portfolio includes numerous tolling agreements for gas-fired generators. A tolling agreement is an agreement for generating capacity and electric energy where the buyer delivers fuel to the seller and the seller delivers electric energy to the buyer.[2] In this case, PG&E (as buyer) delivers natural gas to the owner of the generating facility (the seller) and in exchange receives energy and other services. PG&E dispatches these tolled facilities according to least-cost dispatch principles. These agreements are listed in Table 6-2.

---

1 When burning natural gas, the units at Humboldt require a small amount of distillate fuel for ignition.

2 Tolling agreements are structured arrangements that can include a variety of services including capacity, energy, and ancillary services.

**TABLE 6-2**
**PG&E'S TOLLING AGREEMENTS IN 2022**

| Line No. | Name | Location | Counterparty | Capacity (MW) | Technology | Heat Rate (MMBtu/MWh) |
|---|---|---|---|---|---|---|
| 1 | Badger Creek Limited | Bakersfield | Badger Creek Limited | 42 | Simple Cycle Combustion Turbine (CT) | 9.4 – 10.5 |
| 2 | Bear Mountain Limited | Bakersfield | Bear Mountain Limited | 42 | Simple Cycle CT | 9.4 – 10.5 |
| 3 | Chalk Cliff Limited | Taft | Chalk Cliff Limited | 42 | Simple Cycle CT | 9.4 – 10.5 |
| 4 | GWF Energy Hanford | Hanford | MRP San Joaquin Energy LLC | 96 | Simple Cycle CT | 10.1 – 12.9 |
| 5 | GWF Energy Henrietta | Henrietta | MRP San Joaquin Energy LLC | 96 | Simple Cycle CT | 10.1 – 12.9 |
| 6 | GWF Tracy | Tracy | MRP San Joaquin Energy LLC | 323 | Combined Cycle | 7.8 – 8.5 |
| 7 | Live Oak Limited | Bakersfield | Live Oak Limited | 42 | Simple Cycle CT | 9.4 – 10.5 |
| 8 | Los Esteros Critical Energy Facility | San Jose | Los Esteros Critical Energy Facility, LLC | 294 | Combined Cycle | 8.0 – 9.4 |
| 9 | Mariposa | Byron | Mariposa Energy | 194 | Simple Cycle CT | 9.9 – 11.7 |
| 10 | Marsh Landing Generating Station | Antioch | Marsh Landing, LLC | 801 | Simple Cycle CT | 10.2 – 12.8 |
| 11 | McKittrick Limited | McKittrick | McKittrick Limited | 42 | Simple Cycle CT | 9.4 – 10.5 |
| 12 | Panoche Energy Center | Firebaugh | Panoche Energy Center, LLC | 399 | Simple Cycle CT | 9.3 – 13.8 |
| 13 | Russell City Energy Center | Hayward | Russell City Energy Company, LLC | 601 | Combined Cycle | 7.2 – 8.0 |
| 14 | Midway Peaking | Firebaugh | Midway Peaking, LLC | 118 | Simple Cycle CT | 10.7 – 12.0 |

#### c. PG&E's Gas Supply Transactions Are Fully Compliant With Commission Guidance

PG&E's Bundled Procurement Plan (BPP) establishes upfront achievable standards and criteria for PG&E's procurement activities and the recovery of procurement costs.[1]

With respect to natural gas procurement activities, these standards and criteria include approved products, approved procurement methods, approved procurement limits, and specify when consultation with the Procurement Review Group (PRG) is required.

In 2022, PG&E's gas procurement activities met these standards and criteria. A high-level review of compliance is provided in this section and a detailed demonstration is provided in each of PG&E's 2022 Quarterly Compliance Reports (QCR), which are included in PG&E's workpapers to PG&E's Prepared Testimony. The confidential attachments to the QCRs detail all of PG&E's transactions for physical gas supply, including product type and method of transaction.

##### 1) PG&E Transacted Using Approved Products for Purchase or Sale

All of PG&E's electric portfolio transactions for natural gas in 2022 were for products approved in PG&E's 2014 BPP.[2] These products are found in Table A-3, Sheet 43 of PG&E's 2014 BPP. PG&E utilized the following products in 2022:

- Natural Gas Physical Supply (Spot and Term);
- Gas Storage, including parking and lending; and
- Gas Transportation.

Table 6A-1 in Attachment A details total costs allocated to and volumes burned at each generator in PG&E's portfolio. Attachments to PG&E's 2022 QCRs detail each transaction, including product type.[3]

---

1 2014 BPP, Sheet 1.

2 PG&E's 2014 BPP, which was approved in D.15-10-031, is included as part of PG&E's confidential workpapers.

3 The 2022 QCRs are included as part of PG&E's confidential workpapers.

### 2) PG&E Transacted Using Approved Procurement Processes

All of PG&E's electric portfolio transactions for natural gas in 2022 used procurement processes and methods approved in PG&E's 2014 BPP. These procurement processes are found in Table B-1, Sheet 56 of PG&E's 2014 BPP. All of the transaction processes PG&E used in 2022 are listed below:

- Bilateral Transactions, short-term (three months or less);
- Transparent Exchanges, including brokers; and
- Electronic Solicitations.

For day-ahead transactions—for gas deliveries the next business day, or next few business days (in the event of a weekend or holiday)—electronic solicitations, bilateral and transparent exchange transactions were the most common procurement process used by PG&E. For longer-term transactions, most were conducted via transparent exchanges (including brokers) and electronic solicitations. The 2014 BPP defines an electronic solicitation as any competitive process where products are requested from the market[4] including e-mail, instant message, auction platforms, telephone survey and may also be informed by market prices on transparent exchanges and from brokers. Attachments to PG&E's 2022 QCRs detail each physical gas transaction, including its procurement method.

### 3) PG&E Transacted Within BPP Procurement Limits

PG&E's compliance with the 2014 BPP Pipeline Capacity Procurement Limits[5] is demonstrated in Table 6A-2 and compliance with the Natural Gas Storage Procurement Limits[6] is demonstrated in Table 6A-3.

### 4) PG&E Consulted With Its PRG as Required

PG&E is required to consult its PRG for transactions with delivery periods greater than three months. For certain

---

[4] 2014 BPP, Sheet 51.

[5] 2014 BPP, Appendix C, Section B.2., Sheets 75-76.

[6] 2014 BPP, Appendix C, Section B.3., Sheets 76-77.

transactions, PG&E may preview the plan or strategy prior to execution, and then share the transactions executed at the next quarterly PRG meeting.[7] PG&E made all required consultations with its PRG as follows:

1) December 14, 2021, for the first quarter of 2022 (January 1-March 31, 2021);
2) March 15, 2022, for the second quarter of 2022 (April 1-June 30, 2021);
3) June 21, 2022 for the third quarter of 2022 (July 1-September 30, 2021); and
4) September 20, 2022, for the fourth quarter of 2022 (October 1-December 31, 2021).

In these quarterly consultations, PG&E also shared with the PRG, as required by D.15-10-031, any transactions executed according to the previously shared strategy or plan. A copy of each PRG presentation is included in the confidential attachments to the QCR, which are included as workpapers for PG&E's Prepared Testimony.

### C. Distillate Expenses

In addition to natural gas, PG&E also purchases distillate as a pilot and backup fuel at Humboldt. Humboldt consists of 10 reciprocating engines, 16.3 MW each, that burn a mix of natural gas as primary fuel and distillate as pilot fuel. During times of limited natural gas delivery to the Humboldt area, the units are able to burn 100 percent distillate. During the record period, PG&E consumed distillate fuel for Humboldt at a total cost of $346,600. The calculation is performed on industry acceptable practice of Last-In First-Out (LIFO) basis. The LIFO method was first approved by the Commission in Advice Letter (AL) 1153-E associated with the Energy Cost Adjustment Clause (precursor to Energy Resource Recovery Account (ERRA)) balancing account.

### D. Water Purchased for Power

PG&E makes payments to various entities to obtain water for use in PG&E's hydro generation powerhouses, supplementing what is available from normal

---

[7] D.15-10-031, OP 1h.

inflows. These include water purchases and headwater payments. In addition, PG&E pays water rights fees to the State Water Resources Control Board. PG&E made water-for-power payments totaling $1,731,345 during the record period. Generation benefits are not necessarily coincident within the time period when the payments are made. For example, payment for a water diversion or purchase may occur months after the water was obtained or used.

## E. Nuclear Fuel Expenses

The framework for PG&E’s 2022 nuclear fuel procurement activity is articulated in the Nuclear Fuel Procurement Plan included in PG&E’s 2014 BPP, Appendix F as amended in AL 5202-E. Nuclear fuel expenses are based on the amortization of the costs of the in-core fuel, the actual cycle burn-up rate for the re-load, and DCPP’s monthly generation. Each fuel re-load includes: the costs of uranium; conversion services; enrichment services; fabrication; and state and local use taxes, with the total costs dependent on the specific core design. Table 6-3 reflects component coverage targets in PG&E’s 2014 BPP.

**TABLE 6-3**
**SUMMARY OF PG&E'S 2014 BPP NUCLEAR FUEL COMPONENT COVERAGE TARGETS**

[redacted]

Table 6-4[8] reflects PG&E's strategic inventory coverage targets.

**TABLE 6-4**
**SUMMARY OF PG&E'S NUCLEAR FUEL STRATEGIC INVENTORY COVERAGE TARGETS**

[redacted]

For the period of January 1 through December 31, 2022, DCPP's recorded nuclear fuel expenses were [redacted].

During the period January 1 through December 31, 2022, DCPP's Unit 1 completed its 23rd cycle of operation, underwent a 26-day refueling outage and started its 24th cycle of operation upon completion of the planned refueling outage. The average annual capacity factor for Unit 1 during 2022 was 90.6 percent. The total Unit 1 nuclear fuel expense for 2022 was [redacted].

During the period January 1 through December 31, 2022, DCPP's Unit 2 completed its 23rd cycle of operation, underwent a 39-day refueling outage and

---

8 Strategic Inventory percentage is [redacted].

started its 24th cycle of operation upon completion of the planned refueling outage. The average annual capacity factor for Unit 2 during 2022 was 89.1 percent. The total Unit 2 nuclear fuel expense for 2022 was [redacted].

Miscellaneous fuel expenses for the record period include costs associated with Nuclear Fuel purchasing activities. Nuclear Fuel purchasing activities are provided in Table 6A-4. Nuclear Fuel Contracts executed during the record period are included in Table 6A-5. The transactions were consistent with the Commission-approved Nuclear Fuel Procurement Plan.

Pursuant to D.05-09-006, PG&E agreed to provide certain information on Fuelco activities and operating costs to the Commission in the annual ERRA compliance review proceeding. Fuelco was dissolved in December of 2021. Therefore, there is no activity to report in this ERRA compliance proceeding. Administrative and overhead costs for Nuclear Fuel purchasing activities were [redacted].

### F. Nuclear Fuel Carrying Costs

Nuclear fuel inventory carrying costs are recovered through the Portfolio Allocation Balance Account at the short-term interest rate. The nuclear fuel inventory carrying costs for 2022 are [redacted].

### G. STARS Alliance

OP 3 of D.12-05-010 directed PG&E to provide a report concerning its activities and operating costs associated with PG&E's participation in the STARS Alliance. The objective of the STARS Alliance is to increase efficiency and to reduce costs related to the operation of the members' nuclear power generation facilities. The other anticipated benefits include more efficiently coordinating the purchase and location of assets necessary to ensure purchasing power and effective responses to potential disruption in operations, and collectively to achieve the safest and most efficient generation of electricity from nuclear units.

PG&E provides as Attachment B-1 the Annual Report of Utility on the Activities of the STARS Alliance for the recorded and budget year 2022 in the format required by the Commission in D.12-05-010, Appendix A. Attachment B-2 also specifies the Utility Savings/Avoided Costs by STARS Team/Project as required by D.12-05-010. The cost of the STARS Alliance allocated to PG&E was $541,250, with the preliminary savings/avoided costs of $15,430,789 for all four STARS Alliance members. Based on the results for 2022, if not for PG&E's participation in the STARS Alliance, the costs to operate DCPP would have been higher. Treatment of cost recovery and avoided cost aspects of PG&E's participation in the STARS Alliance is subject to review in PG&E's General Rate Case proceeding.

## H. Electric Portfolio Hedging

### 1. Background

PG&E's 2014 BPP Hedging Plan was approved on October 22, 2015. Updates to PG&E's Hedging Plan were approved May 20, 2021. During 2022, PG&E continued implementing the plan for hedges executed for the 2022-2023 delivery period. PG&E demonstrates compliance with its Hedging Plan in this section.

### 2. All Transactions Complied With Approved Products and Approved Transaction Processes

During 2022, all PG&E financial transactions used only approved products (2014 BPP, Appendix A, Table A-1 for electric products and Table A-4 for gas products), and approved procurement processes (2014 BPP, Appendix B, Table B-1). Each transaction and its approved product type and transaction process is included in PG&E's QCR filings, and also summarized in Tables 6A-7 through 6A-10.

### 3. PG&E Consulted With the PRG as Required

PG&E consulted its PRG prior to executing hedging transactions beyond three months in duration. PG&E reviewed with the PRG its planned and expected execution of hedges on:

1) December 14, 2021, for hedging activities in the first quarter of 2022 (January 1-March 31, 2022);
2) March 15, 2022, for hedging activities in the second quarter of 2022 (April 1-June 30, 2022);
3) June 21, 2022, for hedging activities in the third quarter of 2022 (July 1-September 30, 2022); and
4) September 20, 2022, for hedging activities in the fourth quarter of 2022 (October 1-December 31, 2022).

In each of these quarterly consultations, PG&E also shared with the PRG, as required by D.15-10-031, any transactions executed according to the previously shared strategy or plan. A copy of each PRG presentation is included in the confidential attachments to the QCR, which are included as workpapers for PG&E's Prepared Testimony.

### 4. Transaction Compliance Reports

Transaction Compliance Reports, which are included in Attachment L of each QCR, demonstrate that each financial transaction complies with each of the applicable provisions of the Hedging Plan, and also with the 2014 BPP procurement limits. The Hedging Plan includes seven provisions that can apply to each transaction, depending on the type of product transacted. The compliance reports demonstrate how the transaction complied with each of these provisions.

### 5. PG&E Managed Its Hedging Position in Compliance With Its Hedging Plan

As detailed in Section D.2 of the Hedging Plan,[9] PG&E's compliance with the Plan, as measured against the Hedging Targets, is judged at the end of [redacted].[10] [redacted][11] [redacted]

[redacted][12]

Table 6A-11 shows PG&E's electric portfolio financial position [redacted], and demonstrates that PG&E's hedging positions, as measured against the Hedging Targets, complied with the Hedging Plan and

[9] PG&E's Hedging Plan is Appendix E of the 2014 BPP.

[10] [redacted]

[11] PG&E's 2014 BPP Hedging Plan, Section C.2. (previous Hedging Plan), Section D.2 (updated Hedging Plan), Hedging Targets.

[12] *Id.*

AL 6204-E. The footnote with Table 6A-11 describes the actions PG&E took, by delivery period, to comply with its Hedge Plan. [redacted]

[redacted] [redacted][13] [redacted]

### 6. PG&E Transacted Within BPP Procurement Limits

PG&E's 2014 BPP includes limits on electric energy and natural gas procurement.[14] These limits apply to all fixed-price energy and gas contracts beyond prompt month. Figures 6A-1 and 6A-2 demonstrate PG&E compliance with these limits at the end of 2022. The compliance reports included in each QCR demonstrate compliance for every transaction.

## I. Internal Procedures and Controls

Consistent with D.11-07-039, OP 3, PG&E provides the following high-level discussion of its internal procedures and controls for ensuring compliance with its Hedging Plan. PG&E employs the following system of internal procedures and controls to ensure compliance:

1) Segregation of Duties;
2) Risk Management Policies;
3) Prescriptive Hedging Strategies; and
4) Controls Framework.

### 1. Segregation of Duties

PG&E separates the duties of executing, monitoring and tracking, and settling hedging transactions among its Front Office, Middle Office and Back Office. The Middle Office reports to the Chief Risk Officer, while the

---

13 In 2022, [redacted].

14 2014 BPP, Appendix C, Sections A.2. and B.1., Sheets 68-75.

Front Office and Back Office report to the Vice President, Energy Policy and Procurement.

The Front Office is responsible for negotiating and executing transactions that comply with the Hedging Plan and internal controls; and ensuring the terms of the transaction are captured in PG&E's trade capture system.

The Middle Office reviews each transaction for completeness and accuracy and also establishes and manages several of the trading controls in the Controls Framework. The Middle Office also reports the status of hedging programs and portfolio risk measures to PG&E senior management.

The Back Office confirms non-cleared transactions with counterparties and settles transactions after delivery or expiration. The Back Office is also responsible for managing existing contracts.

**2. Risk Management Policies**

PG&E maintains Risk Management Policies and Standards that provide guidelines to the PG&E Front, Middle and Back Offices on management and control of risks associated with fluctuations in electricity and gas prices and counterparty credit exposure. PG&E's Corporation Risk Policy Committee and Utility Risk Management Committee are delegated, from the Board of Directors, the responsibility for ensuring that PG&E management adheres to the Risk Policies and Standards. PG&E's Middle Office monitors compliance with these policies and standards and regularly measures and reports market and portfolio risk to the committees.

**3. Prescriptive Hedging Plan**

PG&E's Hedging Plan is prescriptive, that is, it specifies which positions are to be hedged, which products are to be used, and the timeline for execution. The Hedging Plan is periodically updated and changes are implemented after final CPUC approval is received, and after internal processes are modified to ensure that the updated Hedging Plan can be monitored for consistency with the CPUC-approved plan and internal governance requirements.

### 4. Controls Framework

The Controls Framework is centered on assuring data quality and completeness, guiding trading activities with an electronic model, and monitoring trader activity relative to authorized plans and counterparty credit limits. Controls are separated into six categories:

1) Electronic Model – PG&E uses an electronic model to guide its financial traders in implementing the Hedging Plan. The model includes the long- and short positions in PG&E's portfolio and applies each of the provisions of the Hedging Plan to these positions to determine for the current trading month which products should be traded and the quantity of each product. The model is refreshed overnight after each trading day to ensure the portfolio positions are current. The model is developed by the Middle Office in consultation with the Front Office and is validated for accuracy by a separate, independent team of qualified analysts also in the Middle Office.
2) Trade Limits – PG&E sets limits on its Front Office trading activities to help ensure that its traders comply with its approved Hedging Plan. PG&E breaks down the annual Hedging Plan trading limits approved by its risk committees into monthly limits for monitoring trading activities.
3) Trade Preview – Prior to execution, PG&E traders preview all trades in an electronic blotter system that tests each trade against their monthly trade limits and counterparty credit limits. PG&E traders are not allowed to execute trades that are not pre-approved by this system.
4) Trade Capture – PG&E traders are required to enter all completed transactions into a trade capture system on the day the transaction is executed. PG&E's Middle Office reviews all trades to ensure that they are captured accurately in the trade capture system.
5) Transaction Monitoring – PG&E's risk management system provides reports that monitor compliance with the risk management policies and trading limits. In addition, the system tracks counterparty-credit exposure.
6) Compliance Reports – PG&E developed an automated compliance report that demonstrates compliance of its electric and gas financial hedge trades. The report demonstrates that all the trades executed on

a specified trading day comply with each provision of PG&E's Hedging Plan.

## J. Conclusion

The preceding discussion demonstrates that PG&E procured fuel for its utility-owned generation facilities and tolling agreements, acquired water for hydroelectric generation, and procured nuclear fuel for DCPP consistent with the 2014 BPP and Commission decisions addressing procurement. In addition, the preceding discussion demonstrates that PG&E's electric portfolio hedging activities complied with its Hedging Plan and the 2014 BPP.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 6

# ATTACHMENT A

# GENERATION FUEL COSTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 6
# ATTACHMENT A
# GENERATION FUEL COSTS

**TABLE 6A-1**
**SUMMARY OF 2022 PG&E GAS DELIVERIES BY FACILITY OR TOLLING AGREEMENT**

| Line No. | Generating Facility | Volume[a] (Million MMBtu) | Total Cost[a],[b] ($ Millions) |
|---|---|---|---|
| 1 | PG&E – Gateway | [redacted] | |
| 2 | PG&E – Humboldt | | |
| 3 | PG&E Colusa - Maxwell | | |
| 4 | Calpine Los Esteros | | |
| 5 | GWF Tracy | | |
| 6 | Panoche Energy Center | | |
| 7 | Starwood Power-Midway | | |
| 8 | Mariposa Energy | | |
| 9 | GenOn Marsh Landing | | |
| 10 | Calpine Russell City | | |
| 11 | GWF Energy Hanford | | |
| 12 | GWF Energy Henrietta | | |
| 13 | Badger Creek | | |
| 14 | Bear Mountain | | |
| 15 | Chalk Cliff | | |
| 16 | Live-Oak | | |
| 17 | McKittrick | | |
| 18 | Total | | |
| 19 | Total Unit Cost ($/MMBtu)[b] | | |

(a) Some values for volume and cost appear as zero due to rounding.
(b) Total costs include gas commodity, storage and transport related costs included in PABA and NSGBA.

**TABLE 6A-2**
**2022 DEMONSTRATION OF COMPLIANCE WITH 2014 BPP PIPELINE CAPACITY PROCUREMENT LIMITS[(a)]**

| Line No. | Year | Actual Capacity[(c)] (MMBtu/day) | Limits[(b)] (MMBtu/day) |
|---|---|---|---|
| 1 | 2022 | [redacted] | |
| 2 | 2023 | | |
| 3 | 2024 | | |
| 4 | 2025 | | |

(a) PG&E's actual pipeline capacity holdings were all less than the 2014 BPP limits therefore PG&E was compliant with the Pipeline Capacity Procurement Limits in 2022.

(b) 2014 BPP, Appendix C, Table C-10, Sheet 76.

(c) PG&E elected to stepdown Ruby capacity in 2022 per CPUC Decision (D.21-12-035) Procedures for Exercising Step-Down Capacity Rights.

**TABLE 6A-3**
**2022 DEMONSTRATION OF COMPLIANCE WITH 2014 BPP STORAGE CAPACITY PROCUREMENT LIMITS[(a)]**

| Line No. | Year | Actual Withdrawal Capacity[(c)] (MMBtu/day) | Withdrawal Capacity Limit[(b)] (MMBtu/day) | Actual Injection Capacity[(c)] (MMBtu/day) | Injection Capacity Limit[(b)] (MMBtu/day) | Actual Inventory[(c)] (million MMBtu) | Inventory Limit[(b)] (million MMBtu) |
|---|---|---|---|---|---|---|---|
| 1 | 2022 | [redacted] | | | | | |
| 2 | 2023 | | | | | | |
| 3 | 2024 | | | | | | |
| 4 | 2025 | | | | | | |

(a) PG&E's actual Withdrawal, Injection, and Inventory capacity holdings were all less than the 2014 BPP limits therefore PG&E was compliant with the Storage Capacity Procurement Limits in 2022.

(b) 2014 BPP, Appendix C, Table C-12, Sheet 77.

[redacted]

**TABLE 6A-4**
**NUCLEAR FUEL AND**
**FUEL-RELATED PRODUCTS OR SERVICES**
**(TOTAL COST – MILLIONS OF DOLLARS)**

| Line No. | Contract | Delivery Date | Product | Unit Price ($) | Total Cost | Contract Duration | Market Unit Price ($) At Contract[(a)] | Current Market Unit Price ($)[(b)] |
|---|---|---|---|---|---|---|---|---|
| 1 | [redacted] | | | | | | | |
| 2 | | | | | | | | |
| 3 | | | | | | | | |
| 4 | | | | | | | | |
| 5 | | | | | | | | |
| 6 | | | | | | | | |
| 7 | | | | | | | | |
| 8 | | | | | | | | |
| 9 | | | | | | | | |
| 10 | | | | | | | | |
| 11 | | | | | | | | |
| 12 | | | | | | | | |
| 13 | | | | | | | | |

(a) The historic month-end spot prices for the contract execution date as reported in the 2022 year-end publications for Trade Tech LLC, Nuclear Review, Ux Consulting, Quarterly Market Report – Conversion Market Outlook, Ux Consulting, Quarterly Market Report – Uranium Market Outlook, or Ux Consulting, Quarterly Market Report – Enrichment Market Outlook. Not applicable to fabrication, brokerage, location swap, delivery fees or regulatory fees.

(b) A simple arithmetic average of the spot prices reported in the year-end publications of Trade Tech LLC, Nuclear Market Review dated December 31, 2022, and Ux Consulting, Ux Weekly dated December 26, 2022. Not applicable to fabrication, brokerage, location swap, delivery fees or regulatory fees.

**TABLE 6A-5**
**NUCLEAR FUEL CONTRACTS EXECUTED IN 2022**
**(WITH DELIVERIES BEYOND 2022)**
**(MILLIONS OF DOLLARS)**

| Line No. | Contract No. | Execution Date | Term of Services | Services | Amount |
|---|---|---|---|---|---|
| 1 | [redacted] | | | | |

**TABLE 6A-6**
**SUMMARY OF PG&E ELECTRIC PORTFOLIO**
**GAS FINANCIALTRANSACTIONS**
**LISTED BY 2014 BPP APPROVED PRODUCT**

| Line No. | Product | 2014 BPP Table A-4 Line Number | Volume (MMBtu) | Notional Value ($ Millions) | Number of Trades |
|---|---|---|---|---|---|
| 1 | Natural Gas Futures | 2 | [redacted] | | |
| 2 | Natural Gas Futures (Basis) | 2 | | | |
| 3 | Natural Gas Futures (Swing & Index) | 2 | | | |
| 4 | Financial Options (Calls) and Swaptions | 3 | | | |
| 5 | Total Transacted | | | | |

**TABLE 6A-7**
**SUMMARY OF PG&E ELECTRIC PORTFOLIO**
**GAS FINANCIAL TRANSACTIONS**
**LISTED BY 2014 BPP APPROVED TRANSACTION PROCESS**

| Line No. | Product | 2014 BPP Table B-1 Item Number | Volume (MMBtu) | Notional Value ($ Millions) | Number of Trades |
|---|---|---|---|---|---|
| 1 | Transparent Exchanges (Electronic Trading) | 6 | [redacted] | | |
| 2 | Transparent Exchanges (Voice Brokers) | 6 | | | |
| 3 | Electronic Solicitations (IM or Voice) | 10 | | | |
| 4 | Total Transacted | | | | |

**TABLE 6A-8**
**SUMMARY OF PG&E ELECTRIC PORTFOLIO**
**ELECTRICITY FINANCIAL TRANSACTIONS**
**LISTED BY 2014 BPP APPROVED PRODUCT**

| Line No. | Product | 2014 BPP Table A-1 Line Number | Volume (GWh) | Notional Value ($ Millions) | Number of Trades |
|---|---|---|---|---|---|
| 1 | Electricity Futures | 13 | [redacted] | | |
| 2 | Electricity Options | 7 | | | |
| 3 | Total Transacted | | | | |

**TABLE 6A-9**
**SUMMARY OF PG&E ELECTRIC PORTFOLIO**
**ELECTRICITY FINANCIAL TRANSACTIONS**
**LISTED BY 2014 BPP APPROVED TRANSACTION PROCESS**

| Line No. | Product | 2014 BPP Table B-1 Item Number | Volume (GWh) | Notional Value ($ Millions) | Number of Trades |
|---|---|---|---|---|---|
| 1 | Transparent Exchanges (Electronic Trading Exchange) | 6 | [redacted] | | |
| 2 | Transparent Exchanges (Voice and On-Line Brokers) | 6 | | | |
| 3 | Electronic Solicitations | 10 | | | |
| 4 | Total Transacted | | | | |

**TABLE 6A-10**
**COMPLIANCE WITH 2014 BPP HEDGING TARGETS**
**(MILLIONS OF DOLLARS)**

| Line No. | Position |
|---|---|
| | [redacted] |
| 1 | |
| 2 | |
| 3 | |
| 4 | |
| 5 | |

Note: Table 6A-11 provides PG&E's electric portfolio position at the end of the Plan Year, on [redacted]

**FIGURE 6A-1**
**DEMONSTRATION OF COMPLIANCE**
**WITH 2014 BPP ELECTRICAL ENERGY PROCUREMENT LIMITS**

[redacted]

Note: [redacted]

**FIGURE 6A-2**
**DEMONSTRATION OF COMPLIANCE**
**WITH 2014 BPP NATURAL GAS PROCUREMENT LIMITS**

[redacted]

---

Note: [redacted]

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 6

# ATTACHMENT B

# ANNUAL REPORT OF UTILITY ON THE ACTIVITIES OF STARS ALLIANCE, LLC; UTILITY SAVINGS/AVOIDED COSTS BY STARS TEAM/PROJECT; AND INDEPENDENT AUDITOR'S REPORT AND FINANCIAL STATEMENTS

## ATTACHMENT B

## ANNUAL REPORT OF UTILITY ON THE ACTIVITIES OF STARS ALLIANCE, LLC
## RECORDED YEAR 2022 AND BUDGET YEAR 2022

(All Data in Whole Numbers)

| | Recorded Year 2022 | | Budget Year 2022 | |
|---|---|---|---|---|
| Total Common Costs (1) | | | | |
| Labor, Benefits, & Bonus | $ | 867,712 | $ | 837,000 |
| Travel Expenses | $ | 313,870 | $ | 433,500 |
| Non-travel Meals | $ | 44,710 | $ | 35,000 |
| *Sub-Total Labor, Benefits & Bonus* | $ | 1,226,292 | $ | 1,305,500 |
| Contractor Support | $ | 309,556 | $ | 315,000 |
| Legal | $ | 8,230 | $ | 25,000 |
| Office Supplies & Expenses | $ | 87,052 | $ | 96,000 |
| Building Lease/Utilities | $ | 274,556 | $ | 267,000 |
| Communications | $ | 26,517 | $ | 29,500 |
| Insurance | $ | 15,126 | $ | 15,000 |
| Infrastructure | $ | 89,669 | $ | 58,000 |
| Office Furniture & Equipment | $ | 17,544 | $ | 14,000 |
| Computer Equipment | $ | 39,705 | $ | 40,000 |
| Total STARS Alliance | **$** | **2,094,247** | **$** | **2,165,000** |
| Utility Share (%) | | 25% | | 25% |
| Utility Share ($) | **$** | **523,562** | **$** | **541,250** |
| Total Utility Share | **$** | **523,562** | **$** | **541,250** |

(1) Currently expensed on STARS Alliance books.

**UTILITY SAVINGS / AVOIDED COSTS BY STARS TEAM / PROJECT**

(All Data in Whole Numbers)

| | **STARS Total** |
|---|---|
| Supply Chain (STARS Contracts) (preliminary) | $ 8,753,777 |
| Rebates (preliminary) | $ 6,677,011 |
| **Total Savings / Avoided Costs (preliminary)** | **$ 15,430,788** |

- Teams / Projects may change annually based upon the needs of the Utility and STARS Alliance

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 7

# GREENHOUSE GAS COMPLIANCE

# INSTRUMENT PROCUREMENT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
GREENHOUSE GAS COMPLIANCE
INSTRUMENT PROCUREMENT

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 7
# GREENHOUSE GAS COMPLIANCE INSTRUMENT PROCUREMENT

## A. Introduction

The California Air Resources Board (CARB) Cap-and-Trade regulation established requirements for emissions reporting and compliance demonstrations by covered entities. As a covered entity and to fulfill certain contractual requirements, Pacific Gas and Electric Company (PG&E) needs to procure greenhouse gas (GHG) compliance instruments to satisfy its compliance obligation.

This chapter describes the GHG compliance instrument procurement activities undertaken by PG&E, pursuant to its 2014 Bundled Procurement Plan (BPP) during the January 1 through December 31, 2022 record period.[1] PG&E's 2014 BPP addresses the means, strategies, and limits applicable to PG&E's GHG compliance instrument procurement.

This testimony and supporting workpapers demonstrate that PG&E's 2022 GHG compliance instrument procurement activities complied with the requirements established in the 2014 BPP. This testimony also describes PG&E's bundled electric GHG procurement regulatory framework to illustrate those requirements impacting PG&E's management of its GHG procurement plan. Specifically:

- Section B describes the regulatory authority impacting PG&E's GHG procurement, including: (1) an overview of the CARB Cap-and-Trade Program to regulate GHG emissions; (2) a description of CARB requirements to calculate GHG emissions for covered entities in the electric generation sector; and (3) a summary of the California Public Utilities

---

1 The 2014 BPP was approved by the Commission in D.15-10-031. PG&E has since filed updates to its 2014 BPP Appendix G. Advice Letter (AL) 5473-E filed on January 25, 2019 and approved in Res.E-4998, modified Appendix G so that [redacted]. Pursuant to the requirements of Res.E-4998, PG&E filed its Conformed 2014 BPP Appendix G in AL 5579-E on July 1, 2019. Additionally, PG&E updates its BPP GHG procurement limits annually.

Commission's (Commission) regulatory authority governing PG&E's procurement of GHG compliance instruments on behalf of its bundled electric portfolio;

- Section C describes the resources that comprised PG&E's direct physical obligation to procure compliance instruments during the record period, including Utility-Owned Generation (UOG), imported electricity, and any PG&E contracts with physical settlement of GHG compliance instruments. This section also describes the means by which PG&E procured GHG compliance instruments, including a showing of PG&E's GHG procurement activities during the record period related to PG&E's direct physical obligation, including analysis on financial versus physical settlement of tolling agreements, as established in the *Settlement Agreement Between Pacific Gas and Electric Company (U 39 E) and The Public Advocates Office at the Public Utilities Commission* (2017 Energy Resource Recovery Account (ERRA) Compliance Settlement Agreement (SA)) approved in Decision (D.) 19-02-005; and
- Section D shows that PG&E complied with the requirements set forth in the 2014 BPP to procure GHG compliance instruments, including limits on GHG compliance instrument procurement.

Together, this testimony and the supporting workpapers demonstrate that PG&E's 2022 GHG compliance instrument procurement activities complied with its 2014 BPP.[2]

## B. Background Information

This section describes CARB and Commission requirements relevant to PG&E's GHG compliance instrument procurement for the bundled electric portfolio. This section also establishes that GHG procurement activities are reviewed for compliance with the 2014 BPP in this proceeding.

### 1. Assembly Bill 32 Cap-and-Trade Program

Assembly Bill (AB) 32 required the reduction of statewide GHG emissions to 1990 levels by 2020. To this end, the CARB promulgated a statewide Cap-and-Trade regulation that established a market-based price for GHG emissions. AB 398 extended the Cap-and-Trade Program through

[2] See 2014 BPP, Appendices C and G.

2030 in order to reach the statewide goal set in Executive Order B-30-15 and Senate Bill 32 of reducing GHG emissions to at least 40 percent below 1990 levels by 2030.

For the electric generation sector, covered entities include operators of any facility that annually emits at least 25,000 metric tons of carbon dioxide equivalents ($mtCO_{2e}$).[3] Covered entities are required to obtain and surrender compliance instruments equivalent to the GHG emissions for each such facility. Importers of electricity into California are also responsible for obtaining and surrendering compliance instruments for GHG emissions deemed associated with electricity imports for purposes of compliance with Cap-and-Trade.

There are two types of compliance instruments: (1) allowances, which are limited tradable authorizations created by CARB to emit up to 1 $mtCO_{2e}$; and (2) offset credits, which are tradable compliance instruments issued by CARB that represent verified reductions of 1 $mtCO_{2e}$ from projects whose emissions or avoided emissions are not from a source covered under the Cap-and-Trade Program. For compliance purposes, an offset credit and an allowance have limited differences. Allowances have a unique vintage year, and each vintage may be used in the vintage year issued or in future years, but future vintage allowances may not be used to satisfy any compliance obligations prior to the vintage year. For example, 2019 vintage allowances can be used to fulfill 2019 or 2020 obligations, but not 2016 obligations.

Unlike an allowance, an offset credit is not limited by vintage and can be utilized for any surrender year. However, an entity must abide by the offset quantitative usage limits specified in the Cap-and-Trade regulation. For emissions through 2020, the quantitative usage limit was 8 percent, meaning an entity could fulfill up to 8 percent of its compliance obligation through 2020 using offsets. For 2021 through 2025, this quantitative usage limit decreases to 4 percent, and for 2026 through 2030, the quantitative usage limit is 6 percent. Additionally, starting with 2021 emissions, a new offset usage requirement was added: an entity may fill no more than half of its quantitative usage limit with offsets from projects that do not provide

3 Units of GHG are typically measured in terms of $mtCO_{2e}$.

direct environmental benefits to the state (DEBS). In addition, CARB's Cap-and-Trade regulation allows CARB to invalidate an offset credit for errors, regulatory violations, or fraud.[4]

**2. Electric Sector GHG Emissions**

For the electric generation sector, CARB requires specific methodologies to calculate emissions from electricity generating facilities located in the state of California (in-state facilities) and a separate methodology is required to calculate emissions for electricity imported into the state of California (imported electricity). For in-state electric generation facilities, carbon dioxide equivalent ($CO_{2e}$) compliance obligations are calculated based upon the combustion of fossil fuel used, and not the electrical energy produced. PG&E's UOG facilities and all facilities associated with its tolling contracts are entirely located in the state of California. For imported electricity, $CO_2$e emissions are calculated based on the electrical energy imported. The compliance obligation associated with imported electricity emissions may be further reduced through adjustments for certain renewables procurement and qualified exports.

**3. PG&E's GHG Compliance Instrument Procurement Authority**

On April 19, 2012, the Commission issued D.12-04-046, authorizing PG&E to procure GHG compliance instruments and requiring PG&E to update its 2010 BPP to incorporate the modifications made in that decision, including annual procurement limits. Following that decision, PG&E amended its 2010 BPP to include a GHG Procurement Plan approved by the Commission in late 2012.[5] PG&E's GHG Procurement Plan was subsequently modified in 2014 to reflect changes in regulatory and market conditions.[6] In October 2015, the Commission issued D.15-10-031,

---

4 In event of invalidation, CARB requires the party holding the offset to replace within six months of notification.

5 In October 2012, the Commission issued Resolution (Res.) E-4544, approving PG&E's 2010 BPP, authorizing PG&E to procure allowances and offsets.

6 In December 2013, PG&E filed AL 4331-E concerning updates to its GHG Plan to reflect updated market and regulatory conditions. Res.E-4660 approved certain changes requested by AL 4331-E, and PG&E filed AL 4499-E to comply with the resolution. AL 4499-E was approved on October 15, 2014.

approving PG&E's 2014 BPP, which included an amended GHG Procurement Plan and GHG Procurement Limits.

The Commission has since approved updates to PG&E's GHG Procurement Plan. Res.E-4998 approved comprehensive modifications to the GHG Procurement Plan in the 2014 BPP Appendix G, and in July 2019, following the Commission's resolution, PG&E filed its Conformed 2014 BPP Appendix G via AL 5579-E.

PG&E's 2014 BPP addresses the GHG-related procurement authority necessary for PG&E to comply with the obligations associated with the Cap-and-Trade Program. As a covered entity and to fulfill certain contractual requirements, PG&E needs to procure GHG compliance instruments to satisfy its compliance obligation. PG&E's 2014 BPP further addresses the means, strategies, and limits applicable to PG&E's GHG compliance instrument procurement, including annual GHG Procurement Limits.

## C. PG&E's GHG Procurement Activity During the Record Period

Section C details the resources in PG&E's bundled electric portfolio that require PG&E to engage in the GHG compliance instrument procurement activities reviewed in this proceeding. This section also details PG&E's procurement activity and internal analyses required by the 2017 ERRA Compliance SA and describes the actions PG&E took to comply with its 2014 BPP during that procurement.

### 1. Facilities Comprising PG&E's Direct GHG Costs

To comply with the Cap-and-Trade program, PG&E must procure compliance instruments for GHG emissions obligations associated with qualifying UOG, import electricity, and contracted tolling facilities.

During the record period, PG&E only needed to procure compliance instruments for anticipated GHG obligations related to three of its UOG electric generation facilities: (1) Colusa Generating Station; (2) Gateway Generation Station; and (3) Humboldt Bay Generation Station. For emissions obligations associated with import energy, please see explanation in Section B above.

PG&E's tolling contracts allow PG&E to compensate tolling counterparties for their emissions obligations either through the physical transfer of compliance instruments or through financial settlement. During the record period, PG&E [redacted], pursuant to the Conformed 2014 BPP Appendix G. PG&E's Conformed 2014 BPP Appendix G establishes that PG&E will [redacted][7]

Even though the decision [redacted] is established in the 2014 BPP, PG&E continues to perform an analysis of GHG portfolio costs to compare financial settlement versus physical settlement for its tolling contracts at least twice a year. As required by the 2017 ERRA Compliance SA, which was approved by the Commission in D.19-02-005, this analysis for the record year is provided in the Confidential Workpapers to this chapter.

PG&E also presents its Bundled Electric GHG Position to the Procurement Review Group (PRG) each quarter, which includes the forecasted GHG Position, including PG&E's intention to continue [redacted] of GHG obligations.

**2. PG&E's GHG Procurement Activity**

Emissions allowances are issued by CARB, and CARB sells allowances through quarterly auctions. CARB also issues offset credits pursuant to specific protocols set forth in the Cap-and-Trade Regulation. In addition, compliance instruments are available for purchase bilaterally, or through the market. [redacted]

---

[7] See AL 5579-E filed on and made effective July 1, 2019.

**TABLE 7-1**
**TRANSACTIONS EXECUTED DURING RECORD PERIOD**

[redacted]

**TABLE 7-2**
**PG&E'S PROCURED GHG COMPLIANCE INSTRUMENTS IN THE 2022 RECORD PERIOD**

| Line No. | Procured GHG Compliance Instruments | Quantity ($MTCO_{2e}$) | Cost ($) | Average Cost per Compliance Instrument (Calculated) |
|---|---|---|---|---|
| 1 | Allowances Procured from CARB Auctions | [redacted] | [redacted] | [redacted] |
| 2 | Offsets Procured from Third Parties | [redacted] | [redacted] | [redacted] |
| 3 | Instruments with Future Vintages procured in the Record Period (Do not qualify for the current Cap-and-Trade compliance year of 2022) | [redacted] | [redacted] | [redacted] |
| 4 | Total Instruments Procured that qualify for the current Cap-and-Trade compliance year of 2022 | [redacted] | [redacted] | [redacted] |
| 5 | Total Instruments Procured in 2022 | [redacted] | [redacted] | [redacted] |

### 3. PG&E's GHG CARB Auction Procurement Activity

CARB holds quarterly auctions of current vintage and future vintage allowances. The current vintage auction may include allowances of any vintage that can be used in the current year. During the record period, CARB made available current vintage allowances (i.e., 2022 vintage and unsold earlier vintage allowances) and future vintage (i.e., 2025) allowances. Each quarterly auction has a published settlement price. Annually, CARB sets a floor price for its auctions. In 2022, the floor price was $19.70 per allowance.[8]

[redacted]

[redacted][9] [redacted]

---

[8] https://ww3.arb.ca.gov/cc/capandtrade/auction/auction.htm.

[9] [redacted]

[redacted]

#### 4. PG&E's GHG Market Transactions Procurement Activity

[redacted]

### D. PG&E Complied with the GHG Procurement Plan

This Section demonstrates that PG&E's procurement complied with its 2014 BPP. This section also demonstrates that PG&E's GHG procurement activities complied with the limits established in the 2014 BPP.

#### 1. 2014 BPP GHG Procurement Strategy

PG&E's 2014 BPP includes PG&E's GHG procurement strategy.[10] The strategy defines how PG&E will participate in the GHG market to procure necessary compliance instruments to comply with the Cap-and-Trade Program and meet any physical contractual obligations.

[redacted]

[10] See Conformed 2014 BPP Appendix G, Section D, Sheets 132-138.

### 2. Procurement Limits for GHG Products

The 2014 BPP includes GHG Purchase Limits.[11] The GHG Purchase Limit establishes the maximum amount of GHG products PG&E may purchase in the current year to fulfill its "direct compliance obligation," defined as the tons of emissions for which PG&E has an obligation to retire allowances in the current year on its own behalf as a regulated entity under CARB's Cap-and-Trade Program, and/or is otherwise obligated to procure for a third party. A "purchase" is defined as taking title of the GHG product (i.e., allowance or offset) when it is delivered. Thus, forward purchases count against the procurement limit when the product is delivered, which may not be the same year the transaction is executed.

Table 7-3 demonstrates that PG&E transacted within its 2022 GHG Purchase Limit established by its 2014 BPP. PG&E's GHG Purchase Limit is calculated as set forth in D.12-04-046 and in the 2014 BPP.[12] PG&E's [redacted].

**TABLE 7-3**
**2022 GHG PRODUCTS PURCHASED BY PG&E COMPARED TO GHG LIMIT**
**MILLION $MTCO_{2E}$**

[redacted]

The quarterly PRG presentations concerning GHG compliance instrument procurement and attachments included in each Quarterly Compliance Report (QCR) also demonstrate that PG&E complied with its

---

11 See 2014 BPP, Appendix C, Section C, Sheets 77-81 (regarding GHG procurement limits).

12 2014 BPP, Sheets 79-81.

GHG Purchase Limit.[13] These documents are included as confidential workpapers to support PG&E's Prepared Testimony in this proceeding.

## E. Conclusion

This chapter, as well as information included in PG&E's workpapers to this chapter, demonstrates that during the 2022 record period, PG&E's procurement of GHG compliance instruments complied with the requirements the 2014 BPP because PG&E utilized the means, strategies and limits described therein.

13 See Fourth Quarter 2022 Bundled Electric GHG Position Update, p. 9, included with Fourth Quarter QCR GHG Workpapers.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 8

# RESOURCE ADEQUACY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
RESOURCE ADEQUACY

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 8
# RESOURCE ADEQUACY

## A. Introduction

Pacific Gas and Electric Company's (PG&E) Bundled Procurement Plan (BPP) contains several provisions for how PG&E conducts its procurement and sales of Resource Adequacy (RA) products in order to meet the reliability compliance requirements established in Public Utilities Code Section 380 and implemented by the California Public Utilities Commission (CPUC or Commission) (RA Program) and respective California Independent System Operator (CAISO) Tariff provisions.

This chapter describes the RA procurement and sale efforts (RA Activities) undertaken by PG&E, pursuant to its Conformed 2014 BPP and the Commission directives during the January 1 through December 31, 2022 record period. PG&E's RA Activities were impacted by changes during the record period in the CPUC RA Program.

- Section B provides background information on RA requirements including: (1) existing CPUC RA requirements at the time of the last Energy Resource Recovery Account (ERRA) compliance proceeding; (2) new relevant 2022 CPUC decisions and revised RA program rules as of the filing of this testimony; and (3) CAISO Reliability Requirements.
- Section C describes PG&E's RA Activities during the record period, including: (1) RA position; (2) RA purchases; (3) RA sales; and (4) RA contract management.
- Section D documents how PG&E complied with the Portfolio Allocation Balancing Account (PABA) revenue and cost recording required in the Power Charge Indifference Adjustment (PCIA) Phase 1 Decision (D.) 18–10–019.

Together, this testimony and the supporting workpapers (WP) demonstrate PG&E's 2022 RA Activities complied with its Conformed 2014 BPP.[1]

---

[1] See 2014 BPP, Appendices C and S.

## B. Background Information

### 1. Existing RA Requirements

The CPUC's RA Program, adopted in 2004, was developed in response to the 2000–2001 California energy crisis. The program is designed to ensure reliable electric service in California by requiring all CPUC jurisdictional Load Serving Entities (LSE) (or other entities, such as a central procurement entity, as applicable) to have enough capacity to meet the CPUC RA Program requirements. The CPUC's RA Program contains three distinct requirements: System RA requirements, Local RA requirements, and Flexible RA requirements. System RA requirements are determined one–year forward based on each LSE's California Energy Commission (CEC) adjusted forecast plus a 15 percent Planning Reserve Margin (PRM). Local RA requirements are determined three–years forward based on an annual CAISO study using a 1–in–10 weather year and a NERC P1–P7 contingency. Flexible RA requirements are determined one–year forward based on an annual CAISO study that currently looks at the largest three–hour ramp for each month needed to run the system reliably. There are two types of filings used to comply with the CPUC's RA Program; annual filings (filed by LSEs annually on October 31[2] for the coming year and by the central procurement entities (CPEs) annually in September for the following three years) and monthly filings (filed by LSEs 45 days prior to the compliance month). The CPUC sets the annual and monthly System, Local, and Flexible RA requirements for CPUC–jurisdictional LSEs (or other entities, such as a central procurement entity, as applicable) based on inputs from the CEC and CAISO.

The CPUC RA Program annual filing requires LSEs (and CPEs) to make annual System, Local, and Flexible RA compliance showings for the coming year. For the System showing, LSEs are required to demonstrate they have procured at least 90 percent of their System RA obligation for the five summer months from May through September. For the Local showing, CPEs and applicable LSEs are required to demonstrate that they have

---

2 Pursuant to Rule 1.15 of the CPUC Rules of Practices and Procedure, if the due date falls on a Saturday, Sunday, or holiday, it is extended to the following business day.

procured 100 percent of their Local RA obligation for all 12 months with the CPE absorbing all Local RA obligations after 2022. LSEs are also required to demonstrate that they have procured at least 90 percent of their Flexible RA requirement for all 12 months.

For the monthly filings, LSEs must demonstrate they have procured 100 percent of their monthly System, Flexible and Local RA obligations.

### 2. Relevant 2022 CPUC Decisions and Revised RA Program Rules

In 2022, the CPUC adopted several changes to the RA Program. D.22–06–050, issued on June 23, 2022, adopted local capacity obligations for 2023–2025 and flexible capacity obligations for 2023. D.22–06–050 also adopted additional refinements to the RA program, including: adopting revisions to the RA measurement hours for March and April; adopting revisions to the Maximum Cumulative Capacity buckets 1, 2 and 3 to align with the revised hours; increasing the PRM to 16 percent in 2023 and 17 percent in 2024; adopting new Effective Load Carrying Capacity (ELCC) values for wind and solar in 2023; and adopting a 24–hour Slice–of–Day framework for RA beginning in 2025. D.22–08–039 further adopted regional ELCC values for wind beginning in 2023.

### 3. CAISO Reliability Requirements

In addition to the requirements set by the CPUC, the CAISO includes RA provisions in its Tariff.[3] Working in conjunction with the RA requirements adopted by the CPUC and other provisions of California law applicable to non–CPUC jurisdictional LSEs, the RA provisions in the CAISO Tariff are intended to establish a process that ensures capacity is available when and where it is needed to reliably operate the CAISO grid. Accordingly, the CAISO tracks how each LSE is complying with its RA requirements. If an LSE does not meet its specific requirements (or the CPE does not meet its specific local requirements in years beyond 2022), the costs of CAISO backstop procurement may be allocated to the deficient or non–performing LSE.[4] The CAISO also enforces non–availability

[3] CAISO Tariff, Section 40, Section 9, and Section 43A represent the primary Reliability Requirements in the CAISO Tariff.

[4] CAISO Tariff Section 43A.8.

charges on resources that do not perform consistent with CAISO's expectation.[5]

#### 4. Summer Reliability

In addition to the RA requirements outlined above, in 2021 due to extreme heat outage events in August 2020 the Commission created additional procurement targets incremental to the requirements for the three Investor–Owned Utilities (IOU) in California to address summer reliability concerns. These efforts are classified as "Summer Reliability" and are targeted towards protecting the system and ensuring reliable delivery of service across California.

First, D.21–02–028, issued on February 17, 2021, directed the three IOUs to seek additional capacity to serve peak and net peak demand in the summer of 2021.

Second, D.21–03–056, issued on March 26, 2021, further refined the actions to prepare for potential extreme weather in the summers of 2021 and 2022. All IOUs were allocated incremental procurement targets to achieve an increased interim effective PRM of 17.5 percent for the months of May through October, to be met with both RA eligible and non–eligible resources. PG&E was allocated a minimum target of 450 megawatts (MW). The IOUs were also directed to submit preliminary, non–binding RA Plans for the summers of 2021–23. After meeting the PRM, D.21–03–056 authorized the IOUs to procure additional capacity, or use existing resources from their portfolios, to meet the interim effective 17.5 percent PRM.

Third, D.21–12–015, issued on December 6, 2021, further directed the three IOUs to prepare for potential extreme weather in 2022 and 2023, and raised the minimum contingency procurement target to 900 MW for PG&E. For the months of July, August, and September, the CPUC raised the upper end of its contingency procurement target to 1,350 MW for PG&E. The IOUs are authorized to show excess resources from their existing portfolio of resources to meet the increased requirement.

Finally, on June 30, 2022, the California Governor signed AB 205 into law, which established several programs to address electric reliability,

---

5 CAISO Tariff Section 40.9.

including the ability to reimburse electrical corporations for above–market costs of import capacity delivered between July 1 and September 30, 2022. On July 18, 2022, PG&E entered into an agreement with the California Department of Water Resources (DWR), wherein the DWR will reimburse PG&E for the above–market costs of eligible Summer Import Procurement Contracts (SIPC) executed to support statewide summer electric service reliability.

### C. PG&E's RA Activity During the Record Period

#### 1. RA Position

PG&E manages the RA position to address a few key objectives: (1) to comply with the CPUC RA Program and the CAISO reliability requirements; (2) to enable sales of capacity where appropriate; and (3) to manage its responsibility as a scheduling coordinator (SC). PG&E manages resources and coordinates with regulators (i.e., CEC, CPUC, and CAISO) to make sure these objectives are achieved.

System, Local, and Flexible RA requirements for each LSE are provided by the CPUC in September each year, including Demand Response and Cost Allocation Mechanism allocations.[6] This means PG&E does not have a fixed and certain RA Compliance obligation amount until the September preceding the compliance year. Per the RA requirements under D.19–02–022, CPUC–jurisdictional LSEs are allocated Local RA compliance obligations in each of the local capacity areas within the service area in which they serve load (rather than meeting a Local RA compliance obligation using capacity from any local capacity area). In addition to CPUC compliance requirements, the CAISO releases the Net Qualifying Capacity (NQC) and Effective Flexible Capacity (EFC), which provides the quantity of MW a resource can count for RA compliance, each October. This means PG&E does not have a fixed and certain total resource amount of RA in its portfolio until the October preceding the compliance year. PG&E's RA position is materially impacted by the RA Compliance obligation and CAISO NQC and EFC amounts and the associated distribution timelines. While

6 See D.06–07–029.

requirements and resources are put in place late in the year, PG&E manages its position using the best information available at the time.

PG&E also manages its RA position to address all the compliance requirements across the regulators. For instance, for System RA position, the CPUC compliance rules do not account for forecasted planned outages, whereas CAISO rules require PG&E to manage the System RA position to account for these outages. For Local RA position management, the CPUC requires only August NQCs be used for resource capacity counting in every month of the year, whereas the CAISO requires each monthly NQC be used for resource capacity counting. A complex series of requirements across regulators, challenging timelines for receiving critical compliance obligation information, and fluctuations in RA resource qualifying capacity amounts all have an impact on PG&E's RA position.

PG&E managed its position in the record period in compliance with the Conformed 2014 BPP and in accordance with the key objectives above.

### 2. RA Purchases

PG&E purchased RA to meet its RA compliance obligations during the record period taking into consideration the regulatory changes to Local RA compliance requirements and operational impacts to its portfolio. These transactions were compliant with the BPP and were reported in each 2022 Quarterly Compliance Report (QCR).[7]

### 3. RA Sales

#### a. Compliance with Appendix S – Sales Framework

PG&E's Appendix S – Sales Framework sets parameters within which PG&E will conduct sales, offer volumes for sale, and evaluate offers received from counterparties. PG&E's RA sales in 2022 are documented in the relevant QCRs.

##### 1) Product Volume

Appendix S sets forth the formulas used to determine volumes of System, Local and Flexible RA and import capacity counting rights available for sale as of the date a calculation is performed.

---

7 The 2022 QCRs are included as part of PG&E's confidential WPs.

The BPP does not obligate PG&E to offer any volumes of RA determined to be available pursuant to the formulas set forth in Appendix S, except through the CAISO capacity procurement mechanism competitive solicitation process.

In compliance with Appendix S, PG&E used the required formulas to determine the volume of RA available for sale at various times. PG&E demonstrates the amount of RA determined to be available for sale at various times in its Portfolio Breakdown in the QCR Appendix E. PG&E offered the volumes of RA determined to be available for sale pursuant to the formulas set forth in Appendix S into the CAISO capacity procurement mechanism competitive solicitation process and, while not required by the BPP, also offered all volumes of available RA to the market.

**2) Sales Method**

Appendix S establishes PG&E's solicitation schedule to sell RA products. PG&E held the following solicitations in accordance with Appendix S. These solicitations were reported in the QCR.[8]

Consistent with Appendix S of its BPP, PG&E held a Q2 Balance of Year 2022 solicitation in January 2022, a Q3 Balance of Year 2022 solicitation in April 2022, a Q4 Balance of Year 2022 solicitation in July 2022, a 2023 RA sales solicitation in the third quarter of 2022, and a February through Balance of Year 2023 solicitation in November 2022.

For the annual year–ahead (2023) solicitation, PG&E's capacity was made available shortly after the final RA Compliance obligations were issued by the CPUC. In addition, the CAISO issued its draft NQC and EFC lists prior to the second phase of the solicitation. The issuance of the NQC and EFC lists provided greater certainty to the market on RA values for resources that can be counted towards an LSE's RA obligations.

---

**8** See 6577–E (revised 6577–E–A), 6670–E (supplemental 6670–E–A), 6751–E, and 6844–E.

#### 3) Price Supply Curve

D.19–10–001 found that:

> An investor–owned utility may decide not to sell RA below [a] floor price because the possible California Independent System Operator penalties for doing so could require the IOU to recover costs in excess of the floor price from both bundled service and departing load customers.[9]

In accordance with this finding, Appendix S approves a methodology for PG&E to calculate a price supply curve to determine floor prices. PG&E's floor price evaluates possible CAISO penalties a generating unit may receive, calculated as a function of the probability of a generating unit receiving a penalty and the associated penalty cost. PG&E applied this approved supply curve methodology when evaluating bids to sell RA from PG&E during the record period.

### 4. RA Contract Management

The executed volumes and prices from the solicitations and bilateral contracts are reported in the QCR Attachment E and H. These transactions can be found in Table 8–2. In 2022, PG&E's RA sales contracts were structured such that unit–specified RA was not identified until necessary for its delivery date. PG&E provides counterparties with unit specific resource information in advance of the filing deadline for the CAISO's Supply Plan. PG&E used this approach during 2022 to enable flexibility to manage any unexpected resource outages, load migration, or other issues that may arise. Other routine amendments were made throughout the record period, as shown in Table 8–3 at the end of this chapter.

## D. Accounting for RA Per D.18–10–019 and D.19–10–001

PG&E commits resources to meet its System, Local and Flexible RA obligations in accordance with the rules of its regulatory agencies. PG&E selects resources to fulfill RA sales agreements and for its own compliance.

PG&E determines the volume of RA "Retained" for IOU compliance and RA "Sold" to counterparties after offering all volumes for sale according to the 2014

---

9 D.19–10–001 Finding of Fact 29.

Conformed BPP Appendix S methodology and uses this information for purposes of calculating the PABA true–up as follows, pursuant to D.19–10–001:

PG&E tracks the amount of MWs of RA from each resource that was Sold or Retained. For PG&E's own compliance and RA sales to counterparties, RA Retained or Sold amounts are finalized when a resource is included in PG&E's Supply Plan to the CAISO. Each MW of RA from each resource that is included on the Supply Plan is assigned to an LSE. When the resource capacity is assigned to PG&E, it is considered "Retained" RA. When a resource is assigned to another LSE, the RA is considered Sold RA. The sales price and quantity for each Sold RA transaction are recorded in PABA.

The Retained or Sold volumes and prices associated with a resource is booked to PABA only if that resource is a PCIA–eligible resource. If the resource is a Qualifying Facility that is recovered through Ongoing Competition Transition Charge (CTC), its retained value or sales value would be recorded under the Modified Transition Cost Balancing Account. Similarly, RA associated with Tree Mortality Nonbypassable Charge (TMNBC) resources would be recorded as retained or sold under the TMNBC. If the sales are associated with generation and storage resources that are not otherwise recovered through the CTC, the PCIA, or the TMNBC, the sales are recorded under ERRA.

After determining the total amount of Retained and Sold RA, including offering all volumes for sale according to the 2014 Conformed BPP Appendix S methodology, PG&E calculates the Unsold RA. To do so, PG&E deducts the total amount of Retained and Sold RA from the cumulative NQC of PG&E's portfolio to establish how many MW of RA remain unsold. During the Record Period, PG&E offered all volumes of RA for sale according to the 2014 Conformed BPP Appendix S methodology but was not able to sell all available RA for each month in 2022. This information is recorded in Appendix E of the QCRs.

## E. Conclusion

This chapter, as well as information included in PG&E's WPs to this chapter, demonstrates that during the 2022 record period, PG&E's procurement and sale of RA products complied with the requirements of the 2014 Conformed BPP because PG&E utilized the means, strategies, and limits described therein.

**TABLE 8–1**
**PG&E RA SOLICITATION SCHEDULE PURSUANT TO APPENDIX S OF BPP**

| Line No. | Solicitation | Delivery Term | Products | Anticipated Date |
|---|---|---|---|---|
| 1 | Q2 through Balance of Year 2022 | Monthly, through December 2022 | System RA with/without Flexible RA<br>Local RA with/without Flexible RA<br>Import Capacity Counting Rights | January 2022 |
| 2 | Q3 through Balance of Year 2022 | Monthly, through December 2022 | System RA with/without Flexible RA<br>Local RA with/without Flexible RA<br>Import Capacity Counting Rights | April 2022 |
| 3 | Q4 through Balance of Year 2022 | Monthly, through December 2022 | System RA with/without Flexible RA<br>Local RA with/without Flexible RA<br>Import Capacity Counting Rights | July/August 2022 |
| 4 | Annual (2023) | Monthly, January through December (2023) | System RA with/without Flexible RA<br>Local RA with/without Flexible RA<br>Import Capacity Counting Rights | Q3 2022 |
| 5 | February through Balance of Year 2023 | Monthly, February through December 2023 | System RA with/without Flexible RA<br>Local RA with/without Flexible RA<br>Import Capacity Counting Rights | November 2022 |

**TABLE 8–2**
**RA EXECUTED DURING RECORD PERIOD 2022**

| Line No. | Date | PG&E Log Number | Project Name |
|---|---|---|---|
| 1 | 1/4/2022 | 33B238U06 | East Bay Community Energy Authority – Purchase |
| 2 | 1/10/2022 | 33B238U05 | East Bay Community Energy Authority – Sale |
| 3 | 1/14/2022 | 33B235U11 | Marin Clean Energy – Purchase |
| 4 | 1/19/2022 | 33B273U01 | High Desert Power Project, LLC – Sale |
| 5 | 1/21/2022 | 33B267U02 | Elk Hills Power LLC – Purchase |
| 6 | 1/31/2022 | 33B241U01 | Direct Energy Business Marketing, LLC – Sale |
| 7 | 2/9/2022 | 33B232U06 | Peninsula Clean Energy Authority – Sale |
| 8 | 2/9/2022 | 33B232U07 | Peninsula Clean Energy Authority – Sale |
| 9 | 2/9/2022 | 33B232U08 | Peninsula Clean Energy Authority – Purchase |
| 10 | 2/9/2022 | 33B232U09 | Peninsula Clean Energy Authority – Purchase |
| 11 | 2/9/2022 | 33B235U12 | Marin Clean Energy – Purchase |
| 12 | 2/9/2022 | 33B245U04 | Pioneer Community Energy – Purchase |
| 13 | 2/10/2022 | 33B022U01 | Shell Energy North America (US), L.P. – Purchase |
| 14 | 2/10/2022 | 33B267U03 | Elk Hills Power LLC – Purchase |
| 15 | 2/17/2022 | 33B274U01 | San Diego Community Power – Purchase |
| 16 | 2/23/2022 | 33B238U07 | East Bay Community Energy Authority – Purchase |
| 17 | 3/2/2022 | 33B226U08 | Sonoma Clean Power Authority – Purchase |
| 18 | 3/2/2022 | 33B235U13 | Marin Clean Energy – Purchase |
| 19 | 3/2/2022 | 33B245U05 | Pioneer Community Energy – Purchase |
| 20 | 3/9/2022 | 33B251U01 | Constellation Energy Generation, LLC – Sale |
| 21 | 3/15/2022 | 33B235U14 | Marin Clean Energy – Purchase |
| 22 | 3/17/2022 | 33B217U09 | Southern California Edison Company – Purchase |
| 23 | 3/17/2022 | 33B217U10 | Southern California Edison Company – Sale |
| 24 | 3/25/2022 | 33B235U15 | Marin Clean Energy – Purchase |
| 25 | 4/8/2022 | 33B029U14 | Calpine Energy Services, L.P. – Purchase |
| 26 | 4/8/2022 | 33B029U15 | Calpine Energy Services, L.P. – Purchase |
| 27 | 4/18/2022 | 33B263U01 | Dynegy Marketing and Trade, LLC – Purchase |
| 28 | 4/19/2022 | 33B267U04 | Elk Hills Power LLC – Purchase |
| 29 | 4/29/2022 | 33B202U03 | Commercial Energy of Montana Inc. – Sale |
| 30 | 5/2/2022 | 33B235U16 | Marin Clean Energy – Sale |
| 31 | 5/2/2022 | 33B235U17 | Marin Clean Energy – Purchase |
| 32 | 5/2/2022 | 33B235U18 | Marin Clean Energy – Sale |
| 33 | 5/2/2022 | 33B235U19 | Marin Clean Energy – Purchase |

**TABLE 8–2**
**RA EXECUTED DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name |
|---|---|---|---|
| 34 | 8/9/2022 | 33B236U07 | Central Coast Community Energy – Sale |
| 35 | 8/9/2022 | 33B236U08 | Central Coast Community Energy – Purchase |
| 36 | 9/30/2022 | 33B238V01 | East Bay Community Energy Authority – Sale |
| 37 | 10/3/2022 | 33B232V01 | Peninsula Clean Energy Authority – Sale |
| 38 | 10/21/2022 | 33B202V01 | Commercial Energy of Montana Inc. – Sale |
| 39 | 10/21/2022 | 33B234V01 | The Energy Authority, Inc. – Sale |
| 40 | 10/21/2022 | 33B236V01 | Central Coast Community Energy – Sale |
| 41 | 10/21/2022 | 33B241V01 | Direct Energy Business Marketing, LLC – Sale |
| 42 | 10/24/2022 | 33B232V02 | Peninsula Clean Energy Authority – Purchase |
| 43 | 10/24/2022 | 33B232V03 | Peninsula Clean Energy Authority – Sale |
| 44 | 10/24/2022 | 33B238V02 | East Bay Community Energy Authority – Sale |
| 45 | 10/25/2022 | 33B226V01 | Sonoma Clean Power Authority – Sale |
| 46 | 10/25/2022 | 33B230V01 | Silicon Valley Clean Energy Authority – Sale |
| 47 | 10/25/2022 | 33B251V01 | Constellation Energy Generation, LLC – Sale |
| 48 | 12/16/2022 | 33B236V02 | Central Coast Community Energy – Sale |
| 49 | 12/20/2022 | 33B238V04 | East Bay Community Energy Authority – Sale |
| 50 | 12/22/2022 | 33B263V01 | Dynegy Marketing and Trade, LLC – Sale |
| 51 | 12/27/2022 | 33B238W01 | East Bay Community Energy Authority – Sale |
| 52 | 12/28/2022 | 33B232W01 | Peninsula Clean Energy Authority – Sale |
| 53 | 12/29/2022 | 33B232V04 | Peninsula Clean Energy Authority – Sale |
| 54 | 12/29/2022 | 33B232V05 | Peninsula Clean Energy Authority – Sale |
| 55 | 2/8/2022 | 33B013U01 | Powerex Energy Corp. – Purchase |
| 56 | 2/8/2022 | 33B013U02 | Powerex Energy Corp. – Purchase |
| 57 | 5/25/2022 | 33B013U03 | Powerex Energy Corp. – Purchase |
| 58 | 7/1/2022 | 33B217U11 | Southern California Edison Company – Sale |
| 59 | 7/1/2022 | 33B217U12 | Southern California Edison Company – Sale |
| 60 | 8/10/2022 | 33B217U13 | Southern California Edison Company – Purchase |
| 61 | 10/21/2022 | 33B241V02 | Direct Energy Business Marketing, LLC – Sale |
| 62 | 10/24/2022 | 33B238V03 | East Bay Community Energy Authority – Sale |
| 63 | 10/24/2022 | 33B278V01 | San Diego Community Power – Sale |
| 64 | 10/24/2022 | 33B278V02 | San Diego community power – Sale |
| 65 | 12/21/2022 | 33B241V03 | Direct Energy Business Marketing, LLC – Sale |
| 66 | 12/21/2022 | 33B241V04 | Direct Energy Business Marketing, LLC – Sale |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 1 | 1/5/2022 | 33B238U02 | East Bay Community Energy Authority – Sale | Non–Routine Amendment to Existing Agreement | Amendment reduces PG&E's delivery obligations for a single month. |
| 2 | 5/9/2022 | CPE00001S | PGE Aera Energy Llc. (Coalinga) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 3 | 5/9/2022 | CPE00002S | PGE Alta Power House – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 4 | 5/9/2022 | CPE00003S | PGE Angels Powerhouse – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 5 | 5/9/2022 | CPE00004S | PGE Avenal Park Solar Project – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 6 | 5/9/2022 | CPE00005S | PGE Bakersfield 111 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 7 | 5/9/2022 | CPE00006S | PGE Bakersfield Industrial 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 8 | 5/9/2022 | CPE00007S | PGE Bakersfield Solar 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 9 | 5/9/2022 | CPE00008S | PGE Baker Station Hydro – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 10 | 5/9/2022 | CPE00009S | PGE Balch 2 Ph Unit 2 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 11 | 5/9/2022 | CPE00010S | PGE Balch 2 Ph Unit 3 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 12 | 5/9/2022 | CPE00011S | PGE Bear Creek Solar – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 13 | 5/9/2022 | CPE00012S | PGE Bidart Old River 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 14 | 5/9/2022 | CPE00014S | PGE Calrenew – 1(A) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 15 | 5/9/2022 | CPE00015S | PGE Cantua Solar Station – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 16 | 5/9/2022 | CPE00016S | PGE Ces Dairy Biogas – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 17 | 5/9/2022 | CPE00017S | PGE Chevron Richmond Refinery – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 18 | 5/9/2022 | CPE00018S | PGE Chevron Usa (Coalinga) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 19 | 5/9/2022 | CPE00019S | PGE Chicago Park Powerhouse – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 20 | 5/9/2022 | CPE00020S | PGE Chow II Biomass to Energy – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 21 | 5/9/2022 | CPE00021S | PGE CID Solar – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 22 | 5/9/2022 | CPE00022S | PGE Cloverdale Solar I – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 23 | 5/9/2022 | CPE00023S | PGE Columbia Solar Energy II – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 24 | 5/9/2022 | CPE00024S | PGE Corcoran Solar – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 25 | 5/9/2022 | CPE00025S | PGE Cresta Ph Unit 1 & 2 Aggregate – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 26 | 5/9/2022 | CPE00026S | PGE Crockett Cogen – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 27 | 5/9/2022 | CPE00027S | PGE Drum Ph 1 Units 1 & 2 Aggregate – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 28 | 5/9/2022 | CPE00028S | PGE Drum Ph 1 Units 3 & 4 Aggregate – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 29 | 5/9/2022 | CPE00029S | PGE Drum Ph 2 Unit 5 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 30 | 5/9/2022 | CPE00030S | PGE Dutch Flat 1 Ph – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 31 | 5/9/2022 | CPE00031S | PGE Dutch Flat 2 Ph – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 32 | 5/9/2022 | CPE00032S | PGE El Nido Biomass To Energy – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 33 | 5/9/2022 | CPE00033S | PGE Five Points Solar Station – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 34 | 5/9/2022 | CPE00034S | PGE FPL Energy Montezuma Wind – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 35 | 5/9/2022 | CPE00035S | PGE Ftswrd_7_Qfunts – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 36 | 5/9/2022 | CPE00036S | PGE Gateway Generating Station – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 37 | 5/9/2022 | CPE00037S | PGE Giffen Solar Station – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 38 | 5/9/2022 | CPE00038S | PGE Guernsey Solar Station – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 39 | 5/9/2022 | CPE00039S | PGE Haas Ph Unit 1 & 2 Aggregate – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 40 | 5/9/2022 | CPE00040S | PGE Halsey Hydro – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 41 | 5/9/2022 | CPE00041S | PGE Harris – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 42 | 5/9/2022 | CPE00042S | PGE Helms Pump–Gen Unit 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 43 | 5/9/2022 | CPE00043S | PGE Helms Pump–Gen Unit 2 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 44 | 5/9/2022 | CPE00044S | PGE Huron Solar Station – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 45 | 5/9/2022 | CPE00045S | PGE Kansas – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 46 | 5/9/2022 | CPE00046S | PGE Kerkhoff Ph 2 Unit #1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 47 | 5/9/2022 | CPE00047S | PGE Kettleman Solar – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 48 | 5/9/2022 | CPE00048S | PGE Kings River Hydro Unit 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 49 | 5/9/2022 | CPE00049S | PGE Lakeview Dairy Biogas – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 50 | 5/9/2022 | CPE00050S | PGE Lassen Station Hydro – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 51 | 5/9/2022 | CPE00051S | PGE Lemoore 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 52 | 5/9/2022 | CPE00052S | PGE Lincoln Biomass – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 53 | 5/9/2022 | CPE00053S | PGE Los Esteros Energy Facility Aggregate – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 54 | 5/9/2022 | CPE00054S | PGE Madera Canal Site 980 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 55 | 5/9/2022 | CPE00055S | PGE Madera Chowchilla 2 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 56 | 5/9/2022 | CPE00056S | PGE Madera Chowchilla 3 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 57 | 5/9/2022 | CPE00057S | PGE Madera Chowchilla 4 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 58 | 5/9/2022 | CPE00058S | PGE Merced 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 59 | 5/9/2022 | CPE00060S | PGE Mirant Marsh Landing, LLC (Unit 1) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 60 | 5/9/2022 | CPE00061S | PGE Mirant Marsh Landing, LLC (Unit 3) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 61 | 5/9/2022 | CPE00062S | PGE Mirant Marsh Landing, LLC (Unit 4) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 62 | 5/9/2022 | CPE00063S | PGE Moss 300 (1) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 63 | 5/9/2022 | CPE00064S | PGE Moss 300 (2) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 64 | 5/9/2022 | CPE00065S | PGE Moss 300 (3) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 65 | 5/9/2022 | CPE00066S | PGE Mt. Poso Cogeneration Co. – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 66 | 5/9/2022 | CPE00067S | PGE Newark 1 QF – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 67 | 5/9/2022 | CPE00068S | PGE Newcastle Hydro – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 68 | 5/9/2022 | CPE00069S | PGE NextEra Energy Montezuma Wind II – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 69 | 5/9/2022 | CPE00070S | PGE North Star Solar 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 70 | 5/9/2022 | CPE00071S | PGE Oak Flat – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 71 | 5/9/2022 | CPE00072S | PGE Old River One – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 72 | 5/9/2022 | CPE00073S | PGE PE– Berkeley, Inc. – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 73 | 5/9/2022 | CPE00074S | PGE Poe Hydro Unit 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 74 | 5/9/2022 | CPE00075S | PGE Poe Hydro Unit 2 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 75 | 5/9/2022 | CPE00076S | PGE Redwood Solar Farm 4 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 76 | 5/9/2022 | CPE00077S | PGE Rock Creek Hydro – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 77 | 5/9/2022 | CPE00078S | PGE Rollins Hydro – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 78 | 5/9/2022 | CPE00079S | PGE Russell City Energy Center – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 79 | 5/9/2022 | CPE00080S | PGE Salmon Creek Hydroelectric Project – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 80 | 5/9/2022 | CPE00081S | PGE Sand Drag Solar Project – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 81 | 5/9/2022 | CPE00082S | PGE Shafter Solar – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 82 | 5/9/2022 | CPE00083S | PGE Shiloh III Wind Project – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 83 | 5/9/2022 | CPE00084S | PGE Shiloh IV Wind Project – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 84 | 5/9/2022 | CPE00085S | PGE Shiloh Wind Project 2 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 85 | 5/9/2022 | CPE00086S | PGE Sierra Pacific Ind. (Sonora) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 86 | 5/9/2022 | CPE00087S | PGE Small Qf Aggregation – Zenia – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 87 | 5/9/2022 | CPE00088S | PGE Small Qf Aggregation – Sab Frabcusci – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 88 | 5/9/2022 | CPE00089S | PGE Small Qf Aggregation – Grass Valley – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 89 | 5/9/2022 | CPE00090S | PGE Sonora 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 90 | 5/9/2022 | CPE00091S | PGE South Kern Solar PV Plant – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 91 | 5/9/2022 | CPE00092S | PGE Spaulding Hydro Ph 1 & 2 Aggregate – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 92 | 5/9/2022 | CPE00093S | PGE Spaulding Hydro Ph 3 Unit – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 93 | 5/9/2022 | CPE00094S | PGE Spring Gap Hydro – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 94 | 5/9/2022 | CPE00096S | PGE Stroud Solar Station – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 95 | 5/9/2022 | CPE00097S | PGE Sun City Solar Project – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 96 | 5/9/2022 | CPE00098S | PGE Texaco Exploration & Prod (Se Kern River) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 97 | 5/9/2022 | CPE00099S | PGE Three Forks Water Power Project – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 98 | 5/9/2022 | CPE00100S | PGE Tranquillity 8 Amarillo – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 99 | 5/9/2022 | CPE00101S | PGE Vasco Wind – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 100 | 5/9/2022 | CPE00102S | PGE Wise Hydro Unit 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 101 | 5/9/2022 | CPE00103S | PGE Zero Waste Energy – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 102 | 5/9/2022 | CPE00104S | PGE Helms Pump–Gen Unit 3 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 103 | 5/9/2022 | CPE00105S | PGE Balch 1 Ph Unit 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 104 | 5/9/2022 | CPE00106S | PGE Henrietta Solar Project – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 105 | 5/9/2022 | CPE00107S | PGE Mirant Marsh Landing, LLC (Unit 2) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 106 | 5/9/2022 | CPE00108S | PGE Small QF Aggregation – Vallejo/Dinsmore – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 107 | 5/9/2022 | CPE00109S | PGE Vecino Vineyards LLC – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 108 | 5/9/2022 | CPE00110S | PGE Woodmere Solar Farm – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 109 | 5/9/2022 | CPE00111S | PGE Westside Solar Station – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 110 | 5/9/2022 | CPE00112S | PGE Belden Hydro – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 111 | 5/9/2022 | CPE00113S | PGE Bucks Creek Aggregate – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 112 | 5/9/2022 | CPE00114S | PGE Chevron Usa (Eastridge) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 113 | 5/9/2022 | CPE00115S | PGE Humboldt Bay Generating Station 3 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 114 | 5/9/2022 | CPE00116S | PGE Humboldt Bay Generating Station 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 115 | 5/9/2022 | CPE00117S | PGE Midway Peaking Aggregate – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 116 | 5/9/2022 | CPE00118S | PGE Monticello Hydro Aggregate – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 117 | 5/9/2022 | CPE00119S | PGE Nid Hydro Bowman Powerhouse – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |

**TABLE 8–3**
**RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Description |
|---|---|---|---|---|---|
| 118 | 5/9/2022 | CPE00120S | PGE Rock Creek Hydro Unit 1 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 119 | 5/9/2022 | CPE00121S | PGE Rock Creek Hydro Unit 2 – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 120 | 5/9/2022 | CPE00122S | PGE SRI International – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 121 | 5/9/2022 | CPE00123S | PGE Stanislaus Hydro – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 122 | 5/9/2022 | CPE00124S | PGE Summer Wheat Solar Farm – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 123 | 5/9/2022 | CPE00125S | PGE Tosco (Rodeo Plant) – Sale | Routine Amendment to Existing Agreement | Routine amendment terminates the Agreement upon submittal of a Self-Shown Attestation and receipt of a Self-Shown Validation Notice from the CPE. |
| 124 | 11/16/2022 | 33B236V01 | Central Coast Community Energy – Sale | Routine Amendment to Existing Agreement | Routine amendment modifies the MCC Buckets and Flex Categories. |
| 125 | 11/21/2022 | 33B241V01 | Direct Energy Business Marketing, LLC – Sale | Routine Amendment to Existing Agreement | Routine amendment modifies the MCC Buckets and Flex Categories. |

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 9

# CONTRACT ADMINISTRATION

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
CONTRACT ADMINISTRATION

TABLE OF CONTENTS

TABLE OF CONTENTS
(CONTINUED)

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 9
# CONTRACT ADMINISTRATION

## A. Introduction

Pacific Gas and Electric Company's (PG&E) Contract Management, Settlements, and Reporting (CMSR) Department administers PG&E's energy procurement contracts and payments with counterparties.

During the record period, PG&E complied with the California Public Utilities Commission's (CPUC or Commission) Standard of Conduct 4 (SOC4), adopted in Decision (D.) 02-10-062 and elaborated on in D.02-12-069, D.02-12-074, D.03-06-076, and D.05-01-054, regarding prudent contract administration. This chapter describes PG&E's contract administration practices, changes that occurred to the contracts administered, and the results achieved regarding contract administration during the record period.

In this chapter, PG&E will provide an overview of CMSR processes, including contract administration during the developing and operational phases of a contract, with descriptions of tools, systems, and controls. Additional information about CMSR processes, tools, systems, and controls is provided in the workpapers for this Chapter 9 (Contract Administration). This chapter also describes the following CMSR contract administration activities: (1) procurement programs and solicitations; (2) contracts executed; (3) project development and construction monitoring results; (4) contracts that began delivery; (5) contract amendments, consents to assignment and other transactions; (6) force majeure claims; (7) disputes; (8) contracts that expired or terminated; (9) other matters; and (10) amendments and transactions requiring CPUC approval.

This chapter demonstrates that PG&E complied with SOC4 with regards to prudent contract administration during the record period. A summary of CMSR's contract administration activities during the record period is below:

- CMSR successfully managed and settled 758 contracts, resulting in total energy purchases of 20,320 GWh. The purchase costs of energy and Resource Adequacy totaled $3,027,233,816; and the Renewable Energy Credit and Resource Adequacy sales totaled $171,161,727. The monthly energy purchases and costs incurred during the record period can be found in Table 9-4 at the end of this Chapter 9 (Contract Administration).

- CMSR managed 55 contracts of varying types that began delivery and/or achieved commercial operation. Contracts that began delivery during the record period can be found in Table 9-8, at the end of this Chapter 9 (Contract Administration).
- CMSR reviewed and administered terms of 57 amendments. The executed amendments addressed various matters, some generating customer value and reliability, including: extensions to contract milestones; modifications to contract term end date, contract price, or contract capacity; additional deliveries for summer reliability; increases in Buyer's curtailment rights; amended and restated contracts; repayment of amounts owed to PG&E; low side metering arrangements; consent to assignments (CTAs); and other administrative changes (e.g., typographical errors, multiple CAISO Resource IDs, and general clarifications). PG&E collected liquidated damages in the amount of $7,727,504.90, which represents incremental value for ratepayers through the execution of the amendments. Specifically, the amendments extended the timeline to achieve milestones in exchange for liquidated damages. Descriptions of these amendments can be found in Table 9-9, at the end of this Chapter 9 (Contract Administration).
- In total, CMSR administered 54 force majeure claims during the record period. By the time of this filing, CMSR has closed 36 of 54 force majeure claims and is continuing to monitor 18 force majeure claims. During the record period, 28 force majeure claims were initiated. A description of CMSR's process for administering force majeure claims can be found in Section C.6. of this Chapter 9 (Contract Administration). Descriptions of the force majeure claims administered during the record period can be found in Table 9-10, at the end of this Chapter 9 (Contract Administration).
- CMSR administered one (1) dispute initiated by a counterparty pursuant to the dispute resolution process in connection with the contract. CMSR managed this dispute per the process described in Section B.6. of this Chapter 9 (Contract Administration). This dispute is ongoing and has not been resolved at the time of this filing. A description of this dispute can be found in Section C.7.a. of this Chapter 9 (Contract Administration).

## B. Contract Management (CM) and Energy Settlement Process

### 1. Overview

Once a contract or transaction is executed, administration and settlement of the contract or transaction becomes the responsibility of CMSR. CMSR uses several tools, systems, and controls to administer contracts, and follows processes and procedures to ensure that transactions, new contracts, and amendments to existing contracts are implemented and administered consistently with the terms and conditions contained in each agreement. In general, CMSR processes involve the following, which are described in more detail in the sections below:

- Contract review, interpretation, and administration
- Active compliance monitoring
- Construction monitoring and performance testing
- Settlement and payment
- Dispute resolution
- Tools, systems, and controls

### 2. Contract Review, Interpretation, and Administration

Prior to contract execution, CMSR conducts a thorough review of each proposed transaction. During this review, CMSR works with the assigned settlement and commercial leads for the transaction to ensure that the contract can be administered. After review by CMSR staff, CMSR management approves the proposed transactions.

Once a contract is executed, CMSR reviews the contract data in the Consolidated Energy Contract Management (CECM) Database, and enters contract milestones, requirements, and tasks in the CECM Task Tracking Tool (T3). CMSR meets with key internal groups to review these documents, respond to questions, and obtain uniform understanding of the terms of the contract. CMSR also reviews the payment provisions in the contract.

In addition to this contract review, CMSR reviews and interprets the contract throughout its term in response to specific questions from other PG&E business groups or as issues arise. CMSR also provides support and guidance to the business groups on the use of CMSR tools and systems.

### 3. Active Compliance Monitoring

PG&E ensures compliance with contract terms by monitoring contract requirements throughout the contract lifecycle. Such activities involve tracking contract milestones and deadlines, reviewing documentation, ensuring that PG&E and the contract counterparties comply with contract provisions, and monitoring performance for projects that are already delivering contracted products to PG&E. PG&E also monitors Renewable Portfolio Standard (RPS) contracts consistent with the Commission's request that each utility ensure that Renewable Energy purchases are from an Eligible Renewable Energy Resource, as defined in California Public Utilities Code Section 399.12.

During the record period, CMSR conducted the following active monitoring activities in relation to renewable generation from RPS contracts:

- Regularly reviewed the California Energy Commission (CEC) website and verified that the counterparty's facility was pre-certified as a renewable resource before the facility began delivering electricity to PG&E and remains certified throughout the delivery term.
- Verified that the counterparty has an active account set up in the Western Renewable Energy Generation Information System (WREGIS).
- Reviewed and verified that metered volumes generated by RPS -certified facilities matched the Renewable Energy Certificate (REC) quantities received through WREGIS. PG&E worked with counterparties and WREGIS to identify why any REC deficits occurred and resolved those REC deficits. If REC deficits were unresolved, then PG&E adjusted invoices, as applicable, under the Power Purchase Agreements (PPA).
- Required an attestation included in each counterparty's monthly invoice that the facility is: (1) certified by the CEC as a California RPS-eligible resource; and (2) registered with WREGIS as a Generating Unit (as defined in the WREGIS Operating Rules).

### 4. Construction Monitoring and Performance Testing

#### a. Construction Monitoring and Safety

CMSR monitors the projects under development, generally from contract execution through commercial operation. Typically, a contract requires the counterparty to provide written progress reports on the project's development status to PG&E on a monthly or quarterly basis. CMSR reviews these reports, consulting with a PG&E Engineer when necessary. When further information is required, a follow-up conference call with counterparty personnel and/or a site inspection may be conducted.

During construction monitoring, CMSR reviews and tracks development activities, including site control, permitting, interconnection, financing, construction, and safety. Local, state, and federal agencies that have review and approval authority over the generation facilities are responsible for enforcing safety, environmental, and other regulations for the project, including decommissioning.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility has commenced deliveries under the contract only after the interconnecting utility and the California Independent System Operator (CAISO) have concluded such testing and given permission to commence commercial operations.

#### b. Performance Testing

Some contracts require the counterparty to periodically demonstrate the performance capabilities of the applicable generating station(s) through testing. Engineers may witness performance tests of counterparties' generating stations. Performance testing typically determines a facility's full load-generating capacity and heat rate. Performance test-related activities include developing test procedures, witnessing tests, and reviewing and approving test reports/results. The test results are reported to various organizations within PG&E.

### 5. Settlement and Payment

The Energy Settlements section within CMSR is responsible for ensuring the proper settlement of all contracts in PG&E's electric and gas portfolio. Electric contracts include but are not limited to: RPS; Tolling; Qualifying Facility (QF) Must-Take; QF and Combined Heat and Power (CHP) Settlement; Feed-In Tariff (FIT); Irrigation District and Water Agency (ID&WA) legacy contracts; Short- and Long-Term Resource Adequacy (RA) agreements; Power Trading Master agreements; and Storage agreements.

The purpose of the settlement process is to ensure that all contract payments are in accordance with the terms and conditions of each contract, and that these costs are fully documented and properly reported in PG&E's financial systems. The settlement process includes: collecting and validating generation, generator scheduling, and outage data; collecting pricing from market indices; calculating and composing invoices; and preparing payment data for the Accounts Payable Department.

Settlement data is collected from various sources, including PG&E's metering systems, the CAISO, other PG&E departments, various price indices, and the generators themselves. The settlements cycle generally takes up to 25 calendar days to process all invoices through calculation, approval, and payment.

After each month's settlement activities are complete, Energy Settlements prepares additional financial and other reports. Energy Settlements also oversees process improvements on other information systems in Energy Policy and Procurement (EPP) so that the tools are maintained to keep pace with additional contract requirements. Additional responsibilities include: maintaining and testing EPP's internal controls in accordance with Sarbanes-Oxley requirements; and acting as the liaison to PG&E's Corporate Accounting Department concerning energy-related disclosures for compliance reporting purposes.

The team supporting electric contracts in Energy Settlements currently has four distinct areas of responsibility: (1) RPS Settlements; (2) Tolling and Storage Settlements; (3) QF/CHP and FIT Settlements; and (4) CAISO Settlements and Reporting. These functions and the tools that support these functions are described below:

- **RPS Settlements:** This group is responsible for invoice validation and payment processing of all RPS contracts, bilateral purchase and sales contracts which include Power Trading Master agreements (including all electric financial instruments).
- **Tolling and Storage Settlements:** This group is responsible for the invoice validation and payment processing of all conventional natural gas tolling contracts and Long-Term Resource Adequacy agreements. In addition, this group calculates Greenhouse Gas (GHG) amounts for all contracted Tolling facilities participating in the California Air Resource Board (CARB) Cap-and-Trade program.
- **QF/CHP and FIT Settlements:** This group is responsible for invoice validation and payment processing of all QF Must-Take agreements, ID&WA legacy contract, and form agreements that arose from the QF/CHP Settlement and were approved by the CPUC in D.10-12-035. In addition, this group settles the FIT agreements promulgated by California Assembly Bill (AB) 1969, AB 1613, Senate Bill (SB) 32 Renewable Market Adjusting Tariff (ReMAT), and SB 1122 Bioenergy Market Adjusting Tariff (BioMAT), as well as the quarterly Greenhouse Gas (GHG) invoices from the California Air Resources Board.
- **CAISO Settlements and Reporting:** This group is responsible for validation, settlement and reporting of procurement costs and generation revenues associated with PG&E's participation in the CAISO electricity markets as described in Chapter 10 (CAISO Settlements and Monitoring). This group also provides reporting data and analysis to internal organizations for the monthly Corporate Accounting close, the Controller's Gross Margin Analysis, WREGIS data submittal, RPS reports, the 10-Q/10-K processes, GHG and various internal and external requests.

Energy Settlements uses the following tools and databases for the ongoing processing of invoices and reporting responsibilities discussed above:

- **OpenLink Endur:** The OpenLink Endur system provides a module for managing, invoicing, and reporting all power trading and contract settlement activities. Energy Settlements uses the Endur system to import meter data and outages from upstream systems, and review generation data and to invoice transactions.

- **Energy Settlements Tool for Analysis and Reporting (ESTAR):** ESTAR is used to collect and manage unit-specific temperature and gas meter data to calculate the gas balancing true-up adjustments for Tolling Agreements. ESTAR calculations are sent to the Endur system to complete settlements activities.
- **Market Data Repository (MDR)/ETO1P:** MDR/ETO1P is a PG&E application and database which stores all CAISO market and PG&E settlement data. The information is automatically downloaded from CAISO on a daily basis and includes resource level charges and credits at the interval level. This data is used to compile the financial and regulatory reporting of CAISO market transactions.

For a detailed description of the processes that Settlements uses, refer to the workpapers for this Chapter 9 (Contract Administration) (see “Energy Settlements’ Payment Guide”).

**6. Dispute Resolution**

CMSR manages disputes that arise in connection with the contracts. Initially, CMSR attempts to resolve conflicts through discussions. If the issue cannot be resolved through initial discussions, CMSR may conduct negotiations directly with the counterparty to resolve the dispute, as prescribed by the contract. If such discussions and negotiations are unsuccessful and formal mediation or arbitration becomes necessary, CMSR develops and pursues resolution strategies consistent with the best interests of customers. CMSR supports and participates in these stages of dispute resolution and works with PG&E’s Law Department and other internal stakeholders, as applicable, until a final resolution is achieved. These activities include support for discovery and developing positions and proposals for dispute resolution.

**7. Tools, Systems and Controls**

CMSR uses a number of tools and systems that serve as controls in the CM and Energy Settlements process. These tools and systems help ensure that contracts are administered according to their terms and conditions, and that there is continuity in CMSR for the entire length of the contract term, which is important given that many of PG&E's contracts have terms of 20 years or more.

Furthermore, these tools, systems, and controls play a key role in helping CMSR document, maintain, and report contract information for the purpose of providing data to both internal and external stakeholders.

Upon execution of a contract, an assigned lead creates or updates records within CMSR's tools and systems. The lead requests that the assigned CM Analysts review their entries for completeness. For contract data that changes (e.g., project status), CMSR, along with other PG&E departments (e.g., EPP, Market and Credit Risk Management, etc.), reviews the data for consistency.

The primary tools, systems, and controls used by CMSR are described below:

- **Master Contract List:** A complete listing of all contracts administered by CMSR. The list: (1) is used only by internal stakeholders (e.g., EPP, Law, Internal Audit, etc.); (2) contains links to documents stored in the electronic document management system, Documentum (D2) (described below); and (3) includes the assigned CM Analyst and Settlements Analyst for each contract.
- **D2:** A web-based electronic document management system, offering secure document storage and retrieval, that contains documents pertaining to our contracts. These documents include executed contract documents and significant correspondence.
- **CECM Database:** A database containing information on all contracts managed by CMSR. This database is the source for tools such as the Master Contract List, Executed Transactions List (described below), and for reports. The CECM Database contains information such as: energy products; critical milestones; regulatory and permitting status; and pricing and credit information, as applicable.
- **Task Tracking Tool (T3):** A tracking system within the CECM Database that utilizes contractual milestone dates to provide reminders for contract administration tasks. Task notifications can be configured to

automatically escalate to analysts and managers to ensure obligations are monitored through to their timely resolution.

- **Executed Transactions List (ETL):** A chronological listing of portfolio-level changes (e.g., executions, terminations, and expirations) and executed contract transactions (e.g., amendments, letter agreements, etc.). This tool is used to help prepare and review reports and data requests.
- **Scheduling Protocols:** Contract -specific reports summarizing basic contract information, such as contract quantity, delivery point, contact information, scheduling terms, and operational parameters for PG&E's contracted generation.
- **CM Intranet Site (SharePoint):** An intranet site, maintained and controlled by CMSR, which facilitates the sharing of process documents and contract information with other stakeholders within PG&E. The following tools and systems reside on or can be accessed from the CM SharePoint site: Master Contract List, D2, and Executed Transactions List.

## C. Contract Administration During the Record Period

This section discusses the administration of contracts that were in or added to PG&E's portfolio during the record period, and any significant changes to these contracts that occurred.

### 1. Procurement Programs and Solicitations

This section describes PG&E procurement programs and solicitations administered by CMSR which had activity during the record period. A summary of the following procurement programs and solicitations can be found in Table 9-1, in this Chapter 9 (Contract Administration).

#### a. ReMAT

Pursuant to D.12-05-035 and D.13-05-034, PG&E was allocated 218.8 megawatts (MW) of the 750 MW total statewide goal to procure from small, distributed generation qualifying as "eligible renewable energy resources." On December 15, 2017, the CPUC suspended the ReMAT program.

On October 16, 2020, the CPUC issued decision D.20-10-005 to resume and modify the ReMAT program. Pursuant to the decision, PG&E filed AL 5994-E and AL 5994-E-A, which was approved by the CPUC on January 22, 2021.

On December 17, 2021, the CPUC issued decision D.21-12-032. The decision implemented multiple changes in the ReMAT program, including opening eligibility for storage projects and projects with shared interconnection facilities. PG&E was ordered to respond with a Tier 2 AL within 45 days of the decision. On January 27, 2022, the Executive Director of the CPUC granted a joint extension request from PG&E and the other two IOUs, extending the due date to comply with OP 8 of D.21-12-032 until March 15, 2022. Pursuant to the decision, PG&E submitted AL 6528-E on March 15, 2022, which was approved by the CPUC on September 1, 2022. During the record period, PG&E did not execute any ReMAT PPAs.

**b. BioMAT**

Pursuant to D.14-12-081, D.15-09-004, and Resolution (Res.) E-4922,[1] PG&E issued bi-monthly auctions during the record period for the BioMAT program Category 1 (biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion) and Category 2 (biogas or biomass from dairy and other agricultural waste), and monthly auctions for Category 3 (biogas or biomass using byproducts of sustainable forest management). PG&E was allocated 111 MW of the 250 MW total IOU procurement target for bioenergy resources. On October 11, 2022, the CPUC issued an Order Instituting Rulemaking to implement AB 843, which will allow for Community Choice Aggregators participation in BioMAT. During the record period, PG&E did not execute any BioMAT PPAs.

**c. Carbon Free Energy Sales**

Pursuant to Res.E-5111, which approved updates to Appendix P of the Bundled Procurement Plan (BPP) submitted in PG&E's AL 5930-E,

---

1 Res.E-4922 ordered the IOUs to continue to hold BioMAT program periods, accept new BioMAT applications, and execute BioMAT contracts.

during the record period, PG&E engaged in sales of Carbon Free Energy produced from large hydroelectric and nuclear resources to eligible Load Serving Entities (LSE) for delivery year 2023. In these sales, PG&E offered each eligible LSE a quantity of Carbon Free Energy based on an allocation of the eligible LSE's corresponding customers' proportional share of forecasted monthly load set forth in PG&E's Energy Resource Recovery Account (ERRA) Forecast Application for the year.

The sales complied with Appendix P of the BPP. Additionally, pursuant to Res.E-5111, prior to engaging in sales of Carbon Free Energy for delivery year 2023, PG&E filed AL 6720-E on September 30, 2022, which stated PG&E's intent to sell Carbon Free Energy for 2023. Information regarding PG&E's sales of Carbon Free Energy can be found in Table 9-1, in this Chapter 9 (Contract Administration), and Table 9-5, at the end of this Chapter 9 (Contract Administration).

**d. Disadvantaged Communities Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT)**

Pursuant to D.18-06-027, D.18-10-007, and Res.E-4999, PG&E held two solicitations during the record period for the DAC program. The Summer 2022 solicitation opened on September 6, 2022, and closed on October 3, 2022. There were no contracts executed out of this solicitation. The Winter 2022 solicitation opened on December 21, 2022, and was ongoing at the end of the record period. During the record period, four contracts were executed out of the Fall 2021 solicitation, which was held prior to the record period. Information regarding the solicitations is contained in Chapter 5 (Review Entries Recorded in the DAC-GT Balancing Account and the DAC – CS-GT Balancing Account) and information regarding the administration of DAC contracts, can be found in Table 9-1, in this Chapter 9 (Contract Administration), and Table 9-5, at the end of this Chapter 9 (Contract Administration).

**e. Green Tariff Shared Renewable (GTSR) – Regional Renewable Choice (RRC) and Solar Choice**

Pursuant to D.15-01-051 and D.16-05-006, PG&E held two solicitations during the record period for the RRC and Solar Choice programs. The Spring 2022 solicitation opened on March 31, 2022, and closed on May 6, 2022. The Fall 2022 solicitation opened on October 14, 2022, and closed on November 14, 2022. No contracts were executed out of either solicitation. Information regarding the solicitations is contained in Chapter 11 (Review Entries Recorded in the GTSR Memorandum Account and the GTSR Balancing Account) and information regarding the administration of RRC and Solar Choice contracts can be found in Table 9-1, in this Chapter 9 (Contract Administration), and Table 9-5, at the end of this Chapter 9 (Contract Administration).

**f. New Public Utility Regulatory Policies Act (PURPA) Standard Offer Contract (SOC)**

Pursuant to D.20-05-006, the IOUs developed a new PURPA SOC, which was approved by the CPUC on November 19, 2020, in Res.E-5104, with modifications. On November 30, 2020, PG&E filed AL 6013-E with the requested modifications, which was approved by the CPUC on December 22, 2020. On June 10, 2022, the CPUC issued D. 22-06-003, authorizing the IOUs to offer the new PURPA SOC to hybrid and co-located storage-paired Qualifying Facilities and requiring the IOUs to submit a Tier 1 AL with modifications to the new PURPA SOC within 15 days of the decision. On June 27, 2022, PG&E filed AL 6629-E with the requested modifications, which was approved by the CPUC on November 16, 2022. During the record period, PG&E did not execute any contracts using the new PURPA SOC.

**g. Renewable Energy Sales (Short Term and Long Term REC Sales)**

Pursuant to D.22-01-004, PG&E held a solicitation to sell renewable energy and corresponding RECs through the Bundled RPS Energy Sale Solicitation in July 2022. The sales contracts executed through these solicitations comply with PG&E's 2021 RPS Plan and follow the strategy described in the Sales Framework in Appendix H of the 2021 RPS Plan.

**h. Resource Adequacy (RA)**

PG&E, as an LSE, participates in the CPUC's RA program.[2] PG&E engaged in various RA procurement activities throughout the year. Information regarding RA solicitations and administration of RA contracts can be found in Chapter 8 (Resource Adequacy).

**i. Mid-Term Reliability**

On June 30, 2021, the CPUC issued D.21-06-035 which required PG&E to procure at least 2,302 MW of additional net qualifying capacity, to come online between August 1, 2023, and June 1, 2026. D.21-06-035 requires PG&E to procure and have online 400 MW by August 1, 2023, 1,201 MW by June 1, 2024, 300 MW by June 1, 2025, and 400 MW by June 1, 2026. PG&E issued the Mid-Term Reliability RFO Phase 2 on April 15, 2022, seeking offers from market participants for the purchase of eligible system RA to come online by June 1, 2024, June 1, 2025, or June 1, 2026. During the record period, PG&E executed two (2) contracts related to D.21-06-035.

**j. Demand Response (DR) Bilateral Contracting – (Witness: Sebastien Csapo)**

On December 6, 2021, the CPUC issued D.21-12-015 in the rulemaking (R.20-11-003) to establish policies and processes to ensure reliable service in the event of an extreme heat event.[3] Among numerous actions for strengthening demand side activities, D.21-12-015 ordered the IOUs to engage in bilateral contracting for DR resources and adopt a capacity payment structure using PG&E's Capacity Bidding Program to govern the contract payment framework.[4] During the record

---

[2] D.04-10-035, D.05-10-042, D.06-06-064, D.14-06-050, D.19-02-022, D.20-06-002, D.20-06-028, D.20-06-031, and D.2106-029.

[3] Phase 1 of the Rulemaking resulted in the issuance of D.21-02-028 and D.21-03-056 to support grid needs.

[4] D.21-12-015, OP 13, Attachment 1 at p. 3-4, COL 41, and FOF 112.

period, PG&E issued a solicitation and executed one contract, totaling 5 MW, for RA for the month of September 2022.[5]

**k. Voluntary Allocation and Market Offers (VAMO)**

On May 24, 2021, the CPUC issued D.21-05-030 in the Power Charge Indifference Adjustment (PCIA) rulemaking (R.17-06-026) to establish the VAMO framework for disposition of the utilities' PCIA-eligible products. The decision ordered IOUs to offer PCIA-eligible LSEs voluntary allocations of PCIA-eligible resources, and then sell any unallocated resources through a market offer process. During the record period, PG&E executed ten contracts for the Voluntary Allocation.

**2. Contracts Executed**

The list below summarizes the number of contracts executed during the record period. A detailed listing of the contracts executed during the record period can be found in Table 9-5 at the end of this Chapter 9 (Contract Administration), except for RA contracts, which are addressed in Table 8-2 of Chapter 8 (Resource Adequacy).

---

5 Advice Letter 6619-E approved via disposition letter.

**TABLE 9-1**
**PROCUREMENT PROGRAMS, SOLICITATIONS, AND CONTRACTS EXECUTED**

| Line No. | Type of Contract | Procurement Type | Number of Contracts Executed |
|---|---|---|---|
| 1 | ReMAT | Feed-in Tariff | – |
| 2 | BioMAT | Feed-in Tariff | – |
| 3 | Carbon Free Energy (Sale) | Solicitation | 17 |
| 4 | DAC-GT | Solicitation | 5 |
| 5 | GTSR | Solicitation | - |
| 6 | QF SOC PURPA 2020 | N/A | - |
| 7 | RPS Energy REC Sale | Solicitation | 17 |
| 8 | RA[(a)] | Solicitation | 66 |
| 9 | Energy Storage[(b)] | Solicitation | 2 |
| 10 | EEI Master | N/A | 3 |
| 11 | DR RA Bilateral | Solicitation | 1 |
| 12 | Voluntary Allocation | Allocation/Solicitation | 10 |
| 13 | Total | | 121 |

(a) RA contracts through electronic solicitation.
(b) Contracts resulting from Mid-Term Reliability RFO

### 3. Project Development and Construction Monitoring Results

CMSR monitors projects under development and tracks contract milestones. During the record period, several counterparties exercised permitted extensions of contract milestones or missed key contract milestones. A detailed list of contracts that exercised permitted extensions or missed key contract milestones can be found in Tables 9-6 and 9-7, respectively, at the end of this Chapter 9 (Contract Administration).

### 4. Contracts That Began Delivery

The list below summarizes the number of contracts that began delivering during the record period. A detailed list of the contracts that began delivering during the record period can be found in Table 9-8 at the end of this Chapter 9 (Contract Administration).

**TABLE 9-2**
**CONTRACTS THAT BEGAN DELIVERY**

| Line No. | Type of Contract | Number of Contracts That Began Delivery | Total Contract Size (MW) |
|---|---|---|---|
| 1 | BioMAT | 1 | 3 |
| 2 | Carbon Free Energy (Sale) | 17 | – |
| 3 | Energy Storage | 10 | 687 |
| 4 | QF SOC PURPA 2020 | 1 | 17.45 |
| 5 | RPS | 3 | 76.5 |
| 6 | RPS Energy REC Sale | 22 | – |
| 7 | DR RA Bilateral | 1 | 5 |
| 8 | Total | 55 | 788.95 |

### 5. Contract Amendments, Consents to Assignment and Other Transactions

Contracts that had amendments, Consent to Assignments, and other similar agreements executed during the record period can be found in Table 9-9, at the end of this Chapter 9 (Contract Administration).

### 6. Force Majeure Claims

A force majeure is an instance when unforeseeable circumstances occur that prevent one or both parties from fulfilling obligations under the contract. PG&E responds to force majeure claims by reviewing the contract as well as the facts surrounding the force majeure claim. During the record period, PG&E monitored various force majeure claims, including force majeure claims pertaining to wildfires, COVID-19, supply chain issues, shipping delays, import tariffs, civil unrest, and war. The force majeure claims addressed during the record period can be found in Table 9-10, at the end of this Chapter 9 (Contract Administration).

### 7. Disputes

This section describes matters in which PG&E and a counterparty engaged in a dispute resolution process provided for under the agreement (listed in order by the date the dispute was initiated).

**a. Global Ampersand, LLC, El Nido Biomass Facility and Chowchilla Biomass Facility (PG&E Log Nos. 33R016 and 33R017)**

On May 18, 2022, Global Ampersand, LLC (Global) initiated the dispute resolution process for the El Nido Biomass Facility and the Chowchilla Biomass Facility, related to the administration and settlement of Seller Excuse Hours and performance penalties. PG&E and Global participated in the dispute resolution process during the record period, and both parties remain actively engaged in discussions. The dispute is ongoing and has not been resolved at the time of this filing.

### 8. Contracts That Expired or Terminated

The list below summarizes the number of contracts that expired or were terminated during the record period. A detailed listing of the contracts that expired or were terminated during the record period can be found in Table 9-11 at the end of this Chapter 9 (Contract Administration).

**TABLE 9-3**
**CONTRACTS THAT EXPIRED OR TERMINATED**

| Line No. | Type of Contract | Number of Contracts Expired | Number of Contracts Terminated |
|---|---|---|---|
| 1 | AB1969 | 3 | – |
| 2 | BioMAT | – | 2 |
| 3 | Energy Storage | – | 2 |
| 4 | QF/CHP Settlement | 1 | – |
| 5 | QF | 1 | 1 |
| 6 | ReMAT | – | 1 |
| 7 | RPS | 3 | – |
| 8 | Tolling | 9 | – |
| 9 | DR RA Bilateral | 1 | – |
| 10 | Total | 18 | 6 |

## D. Other Matters

In addition to the activity described above, this section describes other matters that occurred during the record period.

### 1. North Fork Community Power LLC, North Fork Community Power (PG&E Log No. 33R433BIO)

On October 11, 2022, Seller filed for Voluntary Petition for Non-Individuals Filing for Bankruptcy, Chapter 11 in the United States Bankruptcy Court for the Northern District of California, Case: 22-41001 (the

"Bankruptcy Petition"). Pursuant to Section 13.2.1.1 of the PPA, an Event of Default occurs when a Party "becomes Bankrupt", thus Seller's filing of the Bankruptcy Petition constitutes an Event of Default. [redacted]

**2. DR RA Bilateral Contract (PG&E Log No. 2022-DR-RA-1) – (Witness: Sebastien Csapo)**

On December 27, 2022, Voltus, Inc. (Voltus), submitted an invoice for September 2022 deliveries [redacted]. Although PG&E was able to claim the contracted RA for September 2022, [redacted]. On January 20, 2023, PG&E consulted with Energy Division and determined that [redacted]. Accordingly, on January 27, 2023, PG&E sent a response letter to Voltus, [redacted].

PG&E recognizes that Voltus [redacted]. PG&E believes the learnings from the solicitation process, including the use of a non-DR contract (i.e., supply side RA contract) and the leveraging of CAISO data to support settlement, have provided valuable insight to PG&E for future DR contracting.

## E. Request for Approval of Amendments and Transactions

PG&E requests that the Commission approve the following contract amendment that occurred during the record period. PG&E is not requesting express approval of each amendment entered into during the record period. Many amendments and transactions are routine and/or administrative in nature and are approved as a part of PG&E's contract administration during the record period. Other contract amendments and transactions entered into during the record period were submitted to the Commission for review and approval in separate applications or advice letters. PG&E is requesting express Commission approval of one (1) amendment that was not separately approved through another Commission mechanism or process in this ERRA filing. A copy of the amendment for which PG&E is seeking approval for in this Application, as described in this Section E, and a copy of the underlying agreement are included in the workpapers for this Chapter 9 (Contract Administration).

#### 1. Calpine Russell City Energy Center (PG&E Log No. 33B075)

PG&E is requesting Commission review and approval in this ERRA filing of the transaction with Calpine Russell City Energy Center. The contract with Calpine Russell City Energy Center has a term end date of August 7, 2023, which does not coincide with the end of the month. Because RA attributes are a monthly product, PG&E will not be able to claim RA for the month of August 2023 under the contract. On May 20, 2022, parties executed an amendment updating the expiration date of the contract from August 7, 2023, to July 31, 2023. Additionally, the amendment allows Calpine to seek a new buyer of RA attributes for August 2023 and provides savings to ratepayers.

### F. Conclusion

The above testimony describes PG&E’s contract administration practices, changes that occurred to the contracts administered, and the results achieved with regard to contract administration during the record period and demonstrates that PG&E’s contract administration during the record period was reasonable and in compliance with SOC4.

## TABLE 9-4
## ENERGY PURCHASES AND COSTS[1]
## JANUARY 1, 2022, THROUGH DECEMBER 31, 2022

| Line No. | Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Renewable Generation | [redacted] | | | | | | | | | | | | |
| 2 | Total Energy (MWh) | | | | | | | | | | | | | 15,279,280 |
| 3 | Total Payments ($) | | | | | | | | | | | | | $2,097,107,698 |
| 4 | Renewable Energy Credit Sale[2] | | | | | | | | | | | | | |
| 5 | Total Energy (MWh) | | | | | | | | | | | | | (2,936,233) |
| 6 | Total Payments ($) | | | | | | | | | | | | | ($38,778,683) |
| 7 | Qualifying Facility and CHP Generation | | | | | | | | | | | | | |
| 8 | Total Energy (MWh) | | | | | | | | | | | | | 1,842,487 |
| 9 | Total Payments ($) | | | | | | | | | | | | | $223,273,138 |
| 10 | Conventional Generation | | | | | | | | | | | | | |
| 11 | Total Energy (MWh) | | | | | | | | | | | | | 3,164,580 |
| 12 | Total Payments ($) | | | | | | | | | | | | | $571,771,085 |
| 13 | Energy Storage | | | | | | | | | | | | | |
| 14 | Total Energy (MWh) | | | | | | | | | | | | | 0 |
| 15 | Total Payments ($) | | | | | | | | | | | | | $54,334,342 |
| 16 | Other Must-Takes | | | | | | | | | | | | | |
| 17 | Total Energy (MWh) | | | | | | | | | | | | | 33,516 |
| 18 | Total Payments ($) | | | | | | | | | | | | | $3,818,966 |
| 19 | Resource Adequacy | | | | | | | | | | | | | |
| 20 | Total Energy (MWh) | | | | | | | | | | | | | 0 |
| 21 | Total Payments ($) | | | | | | | | | | | | | $76,928,588 |
| 22 | Resource Adequacy Sales[2] | | | | | | | | | | | | | |
| 23 | Total Energy (MWh) | | | | | | | | | | | | | 0 |
| 24 | Total Payments ($) | | | | | | | | | | | | | ($132,383,044) |
| 25 | Total Energy (MWh) | | | | | | | | | | | | | 17,383,630 |
| 26 | Total Payments ($) | | | | | | | | | | | | | $2,856,072,089 |

[1] Energy Purchase and Cost figures provided in this table are intended for illustrative purposes only, and may reflect simplifications and adjustments. See Chapters 12 and 13 of this testimony for more information on PABA and ERRA entries during the record period.

[2] Sales represented as negative payments.

**TABLE 9-5**
**CONTRACT ADMINISTRATION**
**CONTRACTS EXECUTED DURING RECORD PERIOD 2022**

| Line No. | Date | PG&E Log Number | Project Name | Capacity (MW) | Contract Type |
|---|---|---|---|---|---|
| 1 | 1/13/2022 | 33B273 | High Desert Power Project, LLC | 0 | EEI Master |
| 2 | 2/1/2022 | 33R525 | East Bay Community Energy Authority | 0 | RPS Energy REC Sales |
| 3 | 2/4/2022 | 33R526 | Central Coast Community Energy | 0 | RPS Energy REC Sales |
| 4 | 2/9/2022 | 33R527 | Orange County Power Authority | 0 | RPS Energy REC Sales |
| 5 | 2/9/2022 | 33R528 | Orange County Power Authority | 0 | RPS Energy REC Sales |
| 6 | 2/14/2022 | 33R529 | Silicon Valley Clean Energy Authority | 0 | RPS Energy REC Sales |
| 7 | 3/23/2022 | 33R530 | City of San Jose (San Jose Clean Energy) | 0 | RPS Energy REC Sales |
| 8 | 3/23/2022 | 33R531 | City of San Jose (San Jose Clean Energy) | 0 | RPS Energy REC Sales |
| 9 | 6/9/2022 | 2022-DR-RA-1 | DR RA Bilateral Contract | 5 | DR RA Bilateral |
| 10 | 7/21/2022 | VM00006V | City of San Jose | 0 | Voluntary Allocation |
| 11 | 7/21/2022 | VM00005V | Shell North America (US), L.P. | 0 | Voluntary Allocation |
| 12 | 7/25/2022 | VM00001V | City and County of San Francisco, Acting by and through its Public Utilities Commission, CleanPowerSF | 0 | Voluntary Allocation |
| 13 | 7/25/2022 | VM00003V | Commercial Energy of Montana, Inc. | 0 | Voluntary Allocation |
| 14 | 7/25/2022 | VM00002V | Direct Energy Business Marketing, LLC | 0 | Voluntary Allocation |
| 15 | 7/25/2022 | VM00008V | East Bay Community Energy | 0 | Voluntary Allocation |
| 16 | 7/25/2022 | VM00010V | Marin Clean Energy | 0 | Voluntary Allocation |
| 17 | 7/25/2022 | VM00004V | Pioneer Community Energy | 0 | Voluntary Allocation |
| 18 | 7/25/2022 | VM00007V | Silicon Valley Clean Energy | 0 | Voluntary Allocation |
| 19 | 7/26/2022 | VM00009V | Redwood Coast Energy Authority | 0 | Voluntary Allocation |
| 20 | 8/22/2022 | 33R532 | RPCA Solar 6, LLC | 5 | DAC-GT |

**TABLE 9-5**
**CONTRACT ADMINISTRATION**
**CONTRACTS EXECUTED DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Capacity (MW) | Contract Type |
|---|---|---|---|---|---|
| 21 | 8/22/2022 | 33R533 | RPCA Solar 8, LLC | 5 | DAC-GT |
| 22 | 8/22/2022 | 33R534 | RPCA Solar 1, LLC | 5 | DAC-GT |
| 23 | 8/22/2022 | 33R535 | RPCA Solar 1, LLC | 2.56 | DAC-GT |
| 24 | 9/23/2022 | 33B277 | City Of Lancaster | 0 | EEI Master |
| 25 | 9/30/2022 | 33B278 | San Diego Community Power | 0 | EEI Master |
| 26 | 9/30/2022 | 33R536 | East Bay Community Energy Authority | 0 | RPS Energy REC Sales |
| 27 | 9/30/2022 | 33R537 | Clean Energy Alliance | 0 | RPS Energy REC Sales |
| 28 | 9/30/2022 | 33R538 | City Of Lancaster | 0 | RPS Energy REC Sales |
| 29 | 9/30/2022 | 33R539 | East Bay Community Energy Authority | 0 | RPS Energy REC Sales |
| 30 | 10/3/2022 | 33R543 | City of San Jose (San Jose Clean Energy) | 0 | RPS Energy REC Sales |
| 31 | 10/4/2022 | 33R540 | Constellation Energy Generation, LLC | 0 | RPS Energy REC Sales |
| 32 | 10/4/2022 | 33R541 | San Diego Community Power | 0 | RPS Energy REC Sales |
| 33 | 10/4/2022 | 33R542 | San Diego Community Power | 0 | RPS Energy REC Sales |
| 34 | 10/12/2022 | 33R544 | San Diego Community Power | 0 | RPS Energy REC Sales |
| 35 | 10/12/2022 | 33R545 | East Bay Community Energy Authority | 0 | RPS Energy REC Sales |
| 36 | 11/9/2022 | 33R533-AR | RPCA Solar 8, LLC | 5 | DAC-GT |
| 37 | 12/16/2022 | 33B022CA04 | Shell Energy North America (US), L.P. | 0 | Carbon Free Energy (Sale) |
| 38 | 12/16/2022 | 33B113CA02 | 3 Phases Renewables | 0 | Carbon Free Energy (Sale) |
| 39 | 12/16/2022 | 33B202CA04 | Commercial Energy of Montana | 0 | Carbon Free Energy (Sale) |
| 40 | 12/16/2022 | 33B211CA04 | Calpine Energy Solutions, LLC | 0 | Carbon Free Energy (Sale) |

**TABLE 9-5**
**CONTRACT ADMINISTRATION**
**CONTRACTS EXECUTED DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Capacity (MW) | Contract Type |
|---|---|---|---|---|---|
| 41 | 12/16/2022 | 33B226CA04 | Sonoma Clean Power Authority | 0 | Carbon Free Energy (Sale) |
| 42 | 12/16/2022 | 33B230CA04 | Silicon Valley Clean Energy Authority | 0 | Carbon Free Energy (Sale) |
| 43 | 12/16/2022 | 33B232CA04 | Peninsula Clean Energy Authority | 0 | Carbon Free Energy (Sale) |
| 44 | 12/16/2022 | 33B235CA04 | Marin Clean Energy | 0 | Carbon Free Energy (Sale) |
| 45 | 12/16/2022 | 33B236CA05 | Central Coast Community Energy | 0 | Carbon Free Energy (Sale) |
| 46 | 12/16/2022 | 33B238CA05 | East Bay Community Energy Authority | 0 | Carbon Free Energy (Sale) |
| 47 | 12/16/2022 | 33B243CA04 | CleanPowerSF | 0 | Carbon Free Energy (Sale) |
| 48 | 12/16/2022 | 33B245CA04 | Pioneer Community Energy | 0 | Carbon Free Energy (Sale) |
| 49 | 12/16/2022 | 33B247CA04 | City of San Jose (San Jose Clean Energy) | 0 | Carbon Free Energy (Sale) |
| 50 | 12/16/2022 | 33B254CA04 | Valley Clean Energy Alliance | 0 | Carbon Free Energy (Sale) |
| 51 | 12/16/2022 | 33B255CA04 | Direct Energy Business, LLC | 0 | Carbon Free Energy (Sale) |
| 52 | 12/16/2022 | 33B259CA04 | Redwood Coast Energy Authority | 0 | Carbon Free Energy (Sale) |
| 53 | 12/16/2022 | 33B261CA04 | The Regents of the University of California | 0 | Carbon Free Energy (Sale) |
| 54 | 12/22/2022 | 40S041 | Geysers Power Company, LLC | 12 | Energy Storage |
| 55 | 12/22/2022 | 40S042 | Geysers Power Company, LLC | 23.5 | Energy Storage |

Notes: See Chapter 7 for testimony regarding GHG Compliance Instrument Procurement.
See Chapter 8 for testimony regarding RA procurement.

**TABLE 9-6**
**CONTRACT ADMINISTRATION**
**PERMITTED EXTENSIONS DURING RECORD PERIOD 2022**

| Line No. | Date of Request | PG&E Log Number | Project Name | Contract Type | Description |
|---|---|---|---|---|---|
| 1 | 3/8/2022 | 33R470BIO | RuAnn Dairy Digester | BioMAT | GCOD[(a)] was extended from 5/8/2022 to 11/8/2022. |
| 2 | 3/29/2022 | 33R419 | RE Gaskell West 3 | RPS | GCOD was extended from 12/1/2022 to 2/6/2023. |
| 3 | 3/29/2022 | 33R420 | RE Gaskell West 4 | RPS | GCOD was extended from 12/1/2022 to 2/6/2023. |
| 4 | 3/29/2022 | 33R421 | RE Gaskell West 5 | RPS | GCOD was extended from 12/1/2022 to 2/6/2023. |
| 5 | 6/27/2022 | 33R479BIO | Abel Road Bioenergy | BioMAT | GCOD was extended from 7/10/2022 to 7/31/2022. |
| 6 | 12/7/2022 | 33R393 | Java Solar | RPS | GCOD was extended from 10/1/2022 to 1/19/2023. |
| 7 | 9/8/2022 | 33R433BIO | North Fork Community Power | BioMAT | GCOD was extended from 8/22/2022 to 8/22/2023 [(b)]. |

(a) Guaranteed Commercial Operation Date (GCOD).
(b) Subject to payment of delay damages by Seller, per the 8/29/2022 PPA amendment. See Table 9-9 (Contract Amendments and Consents to Assignment) for more information.

**TABLE 9-7**
**CONTRACT ADMINISTRATION**
**MISSED MILESTONES DURING RECORD PERIOD 2022**

| Line No. | Original Milestone Date | PG&E Log Number | Project Name | Contract Type | Milestone | Date of Event | Description |
|---|---|---|---|---|---|---|---|
| 1 | 8/1/2022 | 40S026 | Nexus Renewables | Energy Storage | Expected Initial Delivery Date | 8/1/2022 Missed Expected Initial Delivery Date | [redacted] |
| 2 | 8/1/2022 | 40S027 | Lancaster Battery Area Storage | Energy Storage | Expected Initial Delivery Date | 8/1/2022 Missed Expected Initial Delivery Date | |
| 3 | 8/1/2022 | 40S024 | LeConte Energy Storage | Energy Storage | Expected Initial Delivery Date | 8/1/2022 Missed Expected Initial Delivery Date | |

**TABLE 9-7**
**CONTRACT ADMINISTRATION**
**MISSED MILESTONES DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Original Milestone Date | PG&E Log Number | Project Name | Contract Type | Milestone | Date of Event | Description |
|---|---|---|---|---|---|---|---|
| 4 | 8/23/2022 | 33R433BIO | North Fork Community Power | BioMAT | Guaranteed COD | 8/23/2022 Missed Guaranteed Commercial Operation Date | [redacted] |
| 5 | 10/1/2022 | 40S028 | Pomona Energy Storage | Energy Storage | Expected Initial Delivery Date | 10/1/2022 Missed Expected Initial Delivery Date | |

**TABLE 9-7**
**CONTRACT ADMINISTRATION**
**MISSED MILESTONES DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Original Milestone Date | PG&E Log Number | Project Name | Contract Type | Milestone | Date of Event | Description |
|---|---|---|---|---|---|---|---|
| 6 | 10/1/2022 | 40S029 | Sonoran West Holdings 2 | Energy Storage | Expected Initial Delivery Date | 10/1/2022 Missed Expected Initial Delivery Date | [redacted] |
| 7 | 12/1/2022 | 40S009 | Cascade Energy Storage | Energy Storage | Expected Initial Delivery Date | 12/1/2022 Missed Expected Initial Delivery Date | |

**TABLE 9-8**
**CONTRACT ADMINISTRATION**
**CONTRACTS THAT BEGAN DELIVERING DURING RECORD PERIOD 2022**

| Line No. | Date | PG&E Log Number | Project Name | Capacity (MW) | Contract Type |
|---|---|---|---|---|---|
| 1 | 1/1/2022 | 33B022CA03 | Shell Energy North America (US), L.P. | 0 | Carbon Free Energy (Sale) |
| 2 | 1/1/2022 | 33B113CA01 | 3 Phases Renewables, Inc. | 0 | Carbon Free Energy (Sale) |
| 3 | 1/1/2022 | 33B202CA03 | Commercial Energy of Montana Inc. | 0 | Carbon Free Energy (Sale) |
| 4 | 1/1/2022 | 33B211CA03 | Calpine Energy Solutions, LLC | 0 | Carbon Free Energy (Sale) |
| 5 | 1/1/2022 | 33B226CA03 | Sonoma Clean Power Authority | 0 | Carbon Free Energy (Sale) |
| 6 | 1/1/2022 | 33B230CA03 | Silicon Valley Clean Energy Authority | 0 | Carbon Free Energy (Sale) |
| 7 | 1/1/2022 | 33B232CA03 | Peninsula Clean Energy Authority | 0 | Carbon Free Energy (Sale) |
| 8 | 1/1/2022 | 33B235CA03 | Marin Clean Energy | 0 | Carbon Free Energy (Sale) |
| 9 | 1/1/2022 | 33B236CA04 | Central Coast Community Energy | 0 | Carbon Free Energy (Sale) |
| 10 | 1/1/2022 | 33B238CA04 | East Bay Community Energy Authority | 0 | Carbon Free Energy (Sale) |
| 11 | 1/1/2022 | 33B243CA03 | CleanPowerSF | 0 | Carbon Free Energy (Sale) |
| 12 | 1/1/2022 | 33B245CA03 | Pioneer Community Energy | 0 | Carbon Free Energy (Sale) |
| 13 | 1/1/2022 | 33B247CA03 | San Jose Clean Energy | 0 | Carbon Free Energy (Sale) |
| 14 | 1/1/2022 | 33B254CA03 | Valley Clean Energy Alliance | 0 | Carbon Free Energy (Sale) |
| 15 | 1/1/2022 | 33B255CA03 | Direct Energy Business, LLC | 0 | Carbon Free Energy (Sale) |
| 16 | 1/1/2022 | 33B259CA03 | Redwood Coast Energy Authority | 0 | Carbon Free Energy (Sale) |
| 17 | 1/1/2022 | 33B261CA03 | The Regents of the University of California | 0 | Carbon Free Energy (Sale) |
| 18 | 1/1/2022 | 33R508 | BMW of North America, LLC | 0 | RPS Energy REC Sales |
| 19 | 1/1/2022 | 33R515 | East Bay Community Energy Authority | 0 | RPS Energy REC Sales |
| 20 | 1/1/2022 | 33R516 | Silicon Valley Clean Energy Authority | 0 | RPS Energy REC Sales |

**TABLE 9-8**
**CONTRACT ADMINISTRATION**
**CONTRACTS THAT BEGAN DELIVERING DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Capacity (MW) | Contract Type |
|---|---|---|---|---|---|
| 21 | 4/1/2022 | 25C138QPE | Western Power and Steam II | 17.45 | QF SOC PURPA 2020 |
| 22 | 4/1/2022 | 33R518 | Orange County Power Authority | 0 | RPS Energy REC Sales |
| 23 | 4/1/2022 | 33R519 | Orange County Power Authority | 0 | RPS Energy REC Sales |
| 24 | 4/1/2022 | 40S018 | Coso Battery Storage, LLC | 60 | Energy Storage |
| 25 | 5/1/2022 | 40S011 | Diablo Energy Storage, LLC | 50 | Energy Storage |
| 26 | 5/1/2022 | 40S015 | Diablo Energy Storage, LLC | 50 | Energy Storage |
| 27 | 5/1/2022 | 40S016 | Diablo Energy Storage, LLC | 50 | Energy Storage |
| 28 | 5/1/2022 | 40S017 | Diablo Energy Storage, LLC | 50 | Energy Storage |
| 29 | 5/2/2022 | 33R525 | East Bay Community Energy Authority | 0 | RPS Energy REC Sales |
| 30 | 5/2/2022 | 33R526 | Central Coast Community Energy | 0 | RPS Energy REC Sales |
| 31 | 5/2/2022 | 33R527 | Orange County Power Authority | 0 | RPS Energy REC Sales |
| 32 | 5/2/2022 | 33R528 | Orange County Power Authority | 0 | RPS Energy REC Sales |
| 33 | 5/2/2022 | 33R529 | Silicon Valley Clean Energy Authority | 0 | RPS Energy REC Sales |
| 34 | 5/2/2022 | 33R530 | City of San Jose (San Jose Clean Energy) | 0 | RPS Energy REC Sales |
| 35 | 5/2/2022 | 33R531 | City of San Jose (San Jose Clean Energy) | 0 | RPS Energy REC Sales |
| 36 | 7/26/2022 | 33R479BIO | Abel Road Bioenergy | 3 | BioMAT |
| 37 | 9/1/2022 | 2022-DR-RA-1 | DR RA Bilateral Contract | 5 | DR RA Bilateral |
| 38 | 9/1/2022 | 40S024 | LeConte Energy Storage, LLC | 40 | Energy Storage |
| 39 | 10/1/2022 | 40S030 | Arlington Energy Center III | 63 | Energy Storage |
| 40 | 10/1/2022 | 40S031 | Arlington Energy Center III | 47 | Energy Storage |
| 41 | 11/1/2022 | 33R483 | Burney Forest Products | 29 | RPS |

**TABLE 9-8**
**CONTRACT ADMINISTRATION**
**CONTRACTS THAT BEGAN DELIVERING DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Capacity (MW) | Contract Type |
|---|---|---|---|---|---|
| 42 | 11/1/2022 | 40S027 | Lancaster Area Battery Storage, LLC | 127 | Energy Storage |
| 43 | 11/17/2022 | 33R536 | East Bay Community Energy Authority | 0 | RPS Energy REC Sales |
| 44 | 11/17/2022 | 33R537 | Clean Energy Alliance | 0 | RPS Energy REC Sales |
| 45 | 11/17/2022 | 33R538 | City Of Lancaster | 0 | RPS Energy REC Sales |
| 46 | 11/17/2022 | 33R539 | East Bay Community Energy Authority | 0 | RPS Energy REC Sales |
| 47 | 11/17/2022 | 33R540 | Constellation Energy Generation, LLC | 0 | RPS Energy REC Sales |
| 48 | 11/17/2022 | 33R541 | San Diego Community Power | 0 | RPS Energy REC Sales |
| 49 | 11/17/2022 | 33R542 | San Diego Community Power | 0 | RPS Energy REC Sales |
| 50 | 11/17/2022 | 33R543 | City of San Jose (San Jose Clean Energy) | 0 | RPS Energy REC Sales |
| 51 | 11/18/2022 | 33R393 | Java Solar | 13.5 | RPS |
| 52 | 12/1/2022 | 40S029 | Sonoran West Holdings 2 | 150 | Energy Storage |
| 53 | 12/2/2022 | 33R484 | Wheelabrator Shasta Energy Co, Inc | 34 | RPS |
| 54 | 12/12/2022 | 33R544 | San Diego Community Power | 0 | RPS Energy REC Sales |
| 55 | 12/12/2022 | 33R545 | East Bay Community Energy Authority | 0 | RPS Energy REC Sales |

**TABLE 9-9**
**CONTRACT ADMINISTRATION**
**CONTRACT AMENDMENTS AND CONSENTS TO ASSIGNMENT DURING RECORD PERIOD 2022**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Transaction Description |
|---|---|---|---|---|---|
| 1 | 1/7/2022 | 40S021 | Blythe Energy Storage 110, LLC | Consent to Assignment - Financing | Consent to assignment for project financing. |
| 2 | 3/25/2022 | 40S018 | Coso Battery Storage, LLC | Routine Amendment to Existing Agreement | Routine amendment modifies the maximum days for the IDD Cure Period in which Seller is allowed to pay liquidated damages for delays past the Expected Initial Delivery Date. |
| 3 | 3/25/2022 | 40S027 | Lancaster Area Battery Storage, LLC | Routine Amendment to Existing Agreement | Routine amendment modifies the maximum days for the IDD Cure Period in which Seller is allowed to pay liquidated damages for delays past the Expected Initial Delivery Date. |
| 4 | 3/29/2022 | 33R254 | SPI Biomass Portfolio | Non-Routine Amendment to Existing Agreement | Short-term letter agreement for potential additional energy deliveries in preparation for peak summer conditions pursuant to D.21-03-056 and D.21-12-015. |
| 5 | 3/29/2022 | 33R406 | Shasta - Sustainable Resource Management | Non-Routine Amendment to Existing Agreement | Short-term letter agreement for potential additional energy deliveries in preparation for peak summer conditions pursuant to D.21-03-056 and D.21-12-015. |
| 6 | 4/7/2022 | 24B001FHP | Chevron U.S.A. - McKittrick | Non-Routine Amendment to Existing Agreement | Short-term letter agreement for potential additional energy deliveries in preparation for peak summer conditions pursuant to D.21-03-056 and D.21-12-015. |
| 7 | 4/7/2022 | 25C002 | Chevron U.S.A. (Taft/Cadet) | Non-Routine Amendment to Existing Agreement | Short-term letter agreement for potential additional energy deliveries in preparation for peak summer conditions pursuant to D.21-03-056 and D.21-12-015. |
| 8 | 4/7/2022 | 25C003 | Chevron U.S.A. (Cymric) | Non-Routine Amendment to Existing Agreement | Short-term letter agreement for potential additional energy deliveries in preparation for peak summer conditions pursuant to D.21-03-056 and D.21-12-015. |
| 9 | 4/7/2022 | 25C055 | Chevron U.S.A. (Coalinga) | Non-Routine Amendment to Existing Agreement | Short-term letter agreement for potential additional energy deliveries in preparation for peak summer conditions pursuant to D.21-03-056 and D.21-12-015. |
| 10 | 4/7/2022 | 25C246 | Chevron U.S.A. (SE Kern River) | Non-Routine Amendment to Existing Agreement | Short-term letter agreement for potential additional energy deliveries in preparation for peak summer conditions pursuant to D.21-03-056 and D.21-12-015. |
| 11 | 4/7/2022 | 25C248 | Chevron U.S.A. (Eastridge) | Non-Routine Amendment to Existing Agreement | Short-term letter agreement for potential additional energy deliveries in preparation for peak summer conditions pursuant to D.21-03-056 and D.21-12-015. |
| 12 | 4/13/2022 | 40S015 | Diablo Energy Storage, LLC | Routine Amendment to Existing Agreement | Routine amendment modifies the maximum days for the IDD Cure Period in which Seller is allowed to pay liquidated damages for delays past the Expected Initial Delivery Date. |
| 13 | 4/13/2022 | 40S016 | Diablo Energy Storage, LLC | Routine Amendment to Existing Agreement | Routine amendment modifies the maximum days for the IDD Cure Period in which Seller is allowed to pay liquidated damages for delays past the Expected Initial Delivery Date. |

## TABLE 9-9
## CONTRACT ADMINISTRATION
## CONTRACT AMENDMENTS AND CONSENTS TO ASSIGNMENT DURING RECORD PERIOD 2022
## (CONTINUED)

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Transaction Description |
|---|---|---|---|---|---|
| 14 | 4/13/2022 | 40S017 | Diablo Energy Storage, LLC | Routine Amendment to Existing Agreement | Routine amendment modifies the maximum days for the IDD Cure Period in which Seller is allowed to pay liquidated damages for delays past the Expected Initial Delivery Date. |
| 15 | 4/22/2022 | 33B074 | Midway Peaking | Consent to Assignment - Financing | Consent to assignment for project financing. |
| 16 | 4/22/2022 | 33B101 | MRP San Joaquin Tracy | Consent to Assignment - Financing | Consent to assignment for project financing. |
| 17 | 4/22/2022 | 33B108 | MRP San Joaquin Hanford Facility | Consent to Assignment - Financing | Consent to assignment for project financing. |
| 18 | 4/22/2022 | 33B109 | MRP San Joaquin Henrietta | Consent to Assignment - Financing | Consent to assignment for project financing. |
| 19 | 4/22/2022 | 33R257 | Cuyama Solar Array | Routine Amendment to Existing Agreement | Routine amendment increases Buyer's curtailment rights. |
| 20 | 5/12/2022 | 40S040 | EdSan 1B Group 3, LLC (fka Sanborn ESS III, LLC) | Routine Amendment to Existing Agreement | Routine amendment modifies the timing provisions related to the Conditions Precedent for the Initial Delivery Date. |
| 21 | 5/17/2022 | 33R522 | Jaton LLC | Consent to Assignment - General Consent | Consent to assignment from Jaton LLC to Community Solar Utica 1, LLC. |
| 22 | 5/20/2022 | 33B075 | Calpine Russell City Energy Center | Non-Routine Amendment to Existing Agreement | Amendment modifies the contract expiration date from August 7, 2023, to July 31, 2023. |
| 23 | 6/6/2022 | 33R503 | Nachtigall | Consent to Assignment - General Consent | Consent to assignment from FFP CA Community Solar, LLC to Nachtigall Solar, LLC. |
| 24 | 6/6/2022 | 33R504 | Pistachio Road | Consent to Assignment - General Consent | Consent to assignment from FFP CA Community Solar, LLC to Twisselman Solar, LLC. |
| 25 | 6/6/2022 | 33R505 | Terry | Consent to Assignment - General Consent | Consent to assignment from FFP CA Community Solar, LLC to Terry Solar, LLC. |
| 26 | 6/30/2022 | 33R375 | Westside Solar | Routine Amendment to Existing Agreement | Routine amendment increases Buyer's curtailment rights. |
| 27 | 7/11/2022 | 33R437BIO | Hat Creek Bioenergy, LLC | Non-Routine Amendment to Existing Agreement | Amendment corrects a typographical error made in the First Amendment to incorporate certain revisions pursuant to D. 20-08-043 |
| 28 | 7/13/2022 | 40S025 | North Central Valley Energy Storage, LLC | Non-Routine Amendment to Existing Agreement | Amendment increases contract price. |
| 29 | 7/13/2022 | 40S026 | Nexus Renewables U.S. Inc. | Non-Routine Amendment to Existing Agreement | Amendment allows for reduction in capacity and an extension to the Expected IDD in exchange for payment. |
| 30 | 7/18/2022 | 33R433BIO | North Fork Community Power | Non-Routine Amendment to Existing Agreement | Amendment corrects a typographical error made in the First Amendment to incorporate certain revisions pursuant to D. 20-08-043 |
| 31 | 7/18/2022 | 33R436BIO | Blue Mountain Electric Company | Non-Routine Amendment to Existing Agreement | Amendment corrects a typographical error made in the First Amendment to incorporate certain revisions pursuant to D. 20-08-043 |
| 32 | 7/28/2022 | 33R291 | Shafter Solar | Routine Amendment to Existing Agreement | Routine amendment increases Buyer's curtailment rights. |

## TABLE 9-9
## CONTRACT ADMINISTRATION
## CONTRACT AMENDMENTS AND CONSENTS TO ASSIGNMENT DURING RECORD PERIOD 2022
## (CONTINUED)

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Transaction Description |
|---|---|---|---|---|---|
| 33 | 8/5/2022 | 33B221 | Tesoro Refining and Marketing Company LLC | Routine Amendment to Existing Agreement | Routine Amendment outlines Seller's schedule to repay amounts due to PG&E as allowed under the contract. |
| 34 | 8/12/2022 | 33B075 | Calpine Russell City Energy Center | Routine Amendment to Existing Agreement | Routine amendment (i) modifies insurance provisions in Section 10.8(b) and (ii) eliminates certain separateness covenants to allow Calpine to provide the credit security for Russell City. |
| 35 | 8/12/2022 | 33B075 | Calpine Russell City Energy Center | Routine Amendment to Existing Agreement | Routine amendment changes specific requirements for the resource's Weather Station based on information commercially available to the Seller. |
| 36 | 8/17/2022 | 33R052 | High Plains Ranch II | Routine Amendment to Existing Agreement | Routine amendment allows low side metering arrangement. |
| 37 | 8/17/2022 | 33R088 | High Plains Ranch III | Routine Amendment to Existing Agreement | Routine amendment allows low side metering arrangement. |
| 38 | 8/19/2022 | 33B247CA03 | San Jose Clean Energy | Routine Amendment to Existing Agreement | Routine amendment corrects error in confirm. |
| 39 | 8/22/2022 | 33R052 | High Plains Ranch II | Consent to Assignment - General Consent | Consent to assignment from GIP III Zephyr Acquisitions Holdings, L.P. to TotalEnergies Renewables USA, LLC. |
| 40 | 8/25/2022 | 40S040 | EdSan 1B Group 3, LLC (fka Sanborn ESS III, LLC) | Consent to Assignment - Financing | Consent to assignment for project financing. |
| 41 | 8/29/2022 | 33R433BIO | North Fork Community Power | Routine Amendment to Existing Agreement | Routine amendment allows for 12-month extension of the PPA's GCOD, Seller's payment of Daily Delay Liquidated Damages and increase of the Seller's collateral requirement. |
| 42 | 8/31/2022 | 33R088 | High Plains Ranch III | Consent to Assignment - General Consent | Consent to assignment from GIP III Zephyr Acquisitions Holdings, L.P. to TotalEnergies Renewables USA, LLC |
| 43 | 9/2/2022 | 01C045 | Crockett Cogeneration | Non-Routine Amendment to Existing Agreement | Short-term letter agreement for potential additional energy deliveries in preparation for peak summer conditions pursuant to D.21-03-056 and D.21-12-015. |
| 44 | 9/6/2022 | 01C045 | Crockett Cogeneration | Non-Routine Amendment to Existing Agreement | Short-term letter agreement for potential additional energy deliveries in preparation for peak summer conditions pursuant to D.21-03-056 and D.21-12-015. |
| 45 | 9/7/2022 | 40S033 | Poblano Energy Storage, LLC | Non-Routine Amendment to Existing Agreement | Amendment increases contract price, updates the Expected IDD, and reduces capacity. |
| 46 | 9/13/2022 | 40S038 | Beaumont ESS 1, LLC | Non-Routine Amendment to Existing Agreement | Amendment increases contract price, updates the Expected IDD, and extends the IDD Cure Period. |
| 47 | 9/13/2022 | 40S039 | Canyon Country ESS I, LLC | Non-Routine Amendment to Existing Agreement | Amendment increases contract price, updates the Expected IDD and extends the IDD Cure Period. |

**TABLE 9-9**
**CONTRACT ADMINISTRATION**
**CONTRACT AMENDMENTS AND CONSENTS TO ASSIGNMENT DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date | PG&E Log Number | Project Name | Transaction Type | Transaction Description |
|---|---|---|---|---|---|
| 48 | 9/19/2022 | 40S037 | Nighthawk Energy Storage, LLC | Non-Routine Amendment to Existing Agreement | Amendment increases contract price. |
| 49 | 10/17/2022 | 40S022 | Daggett Solar Power 2 LLC | Routine Amendment to Existing Agreement | Routine amendment providing the option to modify the maximum days for the IDD Cure Period in which Seller is allowed to pay liquidated damages for delays past the Expected Initial Delivery Date. |
| 50 | 11/9/2022 | 33R533-AR | RPCA Solar 8, LLC | Non-Routine Amendment to Existing Agreement | Amendment and restatement of the contract. |
| 51 | 11/16/2022 | 40S026 | Nexus Renewables U.S. Inc. | Consent to Assignment - General Consent | Consent to Assignment from Nexus Renewables U.S. Inc. to Amcor Storage LLC. |
| 52 | 11/21/2022 | 25C138QPE | Western Power and Steam II | Routine Amendment to Existing Agreement | Routine amendment memorializes Seller's agreement to reimburse PG&E the CAISO charges incurred by PG&E, as the SC, regarding Seller’s Outage. |
| 53 | 11/29/2022 | 33R107AB | SGE Site 1 | Consent to Assignment - General Consent | Consent to assignment from Sierra Green Energy LLC to Four Dog Energy LLC. |
| 54 | 12/2/2022 | 40S032 | Moss Landing Energy Storage 3 | Routine Amendment to Existing Agreement | Letter agreement allowing project to have one of more CAISO Resource IDs. |
| 55 | 12/7/2022 | 33R499 | Fresno Disadvantaged Community Solar Project | Consent to Assignment - Financing | Consent to assignment for project financing. |
| 56 | 12/19/2022 | 40S029 | Sonoran West Holdings 2 | Routine Amendment to Existing Agreement | Routine amendment clarifying procedures of hold-back capacity. |
| 57 | 12/29/2022 | 33R437BIO | Hat Creek Bioenergy, LLC | Consent to Assignment - Financing | Consent to assignment for project financing. |
| 58 | 1/27/2023 | 2022-DR-RA-1 | DR RA Bilateral | Other | Forbearance agreement. |

**TABLE 9-10**
**CONTRACT ADMINISTRATION**
**FORCE MAJEURE CLAIMS DURING RECORD PERIOD 2022**

| Line No. | Date of Claim | PG&E Log Number | Project Name | Contract Type | Date Closed | Description |
|---|---|---|---|---|---|---|
| 1 | 7/23/2020 | 40S019 | Moss 100 | Energy Storage | 1/7/2022 | [redacted] |
| 2 | 8/31/2020 | 40S019 | Moss 100 | Energy Storage | 1/7/2022 | |
| 3 | 9/19/2020 | 33R063 | Ivanpah Unit 1 | RPS | Pending* | |
| 4 | 9/19/2020 | 33R064 | Ivanpah Unit 3 | RPS | Pending* | |
| 5 | 10/20/2020 | 33R337RM | Clover Flat LFG | ReMAT | Pending* | |
| 6 | 1/19/2021 | 33R093 | Geysers | RPS | 2/15/2022 | |
| 7 | 4/30/2021 | 40S020 | Gateway Energy Storage, LLC | Energy Storage | 1/12/2022 | |
| 8 | 5/7/2021 | 40S011 | Diablo Energy Storage | Energy Storage | 6/2/2022 | |
| 9 | 5/7/2021 | 40S011 | Diablo Energy Storage | Energy Storage | 6/2/2022 | |
| 10 | 5/7/2021 | 40S015 | Diablo Energy Storage | Energy Storage | 6/2/2022 | |
| 11 | 5/7/2021 | 40S015 | Diablo Energy Storage | Energy Storage | 6/2/2022 | |
| 12 | 5/7/2021 | 40S016 | Diablo Energy Storage | Energy Storage | 6/2/2022 | |
| 13 | 5/7/2021 | 40S016 | Diablo Energy Storage | Energy Storage | 6/2/2022 | |
| 14 | 5/7/2021 | 40S017 | Diablo Energy Storage | Energy Storage | 6/2/2022 | |
| 15 | 5/7/2021 | 40S017 | Diablo Energy Storage | Energy Storage | 6/2/2022 | |

**TABLE 9-10**
**CONTRACT ADMINISTRATION**
**FORCE MAJEURE CLAIMS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date of Claim | PG&E Log Number | Project Name | Contract Type | Date Closed | Description |
|---|---|---|---|---|---|---|
| 16 | 5/7/2021 | 40S018 | Coso Battery Storage, LLC | Energy Storage | 3/17/2022 | [redacted] |
| 17 | 8/12/2021 | 33R063 | Ivanpah Unit 1 | RPS | Pending | |
| 18 | 8/12/2021 | 33R064 | Ivanpah Unit 3 | RPS | Pending* | |
| 19 | 8/30/2021 | 40S018 | Coso Battery Storage, LLC | Energy Storage | 3/17/2022 | |
| 20 | 10/8/2021 | 40S029 | Sonoran West Holdings 2 | Energy Storage | 9/16/2022 | |
| 21 | 10/26/2021 | 40S027 | Lancaster Area Battery | Energy Storage | 4/29/2022 | |
| 22 | 11/4/2021 | 40S027 | Lancaster Area Battery | Energy Storage | Pending | |
| 23 | 11/4/2021 | 40S027 | Lancaster Area Battery | Energy Storage | Pending | |
| 24 | 11/10/2021 | 40S027 | Lancaster Area Battery | Energy Storage | Pending | |
| 25 | 11/17/2021 | 40S029 | Sonoran West Holdings 2 | Energy Storage | 9/16/2022 | |
| 26 | 12/23/2021 | 40S027 | Lancaster Area Battery | Energy Storage | 4/29/2022 | |
| 27 | 1/26/2022 | 40S027 | Lancaster Area Battery | Energy Storage | 4/29/2022 | |
| 28 | 1/26/2022 | 40S027 | Lancaster Area Battery | Energy Storage | Pending | |

**TABLE 9-10**
**CONTRACT ADMINISTRATION**
**FORCE MAJEURE CLAIMS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date of Claim | PG&E Log Number | Project Name | Contract Type | Date Closed | Description |
|---|---|---|---|---|---|---|
| 29 | 1/26/2022 | 40S027 | Lancaster Area Battery | Energy Storage | Pending | [redacted] |
| 30 | 2/4/2022 | 40S023 | Daggett Solar Power 3 | Energy Storage | Pending | |
| 31 | 2/4/2022 | 40S022 | Daggett Solar Power 2 | Energy Storage | Pending* | |
| 32 | 2/4/2022 | 40S023 | Daggett Solar Power 3 | Energy Storage | Pending | |
| 33 | 2/4/2022 | 40S022 | Daggett Solar Power 2 | Energy Storage | Pending* | |
| 34 | 2/10/2022 | 40S032 | Moss Landing Energy Storage 3 | Energy Storage | Pending | |
| 35 | 3/7/2022 | 40S032 | Moss Landing Energy Storage 3 | Energy Storage | Pending | |
| 36 | 3/29/2022 | 40S029 | Sonoran West Holdings 2 | Energy Storage | 12/15/2022 | |
| 37 | 3/29/2022 | 40S029 | Sonoran West Holdings 2 | Energy Storage | 12/15/2022 | |
| 38 | 3/31/2022 | 40S032 | Moss Landing Energy Storage 3 | Energy Storage | Pending | |
| 39 | 4/8/2022 | 40S029 | Sonoran West Holdings 2 | Energy Storage | 12/15/2022 | |
| 40 | 4/8/2022 | 40S029 | Sonoran West Holdings 2 | Energy Storage | 12/15/2022 | |

**TABLE 9-10**
**CONTRACT ADMINISTRATION**
**FORCE MAJEURE CLAIMS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date of Claim | PG&E Log Number | Project Name | Contract Type | Date Closed | Description |
|---|---|---|---|---|---|---|
| 41 | 4/8/2022 | 40S029 | Sonoran West Holdings 2 | Energy Storage | 12/15/2022 | [redacted] |
| 42 | 4/18/2022 | 33R393 | Java Solar | RPS | 9/16/2022 | [redacted] |
| 43 | 4/19/2022 | 40S023 | Daggett Solar Power 3 | Energy Storage | Pending | [redacted] |
| 44 | 4/19/2022 | 40S022 | Daggett Solar Power 2 | Energy Storage | Pending* | [redacted] |
| 45 | 4/21/2022 | 40S029 | Sonoran West Holdings 2 | Energy Storage | 12/15/2022 | [redacted] |
| 46 | 5/2/2022 | 40S033 | Poblano Energy Storage | Energy Storage | 9/23/2022 | [redacted] |
| 47 | 5/2/2022 | 40S033 | Poblano Energy Storage | Energy Storage | 9/23/2022 | [redacted] |
| 48 | 5/2/2022 | 40S033 | Poblano Energy Storage | Energy Storage | 9/23/2022 | [redacted] |
| 49 | 5/27/2022 | 40S032 | Moss Landing Energy Storage 3 | Energy Storage | Pending | [redacted] |
| 50 | 8/12/2022 | 33R063 | Ivanpah Unit 1 | RPS | Pending | [redacted] |

**TABLE 9-10**
**CONTRACT ADMINISTRATION**
**FORCE MAJEURE CLAIMS DURING RECORD PERIOD 2022**
**(CONTINUED)**

| Line No. | Date of Claim | PG&E Log Number | Project Name | Contract Type | Date Closed | Description |
|---|---|---|---|---|---|---|
| 51 | 8/12/2022 | 33R064 | Ivanpah Unit 3 | RPS | Pending | [redacted] |
| 52 | 10/7/2022 | 40S032 | Moss Landing Energy Storage 3 | Energy Storage | Pending | [redacted] |
| 53 | 10/7/2022 | 40S032 | Moss Landing Energy Storage 3 | Energy Storage | Pending | [redacted] |
| 54 | 12/9/2022 | 40S032 | Moss Landing Energy Storage 3 | Energy Storage | Pending | [redacted] |

* Force majeure claim was closed out in 2023 before the filing of this application but after the 2022 Record Period ended and will be reported in the 2023 ERRA Compliance proceeding.

**TABLE 9-11**
**CONTRACT ADMINISTRATION**
**CONTRACTS THAT EXPIRED OR TERMINATED DURING RECORD PERIOD 2022**

| Line No. | Date | PG&E Log Number | Project Name | Contract Type | Description |
|---|---|---|---|---|---|
| 1 | 1/26/2022 | 10C008 | Lassen Community College | QF | Terminated |
| 2 | 3/15/2022 | 10H013 | Hypower, Inc. | QF | Expired |
| 3 | 3/25/2022 | 33R469BIO | Lisa Boone Harris | BioMAT | Terminated |
| 4 | 3/31/2022 | 25C138QPA | Western Power and Steam II | QF/CHP Settlement | Expired |
| 5 | 4/11/2022 | 33R250AB | Browns Valley Irrigation District | AB1969 | Expired |
| 6 | 4/30/2022 | 33B112 | Bear Mountain Limited | Tolling | Expired |
| 7 | 4/30/2022 | 33B121 | Badger Creek Limited | Tolling | Expired |
| 8 | 4/30/2022 | 33B122 | Live Oak Limited | Tolling | Expired |
| 9 | 4/30/2022 | 33B123 | McKittrick Limited | Tolling | Expired |
| 10 | 4/30/2022 | 33B124 | Chalk Cliff Limited | Tolling | Expired |
| 11 | 4/30/2022 | 33R230AB | Wolfsen Bypass | AB1969 | Expired |
| 12 | 4/30/2022 | 33R231AB | San Luis Bypass | AB1969 | Expired |
| 13 | 8/8/2022 | 33R521RM | Hat Creek Hereford Ranch Power | ReMAT | Terminated |
| 14 | 9/30/2022 | 33B092 | Mariposa | Tolling | Expired |
| 15 | 9/30/2022 | 2022-DR-RA-1 | DR RA Bilateral Contract | DR RA Bilateral | Expired |
| 16 | 10/31/2022 | 33B101 | MRP San Joaquin Tracy | Tolling | Expired |
| 17 | 10/31/2022 | 33R404 | Burney Forest Products | RPS | Expired |
| 18 | 11/21/2022 | 33R470BIO | RuAnn Dairy Digester | BioMAT | Terminated |
| 19 | 12/1/2022 | 33R406 | Shasta - Sustainable Resource Management | RPS | Expired |
| 20 | 12/5/2022 | 40S026 | Nexus Renewables U.S. Inc. | Energy Storage | Terminated |
| 21 | 12/14/2022 | 40S028 | Pomona Energy Storage 2 LLC | Energy Storage | Terminated |
| 22 | 12/31/2022 | 33B108 | MRP San Joaquin Hanford Facility | Tolling | Expired |
| 23 | 12/31/2022 | 33B109 | MRP San Joaquin Henrietta | Tolling | Expired |
| 24 | 12/31/2022 | 33R246 | Wind Resource I | RPS | Expired |

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 10

# CAISO SETTLEMENTS AND MONITORING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
CAISO SETTLEMENTS AND MONITORING

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 10
# CAISO SETTLEMENTS AND MONITORING

## A. Introduction

This chapter describes the procurement costs and revenues associated with Pacific Gas and Electric Company's (PG&E) participation in the California Independent System Operator (CAISO) electricity markets, both Day Ahead (DA) and Real-Time (RT) in 2022.

PG&E receives revenue for electric generation provided to the CAISO markets and is charged for demand representing PG&E's bundled customer load. The costs and revenues described here reflect the portion of PG&E's electric supply portfolio for which PG&E is the Scheduling Coordinator (SC). SCs are entities authorized by the CAISO to schedule and bid power on behalf of CAISO market participants. SCs also make and receive market payments and can validate and dispute market charges with the CAISO. The CAISO Settlements Department is responsible for fulfilling this payment and validation role within PG&E. The CAISO utilizes over 200 charge codes to settle its markets and the various instruments and products associated with those markets. The CAISO publishes multiple iterations of settlement statements that market participants can download and validate prior to invoicing. Settlement statements are published for each trade date. SCs can dispute these statements if errors are discovered.

During the Record Period, PG&E successfully validated and processed 220 CAISO invoices relating to PG&E's market activities. All invoices were paid on time and totaled to a net credit of ($1,111,710,194). At the end of each month, Energy Settlements is required to report monthly accruals to Corporate Accounting. The financial accrual process records all CAISO market activities for the current month in addition to prior period true-ups in accordance with the CAISO market timeline. The accruals are then approved each month by the Energy Settlements manager and recorded into SAP, PG&E's system of record for accounting transactions, by Corporate Accounting. The integrity of PG&E's financial reporting was reviewed and tested by several external and internal entities in 2022, including: (1) Deloitte & Touche, PG&E's external auditors, who conducted quarterly testing in 2Q and 3Q and 2022 year-end testing in January 2023, (2) Cal Advocates who reviewed 30 CAISO invoices and proof of payments for their audit in 2Q 2022, and (3) PG&E's Internal Audit department who completed a comprehensive audit of the Retail Energy Resource Recovery Account (ERRA) in 2Q 2022. All audits unanimously passed their review and testing requirements without incident.

**B. Balancing Account Allocation of 2022 CAISO Settlement Data**

Beginning in 2019 and continuing through 2022, PG&E modified its balancing accounts and created the Portfolio Allocation Balancing Account (PABA) to comply with Decision (D.) 18-10-019, as discussed in Chapter 12. PG&E used the implementation of PABA in 2019 as an opportunity to separate settlement data for 4 other balancing accounts in addition to PABA, that were reported under ERRA prior to 2019. These include: (1) Modified Transition Cost Balancing Account (MTCBA), (2) Green Tariff Shared Renewables Balancing Account (GTSRBA), (3) Bioenergy Market Adjustment Tariff (BioMAT) BioMAT Non-Bypassable Charge Balancing Account (BNBCBA), and (4) Public Policy Charge Balancing Account (PPCBA). The Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA) data are included in the "ERRA Grid" worksheet in the Chapter 10 workpapers under the column headings Bioenergy Renewable Auction Mechanism Memorandum Account and BioMass Memorandum Account (BioMASSMA).

CAISO settlement data for market participants contain unique identifiers called Resource Identifications. These allow PG&E to recognize retail load, third party generation and Utility Owned Generation revenues and charges on a resource level in order to determine which balancing account the settlement data is assigned for reporting and cost recovery purposes.

Chapter 10 includes the latest settlement statement data published by CAISO for 2022 trade months recorded as of January 2023 and prepared for this Chapter on February 1, 2023. There are no estimates or amounts included for periods prior to 2022. Beginning on the January 1, 2021 trade date, CAISO revised its timeline for publishing settlement data to T+9B, T+70B, T+11M, T+21M and T+24M.[1] The T+11M settlement statements were included for trade month January 2022, T+70B statements were included for February 2022 through September 2022 and T+9B statements were included for October 2022 through December 2022. Each month includes the same statement version for each day of the month and is updated only when CAISO publishes any revised statement versions for all trading days of the month. In contrast, the 2022 CAISO settlement amounts reflected in Chapters 12 and 13 are based upon entries recorded during 2022 through the December 2022 accounting close and include December estimated data and resettlement values for pre-2022 trade months recorded in 2022.

As indicated above, total PG&E revenues and charges from CAISO netted to a credit of ($1,111,710,194) in 2022. These amounts were allocated and reported by balancing account as follows:

**TABLE 10-1**
**2022 CAISO SETTLEMENT CHARGES/(REVENUES) BY BALANCING ACCOUNT**

| | TOTAL | ERRA | PABA | MTCBA | TMNCBA | GTSRBA | BioMAT | PPCBA | PG&E Sanctions |
|---|---|---|---|---|---|---|---|---|---|
| **Day-Ahead Market** | ($1,168,472,926) | $3,113,031,113 | ($4,016,368,829) | ($185,311,449) | ($62,080,778) | ($7,325,819) | ($9,254,144) | ($1,163,020) | $0 |
| **Real-Time Market** | $81,592,837 | ($59,330,609) | $132,548,849 | $6,079,648 | $0 | $309,114 | $1,868,692 | $117,143 | $0 |
| **Congestion Revenue Rights** | ($80,695,632) | ($80,695,632) | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Grid Management Charges** | $33,510,768 | $14,058,683 | $18,630,950 | $724,044 | $0 | $59,764 | $32,138 | $5,189 | $0 |
| **FERC Fees** | $3,343,697 | $3,343,697 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Other** | $19,011,063 | $148,062,775 | ($128,970,588) | ($110,727) | $0 | $18,047 | $10,355 | $1,200 | $2,000 |
| **TOTAL (Excluding PG&E Sanctions)** | **($1,111,710,194)** | **$3,138,470,026** | **($3,994,159,617)** | **($178,618,484)** | **($62,080,778)** | **($6,938,894)** | **($7,342,959)** | **($1,039,489)** | **$2,000** |

Power costs recorded in ERRA are applicable solely to PG&E's bundled customers while power costs incurred on behalf of both bundled and departing load customers are recorded and recovered in PABA. The purpose of the MTCBA is to recover net above market costs associated with Ongoing Competition Transition Charge eligible generation. TMNBCBA recovers the net electric procurement costs of Power Purchase Agreements (PPA) related to Tree Mortality in compliance with Senate Bill (SB) 859 and Resolutions E-4770 and E-4806 as defined in D.18-12-003. The GTSRBA tracks revenues received and actual expenses incurred to procure renewable generation resources for

---

[1] CAISO settlement statement publications include: T+9B (9 business days after the trade day), T+70B (70 business days after the trade day),T+11M (11 months after the trade day), T+21M (21 months after the trade day) and T+24M (24 months after the trade day).

customers participating in Green Tariff Shared Renewables programs. The BNBCBA records the net costs of BioMAT contracts in compliance with SB 1122, as revised in D.20-08-043. Finally, the PPCBA was created and defined in D.22-02-002. In this decision, the California Public Utilities Commission directed PG&E to retire the PABA non-vintage subaccount and transfer the 2021 end of year balance recorded in the PABA non-vintage subaccount to PPCBA. Any future costs and revenues will be tracked in the PPCBA.

### 1. CAISO Market Costs

The charges and revenues that result from the CAISO's market activity are described in this section.

#### a. DA Market

The CAISO runs a DA Market for energy and Ancillary Service (A/S), referred to as the Integrated Forward Market (IFM). PG&E's electric supply portfolio receives revenues for awarded energy and A/S capacity through these markets. PG&E is also charged for the amount of demand scheduled and bid on behalf of PG&E's bundled load. In addition to the energy and A/S markets, the CAISO runs a Residual Unit Commitment (RUC) process after the IFM. If needed, the CAISO procures additional capacity through this process. Based on the CAISO's procurement through the IFM and RUC, it may be necessary to collect additional funds, or market uplifts, from market participants based on their net market positions. These uplift charges are often based on the amount of demand a market participant has in the CAISO markets. This amount includes charges for energy purchased for PG&E's bundled customer load, A/S portfolio obligations, and market uplifts needed to maintain cash neutrality for the CAISO. These charges are offset by revenues for awarded energy and A/S schedules for PG&E's portfolio generation.

#### b. Real-Time Market

The CAISO's Real-Time Market (RTM) includes the costs and revenues related to the dispatch of energy, unscheduled bundled customer load and procurement of A/S. The RTM is comprised of

5-minute dispatch and settlement and the Fifteen-Minute Market (FMM) resulting from the implementation of Federal Energy Regulatory Commission (FERC) Order 764 beginning in 2014. Also included are the financial settlements related to intertie awards, for both imports and exports, which are generated through the Hour-Ahead Scheduling Process and the FMM. The dispatch of energy in RT is settled through the use of imbalance energy charge codes. Dispatches are paid or charged through the Instructed Imbalance Charge Code mechanism, while deviations from schedule or dispatch are settled through the Uninstructed Imbalance Charge Code mechanism. Similar to the DA Markets, market uplifts are utilized to fund any revenue shortfalls in the RTM.

**c. Congestion Revenue Rights**

Congestion Revenue Rights (CRR) are financial instruments that allow the holder to hedge congestion costs in the IFM. CRRs are defined between any two nodes in the CAISO transmission network model. The revenue (or shortfall) associated with a CRR on a path is the difference between the congestion component of the source Locational Marginal Price (LMP) and the congestion component of the sink LMP. CRRs, with their associated cash flows, enable Load Serving Entities (LSE), such as PG&E, to mitigate potential congestion costs associated with the price the CAISO charges to serve LSE loads. CRRs are acquired through a yearly and monthly allocation and auction process.

**d. Grid Management Charges**

Grid Management Charges (GMC) are comprised of daily and monthly charges which are assessed to market participants for the purpose of recovering all CAISO operating costs. The CAISO currently has incorporated three cost service-based GMCs, a fixed Transmission Ownership Rights GMC, as well as four transactional and administrative GMCs. The cost services GMC consist of: (1) a Market Services Charge; (2) a System Operations Charge; and (3) a CRR Services Charge. The five transactional and administrative fees consist of: (1) a

Bid Segment Fee; (2) a CRR Transaction Fee; (3) an Inter-SC Trade Transaction Fee; (4) a SC ID Charge and (5) a Reliability Coordinator Services Charge. All of these GMCs represent the various ways market participants interact with the CAISO on a day-to-day basis.

**e. FERC Fees**

FERC fees are allocated to CAISO market participants in accordance with the CAISO Tariff. The fees represent estimated and actual FERC operating costs for its electric regulatory program. The CAISO allocates the fees to each market participant based on their use of the CAISO grid.

**f. Other**

Other charges and credits include Unaccounted for Energy, Bid Cost Recovery, Convergence Bidding, A/S, DA IFM Credit Allocation, RT Imbalance Energy Offset, Resource Adequacy Availability Incentive Mechanism (RAAIM) and other miscellaneous categories.

## C. Miscellaneous

### 1. CAISO Tariff Section 37 Rules of Conduct

CAISO Tariff Section 37 Rules of Conduct set forth the guiding principles for participation in the markets administered by the CAISO. Under these rules, sanction charges can be assessed as the result of market participants' failure to respond to CAISO requests for data or perform certain functions across a potential range of areas.[2] Incidents that can trigger a sanction include failure on a timely basis to report generator outages, submit meter data and/or provide other information required by the CAISO Tariff. Responsibility to comply with CAISO Section 37 requests can rest with third party generators.[3]

During the record period, PG&E was assessed Section 37 charges totaling $41,000 for non-compliance with CAISO Tariff Section Rules of Conduct. These charges were associated with either PG&E's generation or load (non-demand response) as follows:

---

[2] See CAISO Tariff Section 37 – Rules of Conduct (Rev. 1-1-21).

[3] CAISO Tariff Section 37.9.3.3 – Other Responsible Party.

- $39,000 in sanction charges was attributed to 7 contracted generating resources failing to resolve telemetry communication issues by the CAISO mandated deadlines. PG&E, as SC for these 7 contracted generators, received the sanction charges via CAISO invoices, however, these costs are the responsibility of the generators per their PPA with PG&E. As such, PG&E passed through the $39,000 in charges to the 7 generators as offsets to their monthly contract settlement payments in 2022. These charges are included in the PABA column in Table 10-1 above and in workpaper Chapter 10 Retail_ISO_PABA_GRID_YTD_2022_FINAL.xlsx, Tab entitled "PABA Grid", Column A; and
- $2,000 in sanction charges was due to PG&E's late submission of generation and load Settlement Quality Meter Data (SQMD) for trade dates August 3 and August 4, 2021. These charges were included in the T+70B statement for September 26, 2022 and resulted from a system interface connection issue between PG&E and CAISO during PG&E's 2021 Fall System Disaster Recovery (DR) failover exercise. The SQMD DR application interface was linked incorrectly to CAISO's Market Results Interface -Settlements (MRI-S) Market and Performance (MAP) stage instead of CAISO's MRI-S Production environment. Upon discovery, PG&E updated the interfaces to the CAISO MRI-S Production system and resubmitted the meter data. The meter data for the two trade dates above, however, were after CAISO's submission deadline. To mitigate this error for future DR exercises, PG&E redesigned its SQMD application to allow users to view the interface location and added a step in the procedure to validate submitted meter data in the CAISO's MRI-S Production environment before the submission deadline. The $2,000 is identified in PG&E's monthly financial reporting as "PG&E Sanctions." This $2,000 is not recovered from customers. Please see above Table 10-1 above and workpaper Chapter 10 Retail_ISO_PABA_GRID_YTD_2022_FINAL.xlsx, Tab entitled "PABA Grid", Column T.

The $41,000 of charges represents all 2022 Section 37 sanctions received by PG&E through the September 2022 T+70B statements. Any additional sanctions in October 2022 to December 2022 T+70B statements will be included as reconciling items in Chapter 10 Testimony for 2023 ERRA Compliance.

**D. Conclusion**

The above testimony describes the CAISO costs that were incurred during the record period and demonstrates that these costs were reasonable and prudently incurred.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 11

# REVIEW ENTRIES RECORDED IN THE GREEN TARIFF SHARED RENEWABLES MEMORANDUM ACCOUNT AND THE GREEN TARIFF SHARED RENEWABLES BALANCING ACCOUNT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
REVIEW ENTRIES RECORDED IN THE GREEN TARIFF SHARED RENEWABLES MEMORANDUM ACCOUNT AND THE GREEN TARIFF SHARED RENEWABLES BALANCING ACCOUNT

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 11
# REVIEW ENTRIES RECORDED IN THE GREEN TARIFF SHARED RENEWABLES MEMORANDUM ACCOUNT AND THE GREEN TARIFF SHARED RENEWABLES BALANCING ACCOUNT

## A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents its 2022 recorded Green Tariff Shared Renewables (GTSR) administrative and marketing (A&M) costs for reasonableness review, as directed by the California Public Utilities Commission (CPUC or Commission) in Decision (D.) 15-01-051, the *Decision Approving Green Tariff Shared Renewables Program for San Diego Gas & Electric Company, Pacific Gas and Electric Company, and Southern California Edison Company Pursuant to Senate Bill 43*. In addition, PG&E is presenting costs and revenues recorded to the Green Tariff Shared Renewables Balancing Account (GTSRBA) for review to ensure compliance with applicable tariffs[1] and Commission directives, as required in D.15-01-051.[2]

Senate Bill (SB) 43 required the three large, investor-owned utilities (IOU) to implement the GTSR Program. SB 43 further required that participating customers pay the administrative and marketing costs of the GTSR Program.[3] The IOUs collect administrative costs, as well as marketing costs, from GTSR customers through program-specific charges on participating customers' bills. Thus, all three IOUs have a GTSR-specific A&M rate included in their GTSR

---

1 GTSRBA – Electric Preliminary Statement GR: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_GR.pdf.

2 D.15-01-051, Finding of Fact (FOF) 137: Coordinating review of true-up of GTSR charges and credits with the ERRA process will provide greater certainty that entries to the GTSR accounts are stated correctly and are consistent with Commission decisions and Conclusion of Law (COL) 59: It is appropriate for an IOU to provide a summary and true-up of costs and revenues against charges and credits applied to GTSR customers on an annual basis, either through the IOU's annual ERRA process or in a separate application.

3 D.15-01-051, p. 108.

Program charge. PG&E's GTSR tariffs indicate A&M rates that are applicable to the Program.[4]

In D.15-01-051, the Commission required that administrative and marketing costs for the GTSR program be tracked in a memorandum account and be subject to reasonableness review in each IOU's annual Energy Resource Recovery Account (ERRA) compliance review. Costs that are found not to be reasonable cannot be collected from customers participating in the program and will be borne by shareholders. Program startup costs found to be reasonable can be amortized.[5]

In D.15-10-051, the CPUC approved two program offerings under the GTSR: (1) a "green tariff" (which PG&E began offering to customers in January 2016 under the program name "PG&E's Solar Choice"); and (2) an enhanced community renewables (ECR) offering—which PG&E opened for developer participation in November 2015 and is called "Regional Renewable Choice." In D.16-05-006, the *Decision Addressing Participation of Enhanced Community Renewables Projects in the Renewable Auction Mechanism and Other Refinements to the Green Tariff Shared Renewables Program*, the Commission provided further refinements to both programs.

**B. PG&E's Petition to Modify D.15-01-051**

In the first three months of 2021, there was a significant increase in Solar Choice enrollment due to favorable rates for participants. The increase in enrollment very quickly surpassed PG&E's GTSR dedicated resource pool's capacity. On April 30, 2021, PG&E filed an Emergency Petition to Modify D.15-01-051 (Emergency Petition) which sought modification of D.15-01-051 to allow PG&E to use, on a temporary basis, excess existing renewable resources previously procured separately from its Solar Choice Program to form a temporary resource pool to meet the needs of the increase in Solar Choice

---

**4** See GTSR Electric Green Tariff (E-GT) and ECR (E-ECR) tariffs: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-GT.pdf and https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-ECR.pdf.

**5** D.15-01-051, p. 113.

customer enrollments.[6] In December 2021 the Commission approved PG&E's Emergency Petition in D.21-12-036, which included a requirement to file a Tier 3 Advice Letter (AL) within 15 days of issuance that would establish the interim pool of Renewable Portfolio Standard (RPS) resources needed to support the Solar Choice Program. AL 6451-E was filed on December 30, 2021, requesting approval of an interim pool of resources. The CPUC approved that AL effective June 29, 2022 by Resolution E-5218.

## C. Green Tariff Shared Renewables Memorandum Account

### 1. Description of Costs Incurred

In 2022, PG&E incurred $313,708 in expenses to implement and manage the GTSR Program[7]. These expenses fall into five major categories: (1) program management; (2) Information Technology (IT)/billing system; (3) energy procurement; (4) contact center operations; and (5) outreach. The recorded expenses, by category, are shown in Table 11-1. The expenses were recorded into the GTSRMA in accordance with D.15-01-051.[8] PG&E uses internal order numbers to carefully track GTSR administrative and marketing costs in a manner that maintains non-participant indifference to these costs.[9]

**TABLE 11-1**
**GTSR MEMO ACCOUNT 2022 RECORDED COSTS**

| Line No. | Description | Amount |
|---|---|---|
| 1 | Program Management | $186,117 |
| 2 | IT/Billing System | 16,620 |
| 3 | Energy Procurement | 105,066 |
| 4 | Contact Center Operations | TBD |
| 5 | Outreach/Marketing | 5,905 |
| 6 | Total | $313,708 |

6 As stated in PG&E's April 30, 2021 Emergency Petition, because of the emergency nature of the need for resources to serve Solar Choice customers, PG&E requested the Commission grant its Emergency Petition by no later than June 2021.

7 Contact Center Operations expenses will be included in supplemental testimony, which will increase total expenses.

8 D.15-01-051, COL 58, p. 178.

9 PG&E is providing workpapers for this chapter which provide additional detail.

### 2. Program Management

In 2022, PG&E incurred $186,117 in program management labor and expenses to administer the GTSR Program, comprised of order numbers 8119888 in the GTSRMA budget detail provided in the workpapers. The activities associated with this work included ensuring compliance with all regulatory requirements, implementing customer-facing changes to rates and tariffs, overseeing the contact center and billing operations functions, addressing customer inquiries, and filing required reports. The program management function also managed the external advisory board and ran two advisory board meetings in 2022.

This category of expenses also included project management functions, such as developing budgets and detailed schedules, establishing internal reports, and managing regular team meetings. It includes financial planning and analysis for the program, as well as incidental administrative charges, such as the Green-e Energy certification fee. Finally, this category includes Green Access Program proceeding participation in which the CPUC is considering possible modifications of the GTSR Program.

### 3. IT/Billing System Work

In 2022, PG&E incurred $16,620 in expenses associated with both maintaining the IT and billing system for the GTSR Program as well as improving or expanding existing functionality due to program needs, as necessary. This category is comprised of order numbers 8171723 and 8199462 in the GTSRMA budget detail provided in the workpapers. The GTSR program required relatively little work in this category in 2022 relative to previous years.

### 4. Energy Procurement

PG&E incurred $105,066 in energy procurement expenses associated with administration of the GTSR program in 2022. This work included running a Spring 2022 Solar Choice (GT) solicitation, a Spring 2022 Renewable Regional Choice (ECR) solicitation, a Fall 2022 Solar Choice solicitation, and a Fall 2022 Renewable Regional Choice solicitation. Additional miscellaneous program support included strategic planning for Green Tariff/Solar Choice procurement. Energy procurement work also included managing existing contracts, settlements, outreach and reporting work, as well as renewable energy credit tracking, reporting, and retirement.

### 5. Contact Center Operations

PG&E incurred contact center operations expenses in 2022 to support customer inquiries, re-enroll any accidentally unenrolled customers who wished to return to the program, and unenroll participants through the contact centers. It also included maintenance of contact center tools and resources, such as the Interactive Voice Response system and the CSR tools, to better support customers in learning about the program. However, the methodology used to identify Solar Choice (GT) calls received in PG&E's contact centers was discovered to be inaccurate. Accordingly, PG&E is creating a new methodology to accurately identify Solar Choice calls using a speech analytics tool and plans to submit supplemental testimony with updated contact center operations costs on April 28, 2023.

### 6. Outreach/Marketing

PG&E incurred $5,905 in contract and labor costs in outreach in 2022, comprised of order numbers 8157041 and 8172269 in the GTSRMA budget detail provided in the workpapers. As PG&E cannot enroll new customers due to D.21-12-036, approving PG&E's Emergency Petition, no acquisition marketing for GT took place in 2022. Outreach to existing customers included sharing information about rate changes, as many customers experiencing a discount relative to their Otherwise Applicable Tariff in 2021 shifted to paying a premium in 2022. No outreach costs were incurred related to ECR as that program does not have any developers actively marketing projects.

## D. Green Tariff Shared Renewables Balancing Account

### 1. Background

As discussed above, the Commission approved D.15-01-051, implementing the GTSR Program in January 2015. PG&E's program includes two GTSR electric rate schedules: Schedule E-GT (Green Tariff Program, otherwise known as Solar Choice) and Schedule E-ECR (ECR Program, otherwise known as Regional Renewable Choice). Under E-GT, customers purchase energy supplies via a portfolio of solar photovoltaic generation facilities sized 0.5 to 20 megawatts located within PG&E's service area and under contract with PG&E. In 2022, no customers took service under the E-ECR tariff. Consistent with the legislative requirement that non-participating customers remain indifferent to the GTSR Program, the Commission determined that each IOU is required to establish a balancing account to track the costs and revenues of the program.[10]

The purpose of the GTSRBA is to track revenues received and actual expenses incurred to procure renewable generation resources for customers participating in the GTSR Program, taking service under the Green Tariff Rate (Schedule E-GT) and the ECR (Schedule E-ECR). During the record period, customers only took service under the E-GT option. An overview of the GTSR Memorandum Account and GTSRBA is shown in Table 11-2 below.

**TABLE 11-2**
**MEMORANDUM AND BALANCING ACCOUNTS**

| | GTSR Memorandum Account | GTSR Balancing Account | Generation Revenue and Energy Resource Recovery Account (ERRA) |
|---|---|---|---|
| **Credit** | ***Revenues***:<br>- GT/ECR Admin.<br>- GT Marketing<br>- ECR Marketing | ***Revenues:***<br>- Solar Generation (GT only)<br>- Program Charge – less A&M<br><br>***Expense***<br>- GT Solar Resource backstop | ***Expense:***<br>- Solar Generation (GT only)<br>* Interim Pool Only<br>- Program Charge – less A&M |
| **Debit** | ***Expenses:***<br>- GT/ECR Admin<br>- GT Marketing<br>- ECR Marketing | ***Expenses:***<br>- Solar Generation (GT only)<br>* Interim Pool and/or<br>* GT Solar Resources<br>- Program Charge – less A&M | ***Generation Revenue***:<br>- Class Average Gen. Credit<br><br>***Expense:***<br>***GT Resources***<br>- GT Solar Resource backstop<br>***ECR Resources:***<br>- unsubscribed ECR energy |

---

10 D.15-01-051, p. 129; FOF 145, "A balancing account will allow the IOU to track revenue under and over collection of GTSR costs using balancing account ratemaking standards."

### 2. Rate Design Overview

Table 11-3 below provides the framework for how the credit and charge components are included in the E-GT tariff option, by illustrating where each of the components is reflected in the rates shown in the tariff and how the tariff rates are presented on customers' bills. As shown in the tables below, the rate components will roll up to either to the Solar Charge, Power Charge Indifference Adjustment (PCIA) Program Charge or the Program Charge-Other (generation-related).

**TABLE 11-3**
**ALLOCATION OF CHARGES AND CREDITS**

<table>
<tr><th>Component</th><th>Charges</th><th>Credits</th><th>Tariff Presentation</th><th>Bill Presentation</th></tr>
<tr><td>Solar Generation</td><td></td><td></td><td rowspan="3">Solar Charge</td><td rowspan="3">Solar Charge</td></tr>
<tr><td>– GT Interim Pool</td><td>✓</td><td></td></tr>
<tr><td>– GT Solar Resource</td><td>✓</td><td></td></tr>
<tr><td>Power Charge Indifference Adjustment (PCIA)</td><td>✓</td><td></td><td>Program Charge - PCIA</td><td>Program Charge - PCIA</td></tr>
<tr><td>Renewable Integration</td><td>✓</td><td></td><td rowspan="7">Program Charge - Other (Gen-Related)</td><td rowspan="8">Program Charge</td></tr>
<tr><td>Resource Adequacy</td><td>✓</td><td></td></tr>
<tr><td>Grid Management Charges</td><td>✓</td><td></td></tr>
<tr><td>WREGIS Fees</td><td>✓</td><td></td></tr>
<tr><td>Solar Value Adjustments</td><td></td><td></td></tr>
<tr><td>- Time of Use</td><td></td><td>✓</td></tr>
<tr><td>- Resource Adequacy</td><td></td><td>✓</td></tr>
<tr><td>Program Administration and Marketing</td><td>✓</td><td></td><td>Program Charge - (Marketing & Admin)</td></tr>
<tr><td>Class Average Generation Credit</td><td></td><td>✓</td><td>Generation Credit</td><td>Generation Credit</td></tr>
</table>

Revenues billed under the E-GT option are credited to the GTSRBA E-GT subaccount. Specifically, billed revenues to be credited to the account are as follows:

- Solar Generation;
- Program Charge – PCIA; and
- Program Charge – Other.

Expenses for the E-GT option recorded to the GTSRBA E-GT Subaccount include solar generation expenses, the PCIA Program Charge, and a Program Charge for the other expenses (generation-related), net of marketing and administration costs. In 2022, the E-GT Program was served with dedicated resources which were operational in 2022. The 2022 E-GT program subscription level continued to be in excess of the dedicated resource generation output due to program growth which occurred in 2021. The 2022 E-GT Program subscription levels were supplemented with interim pool resources, as approved in D.21-12-036 and Resolution E-5218.[11]

Subsequent to Resolution 5218-E issuance, PG&E submitted Advice Letter 6677-E on August 11, 2022, requesting tariff modifications to PABA and ERRA that would facilitate the transfer of the interim pool resource costs and associated market revenues to the GTSRBA and ERRA, respectively. Advice Letter 6677-E was approved on November 16, 2022.

The costs of the dedicated resources were recorded directly to the GTSRBA throughout 2022. The costs of the interim pool resources were recorded to the GTSRBA in the December 2022 accounting close process for years 2021 and 2022 up to the Solar Choice subscription level net short position. The prior period adjustment for interim pool resource costs is discussed in more detail in Section 3 below.

Expenses for the generation-related program charge were credited from ERRA and debited to the GTSRBA based on the generation-related program charge, less allowance for Revenue Fees and Uncollectibles accounts expense, multiplied by customer usage, in kilowatt-hour.

---

[11] Resolution 5218-E, issued on June 23, 2022, approved the interim pool resource list submitted in Advice Letter 6451-E, on December 30, 2021.

The class average generation revenue credit on customer bills was allocated to the generation balancing accounts based on PG&E's Preliminary Statement I allocations. The generation revenue credits will offset the otherwise applicable schedule's generation revenues, recorded to the generation accounts.

### 3. Balancing Account Entries for the Record Period

As noted above, with the approval of tariff changes requested in Advice 6677-E, which facilitated entries for interim pool resources expenses for 2021 and 2022, a prior period adjusting entry for interim pool resource use in 2021 and 2022 was implemented as part of the December close process. Table 11-4 below summaries the expenses associated with the interim pool resources that was transferred from PABA to cover the net short subscription level for the E-GT program.

**TABLE 11-4**
**2021 AND 2022 INTERIM POOL RESOURCE PRIOR PERIOD ADJUSTMENT**

| Line No. | Description | | 2021 | | 2022 | | Total |
|---|---|---|---|---|---|---|---|
| | | | ***Supply Demand Balance*** (MWh) | | | | |
| 1 | Demand | | 470,554 | | 441,348 | | 911,902 |
| 2 | Dedicated GTSR Supply | | 175,075 | | 121,685 | | 296,760 |
| 3 | Net Short = Interim Pool | | 295,479 | | 319,663 | | 615,142 |
| 4 | Cost ($/MWh) | $ | 78.70 | $ | 79.40 | | |
| 5 = 3 x 4 | **PAR Entry** | **$** | **23,253,629** | **$** | **25,380,379** | **$** | **48,634,008** |

| Line No. | Vintage | | 2021 | | 2022 | | TOTAL |
|---|---|---|---|---|---|---|---|
| | | | ***PAR Cost Entry, by Vintage*** | | | | |
| 1 | 2012 | $ | 2,593,406 | $ | 2,694,248 | $ | 5,287,654 |
| 2 | 2013 | $ | 9,411,735 | $ | 9,972,441 | $ | 19,384,176 |
| 3 | 2014 | $ | 4,573,178 | $ | 5,002,871 | $ | 9,576,049 |
| 4 | 2015 | $ | 6,675,311 | $ | 7,710,819 | $ | 14,386,130 |
| | | **$** | **23,253,629** | **$** | **25,380,379** | **$** | **48,634,008** |

Table 11-5 summarizes the balancing account entries for the record period. As described above, the billed revenues and expenses recorded to the account follow the categories illustrated in Table 11-3 above. Aside from the interim pool resource cost adjusting energy, an adjusting entry to true-up the Resource Adequacy (RA) charge using the final RA adder issued in PG&E's ERRA Forecast proceeding was implemented during the December close and the results are reflected in the GTSRBA ending balance.

The GTSRBA was under-collected in 2022 by approximately $7.3 million. The primary drivers contributing to this balance were dedicated resource and interim pool resource actual costs that were higher than forecast and the true-up of the RA charge using the final RA market price benchmark for 2022 also increased the expenses in the account.

## E. Conclusion

In this chapter, PG&E described its 2022 recorded administrative and outreach expenses for the GTSR Program. PG&E's workpapers include more detailed information regarding the specific, recorded administrative and outreach expenses. PG&E requests that the Commission review and approve as reasonable PG&E's 2022 recorded administrative and outreach expenses.

Additionally, this chapter presents PG&E's entries to the GTSRBA for compliance review. PG&E requests that the Commission find the entries were made to the GTSRBA in compliance with the applicable tariffs and Commission directives.

**TABLE 11-5**
**BALANCING ACCOUNT ENTRIES**

**GREEN TARIFF SHARED RENEWABLES BALANCING ACCOUNT**

| Tariff Line Item | Tariff Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | FY 2022 YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5.A | **GT Subaccount** | | | | | | | | | | | | | |
| **Billed Revenues - Net, excluding the allowance for RF&U accounts expense** | | | | | | | | | | | | | | |
| | The following revenue entries shall be made each month: | | | | | | | | | | | | | |
| 5.A.1 | E-GT Solar Charge Revenue | (2,291,932) | (2,709,846) | (2,354,991) | (3,010,969) | (1,812,844) | (879,160) | (2,945,504) | (2,199,337) | (3,757,522) | (3,011,468) | (1,892,571) | (2,476,147) | (29,342,291) |
| 5.A.2 | E-GT Program Charge Revenue, including PCIA and excluding A&M | (1,337,653) | (1,637,399) | (3,706,550) | (3,156,842) | (1,922,652) | (953,790) | (3,131,254) | (2,309,274) | (3,930,361) | (3,140,706) | (1,972,752) | (2,592,636) | (29,791,870) |
| | **Net Revenues - GT Subaccount** | (3,629,584) | (4,347,245) | (6,061,542) | (6,167,811) | (3,735,496) | (1,832,950) | (6,076,758) | (4,508,611) | (7,687,883) | (6,152,174) | (3,865,324) | (5,068,783) | (59,134,161) |
| **Expenses - Solar Charge and Program Charge (includes PCIA)** | | | | | | | | | | | | | | |
| | The following expense entries shall be made each month: | | | | | | | | | | | | | |
| 5.A.3 | Interim Pool Solar Generation Expense | [redacted] | | | | | | | | | | | | |
| 5.A.4 | GTSR Dedicated Resource Expense | | | | | | | | | | | | | |
| 5.A.5 | Program Charge expense, including PCIA and excluding A&M | | | | | | | | | | | | | |
| | **Net Expenses - GT Subaccount** | 1,679,747 | 2,236,082 | 4,431,723 | 3,882,902 | 2,802,878 | 1,853,632 | 4,352,352 | 3,326,166 | 4,757,439 | 3,739,245 | 2,409,888 | 2,859,051 | 38,331,105 |
| | **Net Activity before interest - GT Subaccount** | (1,949,837) | (2,111,163) | (1,629,819) | (2,284,909) | (932,618) | 20,682 | (1,724,406) | (1,182,444) | (2,930,445) | (2,412,929) | (1,455,435) | (2,209,732) | (20,803,056) |
| 5.A.6 | Interest | (2,404) | (3,028) | (4,567) | (14,731) | (21,519) | (27,143) | (27,676) | (66,123) | (74,192) | (80,072) | (125,102) | (58,240) | (504,796) |
| **Expense True-up Entries** | | | | | | | | | | | | | | |
| | The following entries will be made annually as data becomes available: | | | | | | | | | | | | | |
| 5.A.7 | Interim Pool Solar Generation Expense True-up | | | | | | | | | | | | [redacted] | |
| 5.A.8 | Program Charge expense True-up | | | | | | | | | | | | | |
| | **Net Activity - GT Subaccount** | (1,952,241) | (2,114,191) | (1,634,386) | (2,299,640) | (954,137) | (6,461) | (1,752,082) | (1,248,567) | (3,004,636) | (2,493,002) | (1,580,537) | 47,563,419 | 28,523,539 |
| | Beginning Balance | (21,215,063) | (23,167,304) | (25,281,495) | (26,915,881) | (29,215,520) | (30,169,658) | (30,176,119) | (31,928,201) | (33,176,768) | (36,181,405) | (38,674,406) | (40,254,943) | (21,215,063) |
| | **Ending Balance - GT Subaccount** | (23,167,304) | (25,281,496) | (26,915,881) | (29,215,520) | (30,169,658) | (30,176,119) | (31,928,201) | (33,176,768) | (36,181,405) | (38,674,406) | (40,254,943) | 7,308,476 | 7,308,476 |
| | | | | | | | | | | | | | | |
| 6 | **DISPOSITION** | | | | | | | | | | | | | |
| 6.a | Disposition of the GTSRBA balance attributable to oversupply of dedicated resources | | | | | | | | | | | | | - |
| 6.b | Disposition of the GTSRBA balance excluding amounts attributable oversupply of dedicated resources through: (a) the advice letter process or (b) through an Application. | | | | | | | | | | | | | |
| | **GTSRBA Beginning Balance** | (21,215,063) | (23,167,304) | (25,281,495) | (26,915,881) | (29,215,520) | (30,169,658) | (30,176,119) | (31,928,201) | (33,176,768) | (36,181,405) | (38,674,406) | (40,254,943) | (21,215,063) |
| | **GTSRBA Ending Balance** | (23,167,304) | (25,281,496) | (26,915,881) | (29,215,520) | (30,169,658) | (30,176,119) | (31,928,201) | (33,176,768) | (36,181,405) | (38,674,406) | (40,254,943) | 7,308,476 | 7,308,476 |

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 11**

**ATTACHMENT A**

**GTSRMA DETAIL FOR PLANNING YEAR 2022**

| Current Year Organiz | Planning Order | Planning Order Description | Order | Order Description | Cost Element | Sum of Jan | Sum of Feb | Sum of Mar | Sum of Apr | Sum of May | Sum of Jun | Sum of Jul | Sum of Aug | Sum of Sep | Sum of Oct | Sum of Nov | Sum of Dec | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Community Solar Choice | 5244393 | CES-14708-GTSRMA | 8119888 | Community Renewables ProgMgmt | Contract | $ 23,840.00 | $ - | $ - | $ - | $ - | $ 6,750.00 | $ - | $ - | $ - | $ - | $ - | $ - | $ 30,590.00 |
| Community Solar Choice | 5244393 | CES-14708-GTSRMA | 8119888 | Community Renewables ProgMgmt | Labor Internal | $ 11,082.64 | $ 13,896.74 | $ 9,275.92 | $ 14,868.25 | $ 7,076.48 | $ 3,579.73 | $ 15,625.14 | $ 19,615.56 | $ 8,988.51 | $ 18,178.78 | $ 14,294.81 | $ (774.94) | $ 135,707.62 |
| Community Solar Choice | 5244393 | CES-14708-GTSRMA | 8119888 | Community Renewables ProgMgmt | Other | $ - | $ - | $ - | $ 80.14 | $ - | $ - | $ - | $ 3,204.00 | $ - | $ - | $ - | $ 16,535.00 | $ 19,819.14 |
| **Community Solar Choice** | **5244393** | **CES-14708-GTSRMA** | **8119888** | **Community Renewables ProgMgmt Total** | | **$ 34,922.64** | **$ 13,896.74** | **$ 9,275.92** | **$ 14,948.39** | **$ 7,076.48** | **$ 10,329.73** | **$ 15,625.14** | **$ 22,819.56** | **$ 8,988.51** | **$ 18,178.78** | **$ 14,294.81** | **$ 15,760.06** | **$ 186,116.76** |
| **Community Solar Choice** | **5249192** | **CHIN-GTSRMA-IT** | **8171723** | **Solar Choice IT Add Work Total** | Labor External | **$ 223.49** | **$ 2,011.41** | **$ 446.98** | **$ 223.49** | **$ -** | **$ 457.82** | **$ 457.82** | **$ -** | **$ 7,325.12** | **$ (7,096.21)** | **$ -** | **$ -** | **$ 4,049.92** |
| Community Solar Choice | 5249192 | CHIN-GTSRMA-IT | 8199462 | Regional Renewable Choice Add IT | Contract | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,576.39 | $ - | $ - | $ 2,576.39 |
| Community Solar Choice | 5249192 | CHIN-GTSRMA-IT | 8199462 | Regional Renewable Choice Add IT | Labor External | $ - | $ 1,666.66 | $ 833.33 | $ 833.33 | $ 833.33 | $ 833.33 | $ 833.33 | $ 833.33 | $ 833.33 | $ 833.33 | $ 833.33 | $ 833.33 | $ 9,999.96 |
| Community Solar Choice | 5249192 | CHIN-GTSRMA-IT | 8199462 | Regional Renewable Choice Add IT | Other | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (6.44) | $ - | $ - | $ (6.44) |
| **Community Solar Choice** | **5249192** | **CHIN-GTSRMA-IT** | **8199462** | **Regional Renewable Choice Add IT Total** | | **$ -** | **$ 1,666.66** | **$ 833.33** | **$ 833.33** | **$ 833.33** | **$ 833.33** | **$ 833.33** | **$ 833.33** | **$ 833.33** | **$ 3,403.28** | **$ 833.33** | **$ 833.33** | **$ 12,569.91** |
| **Community Solar Choice** | **5250707** | **CHIN-GTSRMA-MARKETING GTSR** | **8157041** | **Solar Choice Marketing Total** | Labor Internal | **$ (125.76)** | **$ (1,381.38)** | **$ (3,503.56)** | **$ 907.31** | **$ 19.40** | **$ 10.14** | **$ 22.05** | **$ 213.39** | **$ 10.14** | **$ -** | **$ -** | **$ 473.45** | **$ (3,354.82)** |
| **Community Solar Choice** | **5250707** | **CHIN-GTSRMA-MARKETING GTSR** | **8172269** | **Solar Choice BES Total** | Labor Internal | **$ 221.94** | **$ 1,686.75** | **$ 3,750.81** | **$ 865.57** | **$ 665.85** | **$ 554.85** | **$ 399.50** | **$ 177.55** | **$ 88.77** | **$ 171.53** | **$ 193.56** | **$ 483.61** | **$ 9,260.29** |
| **Community Solar Choice** | **5250708** | **CHIN-GTSRMA-CCO** | **8165616** | **Community Renewables CCO Total** | Labor Internal | **TBD** | **TBD** | **TBD** | **TBD** | **TBD** | **TBD** | **TBD** | **TBD** | **TBD** | **TBD** | **TBD** | **TBD** | **TBD** |
| **Community Solar Choice** | **5250709** | **CHIN-GTSRMA-EP** | **8162779** | **Community Renewables EP Total** | Labor Internal | **$ 6,409.64** | **$ 7,628.82** | **$ 13,949.79** | **$ 6,627.27** | **$ 8,961.65** | **$ 8,102.90** | **$ 2,568.33** | **$ 11,121.49** | **$ 6,852.23** | **$ 3,445.69** | **$ 14,488.35** | **$ 14,909.91** | **$ 105,066.07** |
| **Community Solar Choice Total** | | | | | | **$ 41,651.95** | **$ 25,509.00** | **$ 24,753.27** | **$ 24,405.36** | **$ 17,556.71** | **$ 20,288.77** | **$ 19,906.17** | **$ 35,165.32** | **$ 24,098.10** | **$ 18,103.07** | **$ 29,810.05** | **$ 32,460.36** | **$ 313,708.13** |
| Grand Total | | | | | | | | | | | | | | | | | | |

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 12

# SUMMARY OF PORTFOLIO ALLOCATION BALANCING ACCOUNT ENTRIES FOR THE RECORD PERIOD

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
SUMMARY OF PORTFOLIO ALLOCATION BALANCING ACCOUNT ENTRIES
FOR THE RECORD PERIOD

TABLE OF CONTENTS

TABLE OF CONTENTS
(CONTINUED)

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 12
# SUMMARY OF PORTFOLIO ALLOCATION BALANCING ACCOUNT ENTRIES FOR THE RECORD PERIOD

## A. Introduction

This chapter presents the accounting entries made to Pacific Gas and Electric Company's (PG&E) Portfolio Allocation Balancing Account (PABA) for the period January 1 through December 31, 2022 (record period). Section B describes the background and structure of PABA, Section C describes the activity recorded to PABA, and Section D shows a variance analysis of the forecasted costs compared to the actual 2022 amounts recorded in PABA. This testimony demonstrates that the entries recorded to the PABA comply with California Public Utilities Commission (Commission) rules and decisions.

## B. Background and PABA Structure

Decision (D.) 18-10-019 issued in the Power Charge Indifference Amount (PCIA) Rulemaking 17-06-026 significantly modified the accounting for the PCIA by requiring that PCIA revenues from customers and costs be trued-up on an annual basis. To do so, D.18-10-019, Ordering Paragraph (OP) 8, required each utility to modify its Energy Resource Recovery Account (ERRA) and any other balancing accounts, as necessary, to be consistent with the PABA vintage subaccount structure adopted in the decision. PG&E Advice Letter (AL) 5440-E implemented these changes and was approved with an effective date of January 1, 2019. PG&E implemented the changes authorized in AL 5440-E during the June 2019 business close.

In D.19-10-001, the Commission established the methodology to true-up the Market Price Benchmarks (MPB) for Renewable Portfolio Standard (RPS) and Resource Adequacy (RA) attribute values from the forecast values. The final 2022 MPB values were incorporated into the PABA during the October close to reflect final actual attribute values for the retained RPS and RA attributes.

The purpose of the PABA is to recover the above-market costs for all generation resources eligible for recovery through the PCIA.[1] The PCIA is recovered from both bundled and departing load customers. Above market costs include the categories of activity detailed in Section C below.

The PCIA assigns cost responsibility for vintages of generation resources based upon when the customer departed bundled service. Consistent with developing PCIA rates in the annual ERRA Forecast proceedings, PCIA-eligible generation resources are generally assigned to vintages based on the year the resource commitment is made (i.e., contract execution date, legacy Utility-Owned Generation (UOG) or construction/acquisition date for other UOG after 2002).[2] As a result, the PABA is comprised of subaccounts for each year's vintage portfolio that records the costs and revenues associated with the categories of activity described above for all generation resources executed or approved by the Commission for cost recovery that year.

## C. Activity Recorded to the PABA

Activity recorded in the PABA includes the following categories: Revenues from Customers, RPS Activity,[3] RA Activity,[4] System RA Value Transferred to the System Reliability Incremental Procurement Subaccount of New System Generation Balancing Account (NSGBA), Adopted UOG Revenue Requirements, CAISO Related Charges and Revenues, Fuel Costs, Contract Costs, Greenhouse Gas (GHG) Costs, Green Tariff Shared Renewables (GTSR) PCIA Program Charges,[5] and Miscellaneous Costs.[6] These entries are further described below.

---

1 See PG&E's approved Electric Preliminary Statement Part HS tariff (hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_HS.pdf.

2 Please see further discussion on definition of UOG vintages in Section C.5 below.

3 Within PABA, RPS and RA are categorized together as Sold RPS and RA and Retained RPS and RA. PG&E organized this chapter to more clearly demonstrate how each RA and RPS product is accounted as Sold, Unsold, and Retained.

4 *Id.*

5 2020 ERRA Compliance Settlement Agreement (SA) (A-21-03-008) and AL 6297-E approved on January 1, 2022 to record the transfer of PCIA program Charge expense associated with the GTSR Program for customers taking service under Schedule E-GT and E-ECR to PABA.

6 Interest is also recorded in PABA that is based on the on the average balance in the account at the beginning of the month and the balance after the accounting procedures

### 1. Revenues from Customers

As required by Generally Accepted Accounting Principles, PG&E recognizes customer revenue for any balancing account based on when the revenue is earned, not when it is billed to customers. As a result, the revenues recorded to PABA in any given month include revenues billed to customers for usage during the current month and an estimate of revenues earned from providing electricity to customers that has not yet been billed to customers, referred to as unbilled revenue.

Because customer billing cycles vary throughout the month, the amount of revenue on a customer's bill reflects both a portion of usage from the current month, as well as a portion of usage from the prior month. For example, if a customer is billed on the 16th of each month, the March 16th bill will reflect the following:

- Current month usage for March 1st through March 16th;
- Prior month usage for February 17th through February 28th; and
- To estimate the remaining unbilled revenue for March, PG&E's process is based upon the sum of unbilled usage by customer billing cycle multiplied by the average billed rate for that cycle, with no delineation between bundled or departed load. This approach to estimating total unbilled revenue is based on summarized unbilled customer usage and average rates from PG&E's billing system. This reflects a reasonable estimate of total revenue attributable to the calendar month.

The total unbilled revenue for all billing cycles is then allocated first to balancing accounts that have a rate on Electric Preliminary Statement

---

for the current month are recorded times one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.

Part I,[7] which is determined by multiplying the rate by the total unbilled usage. The Preliminary Statement I states the specific rate for a balancing account that is part of the rate component used for revenue allocation for a specific rate component by balancing account.[8] The remaining unbilled revenue is then allocated to balancing accounts that record revenues but do not have a rate on Preliminary Statement I based on actual billed revenues for that balancing account over the sum of actual revenues for balancing accounts that do not have a rate on Preliminary Statement I. This approach to estimating unbilled revenue by balancing account does not rely upon detailed unbilled usage by customer type (bundled or departed customers) or specific rates by function associated with a specific balancing account, such as the PABA. Importantly, continuing with the example from above, the estimated unbilled revenue for March 17th through March 31st is reversed the following month and replaced with the actual amount billed to the customer.

Additionally, PCIA billed revenues from departed load customers and the PCIA portion of bundled customer's generation revenue is recorded to the PABA vintage subaccounts using incremental PCIA rates applicable to each vintage subaccount. The incremental PCIA rates recover the net resource costs recorded to the PABA vintages. Customers' billed vintage specific PCIA rates reflect the cumulative incremental rates for each vintage. PG&E uses a power query revenue model that facilitates the disaggregation of the cumulative PCIA revenues, by customer vintage, into incremental

---

**7** PCIA rates are stated on the Preliminary Statement Part I. However, the rates on the Preliminary Statement Part I are not used to calculate the unbilled revenue like the balancing accounts that have rates on Preliminary Statement Part I. To use the rate on Preliminary Statement Part I for unbilled revenue calculation, the rate must be able to be applied to a system-wide or customer class volume. PG&E does not have enough information to separately forecast unbilled usage for individual customer types such as departed load, nor by customer vintage. In that case, the allocation methodology for the remaining unbilled revenues as described below is used. After determining the unbilled revenue for PCIA by bundled, Direct Access and Community Choice Aggregation Customers, the unbilled revenue is then allocated in vintage over total billed revenue for the customer type.

**8** This first step in allocating unbilled revenue to balancing accounts using Preliminary Statement I rates is the same as how billed revenues are allocated to balancing accounts.

PCIA revenues, by bundled and departing load and vintage subaccounts. The power query model also uses customer revenue and usage information from PG&E's revenue reporting system, which is based on PG&E's Billing System.

Lastly, the transfer of net PCIA revenues for bundled customers served under the DAC-GT and CS-GT tariffs to the respective DAC-GT and CS-GT subaccounts in the PCCBA are found in accounting procedure 5.d. and 5.e.[9]

**2. RPS Activity**

In D.19-10-001 the Commission directed the utilities to value sold, unsold, and retained RPS products as follows: (1) sold RPS (actual transacted volumes) at the actual transacted prices, (2) unsold RPS (actual unsold volume) at $0; and (3) retained RPS (volume used for Investor-Owned Utility (IOU) compliance from PCIA-eligible portfolio) at the Final RPS Adder, or benchmark price.[10]

Table 12-1 summarizes the value of Sold, Unsold, and Retained RPS recorded to the PABA. The sold RPS represent all RPS sales transacted for 2022 deliveries through PG&E's Bundled RPS Sales Solicitations and settled during the record period[11] as well as Renewable Energy Credits (REC) delivered in 2021 but invoiced in 2022. These entries totaled to a value of [redacted] gigawatt-hour (GWh) at the transacted price. During the record period, PG&E did not record any unsold RECs to PABA. Lastly, the retained RECs for PCIA-eligible resources represent the total 2022 PCIA-eligible generation, less the sold RPS quantity, less the unsold RPS quantity,[12] totaling a value of [redacted] at the RPS Adder, or benchmark price of $13.24 per MWh.

---

9 AL 5763-E/E-A approved the proposal to separately record interim resources net costs entries by type for DAC-GT and CS-GT and to reflect that the transfer of certain net cost entries supporting these programs will be from the PABA.

10 D.19-10-001, Table III: RPS Value True Up (Price and Quantity).

11 REC volumes are associated with 2022 deliveries recorded through the December 2022 close and do not include any true-ups found in periods after December 2022.

12 As noted above, PG&E did not record any unsold volumes during 2022.

**TABLE 12-1**
**RPS ATTRIBUTE VALUE FOR PABA**

| Line No. | | Value ($ per MWh) | GWh | $ millions |
|---|---|---|---|---|
| 1 | Sold RPS (Valued at Transacted Price) | [redacted] | | |
| 2 | Unsold RPS (Valued at $0) | – | – | – |
| 3 | Retained RPS (Valued at RPS Adder) | $13.24 | [redacted] | |

### a. Sold RPS

PG&E sold RPS volumes for 2022 deliveries, in adherence with the Commission-approved Sales Framework in its 2017 RPS Plan and its 2018 RPS Plan.[13] The total sales for 2022 deliveries equate to [redacted] of PCIA-recoverable resources. However, as sales are not invoiced and settled until after Western Renewable Energy Generation Information System (WREGIS) certification of RECs, they are subject to an approximately 4 to 5-month lag. Transactions related to PCIA-recoverable resources delivered in 2022 that were also recorded to PABA during 2022 totaled approximately [redacted] and were recorded in PABA as sold RPS at transaction prices ranging from [redacted], totaling to a notional value of [redacted] for 2022 deliveries. The total value of these deliveries plus adjustments for 2021 deliveries invoiced during 2022 equals a total of $38 million as recorded in Accounting Procedure 5.f. of Preliminary Statement HS.

### b. Unsold RPS

Pursuant to D.20-02-047, PG&E is not including actual Unsold RPS for 2022 as a tracking framework within PABA has yet to be developed to determine ‘whether retired RECs in PABA were “unsold” or “retained” for compliance.

### c. 2022 Retained RPS

PG&E’s retained RPS volumes for 2022 deliveries are calculated by taking the total 2022 RPS generation, less the quantity sold, less the unsold RPS for 2022 deliveries. This calculation equates to [redacted] (total PCIA-eligible 2022 generation) – [redacted] (total

---

13 The RPS sales framework was approved in D.19-12-042.

RPS sales for PCIA-eligible 2022 deliveries) – 0 GWh (unsold RPS sales for 2022 deliveries in the 2022 Bundled RPS Sale Solicitation) or [redacted] of PCIA-eligible retained RPS. As required by D.19-10-001, PG&E records retained RPS volumes at the Final RPS Adder benchmark price published by Energy Division and recorded a total value of [redacted] for these 2022 deliveries. In addition, during the record period PG&E also recorded [redacted] in prior period related to adjustments for 2019 through 2021 deliveries.[14] The total value of these adjustments plus 2022 deliveries equals a total of $183 million as recorded in Accounting Procedures 5.h. and 5.i. of Preliminary Statement HS.

**d. Allocation of Retained REC Value and Sold RECs to PABA Vintages**

The 2022 Retained and Sold RECs recorded in the PABA were allocated to the vintages based on the adopted 2022 ERRA Forecast portfolio position.[15] Specifically, the allocation factors were developed using the forecasted GWhs of eligible RPS energy assigned to each vintage.[16] The 2022 allocation rate for Retained RECs was approved on February 2022 and was scheduled to be effective on March 2022. As a result, for the first two months, the Retained RECs utilized 2021 rates, and for the remaining ten months of the year the 2022 rates were utilized.[17] The table below shows the 2022 REC allocation factors used to allocate recorded retained REC amounts and proceeds associated with RECs sold to third parties.

---

14 During the record period, PG&E recorded [redacted] in true-ups for 2021 in the normal course of business, partially offset by the transfer of retained REC credits from PABA to PPCBA due to the implementation of AL 6524-E for Standard Offer Contracts, please see Section C.8 below.

15 As Unsold RECs have a $0 value, they are not directly recorded into the PABA.

16 The forecasted GWhs were extracted from PG&E's Joint IOU Common Template workpaper supporting the 2022 Update to Prepared Testimony filed during December 2021 in A.21-06-001, and supporting D.22-02-002.

17 Decision (D.)22-02-022 was issued on February 10, 2022, which approves the Retained REC Allocation rate for 2022. The decision approved for the 2022 rate to be applied to March 2022 until the end of 2022.

**TABLE 12-2**
**2022 REC ALLOCATION FACTORS BY PABA SUBACCOUNT EFFECTIVE JAN-22 & FEB-22**

| Line No. | | Legacy UOG | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | GWh | 3987.24 | 6,37.84 | 4,517.87 | 1,370.54 | 1,820.58 | 1,148.42 | 193.14 | 367.60 | 10.00 | 22.07 | 0.00 | 12.98 | 2.20 | 19,830.49 |
| 2 | Percent of Total GWh | 20.11% | 32.16% | 22.78% | 6.91% | 9.18% | 5.79% | 0.97% | 1.85% | 0.05% | 0.11% | 0.00% | 0.07% | 0.01% | 100% |

**TABLE 12-2A**
**2022 REC ALLOCATION FACTORS BY PABA SUBACCOUNT EFFECTIVE MAR-22 TO DEC-22**

| Line No. | | Legacy UOG | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | GWh | 794.94 | 7,226.11 | 4,483.40 | 1,362.00 | 1,767.42 | 1,132.17 | 188.07 | 365.32 | 15.90 | 22.03 | 0.00 | 0.00 | 0.00 | 19.79 | 17,377.14 |
| 2 | Percent of Total GWh | 4.75% | 41.58% | 25.80% | 7.84% | 10.17% | 6.52% | 1.08% | 2.10% | 0.09% | 0.13% | 0.00% | 0.00% | 0.00% | 0.11% | 100% |

### 3. RA Activity

As part of the RA program codified in Section 380 of the Public Utilities Code and CAISO Tariff provisions related to RA, PG&E complies with RA requirements related to system capacity requirements, local capacity requirements, and flexible capacity requirements. For a discussion of the RA procurement activities undertaken by PG&E pursuant to its Conformed 2014 Bundled Procurement Plan (BPP) and Commission directives during the January 1 through December 31, 2022 record period, please see Chapter 8.

In D.18-10-019, the Commission adopted the California Large Energy Consumer Association's proposal to reflect system, local, and flexible RA in the PCIA as follows:

- RA that provides both system and flexible capacity shall be counted as flexible RA capacity;
- RA that provides both system and local capacity shall be counted as local RA capacity; and
- RA that provides all three types of RA capacity shall be counted as local RA capacity.

In D.19-10-001, the Commission directed the utilities to value retained, sold, and unsold RA products as follows: (1) sold RA (actual transacted volumes) at the actual transacted prices; (2) unsold RA (volume offered for sale but not sold or used by the IOU) at $0; and (3) retained RA (volume used for IOU compliance and retained for IOU use) at the Final RA Adder, or MPB.[18]

The following sections describe how PG&E's RA activities described in Chapter 8 during the 2022 record period are accounted for in the PABA account.

#### a. Sold RA

PG&E offered to sell 2022 RA volumes in accordance with Appendix S of its BPP, as described in Chapter 8. Table 12-3 summarizes the notional volumes sold and recorded to PABA for the Record Period.

---

[18] D.19-10-001, Table IV: RA Value True Up (Price and Quantity).

**TABLE 12-3**
**SOLD RA VOLUMES**

| Line No. | | Volume (megawatt (MW))-Year) |
|---|---|---|
| 1 | Local | [redacted] |
| 2 | Flex | |
| 3 | System | |
| 4 | Total | |

The total value of sold RA recorded to PABA amounts to $122 million for the record period.[19]

**b. Unsold RA**

PG&E's unsold RA volumes for 2022 deliveries represent RA amounts that were offered for sale, but were not sold or used by the IOU, as described in Chapter 8. PG&E documents the volumes of RA offered for sale in the Quarterly Compliance Report (QCR), which includes showing that it is consistent with Appendix S of its BPP.[20] In total, [redacted] of unsold RA volumes related to PCIA-eligible resources.

D.18-10-019 directed the IOUs to value all RPS and RA attributes in the PCIA-eligible portfolio, regardless of whether they were retained for compliance or they were unsold, at the forecast MPB for the attribute until a decision was issued in Phase 2 of PCIA Order Instituting Rulemaking. In D.19-10-001, the Commission ruled that all unsold RA product shall be valued at zero.[21]

**c. 2022 Retained RA**

As described in Chapter 8, the volume of retained RA is based on the resources used for PG&E's compliance and retained for IOU use. As required by D.19-10-001, PG&E records retained RA volumes at the Forecast RA Adder throughout the year, which is trued up using the

---

**19** 2022 Sold RA value recorded to Accounting Procedure 5.g. of Preliminary Statement Part HS includes any adjustments for true-ups to prior periods.

**20** PG&E's 2022 QCRs were submitted to the Commission in the following ALs: (1) AL 6577-E (Quarter 1), (2) AL 6670-E (Quarter 2), (3) AL 6751-E (Quarter 3); and (4) AL 6844-E (Quarter 4).

**21** D.19-10-001, OP 3.e.

Final RA Adder, as calculated by Energy Division. Table 12-4 summarizes the Final RA Adder by RA type and the total retained RA volumes.

**TABLE 12-4**
**RETAINED RA VALUE**

| Line No. | | Final Adder ($/kW-Month) | Total Retained RA (MW-Year) | Notional Value ($ millions) |
|---|---|---|---|---|
| 1 | Local – PG&E | $6.84 | [redacted] | |
| 2 | Local – SCE | $6.60 | | |
| 3 | Flex | $6.39 | | |
| 4 | System | $8.11 | | |

**d. Allocation of Retained RA Value and Sold RA to PABA Vintages**

The 2022 retained and sold RA recorded in the PABA were allocated pro-rata to the vintages based on the adopted 2022 ERRA Forecast portfolio position. Specifically, the allocation factors were developed using the forecasted Net Qualifying Capacity (NQC) assigned to each vintage for each RA type.[22] The 2022 allocation rate for Retained RA was approved on February 2022 and was scheduled to be effective on March 2022. As a result, for the first two months, the Retained RAs utilized 2021 rates, and the remaining ten months of the year the 2022 rates were utilized.[23] Table 12-5 below shows the 2022 RA allocation factors used to allocate recorded retained RA amounts and revenues associated with RA sold to third parties.

---

**22** The forecasted NQCs were extracted from PG&Es Joint IOU Common Template workpaper supporting the 2022 Update to Prepared Testimony filed during December 2021 in A.21-06-001 and supporting D.22-02-002.

**23** Decision (D)22-02-022 was issued on February 10, 2022, which approves the Retained RA Allocation rate for 2022. The decision approved for the 2022 rate to be applied to March 2022 until end of 2022.

**TABLE 12-5**
**2022 RA ALLOCATION FACTORS BY RA TYPE AND PABA SUBACCOUNT EFFECTIVE JAN-22 & FEB-22**

| Line No. | | Legacy UOG | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Local | | | | | | | | | | | | | | | |
| 2 | NQC (MW-Year) | 38,925.33 | 20,732.85 | 1,266.07 | 2,584.21 | 885.43 | 103.75 | 36.20 | 148.81 | 0.00 | 9.24 | 0.00 | 993.45 | 0.00 | 0.00 | 66,685.34 |
| 3 | Percent of Total | 59.26% | 31.56% | 1.93% | 3.93% | 1.35% | 0.16% | 0.06% | 0.23% | 0.00% | 0.01% | 0.00% | 1.51% | 0.00% | 0.00% | 100.00% |
| 4 | Flex | | | | | | | | | | | | | | | |
| 5 | NQC (MW-Year) | 16,607.86 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 16,607.86 |
| 6 | Percent of Total | 100.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 100.00% |
| 7 | System | | | | | | | | | | | | | | | |
| 8 | NQC (MW-Year) | 34,337.27 | 1,833.49 | 1,376.73 | 662.33 | 995.32 | 557.63 | 36.79 | 27.82 | 192.95 | 7.15 | 0.00 | 0.00 | 0.00 | 0.00 | 40,027.48 |
| 9 | Percent of Total | 85.78% | 4.58% | 3.44% | 1.65% | 2.49% | 1.39% | 0.09% | 0.07% | 0.48% | 0.02% | 0.00% | 0.00% | 0.00% | 0.00% | 100.00% |

**TABLE 12-5A**
**2022 RA ALLOCATION FACTORS BY RA TYPE AND PABA SUBACCOUNT EFFECTIVE MAR-22 TO DEC-22**

| Line No. | | Legacy UOG | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Local | | | | | | | | | | | | | | | |
| 2 | NQC (MW-Year) | 1,908.10 | 2,266.36 | 102.31 | 214.11 | 126.51 | 9.06 | 2.60 | 12.24 | 0.00 | 52.75 | 0.00 | 208.31 | 10.00 | 0.41 | 4,912.76 |
| 3 | Percent of Total | 38.84% | 46.13% | 2.08% | 4.36% | 2.58% | 0.18% | 0.05% | 0.25% | 0.00% | 1.07% | 0.00% | 4.24% | 0.20% | 0.01% | 100.00% |
| 4 | Flex | | | | | | | | | | | | | | | |
| 5 | NQC (MW-Year) | 371.42 | 903.80 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1,275.22 |
| 6 | Percent of Total | 29.13% | 70.87% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 100.00% |
| 7 | System | | | | | | | | | | | | | | | |
| 8 | NQC (MW-Year) | 2,676.12 | 393.24 | 115.06 | 55.19 | 39.74 | 45.84 | 3.07 | 3.46 | 0.61 | 0.50 | 0.00 | 0.00 | 0.00 | 3.18 | 3,336.01 |
| 9 | Percent of Total | 80.22% | 11.79% | 3.45% | 1.65% | 1.19.% | 1.37% | 0.09% | 0.10% | 0.02% | 0.01% | 0.00% | 0.00% | 0.00% | 0.10% | 100.00% |

### 4. System RA Value Transferred to the System Reliability Incremental Procurement Subaccount

D.21-03-056 directs PG&E to prepare for potential extreme weather by increasing the peak and net peak supply to prevent the need for rotating outages. The Commission authorized recovery of the costs associated with increasing peak and net peak supply through the CAM methodology, which is recorded in the NSGBA. However, one type of transaction associated with increasing peak and net peak supply is recorded to PABA: Excess RA capacity value transferred to the System Reliability Incremental Procurement (Reliability OIR), a subaccount of the NSGBA. This program is used to meet the system reliability incremental procurement targets, or for new long-term procurement that meets the 2021 and 2022 emergency procurement requirements pursuant to D.21-03-056. Transfers from PG&E's existing portfolio to the Reliability OIR can occur after having made reasonable attempts to sell excess capacity to other load-serving entities to meet their 15 percent planning reserve margin are found in accounting procedure 5.I.[24] Transfers from PG&E's PCIA resource portfolio results in a credit to PABA and a debit to NSGBA[25]. PG&E transferred a total of 923 MW of excess capacity in 2022.

### 5. Adopted UOG Revenue Requirements

As affirmed in D.18-10-019,[26] the adopted PCIA-eligible UOG revenue requirement has been assigned to PABA vintage subaccounts based whether the resources are legacy UOG or were built or acquired after

---

24 AL 6222-E approved on December 28, 2020. PG&E expects the need for longer term procurement to meet bundled service customer's load given the recent proposed decision and alternate proposed decision issued in the Integrated Resource Plan Rulemaking, R.20-05-003.

25 During 2022, Diablo Canyon was used as the available resource with excess capacity to help meet the system reliability incremental procurement targets. However, this process could apply to any relevant PCIA resource.

26 D.18-10-019, pp. 51-59 and Conclusion of Law 12 and 13.

2002.[27] Legacy UOG includes PG&E's hydroelectric facilities and Diablo Canyon Power Plant (DCPP). Facilities constructed after 2002 include PG&E's Colusa, Gateway, and Humboldt Power Plants, PG&E's solar facilities and two fuel cells.[28] The vintage for facilities built after 2002 is based on the facilities' construction start date. The first annual vintage subaccount is 2009, so resources built between 2002 and 2008 are assigned to UOG Legacy vintage and remaining resources are assigned to the 2009 and later vintages.

The Commission approved UOG construction start date as an attribute that would define UOG vintage for cost recovery purposes. PG&E has developed a formal definition of "UOG construction start date" and supporting documentation to enable a standardized process to assign vintages to UOG facilities and communicated to all stakeholders for use in the UOG vintaging process:

> For the purpose of determining the "Construction Start Date" for PCIA-eligible utility-owned (UO) generation resources and storage resources, PG&E shall use the later of: (1) the first date that expenditures are recorded to SAP Project Order(s) established for the resource that are associated with site-specific construction work and that will be capitalized once the project reaches commercial operation, or (2) the date the Commission approves the new generation resource for cost recovery. Alternatively, if the Commission decision directing procurement assigns a resource vintage prior to selection of the resource, the Commission-assigned vintage will supersede vintaging the resource based on a construction start date.[29]

---

**27** The adopted UOG revenue requirement also includes Electric Supply Administration (ESA) costs, which is embedded in the adopted generation base revenue requirement approved in PG&E's General Rate Case. ESA costs allocated to the electric generation balancing accounts was adjusted to exclude Core Gas Supply costs. A portion of the ESA costs are then proportionally allocated to the PABA vintage subaccounts.

**28** Fuel cells were decommissioned during 2021. However, PG&E's UOG revenue requirements are on a forecast levelized basis through 2022. These are flagged for any residual allocations for the final period of the GRC rate case period.

**29** In reviewing all UOG facility assignments during and internal audit initiated during 2020, PG&E determined four resources that were given later PCIA vintages than otherwise allowable under this definition. Two of these resources were pre-2009 and would require no change to entries into PABA. PG&E Huron was given a 2011 vintage instead of 2010, while PG&E Guernsey was given a 2012 vintage instead of 2011. As explained in PG&E's 2021 ERRA Compliance Filing, formal grandfathering of the other two resources was recommended.

Under this formal definition, no PCIA-eligible UOG facilities were approved by the Commission nor started site-specific construction during the Record Period of 2022.

Other electric generation amounts approved by the Commission to be recovered through the PABA include: (1) approved pension contribution revenue requirement associated with the UOG revenue requirement; (2) adjustments to PG&E's UOG revenue requirement (e.g., cost of capital and tax reform); (3) gain or loss on sale of electric generation non-depreciable assets, including removal of assets sold that are embedded in the generation base revenue requirement; (4) DCPP employee retention program and license renewal costs; and (5) transfer of generation related amounts from other accounts. The following table summarizes how the adopted UOG amounts recorded in the PABA are assigned/allocated to the vintages.[30]

**TABLE 12-6**
**ADOPTED UOG ASSIGNMENT/ALLOCATION TO PABA**

| UOG Item | | Assignment/Allocation |
|---|---|---|
| Pension | | Allocated to UOG facilities and ESA based on adopted 2020 General Rate Case (GRC). Electric Generation Results of Operations (RO) labor expenses for each facility. |
| UOG Revenue Requirement | Facility: Hydro and Nuclear | UOG Legacy |
| | Fossil: Gateway, Colusa, Humboldt | 2009 Vintage |
| | Fuel Cell | 2020 Vintage |
| | Solar Photovoltaic | 2010 - 2012 Vintages |
| | ESA* | Allocated among PABA, ERRA, and NSGBA based on adopted 2020 RRQ for each account. Amount assigned to PABA is further allocated based on the adopted 2020 RRQ (Advice 5781-E, Appendix B) |
| | Cost of Capital Adjustment | Allocated to UOG facilities and ESA based on adopted 2020 General Rate Case (GRC). Electric Generation Results of Operations (RO) Ratebase. |
| | Ex Parte Penalty | Amounts are based on a Settlement Agreement approved by the Commission in 2018 related to the Ex Parte investigations. |
| Gain/Loss on sale of asset | | Assigned to same vintages as asset sold |
| DCPP Employee Retention and License Renewal | | UOG Legacy |

* Excludes Core Gas Supply amounts assigned to ERRA for recovery.

Finally, the Power Generation portion of the adopted Catastrophic Event Memorandum Account interim rate relief recorded in PABA is related to

30 The vintage assignments found in Table 12-6 are consistent with the final UOG Resource vintage determination described in Section C.2. above.

PG&E's hydroelectric generation facilities and therefore assigned to the UOG Legacy vintage.

### 6. CAISO Related Charges and Revenues

As described in Chapter 10, PG&E incurs procurement costs and receives revenues for various interactions through its participation in the CAISO market. PG&E incurs costs for the following activities: day ahead (DA) and real-time purchases, grid management charges, Federal Energy Regulatory Commission Fees, and other miscellaneous CAISO charges. PG&E receives revenues related to DA and real-time sales, scheduling coordinator fees, and congestion revenue rights. Section 37 sanctions are excluded from the CAISO Settlement Charges/(Revenues) which include failure on a timely basis to report generator outages, submit meter data and/or provide other information required by CAISO Tariff. PG&E assigns these CAISO related charges and revenues to PABA vintages based upon the vintage the contract or UOG resource is assigned.

During 2022, PG&E transferred net CAISO Revenues related to DAC-GT interim renewable resources out of PABA for vintages 2012, 2013 and 2015 to support the DAC-GT program; this entry is included in accounting procedure 5.t.[31] In addition, PABA transfers of net CAISO Revenues related to 2021 and 2022 GTSR interim renewable resources out of PABA for vintages 2012 to 2015 to support the GTSR program to ERRA are also included in accounting procedure 5.t.[32]

The total amount recorded in the PABA for the recorded period is a credit of $3,694 million.[33] Further details on the types of charges, PG&E activities in the CAISO Market, and the basis for assigning to vintages is included in Chapter 10.

---

[31] AL 5763-E/E-A approved on December 21, 2020 to separately record interim resources net costs entries by type for DAC-GT and CS-GT and to reflect that the transfer of certain net cost entries supporting these programs will be from the PABA.

[32] AL 6677-E approved on November 16, 2022 to separately record interim resources net costs entries for GTSR and to reflect that the transfer from PABA to ERRA.

[33] This amount includes all CAISO settlement amounts recorded during 2022 accounting closes through December 31, 2022. CAISO settlement amounts reflected in Chapter 10 includes all settlement data for 2022 trade months, including those recorded during January 2023 accounting close.

### 7. Fuel Costs

As described in Chapter 6, costs of fuel used to supply UOG facilities and tolling contracts are recoverable in PABA and are allocated to the same vintages that the UOG facilities and contracts are assigned. Total gas costs are allocated based on fuel used by each UOG facility and tolling contract as a percentage of the total fuel used for each month. Fuel costs assigned to UOG facilities are recorded in PABA pursuant to accounting procedure 5.w. and fuel costs assigned to tolling contracts are recorded in the same accounting procedure that the contract costs are recorded in PABA. For example, if the contract costs are recorded in PABA pursuant to accounting procedure 5.ac., then the fuel costs are also recorded in that same tariff line item.

PG&E also records other non-gas fuel and related transportation and miscellaneous costs according to other accounting procedures in this section of Preliminary Statement HS, including distillate fuel, hydroelectric fuel, and nuclear fuel and associated carrying costs.

### 8. Contract Costs

As described in Chapter 9 and stated in the accounting procedures of PG&E's approved PABA preliminary statement, the majority of PCIA-eligible contract costs were assigned to vintages in the PABA based on the year the resource commitment was made, which in the case of procurement contracts is contract execution date. The transfers of the DAC-GT interim renewable resources related to Renewable Bilateral costs associated with participating in WREGIS are in PABA for vintages 2012, 2013 and 2015 to support the DAC-GT program and is found in accounting procedure 5.ad.[34]

In addition, new Qualifying Facility Standard Offer Contract obligations authorized pursuant to D.20-05-005 were previously recorded into a non-vintage subaccount. PG&E proposed to move these costs from the non-vintage subaccount in PABA to the PPCBA as part of its 2022 ERRA Forecast Application (A.21-06-001). In D.22-02-002, the Commission approved this proposal, and upon disposition of AL 6524-E, PG&E

---

[34] AL 5763-E/E-A approved on 12/21/2020 to separately record interim resources net costs entries by type for DAC-GT and CS-GT and to reflect that the transfer of certain net cost entries supporting these programs will be from the PABA.

transferred the costs to a new PPCBA subaccount and disposed of the nonvintage subaccount and related Standard Offer Contract tariff line item.

In OP 10 of D.12-04-046, PG&E was granted authority to recover the costs incurred for GHG compliance instrument transactions through ERRA. D.18-10-019, OP 8 modified D.12-04-046 andrequired each utility to modify its ERRA and any other balancing accounts, as necessary, to be consistent with the PABA vintage subaccount structure adopted in the decision. This change was implemented via AL 5440-E and granted PG&E the authority to recover the costs incurred for GHG compliance instrument transactions through PABA pursuant to accounting procedure 5.ag. that was effective as of January 1, 2019.[35]

In addition, pursuant to D.20-12-005, PG&E was authorized to recover the GHG carrying costs through the ERRA and AGT proceedings.[36] These costs will be recorded to the PABA, as recorded under "GHG Costs" in tariff line item 5.ag. upon approval of 2022 ERRA Forecast decision, beginning in 2022.[37]

PG&E incurs both direct GHG costs and financially settled GHG costs. Direct GHG costs are those costs related to PG&E's physical procurement of GHG compliance instruments consistent with its BPP authority, whereas financially settled GHG costs are obligations that can be financially settled as described in Section 9.b. below.

In addition, the Commission's D.20-05-004 ordered Southern California Edison Company (SCE) to work in conjunction with other IOUs, and the Public Advocates Office to address balancing account treatment of direct GHG costs and to provide transparency where these costs are recovered. The decision directed SCE to file a Petition for Modification to modify D.19-04-016 addressing the improvement of recording and presenting the Direct GHG costs in their respective balancing accounts, in a manner consistent with their associated resource costs. For example, GHG costs

---

**35** Any applicable broker fees are included in this line item. PG&E is authorized to use brokers for GHG procurement in its BPP.

**36** Issued by the Commission on December 11, 2020.

**37** PG&E filed AL 6175-E for minor tariff revisions and to notify the Commission that it would present such carrying costs in its 2022 ERRA Forecast Application.

for PCIA-eligible resources will be recorded in PABA, Cost Allocation Mechanism-eligible resources will be recorded in NSGBA, and bundled-only resources will be recorded in ERRA. Accordingly, a new GHG Balancing Account Table was added to Attachment A to show the total GHG costs recorded to each balancing account during the record year.

**a. PG&E's Process for Recording Direct GHG Costs**

As explained below, the costs associated with PG&E's purchases of GHG compliance instruments in a given year will not match with the costs recorded in the PABA for the same year. If PG&E were to participate in the quarterly Air Resources Board (ARB) auction, those compliance instruments would be recorded to PG&E's inventory when auction results are released. GHG compliance instruments and offset credits purchased from other third-party sellers are recorded to PG&E's inventory when they are received. Each month, GHG emissions costs are recorded in PABA based on the accrual method of accounting using the best available volume of emissions and Weighted Average Cost (WAC) price at the time the emissions costs are recorded. Physical compliance obligation costs are calculated as the WAC price of Eligible Compliance Instruments held in inventory at the end of a month multiplied by the quantity of emissions generated in that month. The accrual amount will continue to be trued-up in subsequent months as new or additional information becomes available for emission quantities and for WAC price changes.[38]

PG&E's current methodology for calculating the WAC is consistent with D.19-04-016.[39] The WAC is calculated for each specified compliance period. When compliance instruments are purchased, they are held in Inventory at the purchase price. When compliance instruments are added, the Inventory increases, and the WAC price may

38 When the cost, or debit, is recorded in the PABA, a corresponding entry, a credit, is recorded to a liability account, reflecting PG&E's liability to surrender GHG compliance instruments to the ARB. The inventory and liability accounts are reduced when the GHG compliance instruments have been surrendered to the ARB and/or transferred to a third party.

39 Issued by the Commission on April 25, 2019.

change. The cost of inventory also increases when there are payments in fees or premiums related to the compliance instruments. The WAC is calculated as the total cost, inclusive of fees and premiums, of eligible compliance instruments in inventory, divided by the total quantity of eligible compliance instruments in inventory. Compliance instruments held in inventory are segregated by their eligible compliance periods (based on the vintage year). This methodology is done in accordance with generally accepted accounting practices.

The accounting expense is then determined by comparing the total change in the expected gross emissions expense inception to date less the total cumulative recorded emissions expense inception to date. The emissions expense is based on the current WAC of inventory ($/mt$CO_2$e) multiplied by emissions volumes ($/mt$CO_2$e). GHG costs are associated with PG&E's fossil fuel UOG facilities and therefore assigned to the same vintage in PABA as those facilities.

#### b. PG&E's Process for Recording Financially Settled GHG Emissions Costs

As noted in Chapter 7, GHG Compliance Instrument Procurement, some PG&E tolling contracts allow PG&E to elect financial settlement of GHG emissions obligations.[40] In these cases, GHG emission costs are embedded within the contract payments made to the counterparty and therefore recorded in the same balancing account and accounting procedure as the contract costs. For example, financially settled tolling agreement costs for both the contract and GHG emissions payments made to the counterparty that are recorded in the PABA are recorded in accounting procedure 5.ac for bilateral contracts.

### 9. GTSR PCIA Program Charges

PG&E is authorized to transfer PCIA related Program Charge expense associated with the GTSR Program dedicated resources for customers taking service for the GT and ECR subaccounts from the PABA to the

[40] See Chapter 7, Section C.1.

GTSRBA.[41] During the record period PG&E recorded $7.5 million in PCIA Program Charge credit in procedure 5.ah for GTSR program charges. In addition, PG&E is authorized to transfer interim pool resource's contract expenses in PABA for vintages 2012 to 2015to GTSRBA, which can be found in accounting procedure 5.aj.[42] During the record period PG&E recorded $48.6 million to transfer 2021 and 2022 interim pool resource's contract costs associated with the GTSR Program from PABA to GTSRBA.

**10. Miscellaneous Costs**

PG&E is authorized to recover indirect costs that support PG&E's management of its procurement/generation resource portfolio.[43] These costs include credit and collateral and third-party independent evaluator reviews.[44] Additionally, PG&E is authorized to transfer amounts to recover the transfer or repayment of the under-collection due to the PCIA revenue shortfall from the applicable PABA subaccount to the PCIA Undercollection Balancing Account (PUBA).[45] Finally, PG&E is authorized to transfer amounts to or from other accounts as authorized by the Commission.[46]

In Advice 5440-E, the Commission approved allocating credit and collateral and WREGIS certificate fees among PABA, ERRA, and the NSGBA based on the adopted revenue requirements for each of the

---

**41** 2020 ERRA Compliance SA (A-21-03-008) and AL 6297-E approved on 1/1/2022 to record the transfer of PCIA program Charge expense associated with the GTSR Program for customers taking service under Schedule E-GT and E-ECR to PABA.

**42** AL 6677-E approved on 11/16/2022 to separately record interim resources contract expenses for GTSR and to reflect that the transfer from PABA to GTSRBA.

**43** See PG&E's approved PABA tariff, Electric Preliminary Statement Part HS.

**44** As approved in Advice 5440-E, hedging costs, Net Energy Metering payments and Energy Storage Evaluation Program funding remain in ERRA for recovery from bundled customers.

**45** See PG&E's approved PABA tariff, Electric Preliminary Statement Part HS, Accounting Procedure 5.am.

**46** For example, in D.22-04-041 the Commission authorized PG&E to transfer $4.727 million in revenue requirements from the 2014 and 2017 Diablo Canyon Seismic Studies Balancing Account based on the 2020 ERRA Compliance Settlement Agreement (A-21-03-008) & approval of 2020 ERRA Compliance Final Decision (D.22-04-041) issued on 4/27/2022. PG&E recorded this entry in April 2022.

accounts.[47] Independent evaluator expenses are assigned to PABA, ERRA, or NSGBA based on the account the generation resource being evaluated is recorded and recovered. However, if the expenses are not associated with a specific resource, which is generally the case, the expenses are allocated to PABA vintages the same as credit and collateral and WREGIS expenses.

In compliance with D.18-10-019 and D.20-02-047,[48] PABA began recording the transfer of the under-collection due to the PCIA revenue shortfall from PABA to PUBA. This amount is equal to the difference between the uncapped vintaged PCIA rate by customer class minus the capped vintage PCIA rate by customer class applicable to departing load customers (net of Revenue Fees and Uncollectibles) multiplied by the departing load's usage by customer class for each vintage. Subsequently, D.20-12-038 authorized an incremental rate adder to departed load PCIA rates to repay the forecast 2020 undercollection over three years from 2021 through 2023. These incremental rates are being transferred from PABA to PUBA to recognize the reduction in the outstanding undercollection due to PCIA capped rates. This was slightly offset for remaining 2020 bills that were collected in January, or to the extent that rebates and rebills of prior years occurred throughout the record period.

Finally, transfer of amounts from other accounts to the PABA are generally assigned to the same vintage as the associated base generation costs. For example, costs recorded in the Diablo Canyon Seismic Studies Balancing Account, are assigned to the same PABA vintage as DCPP costs, which are recorded in the UOG Legacy vintage.

## D. Variance Analysis

In Table 12-7, PG&E provides a summary of the PABA portfolio costs recorded in the current record period compared to the forecast included in its 2022 ERRA Forecast November Update Application, approved by the Commission in D.22-02-002.

---

47 AL 5527-E, Appendix A and Appendix C. Note that amounts allocated to the NSGBA are approved to be recorded in the ERRA.

48 Entries implemented pursuant to ALs 5624-E and 5781-E.

**TABLE 12-7**
**2022 ACTUAL RECORDED COSTS COMPARED TO APPROVED FORECAST**

| Line No. | Description | Recorded (PABA) Millions of Dollars | Forecast Millions of Dollars t | Variance Millions of Dollars |
|---|---|---|---|---|
| 1 | Fuel Cost for UOG Facilities | [redacted] | | |
| 2 | UOG Costs (GRC Costs) | | | |
| 3 | CAISO Cost | | | |
| 4 | Contract & GHG Costs | | | |
| 5 | Renewable Portfolio Standard-Eligible Contracts | | | |
| 6a | Retained RPS | | | |
| 6b | Retained RA | | | |
| 7 | Green Tariff Shared Renewables (GTSR) PCIA Program Charges | | | |
| 8 | Miscellaneous Costs | | | |
| 9 | Total Procurement Costs in ERRA Forecast Proceeding | | | |

As Table 12-7 indicates, PG&E's procurement costs recorded across the portfolio were ($252.5) million lower than forecasted, primarily due to higher-than-forecast net CAISO market revenues due to higher market electricity prices offset by a reduction in expected total generation, lower than expected contract costs, and lower Retained RPS offset by lower-than-forecast RPS-eligible contracts. RPS costs are lower than forecast due to the energy revenue component of RPS and other energy sale contracts being incorporated in the contract forecast while the recorded benefit is under CAISO market revenues. RPS costs are still lower than forecast due to higher than forecast RPS-eligible energy due to higher CAISO market electricity prices for contracts, greater generation from variable priced wind resources, and higher-than expected RPS sales. In addition, the 2021 and 2022 Interim Resources Contract Costs associated with the shortfall of the GTSR Program moved from PABA (vintages 2012-2015) to GTSRBA and 2021 and 2022 Interim Resources CAISO Market Revenues moved from PABA (vintages 2012-2015) to ERRA, which was not forecasted.

A more detailed variance analysis of forecasted and actual amounts is included in PG&E's confidential workpapers for Chapter 12.

## E. Conclusion

PG&E has complied with the Commission's directives and has appropriately recorded entries to the PABA. PG&E requests that upon verification and review of the costs and revenues recorded in the PABA, the Commission find the recorded entries in PABA for the record period are appropriate, correctly stated, and in compliance with Commission decisions.

**TABLE 12-8**
**FOR THE YEAR ENDING DECEMBER 31, 2022**

| Tariff Line Item | DR/CR | Tariff Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | FY 2022 YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Billed Revenue** | | | | | | | | | | | | | | | |
| 5.a. | CR | A credit entry equal to PCIA revenues attributable to the Vintage from bundled customers | [redacted] | | | | | | | | | | | | (725,282,842.65) |
| 5.b. | CR | A credit entry equal to PCIA revenues attributable to the Vintage from DA customers | [redacted] | | | | | | | | | | | | (120,409,851.38) |
| 5.c. | CR | A credit entry equal to PCIA revenues attributable to the Vintage from CCA customers | [redacted] | | | | | | | | | | | | (806,600,264.79) |
| | | Revenues Net of RF&U | [redacted] | | | | | | | | | | | | (1,652,292,958.81) |
| 5.d. | DR/CR | A debit or credit entry equal to the difference between the vintaged PCIA revenues attributed to bundled customers served under the Disadvantaged Communities Green Tariff (DAC-GT) rate schedule and PCIA billed under DAC-GT customer's otherwise applicable rate tariff. | [redacted] | | | | | | | | | | | | – |
| 5.e. | DR/CR | A debit or credit entry equal to the difference between the vintaged PCIA revenues attributed to bundled customers served under the Community Solar Green Tariff (CS-GT) rate schedule and PCIA billed under DAC-GT customer's otherwise applicable rate tariff. | [redacted] | | | | | | | | | | | | – |
| **Actual Sold Renewable Portfolio Standard (RPS) & Resource Adequacy (RA) Transaction** | | | | | | | | | | | | | | | |
| 5.f. | CR | A credit entry equal to revenues received for Actual Sold RPS (REC) transactions | [redacted] | | | | | | | | | | | | (36,984,756.41) |
| 5.g. | CR | A credit entry equal to revenues received for Actual Sold RA transactions | [redacted] | | | | | | | | | | | | (122,195,341.41) |
| **Retained RPS & Retained RA Value** | | | | | | | | | | | | | | | |
| 5.h. | CR | A credit entry equal to the Retained RPS Value, determined using the most current Commission-adopted RPS Adder multiplied by Actual Retained RPS quantities. A corresponding debit entry equal to the Retained RPS Value is recorded in ERRA. | [redacted] | | | | | | | | | | | | (187,767,974.35) |
| 5.i. | DR/CR | A debit or credit entry to true-up the Retained RPS Value, determined using the Forecast RPS Adder to the Actual Retained RPS Value using the Final RPS Adder. A corresponding credit or debit entry equal to the true-up of the Retained RPS Value is recorded in ERRA. | [redacted] | | | | | | | | | | | | 5,016,918.64 |
| 5.j. | CR | A credit entry equal to the Retained RA Value, determined using the most current Commission-adopted RA Adder, multiplied by the Actual Retained RA quantities. A corresponding debit entry equal to the Retained RA Value is recorded in ERRA. | [redacted] | | | | | | | | | | | | (524,009,079.23) |
| 5.k. | DR/CR | A debit or credit entry to true-up the Retained RA Value, determined using the Forecast RA Adder to the Retained RA Value using the Final RA Adder. A corresponding credit or debit entry equal to the true-up of the Retained RA Value is recorded in ERRA. | [redacted] | | | | | | | | | | | | (76,445,104.89) |

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2022
(CONTINUED)

| Tariff Line Item | DR/CR | Tariff Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | FY 2022 YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| System RA Value Transferred to the System Reliability Incremental Procurement Subaccount | | | | | | | | | | | | | | | |
| 5.l. | CR | A credit entry equal to the value of RA capacity that is excess or unsold RA capacity that is transferred to the System Reliability Incremental Procurement Subaccount of NSGBA and used to meet the system reliability incremental procurement targets pursuant to D.21-03-056, after having made reasonable attempts to sell excess capacity to other load-serving entities to meet their 15% planning reserve margin. The credit entry will use the most current market price benchmark for system RA approved int he Annual ERRA Forecast, which is used to calculate the value of RA capacity in the PCIA calculation. | [redacted] | | | | | | | | | | | | (7,481,556.10) |
| UOG Costs | | | | | | | | | | | | | | | |
| 5.m. | DR | A debit entry equal to one-twelfth of the electric generation portion of revenue requirement associated with the CPUC authorized pension contr bution amount | [redacted] | | | | | | | | | | | | 34,196,439.62 |
| 5.n. | DR | A debit entry equal to the annual authorized revenue requirements associated with PG&E's owned generation divided by twelve, excluding PCIA-eligible UOG resource costs that have been procured by Central Procurement (CPE) for recovery through the New System Generation Charge (NSGC) & recorded to the Centralized Local Procurement Subaccount (CLPSA) of the New System Generating Balancing Account (NSGBA). | [redacted] | | | | | | | | | | | | 1,169,521,268.29 |
| 5.o. | DR/CR | A debit or credit entry, as appropriate, to record ESA costs associated with PCIA eligible generation resources portfolio/ procurement activity (which is embedded in the annual authorized revenue requirements associated with PG&E's owned generation) | [redacted] | | | | | | | | | | | | 1,118,917,220.52 |
| 5.p. | DR/CR | A debit or credit entry, as appropriate, to record the gain or loss on the sale of an electric generation non-depreciable asset, as approved by the CPUC | [redacted] | | | | | | | | | | | | (3,917,310.12) |
| 5.q. | DR | A debit entry equal to one-twelfth of the annual authorized revenue requirement for the Diablo Canyon Power Plant Employee Retention Program (see corresponding entry in the Employee Retention Subaccount of the Diablo Canyon Retirement Balancing Account (DCRBA) per Preliminary Statement HK, 5b.1) | [redacted] | | | | | | | | | | | | 49,761,991.20 |
| 5.r. | DR | A debit entry equal to one-twelfth of the annual authorized revenue requirement for the Diablo Canyon Power Plant license renewal costs | [redacted] | | | | | | | | | | | | 2,324,999.98 |
| 5.s. | DR | A debit entry equal to one-twelfth (or amortization period approved) of the power generation portion of the Catastrophic Event Memorandum Account (CEMA) interim rate relief for costs incurred in 2016 and 2017, as authorized by the CPUC in Decision 19-04-039 on April 25, 2019. | [redacted] | | | | | | | | | | | | – |
| ISO Related Charges/ Revenues | | | | | | | | | | | | | | | - |
| 5.t. | DR/CR | A debit or credit entry equal to the net charges or revenues for energy | [redacted] | | | | | | | | | | | | (3,589,550,724.53) |

## TABLE 12-8
## FOR THE YEAR ENDING DECEMBER 31, 2022
## (CONTINUED)

| Tariff Line Item | DR/CR | Tariff Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | FY 2022 YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | associated with generating resources recovered in PABA, which excludes net charges or revenues for energy associated with PCIA-elig ble resources procured by the Central Procurement Entity for recovery through the NSGC & recorded to the CLPSA of the NSGBA, and excludes charges and energy revenues associated with interim pool renewable resources that support the DAC-GT program. | [redacted] | | | | | | | | | | | | |
| 5.u. | DR/CR | A debit or credit entry equal to the net charges or revenues for miscellaneous CAISO charges/credits associated with generating resources recovered in PABA, which excludes net charges or revenue for miscellaneous CAISO charges/credits associated with PCIA-elig ble resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | (44,333,148.85) |
| 5.v. | DR/CR | A debit or credit entry equal to the net charges or revenues for ancillary services associated with generating resources recovered in PABA, excluding net charges or revenues for ancillary services associated with PCIA-elig ble resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | (59,977,394.58) |
| **Fuel Costs** | | | | | | | | | | | | | | | - |
| 5.w. | DR | A debit entry equal to natural gas fuel and related transportation and miscellaneous expenses for PCIA eligible UOG resources and contracts, excluding expenses in this category that have been allocated to PCIA-elig ble UOG and contract resources that have been procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | 406,809,120.24 |
| 5.x. | DR | A debit entry equal to distillate fuel and related transportation and miscellaneous expenses used at PG&E's fossil plants as a back-up, excluding expenses in this category that can be allocated to PCIA-eligible UOG and contract resources procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | 346,600.22 |
| 5.y. | DR | A debit entry equal to the hydroelectric fuel and related transportation and miscellaneous expenses, excluding expenses in this category that can be allocated to PCIA-elig ble UOG and contract resources procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA. The fuel expenses include water purchase costs for the hydroelectric plants. | [redacted] | | | | | | | | | | | | 1,731,344.80 |
| 5.z. | DR | A debit entry equal to nuclear fuel and miscellaneous expenses for the Diablo Canyon Nuclear Power Plant. | [redacted] | | | | | | | | | | | | 107,415,638.43 |
| 5.aa. | DR | A debit entry for nuclear fuel carrying costs equal to the interest on the monthly nuclear fuel inventory at the beginning of the month and one-half the balance of the current month's activity, multiplied at | [redacted] | | | | | | | | | | | | 4,707,781.37 |

**TABLE 12-8**
**FOR THE YEAR ENDING DECEMBER 31, 2022**
**(CONTINUED)**

| Tariff Line Item | DR/CR | Tariff Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | FY 2022 YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | a rate equal to one-twelfth of the rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. | [redacted] | | | | | | | | | | | | |
| **Contract Costs** | | | | | | | | | | | | | | | - |
| | DR | A debit entry equal to total costs associated with New QF SOC obligations authorized pursuant to D.20-05-005, which excludes New QF SOC costs associated with PCIA-elig ble resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | 151,131.98 |
| 5.ab. | DR | A debit entry to total costs associated with QF obligations that are not eligible for recovery as an ongoing CTC, which excludes non-CTC QF costs associated with PCIA-elig ble resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | – |
| 5.ac. | DR | A debit entry equal to bilateral contract obligations, which excludes bilateral costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA | [redacted] | | | | | | | | | | | | 610,448,153.22 |
| 5.ad. | DR/CR | A debit or credit entry equal to renewable contract obligations, and fees associated with participating in WREGIS, net of interim renewable resource costs supporting the DAC-GT Program, and net of WREGIS fees supporting the DAC-GT and the CS-GT Programs. | [redacted] | | | | | | | | | | | | 1,985,838,399.16 |
| 5.ae. | DR | A debit entry equal to the capacity and energy costs for QF/non-CHP Program contracts, which excludes QF/Non-CHP costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | (13,609,840.00) |
| 5.af. | DR/CR | A debit or credit entry equal to the cost or revenue associated with combined heat and power systems authorized in D.09-12-042, D.10-12-055 and D.11-04-033, and defined in PG&E's tariffs E-CHP, E-CHPS, and E-CHPSA, which excludes combined heat and power costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | 3,187,563.48 |
| **GHG Costs** | | | | | | | | | | | | | | | - |
| 5.ag. | DR | A debit entry equal to the greenhouse gas costs related to PG&E's generating facilities and physically settled compliance instruments associated with contracts, including carrying costs, which excludes GHG costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | 55,503,686.27 |
| **Green Tariff Shared Renewables (GTSR) Program Entries** | | | | | | | | | | | | | | | - |

**TABLE 12-8**
**FOR THE YEAR ENDING DECEMBER 31, 2022**
**(CONTINUED)**

| Tariff Line Item | DR/CR | Tariff Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | FY 2022 YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5.ah. | **DR/CR** | A credit or debit to reflect the transfer of PCIA Program Charge expense associated with the GTSR Program for customers taking service under Schedule E-GT, equal to the PCIA Program Charge rate, multiplied by the kWh delivered under the program to the E-GT customers for the month, and/or entry to reflect any subsequent true-up of the Program Charge components' expense to actual costs. | [redacted] | | | | | | | | | | | | (7,503,341.17) |
| 5.ai. | **DR/CR** | A credit or debit entry to reflect the transfer of PCIA Program Charge expense associated with the GTSR Program for customers taking service under Schedule E-ECR, equal to the PCIA Program Charge rate, multiplied by the kWh delivered under the program to the E-ECR customers for the month, and/or entry to reflect any subsequent true-up of the Program Charge components' expense to actual costs. | [redacted] | | | | | | | | | | | | – |
| 5.aj. | **DR/CR** | A debit or credit entry to reflect: (1) the transfer of the interim pool resource's contract expense associated with the GTSR Program for customers taking service under Schedule E-GT, equal to the interim pool weighted average costs, multiplied by the portion of kWh delivered under the program to E-GT customers that the vintage's interim pool resources can support for the month or (2) entry to reflect any subsequent true-up of the weighted average price and generation volumes of the interim pool resources used to support the E-GT customers' subscription level to final actual costs and generation amounts available to support the program. | [redacted] | | | | | | | | | | | | (48,634,007.83) |
| **Miscellaneous Costs** | | | | | | | | | | | | | | | |
| 5.ak. | **DR/CR** | A debit or credit entry equal to pre-payments and credit and collateral payments, including all associated fees, for procurement purchase and, if applicable, reimbursements of prepayments, credit and collateral payments. | [redacted] | | | | | | | | | | | | 1,473,378.97 |
| 5.al. | **DR** | A debit entry equal to any other power costs associated with procurement. | [redacted] | | | | | | | | | | | | 1,048,471.50 |

**TABLE 12-8**
**FOR THE YEAR ENDING DECEMBER 31, 2022**
**(CONTINUED)**

| Tariff Line Item | DR/CR | Tariff Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | FY 2022 YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5.am. | DR/CR | A credit/debit entry to transfer/repay the undercollection due to the PCIA revenue shortfall from the applicable PABA subaccount to the PUBA. The PCIA revenue shortfall is equal to the difference between the uncapped vintage PCIA rate by customer class minus the capped vintaged PCIA rate by customer class applicable to departing load customers, net of RF&U, multiplied by the departing load's usage by customer class for each vintage. The PCIA revenue shortfall is mapped to the PABA vintage subaccounts based on incremental revenue shortfall rates. Corresponding debit/credit entries will be recorded in PCIA Undercollection Balancing Account (PUBA), Electric Preliminary Statement Part HZ, based on the cumulative revenue shortfall rates, by customer vintage. | [redacted] | | | | | | | | | | | | 92,430,591.83 |
| 5.an. | DR/CR | A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC. | [redacted] | | | | | | | | | | | | 487,278,303.41 |
| | | **Total Monthly Activity Before Interest** | [redacted] | | | | | | | | | | | | [redacted] |
| 5.ao. | DR/CR | An entry equal to the interest on the average balance of the account at the beginning of the month and the balance after the entries above, at a rate equal to one-twelfth the interest rate of the three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. | [redacted] | | | | | | | | | | | | 2,275,543.33 |
| | | **Beginning Balance** | [redacted] | | | | | | | | | | | | [redacted] |
| | | **PABA Ending Balance** | [redacted] | | | | | | | | | | | | [redacted] |
| **PCIA Subaccount** | | | [redacted] | | | | | | | | | | | | |
| 6.a. | DR | A debit entry equal to imputed PCIA revenue based on the PCIA rate as adopted by the Commission; | [redacted] | | | | | | | | | | | | – |
| 6.b. | DR/CR | A credit or debit entry equal to the recorded PCIA revenues; and | [redacted] | | | | | | | | | | | | – |
| 6.c. | DR/CR | A credit or debit entry to transfer the balance as authorized by the Commission. | [redacted] | | | | | | | | | | | | – |
| | | **Beginning Balance** | [redacted] | | | | | | | | | | | | [redacted] |
| | | **PCIA Subaccount Ending Balance** | [redacted] | | | | | | | | | | | | [redacted] |
| | | **TOTAL PABA ENDING BALANCE** | [redacted] | | | | | | | | | | | | [redacted] |

# TABLE 12-8A
# FOR THE YEAR ENDING DECEMBER 31, 2022
# (YEAR-TO-DATE BY VINTAGE)

| Tariff Line Item | DR/ CR | Tariff Description | Non-Vintage Subaccount | UOG Legacy | 2009 Vintage | 2010 Vintage | 2011 Vintage | 2012 Vintage | 2013 Vintage | 2014 Vintage | 2015 Vintage | 2016 Vintage | 2017 Vintage | 2018 Vintage | 2019 Vintage | 2020 Vintage | 2021 Vintage | 2022 Vintage | Total all Vintages for Current Month |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues from Customers (net billed)** | | | – | 192,705,153.79 | (1,254,317,200.93) | (322,366,426.86) | (89,413,473.11) | (84,007,148.29) | 16,754,007.28 | 5,007,432.38 | 8,524,167.71 | (18,615,127.02) | 10,788,887.15 | 5,541,768.80 | (3,842,532.48) | 178,369,339.11 | (297,421,806 36) | – | – |
| 5.a. | CR | A credit entry equal to PCIA revenues attributable to the Vintage from bundled customers | [redacted] | | | | | | | | | | | | | | | | |
| 5.b. | CR | A credit entry equal to PCIA revenues attributable to the Vintage from DA customers | | | | | | | | | | | | | | | | | |
| 5.c. | CR | A credit entry equal to PCIA revenues attributable to the Vintage from CCA customers | | | | | | | | | | | | | | | | | |
| | | Revenues (Net of RF&U) | | | | | | | | | | | | | | | | | |
| 5.d. | DR/CR | A debit or credit entry equal to the difference between the vintaged PCIA revenues attributed to bundled customers served under the Disadvantaged Communities Green Tariff (DAC-GT) rate schedule and PCIA billed under DAC-GT customer's otherwise applicable rate tariff. | | | | | | | | | | | | | | | | | |
| 5.e. | DR/CR | A debit or credit entry equal to the difference between the vintaged PCIA revenues attributed to bundled customers served under the Community Solar Green Tariff (CS-GT) rate schedule and PCIA billed under CS-GT customer's otherwise applicable rate tariff. | | | | | | | | | | | | | | | | | |
| **Actual Sold Renewable Portfolio Standard (RPS) Transaction** | | | – | (1,883,390.58) | (15,263,590.22) | (9,505,066.12) | (2,887,391 99) | (3,749,483.66) | (2,400,735.45) | (398,954.78) | (774,466.51) | (33,324.61) | (46,702.85) | – | (807.09) | (136.60) | (40,705 96) | – | – |
| 5.f. | – | A credit entry equal to actual revenues for REC sales. | [redacted] | | | | | | | | | | | | | | | | |
| **Actual Sold Resource Adequacy (RA) Transaction** | | | – | (66,338,353 54) | (43,035,480.38) | (2,765,373.27) | (3,423,712.17) | (2,100,057.38) | (697,440.70) | (73,010.09) | (198,321.38) | (27,974.04) | (607,411.68) | – | (2,773,353.44) | (108,548.94) | (46,304.40) | – | – |
| 5.g. | – | A credit entry equal to actual revenues for RA sales. | [redacted] | | | | | | | | | | | | | | | | |
| **Retained Renewable Portfolio Standard (RPS) Value** | | | – | (11,591,199.17) | (74,002,071.04) | (46,545,910.34) | (14,133,879.98) | (18,386,186.18) | (11,758,938.82) | (1,958,663.18) | (3,791,230.58) | (155,090.56) | (228,053.01) | 760.91 | (13,541.63) | (2,303.98) | (184,748.14) | – | – |
| 5.h. | – | A credit entry equal to the Retained RPS Value, determined using the most current Commission-adopted RPS Adder multiplied by Actual Retained RPS quantities. A corresponding debit entry equal to the Retained RPS Value is recorded in ERRA. | [redacted] | | | | | | | | | | | | | | | | |
| 5.i. | – | A debit or credit entry to true-up the Retained RPS Value, determined using the Forecast RPS Adder to the Actual Retained RPS Value using the Final RPS Adder. A corresponding credit or debit entry equal to the true-up of the Retained RPS Value is recorded in ERRA. | | | | | | | | | | | | | | | | | |
| **Retained Resource Adequacy (RA) Value** | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | – | [redacted] | [redacted] | [redacted] | – | – |
| 5.j. | CR | A credit entry equal to the Retained RA Value, determined using the most current Commission-adopted RA Adder, multiplied by the Actual Retained RA quantities. A corresponding debit entry equal to the Retained RA Value is recorded in ERRA. | [redacted] | | | | | | | | | | | | | | | | |
| 5.k. | DR/CR | A debit or credit entry to true-up the Retained RA Value, determined using the Forecast RA Adder to the Retained RA Value using the Final RA Adder. A corresponding credit or debit entry equal to the true-up of the Retained RA Value is recorded in ERRA. | | | | | | | | | | | | | | | | | |

# TABLE 12-8A
# FOR THE YEAR ENDING DECEMBER 31, 2022
# YEAR-TO-DATE BY VINTAGE
# (CONTINUED)

| Tariff Line Item | DR/ CR | Tariff Description | Non-Vintage Subaccount | UOG Legacy | 2009 Vintage | 2010 Vintage | 2011 Vintage | 2012 Vintage | 2013 Vintage | 2014 Vintage | 2015 Vintage | 2016 Vintage | 2017 Vintage | 2018 Vintage | 2019 Vintage | 2020 Vintage | 2021 Vintage | 2022 Vintage | Total all Vintages for Current Month |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| System RA Value Transferred to the System Reliability Incremental Procurement Subaccount | | | - | (7,481,556.10) | - | - | - | - | - | - | - | - | - | - | - | - | - | | (7,481,556.10) |
| 5.l. | CR | A credit entry equal to the value of RA capacity that is excess or unsold RA capacity that is transferred to the System Reliability Incremental Procurement Subaccount of NSGBA and used to meet the system reliability incremental procurement targets pursuant to D.21-03-056, after having made reasonable attempts to sell excess capacity to other load-serving entities to meet their 15% planning reserve margin. The credit entry will use the most current market price benchmark for system RA approved int he Annual ERRA Forecast, which is used to calculate the value of RA capacity in the PCIA calculation. | [redacted] | | | | | | | | | | | | | | | | |
| UOG Costs | | | - | 2,094,602,985.56 | 225,624,582.63 | 15,731,261.12 | 13,374,930 53 | 21,457,433.97 | 291,536.45 | (11,106.28) | 74,904.17 | (67,965.16) | (27,203.91) | (269,746.97) | 20,165.17 | 2,832.19 | - | | 2,370,804,609.48 |
| 5.m. | DR | A debit entry equal to one-twelfth of the electric generation portion of revenue requirement associated with the CPUC authorized pension contribution amount, transferred from UGBA. | [redacted] | | | | | | | | | | | | | | | | |
| 5.n. | DR | A debit entry equal to the annual authorized revenue requirements associated with PG&E's owned generation divided by twelve , transferred from UGBA. | [redacted] | | | | | | | | | | | | | | | | |
| 5.o. | DR/CR | A debit or credit entry, as appropriate, to record ESA costs associated with PCIA eligible generation resources portfolio/ procurement activity (which is embedded in the annual authorized revenue requirements associated with PG&E's owned generation), transferred from UGBA | [redacted] | | | | | | | | | | | | | | | | |
| 5.p. | DR/CR | a debit or credit entry, as appropriate, to record the gain or loss on the sale of an electric generation non-depreciable asset, as approved by the CPUC, transferred from UGBA | [redacted] | | | | | | | | | | | | | | | | |
| 5.q. | DR | a debit entry equal to one-twelfth of the annual authorized revenue requirement for the Diablo Canyon Power Plant Employee Retention Program (see corresponding entry in the Employee Retention Subaccount of the Diablo Canyon Retirement Balancing Account (DCRBA) per Preliminary Statement HK, 5b.1), transferred from UGBA | [redacted] | | | | | | | | | | | | | | | | |
| 5.r. | DR | a debit entry equal to one-twelfth of the annual authorized revenue requirement for the Diablo Canyon Power Plant license renewal costs, transferred from UGBA | [redacted] | | | | | | | | | | | | | | | | |
| 5.s. | DR | A debit entry equal to one-twelfth (or amortization period approved) of the power generation portion of the Catastrophic Event Memorandum Account (CEMA) interim rate relief for costs incurred in 2016 and 2017, as authorized by the CPUC in Decision 19-04-039 on April 25, 2019. | [redacted] | | | | | | | | | | | | | | | | |

# TABLE 12-8A
# FOR THE YEAR ENDING DECEMBER 31, 2022
# YEAR-TO-DATE BY VINTAGE
# (CONTINUED)

| Tariff Line Item | DR/ CR | Tariff Description | Non-Vintage Subaccount | UOG Legacy | 2009 Vintage | 2010 Vintage | 2011 Vintage | 2012 Vintage | 2013 Vintage | 2014 Vintage | 2015 Vintage | 2016 Vintage | 2017 Vintage | 2018 Vintage | 2019 Vintage | 2020 Vintage | 2021 Vintage | 2022 Vintage | Total all Vintages for Current Month |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ISO Related Charges/ Revenues | | | (111,902.99) | (2,586,560,486.19) | (707,294,905.99) | (158,672,141.49) | (78,789,065.69) | (98,412,218.06) | (51,684,199.99) | (2,233,497.87) | (8,332,713.16) | (169,533.48) | (578,979.36) | 50,005.34 | - | - | (1,071,629 04) | | (3,693,861,267.96) |
| 5.t. | DR/CR | A debit or credit entry equal to the net charges or revenues for energy associated with generating resources recovered in PABA, which excludes net charges or revenues for energy associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC & recorded to the CLPSA of the NSGBA, and excludes charges and energy revenues associated with interim pool renewable resources that support the DAC-GT program. | [redacted] | | | | | | | | | | | | | | | | |
| 5.u. | DR/CR | A debit or credit entry equal to the net charges or revenues for miscellaneous CAISO charges/credits associated with generating resources recovered in PABA, which excludes net charges or revenue for miscellaneous CAISO charges/credits associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | | | | | | | | | | | | | | | | | |
| 5.v. | DR/CR | A debit or credit entry equal to the net charges or revenues for ancillary services associated with generating resources recovered in PABA, excluding net charges or revenues for ancillary services associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | | | | | | | | | | | | | | | | | |
| Fuel Costs | | | - | 114,201,364.82 | 411,964,923.06 | (5,155,802.82) | - | - | - | - | - | - | - | - | - | - | - | | 521,010,485.06 |
| 5.w. | DR | A debit entry equal to natural gas fuel and related transportation and miscellaneous expenses for PCIA eligible UOG resources and contracts, excluding expenses in this category that have been allocated to PCIA-eligible UOG and contract resources that have been procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | | | | | |
| 5.x. | DR | A debit entry equal to distillate fuel and related transportation and miscellaneous expenses used at PG&E's fossil plants as a back-up, excluding expenses in this category that can be allocated to PCIA-eligible UOG and contract resources procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | | | | | | | | | | | | | | | | | |
| 5.y. | DR | A debit entry equal to the hydroelectric fuel and related transportation and miscellaneous expenses, excluding expenses in this category that can be allocated to PCIA-eligible UOG and contract resources procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA. The fuel expenses include water purchase costs for the hydroelectric plants. | | | | | | | | | | | | | | | | | |
| 5.z. | DR | A debit entry equal to nuclear fuel and miscellaneous expenses for the Diablo Canyon Nuclear Power Plant. | | | | | | | | | | | | | | | | | |

# TABLE 12-8A
# FOR THE YEAR ENDING DECEMBER 31, 2022
# YEAR-TO-DATE BY VINTAGE
# (CONTINUED)

| Tariff Line Item | DR/ CR | Tariff Description | Non-Vintage Subaccount | UOG Legacy | 2009 Vintage | 2010 Vintage | 2011 Vintage | 2012 Vintage | 2013 Vintage | 2014 Vintage | 2015 Vintage | 2016 Vintage | 2017 Vintage | 2018 Vintage | 2019 Vintage | 2020 Vintage | 2021 Vintage | 2022 Vintage | Total all Vintages for Current Month |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5.aa. | DR | A debit entry for nuclear fuel carrying costs equal to the interest on the monthly nuclear fuel inventory at the beginning of the month and one-half the balance of the current month's activity, multiplied at a rate equal to one-twelfth of the rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release H.15 or its successor. | [redacted] | | | | | | | | | | | | | | | | |
| Contract Costs | | | 151 131.98 | (13 609 840 00) | 1 653 696 678.86 | 490 210 470.95 | 159 732 398.73 | 162 338 104.75 | 77 590 435.20 | 10 980 097.59 | 22 585 746.38 | 632 645.19 | 2 353 050.47 | - | 16 386 590.00 | 1 859 800.00 | 1 108 097.74 | - | 2 586 015 407.84 |
| | DR | A debit entry equal to total costs associated with New QF SOC obligations authorized pursuant to D.20-05-005, which excludes New QF SOC costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | | | | | |
| 5.ab. | DR | A debit entry to total costs associated with QF obligations that are not eligible for recovery as an ongoing CTC, which excludes non-CTC QF costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | | | | | |
| 5.ac. | DR | A debit entry equal to bilateral contract obligations, which excludes bilateral costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA | [redacted] | | | | | | | | | | | | | | | | |
| 5.ad. | DR/CR | A debit or credit entry equal to renewable contract obligations, and fees associated with participating in WREGIS, net of interim renewable resource costs supporting the DAC-GT Program, and net of WREGIS fees supporting the DAC-GT and the CS-GT Programs. | [redacted] | | | | | | | | | | | | | | | | |
| 5.ae. | DR | A debit entry equal to the capacity and energy costs for QF/non-CHP Program contracts, which excludes QF/Non-CHP costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | | | | | |
| 5.af. | DR/CR | A debit or credit entry equal to the cost or revenue associated with combined heat and power systems authorized in D.09-12-042, D.10-12-055 and D.11-04-033, and defined in PG&E's tariffs E-CHP, E-CHPS, and E-CHPSA, which excludes combined heat and power costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | | | | | |
| GHG Costs | | | - | 55,503,686.27 | - | - | - | - | - | - | - | - | - | - | - | - | - | | 55,503,686 27 |

## TABLE 12-8A
## FOR THE YEAR ENDING DECEMBER 31, 2022
## YEAR-TO-DATE BY VINTAGE
## (CONTINUED)

| Tariff Line Item | DR/ CR | Tariff Description | Non-Vintage Subaccount | UOG Legacy | 2009 Vintage | 2010 Vintage | 2011 Vintage | 2012 Vintage | 2013 Vintage | 2014 Vintage | 2015 Vintage | 2016 Vintage | 2017 Vintage | 2018 Vintage | 2019 Vintage | 2020 Vintage | 2021 Vintage | 2022 Vintage | Total all Vintages for Current Month |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5.ag. | DR | A debit entry equal to the greenhouse gas costs related to PG&E's generating facilities and physically settled compliance instruments associated with contracts, which excludes GHG costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA. | [redacted] | | | | | | | | | | | | | | | | |
| Green Tariff Shared Renewables (GTSR) Program Entries | | | - | - | - | - | - | (5,287,653.72) | (19,384,175.62) | (9,576,048.76) | (14,615,326.64) | (61,533.23) | (171,894.19) | (780,090.69) | (203,728.45) | (5,638,497.68) | (401,365 06) | (17,034.95) | (56,137,349.00) |
| 5.ah. | DR/CR | A credit or debit to reflect the transfer of PCIA Program Charge expense associated with the GTSR Program for customers taking service under Schedule E-GT, equal to the PCIA Program Charge rate, multiplied by the kWh delivered under the program to the E-GT customers for the month, and/or entry to reflect any subsequent true-up of the Program Charge components' expense to actual costs. | [redacted] | | | | | | | | | | | | | | | | |
| 5.ai. | DR/CR | A credit or debit entry to reflect the transfer of PCIA Program Charge expense associated with the GTSR Program for customers taking service under Schedule E-ECR, equal to the PCIA Program Charge rate, multiplied by the kWh delivered under the program to the E-ECR customers for the month, and/or entry to reflect any subsequent true-up of the Program Charge components' expense to actual costs. | | | | | | | | | | | | | | | | | |
| 5.aj. | DR/CR | A debit or credit entry to reflect: (1) the transfer of the interim pool resource's contract expense associated with the GTSR Program for customers taking service under Schedule E-GT, equal to the interim pool weighted average costs, multiplied by the portion of kWh delivered under the program to E-GT customers that the vintage's interim pool resources can support for the month or (2) entry to reflect any subsequent true-up of the weighted average price and generation volumes of the interim pool resources used to support the E-GT customers' subscription level to final actual costs and generation amounts available to support the program. | | | | | | | | | | | | | | | | | |
| Miscellaneous Costs (Collateral, Other Procurement Costs & Transfer Amts to Other Accounts) | | | (52,991.76) | 187,975,125.12 | 147,759,590.31 | 20,655,739.83 | 17,119,695 51 | 27,580,621.87 | (23,049,556.60) | 1,409,782.85 | (5,496,710.37) | 4,026,691.72 | (3,426,735.19) | (3,153,984.86) | (2,743,576.28) | (101,887,548.50) | 315,514,602 08 | | 582,230,745.71 |
| 5.ak. | DR/CR | A debit or credit entry equal to pre-payments and credit and collateral payments, including all associated fees, for procurement purchase and, if applicable, reimbursements of prepayments, credit and collateral payments. | [redacted] | | | | | | | | | | | | | | | | |
| 5.al. | DR | A debit entry equal to any other power costs associated with procurement. | | | | | | | | | | | | | | | | | |

**TABLE 12-8A**
**FOR THE YEAR ENDING DECEMBER 31, 2022**
**YEAR-TO-DATE BY VINTAGE**
**(CONTINUED)**

| Tariff Line Item | DR/ CR | Tariff Description | Non-Vintage Subaccount | UOG Legacy | 2009 Vintage | 2010 Vintage | 2011 Vintage | 2012 Vintage | 2013 Vintage | 2014 Vintage | 2015 Vintage | 2016 Vintage | 2017 Vintage | 2018 Vintage | 2019 Vintage | 2020 Vintage | 2021 Vintage | 2022 Vintage | Total all Vintages for Current Month |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5.am. | DR/CR | A credit/debit entry to transfer/repay the undercollection due to the PCIA revenue shortfall from the applicable PABA subaccount to the PUBA. The PCIA revenue shortfall is equal to the difference between the uncapped vintage PCIA rate by customer calls minus the capped vintaged PCIA rate by customer class applicable to departing load customers, net of RF&U, multiplied by the departing load's usage by customer class for each vintage. The PCIA revenue shortfall is mapped to the PABA vintage subaccounts based on incremental revenue shortfall rates. Corresponding debit/credit entries will be recorded in PCIA Undercollection Balancing Account (PUBA), Electric Preliminary Statement Part HZ, based on the cumulative revenue shortfall rates, by customer vintage. | [redacted] | | | | | | | | | | | | | | | | |
| 5.an. | DR/CR | A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC. | [redacted] | | | | | | | | | | | | | | | | |
| | | Total Monthly Activity Before Interest | (31,671.87) | (377,049,687 24) | 143,190,332.71 | (33,272,420.09) | (15,325,292.18) | (11,013,160.78) | (18,379,130.45) | 2,757,250.26 | (3,015,383.36) | (14,497,173.99) | 4,920,384.21 | 1,388,712.54 | (5,442,261.60) | 72,008,040.53 | 17,184,961.11 | (17,034.95) | (236,593,535.16) |
| Interest | | | (2,938.47) | (9,033,111.23) | 8,041,775.16 | 1,020,606.79 | 287,491 26 | 148,093.85 | 91,971.98 | (27,152.16) | 5,825.57 | 72,458 38 | (121,652.45) | (44,377.39) | 300,366.42 | (143,927.14) | 1,680,219.15 | (106.38) | 2,275,543 33 |
| 5.ao. | DR/CR | An entry equal to the interest on the average balance of the account at the beginning of the month and the balance after the entries above, at a rate equal to one-twelfth the interest rate of the three-month Commercial Paper for the previous month, as rep | [redacted] | | | | | | | | | | | | | | | | |
| | | Beginning Balance | 34,610.34 | (574,065,807 86) | 409,182,398.69 | 64,343,515.72 | 23,420,867 25 | 8,100,680.52 | 7,703,799.40 | (5,535,644.34) | (1,948,875.50) | 14,696,331 58 | (10,020,678.53) | (3,946,386.50) | 19,063,125.63 | (50,397,705.17) | (141,405 23) | - | (99,511,174.00) |
| | | PABA Ending Balance | 0.00 | (960,148,606 33) | 560,414,506.56 | 32,091,702.42 | 8,383,066 32 | (2,764,386.41) | (10,583,359.06) | (2,805,546.24) | (4,958,433.29) | 271,615 96 | (5,221,946.76) | (2,602,051.35) | 13,921,230.45 | 21,466,408.22 | 18,723,775.03 | (17,141.33) | (333,829,165.83) |
| PCIA Subaccount | | | - | - | - | - | - | - | - | - | - | - | - | - | - | | | | - |
| 6.a. | DR | A debit entry equal to imputed PCIA revenue based on the PCIA rate as adopted by the Commission | [redacted] | | | | | | | | | | | | | | | | |
| 6.b. | DR/CR | A credit or debit entry equal to the recorded PCIA revenues; and | [redacted] | | | | | | | | | | | | | | | | |
| 6.c. | DR/CR | A credit or debit entry to transfer the balance as authorized by the Commission. | [redacted] | | | | | | | | | | | | | | | | |
| | | PCIA Subaccount Ending Balance | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | Beginning balance | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | PCIA Subaccount Ending Balance | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | TOTAL PABA END NG BALANCE | 0.00 | (960,148,606 33) | 560,414,506.56 | 32,091,702.42 | 8,383,066 32 | (2,764,386.41) | (10,583,359.06) | (2,805,546.24) | (4,958,433.29) | 271,615 96 | (5,221,946.76) | (2,602,051.35) | 13,921,230.45 | 21,466,408.22 | 18,723,775.03 | (17,141.33) | (333,829,165.83) |

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 12**

**ATTACHMENT A**

**FINAL JOINT PROPOSAL ON POTENTIAL VERIFICATION METHOD FOR PG&E'S GREENHOUSE GAS EMISSIONS AND WEIGHTED AVERAGE COSTS (WAC) FOR FUTURE ERRA COMPLIANCE FILING**

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
ATTACHMENT A
FINAL JOINT PROPOSAL ON POTENTIAL VERIFICATION METHOD FOR PG&E'S GREENHOUSE GAS EMISSIONS AND WEIGHTED AVERAGE COSTS (WAC) FOR FUTURE ERRA COMPLIANCE FILING

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 12
# ATTACHMENT A
# FINAL JOINT PROPOSAL ON POTENTIAL VERIFICATION METHOD FOR PG&E'S GREENHOUSE GAS EMISSIONS AND WEIGHTED AVERAGE COSTS (WAC) FOR FUTURE ERRA COMPLIANCE FILING

## A. Definitions of Terms Based on Decision (D.) 14-10-033

1) Recorded Direct Greenhouse Gas Costs:

The recorded direct Greenhouse Gas (GHG) costs include two variables: (a) total direct emissions, and (b) costs of compliance instruments purchased to satisfy this liability. Recorded year direct GHG costs represent the actual costs for Utility-Owned Generation (UOG) and imports, tolls and other contracts for which the utility has responsibility for cap-and trade costs.[1,2]

2) Recorded:

We use the term "recorded" to describe both the actual cost and revenue amounts recorded, and the estimate of indirect GHG costs embedded in electricity prices.[3]

3) Direct Emissions:

Direct emissions should be calculated on an annual basis based on monthly dispatched resources using methodologies consistent with the Auction Rate Bond regulations for measuring GHG emissions.[4]

---

[1] D.14-10-033, p. 18.

[2] D.14-10-033, p. 18. Also, footnote 24, states: "The specific terms of a utility's contract may specify whether the utility provides physical compensation (a transfer of compliance instruments) or financial compensation (payment to the entity for the cost of the applicable compliance instruments) for the cap-and-trade costs. Physical settlement is a direct cost, but the utilities can choose to report financially settled tolling agreements as direct or indirect costs. Financially settled Qualifying Facility (QF) contracts where the financial obligation is embedded in the market price of energy purchases or within the specific contract terms for energy payment may be categorized as indirect GHG costs." D.14-10-033, p. 18.

[3] D.14-10-033, footnote 10, p. 8.

[4] D.14-10-033, p. 18.

## B. PG&E's Proposed Definitions of Terms

1) "December Close" means represents the best available information/data (i.e., Weighted Average Costs (WAC), emissions volumes, etc.) for the entire Record Year as of the month ended December, as available during the month end accounting close.

2) "Direct Physical GHG Costs" means those actual costs resulting from Pacific Gas and Electric Company's (PG&E) need to procure GHG compliance instruments in connection with: (1) UOG facilities; (2) certain tolling agreements where PG&E elects to physically settle contractual GHG obligations; and (3) electricity imports. Direct Physical GHG Costs are recorded to the Portfolio Allocation Balancing Account (PABA) Balancing Account Line Item 5.ah.

3) "Direct Physical GHG Emissions" are GHG emissions associated with (1) UOG facilities; (2) certain tolling agreements where PG&E elects to physically settle contractual GHG obligations; and (3) electricity imports.

4) "Financial GHG Costs" are GHG costs associated with PG&E's tolling agreements and other contracts for which PG&E elects to financially settle contractual GHG obligations or contract with financial settlement specifically for GHG costs. Financial GHG Costs are recorded to PABA Balancing Account Line Items other than Line Item 5.ah.

5) "Financially Settled GHG Emissions" are GHG emissions associated with PG&E's tolling agreements and other contracts for which PG&E elects to financially settle contractual GHG obligations or contracts with financial settlement specifically for GHG costs.

6) "PG&E's Electric Portfolio" includes those UOG or electric generation facilities contracted to PG&E. PG&E's Electric Portfolio does not include resources use to serve PG&E's natural gas utility customers.

7) "Record Year" refers to the calendar year addressed in an Energy Resource Recovery Account (ERRA) Compliance Application.

Attachments A and B physically-settled obligations presented in Attachments A and B are reported based on the best available volume of emissions and Weighted Average Cost price at the time the emissions costs are recorded. Financially-settled obligations, which is included as part of

Attachment B, reported amounts represent emissions based on actual plant output which may be recorded after the December close.

1) To support PG&E's WAC and Direct Physical GHG Costs for the Record Year, PG&E will submit tables in substantially the form of Attachment A as a workpaper to its ERRA Compliance Application.

The purpose of Attachment A, Table 1, is to calculate the WAC of compliance instruments of PG&E's Electric Portfolio.[5] WAC is not impacted by financial settlement of contractual GHG obligations. Attachment A, Table 1 will be submitted as an active spreadsheet showing all calculations and formulas used.

The purpose of Attachment A, Table 2 is to support the applied WAC for monthly Direct Physical GHG Costs of PG&E's Electric Portfolio. Attachment A, Table 2 will be partially submitted as an active spreadsheet showing all calculations and formulas used.

PG&E's official system of record to calculate the WAC of compliance instruments is Endur. While PG&E can replicate calculations performed in Endur to produce the WAC, numbers calculated in the spreadsheet provided may vary from the official record due to rounding in the Endur system versus the spreadsheet.

In May 2020, D.20-05-004 issued by the California Public Utilities Commission on May 15, 2020 ordered Southern California Edison Company to convene a working group with PG&E, SDG&E, and the Public Advocates Office to address balancing account treatment of direct GHG costs. This modification would require that utilities provide a GHG Balancing Account Table to show their recorded GHG costs to the balancing account to which

---

**5** For definition of recorded direct GHG costs, Refer to section 4.2.1 and Footnote 24 of D.14-10-033, p. 18. D.14-10-033 (p. 18) states: "Recorded Direct GHG costs represent the actual costs for utility owned generation and imports, tolls and other contracts for which the utility has responsibility for cap-and-trade costs." Footnote 24 of the Decision states: "The specific terms of a utility's contract may specify whether the utility provides physical compensation (a transfer of compliance instruments) or financial compensation (payment to the entity for the cost of the applicable compliance instruments) for the cap-and-trade costs. Physical settlement is a direct cost, but the utilities can choose to report financially settled tolling agreements as direct or indirect costs. Financially settled QF contracts where the financial obligation is embedded in the market price of energy purchases or within the specific contract terms for energy payment may be categorized as indirect GHG costs."

cost recovery for the underlying procurement resource is approved. This modification superseded in its entirety the version of Attachment C contained in D.14-10-033, as corrected by D.15-01-024, and D.19-04-016 (please refer to Table 12-A5 for the new table).

2) To support PG&E's recorded monthly Direct Physical GHG Costs and Financial GHG Costs as of the Record Year's December Close, PG&E will submit a table in substantially the form of Attachment B, as a workpaper (in a spreadsheet format) to its ERRA Compliance Application.

Included in the spreadsheet (Attachment B), PG&E will provide separate tabs for each of line 2 through line 7, including monthly GHG emissions for the record year, for each source contributing to the total emissions per category recorded as of December close. For example: line 2 would include 12 months entries for each of PG&E's three UOG facilities.

Public Advocates Office at the California Public Utilities Commission ((Cal Advocates) formerly known as ORA) will use PG&E's data provided in Attachment B to draw its sample (see Section 3).

## C. Cal Advocates' Sample

The purpose of the sampling approach is for Cal Advocates to perform a thorough review and verification of PG&E's calculations of GHG emissions and associated GHG costs for the Record Year under review.

The sample will be based on data submitted by PG&E in Attachment B (*Modified* Template D-2 of Attachment D of D.15-01-024).

Provided that PG&E submits a completed Attachment B at the time it files its ERRA Compliance Application, Cal Advocates will draw and provide the sample to PG&E no later than a month from the date PG&E files its ERRA Compliance Application.

## D. PG&E's Response to Cal Advocates Sample

No later than three weeks from the date Cal Advocates provides the Sample to PG&E, PG&E will provide the information listed in Section 5.1 through Section 5.3 to Cal Advocates.

5.1) PG&E's GHG Emissions Recorded During the Record Period From Its UOG Facilities, Specified Imports and Unspecified Imports

a. Calculations of GHG Emissions

PG&E to provide detailed calculations of GHG emissions (in an active spreadsheet format, showing all calculations, assumptions and formulas used), by source for each of the months sampled by Cal Advocates.

PG&E's official system of record to calculate the GHG emissions is Endur. While PG&E can replicate calculations performed in Endur to produce the sampled month's emissions volume, numbers calculated in the spreadsheet provided may have variances due to rounding in the Endur system versus the spreadsheet.

b. Supporting Evidence

PG&E to demonstrate that the methodology used to calculate the GHG emissions is consistent with the draft emissions calculated under the California Air Resources Board Mandatory Reporting Regulation. Supporting evidence will be calculated using the UOG facility's gas burns during the record period and an emission factor from the facility's previous year's Mandatory Reporting Regulation verified report.

5.2) PG&E's GHG Emissions Recorded During the Record Year From Its Physically-Settled Contracts and/or Tolling Agreements

a. Calculations of GHG Emissions:

PG&E to provide detailed calculations of GHG emissions, for each source for each of the months provided in Cal Advocates' sample.

PG&E will use a spreadsheet in a format similar to the spreadsheet provided by PG&E in the 2016 ERRA Compliance case labelled "Data Request 15 (GHG volumes and costs)" in response to ORA's Data Request 15 Q-2.2; with the addition of one data point: GHG unit cost (such as Intercontinental Exchange Inc. (ICE) forward price etc.).

For ease of reference, the following Table 12A-1 for information on physically-settled contracts provides the fields that should be included to populate the spreadsheet:

**TABLE 12A-1**
**(TITLE)**

| Source Name | Unit | Log number | Contract Type (Tolling/QF/Other) | Emission Date (Year and Month) | GHG Emissions (metric tons of carbon dioxide equivalent (mtCO2e)) | Physically-Settled Contracts: Unit GHG Cost ($/mtCO2e) | GHG Costs ($) | ERRA Tariff line item |
|---|---|---|---|---|---|---|---|---|

b. Supporting Evidence:

Invoices showing final settled emissions data and payments. References and excerpts from contracts showing settlement terms covering the calculations of GHG emissions and costs. (See examples from PG&E responses in the 2016 ERRA Compliance case to ORA DR 15, A.17-02-005)

5.3) PG&E's Recorded GHG Emissions Recorded During the Record Year From Its Financially-Settled Contracts and/or Tolling Agreements

a. Calculations of GHG Emissions and Costs

PG&E to provide detailed calculations of GHG emissions and associated costs for each source for each of the months provided in Cal Advocates' sample. PG&E will use a spreadsheet in a format similar to the spreadsheet provided by PG&E labelled in the 2016 ERRA Compliance case "Data Request 15 (GHG volumes and costs)" in response to Cal Advocates' Data Request 15 Q-2.2); with the addition of one data point: GHG unit cost (such as ICE forward price etc.).

For ease of reference, see the following Table 12A-2 for information on financially-settled contracts, which provides the fields that should be included to populate the spreadsheet:

**TABLE 12A-2**
**(TITLE)**

| Source Name | Unit | Log number | Contract Type (Tolling/QF/Other) | Emission Date (Year and Month) | GHG Emissions (mtCO2e) | Physically-Settled Contracts: Unit GHG Cost ($/mtCO2e) | GHG Costs ($) | ERRA Tariff line item |
|---|---|---|---|---|---|---|---|---|

b. Supporting Evidence

Invoices showing settled emissions data and payments during the record period.

References and excerpts from contracts showing settlement terms covering the calculations of GHG emissions and costs.

(See examples from PG&E responses in the 2016 ERRA Compliance case to ORA DR 15, Application 17-02-005)

**TABLE X-X**
**ATTACHMENT B**
**(TITLE)**

*Modified* Template D-2: Annual GHG Emissions and Associated Costs[(a)]

ERRA Compliance Application for Record Period Under Review
(GHG Emissions Recorded in January through December of Record Year)

| Line No. | Description | [Year] |
|---|---|---|
| 1 | Direct GHG Emissions (mtCO2e) | |
| 2 | UOG | |
| 3 | Physically Settled Tolling Agreements | |
| 4 | Energy Imports (Specified) | |
| 5 | Energy imports (Unspecified) | |
| 6 | Physically Settled QF Contracts | |
| 7 | Financially Settled GHG Emissions (mtCO2e) | |
| 8 | Contracts with Financial Settlement | |
| 9 | Subtotal | |
| 10 | GHG Costs ($) | |
| 11 | Direct Physical GHG Costs | |
| 12 | Direct GHG Costs – Financial Settlement | |

(a) As of December, Close of Record Year. Any information recorded or available after December Close will not be reflected in Attachment B.

Notes:

(1) "Attachment B" is a modified version of Template D-2 of Attachment D of D.15-01-024. When filing "Attachment B," PG&E will follow the definitions and conventions as required in Template D-2 of Attachment D of D.15-01-024. PG&E will clearly identify and provide explanation including supporting calculations of any entries deviating from the requirements in Template D-2 of Attachment D of D.15-01-024.

(2) PG&E's Note: Multiplying monthly WACs shown in Table A and monthly physical emissions shown in Table B will not necessarily replicate monthly accounting entries to ERRA line item 5.ah due to PG&E's utilization of gross-on, gross-off accounting.

**TABLE 12A-3**
**ATTACHMENT A**
**REPORTING TEMPLATE TO CALCULATE WEIGHTED AVERAGE COST (WAC) OF COMPLIANCE INSTRUMENTS IN RECORD YEAR**

| Line No. | Month | Transaction Date | Transaction Type | Quantity | Cost ($/MT) | Sales Price ($) | Total Cost ($) | Inventory Balance ($) | Total Qty in Inventory | WAC |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | No Formula | No Formula | No Formula | No Formula | Formula | No Formula | Formula | Formula | Formula | Formula |

**TABLE 12A-4**
**PG&E RECORDED DIRECT PHYSICAL GHG COSTS IN PABA**
**(TARIFF LINE ITEM 5.AH.)**

| Line No. | Month | MM-YY |
|---|---|---|
| 1 | End of Month WAC | Supported by Table 1 |
| 2 | Monthly Emissions (MT) | Fixed Number, No Formula |
| 3 | End of Month WAC * Monthly Emissions | $Formula |
| 4 | Balancing Account Entry with adjustment (as recorded to line 5ah) (Refer to Note 4) | Fixed Number, No Formula (supported by Accounting Entries) |

Notes:

(1) “Attachment A” reflects Template C of Attachment C-1 of D.19-04-016. When filing “Attachment A,” PG&E will follow the definitions and conventions as required in Template C of Attachment C-1 of D.19-04-016. PG&E will clearly identify and provide explanation including supporting calculations of any entries deviating from the requirements in Template C of Attachment C-1 of D.19-04-016.

(2) “Attachment A” or Template C of Attachment C-1 of D.19-04-016 is based (amongst other data) on running WAC of compliance instruments held in inventory since the inception of the program (i.e., since the First Compliance Period under the Cap-and-Trade Program).

(3) PG&E is to provide “Attachment A” in an active spreadsheet format i.e., showing all calculations and formulas used.

(4) PG&E is to provide references and explanation including calculations to any hard entries (not resulting from a calculation or not linked to a referenced calculation).

(5) PG&E is to provide calculations including supporting data used to produce entries recorded under “Balancing Account Entry with adjustment (as recorded to line 5.ag),” as applicable. Note: however, the supporting documentation provided for the monthly entries may differ in future years as PG&E will rely on Endur’s automation process to post the monthly entries. Accounting will provide calculations or reconciliations to demonstrate the GHG emissions expenses recorded during each month as reported, to line 5.ah, was appropriately calculated. For definitions and descriptions, refer to Attachment C of D.19-04-016. Attachment A and resulting WAC calculation are confidential.

**TABLE 12A-5**
**GHG BALANCING ACCOUNT TABLE**
**FOR RECORD YEAR 2022 (IN MILLIONS)**
**(TARIFF LINE PABA ITEM 5 AG & 5 AD & NSGBA ITEM 5.B.2.I)**

| Line No. | GHG Cost Category | PABA | NSGBA | Total |
|---|---|---|---|---|
| 1 | UOG | [redacted] | | |
| 2 | Imported (out-of-state) UOG | | | |
| 3 | Tolling Contracts[a] | | | |
| 4 | Total | | | |

[a] Tolling contracts represent GHG costs that are financially settled and embedded within the contract payments made to the counterparty.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 12

# ATTACHMENT B

# GHG EMISSIONS AND COSTS

| Line No. | Description | **2022** |
|---|---|---|
| 1 | Direct GHG Emissions (MT CO2e) | [redacted] |
| 2 | Utility Owned Generation (UOG) | |
| 3 | Tolling Agreements | |
| 4 | Energy Imports (Specified) | |
| 5 | Energy imports (Unspecified) | |
| 6 | Qualifying Facility (QF) Contracts | |
| 7 | Contracts with Financial Settlement | |
| 8 | Subtotal | |
| | | |
| 15 | GHG Costs ($) | [redacted] |
| 16 | Direct GHG Costs | |
| 17 | Direct GHG Costs - Financial Settlement | |
| 20 | **Total Costs ($)** | |

Note: The data in this table is based on actual emissions during the reporting year.

| | | 2022 Recorded GHG Emissions (MT) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Name** | **Resource ID/Log Number** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Total** |
| Colusa | PGECOLUSA | [redacted] | | | | | | | | | | | | |
| Gateway | PGEGATEWAY | | | | | | | | | | | | | |
| Humboldt | PGEHUMBOLDT | | | | | | | | | | | | | |
| **Total** | | | | | | | | | | | | | | |

| | | 2022 Recorded GHG Emissions (MT) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Tolling Agreement Name** | **Resource ID/Log Number** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Total** |
| **Total** | | [redacted] | | | | | | | | | | | | |

| | 2022 Recorded GHG Emissions (MT) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Name** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Total** |
| Specified Imports | [redacted] | | | | | | | | | | | | |
| **Total** | | | | | | | | | | | | | |

| | 2022 Recorded GHG Emissions (MT)[1] | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Name** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Total** |
| Unspecified Imports | [redacted] | | | | | | | | | | | | |
| **Total** | | | | | | | | | | | | | |

**(1) PG&E will use RPS Adjustments to bring total recorded import GHG obligations to zero MT on its 2022 CARB EPE Report.**

| | | 2022 Recorded GHG Emissions (MT) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| QF Name | Resource ID/Log Number | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | Total |
| | | [redacted] | | | | | | | | | | | | |
| Total | | [redacted] | | | | | | | | | | | | |

| Log Number | Name | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2022 Recorded DIrect GHG Emissions (MT) | | | | | | | | | | | | |
| 24B001FHP | CHEVRON MCKITTRICK | [redacted] | | | | | | | | | | | | |
| 33B121 | Badger Creek | | | | | | | | | | | | | |
| 33B112 | Bear Mountain | | | | | | | | | | | | | |
| 33B099 | Calpine Los Esteros Upgrade | | | | | | | | | | | | | |
| 33B075 | Calpine Russell City Energy Center | | | | | | | | | | | | | |
| 33B124 | Chalk Cliff | | | | | | | | | | | | | |
| 33B108 | GWF Hanford | | | | | | | | | | | | | |
| 33B109 | GWF Henrietta | | | | | | | | | | | | | |
| 33B101 | GWF Tracy | | | | | | | | | | | | | |
| 33B093 | GenOn Marsh Landing | | | | | | | | | | | | | |
| 33B122 | Live Oak | | | | | | | | | | | | | |
| 33B092 | Mariposa | | | | | | | | | | | | | |
| 33B123 | Mckittrick | | | | | | | | | | | | | |
| 33B074 | Starwood | | | | | | | | | | | | | |
| **Total** | | | | | | | | | | | | | | |

| | |
|---|---|
| **Total Direct GHG Costs ($)** | **$ 55,503,686** |

| | 2022 Recorded Direct GHG Emissions (MT) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Category** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Total** |
| UOG (line 2) | [redacted] | | | | | | | | | | | | |
| Bilats (Line 3) | | | | | | | | | | | | | |
| Unspecified Imports (line 5) | | | | | | | | | | | | | |
| QF (line 6) | | | | | | | | | | | | | |
| **Total** | | | | | | | | | | | | | |

| Resource ID/Log Number | Name | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2022 Recorded DIrect GHG Costs - Financial Settlement ($) | | | | | | | | | | | | |
| CHEVRON MCKITTRICK | 24B001FHP | [redacted] | | | | | | | | | | | | |
| Badger Creek | 33B121 | [redacted] | | | | | | | | | | | | |
| Bear Mountain | 33B112 | [redacted] | | | | | | | | | | | | |
| Calpine Los Esteros Upgrade | 33B099 | [redacted] | | | | | | | | | | | | |
| Calpine Russell City Energy Center | 33B075 | [redacted] | | | | | | | | | | | | |
| Chalk Cliff | 33B124 | [redacted] | | | | | | | | | | | | |
| GWF Hanford | 33B108 | [redacted] | | | | | | | | | | | | |
| GWF Henrietta | 33B109 | [redacted] | | | | | | | | | | | | |
| GWF Tracy | 33B101 | [redacted] | | | | | | | | | | | | |
| GenOn Marsh Landing | 33B093 | [redacted] | | | | | | | | | | | | |
| Live Oak | 33B122 | [redacted] | | | | | | | | | | | | |
| Mariposa | 33B092 | [redacted] | | | | | | | | | | | | |
| Mckittrick | 33B123 | [redacted] | | | | | | | | | | | | |
| Starwood | 33B074 | [redacted] | | | | | | | | | | | | |
| **Total Direct GHG Costs - Financial Settlement** | | [redacted] | | | | | | | | | | | | |

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 13

# SUMMARY OF ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES FOR THE RECORD PERIOD

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 13
SUMMARY OF ENERGY RESOURCE RECOVERY ACCOUNT
ENTRIES FOR THE RECORD PERIOD

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 13
# SUMMARY OF ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES FOR THE RECORD PERIOD

## A. Introduction

This chapter presents the accounting entries made to Pacific Gas and Electric Company's (PG&E) Energy Resource Recovery Account (ERRA) for the period January 1 through December 31, 2022 (record period). This testimony demonstrates that the entries to the ERRA comply with the recovery requirements adopted by the California Public Utilities Commission (CPUC or Commission). In addition, this chapter discusses the results of PG&E's Internal Audit of processes and controls over the recording and reporting of costs and revenues to ERRA during the 2021 calendar year. Finally, this chapter also discusses the 2022 activity in the Renewables Portfolio Standard Cost Memorandum Account (RPSCMA), which is authorized for recovery through the ERRA application.

## B. The Energy Revenue Recovery Account

The ERRA is a balancing account that was originally established in Rulemaking (R.) 01-10-024, pursuant to Decision (D.) 02-10-062, Ordering Paragraph (OP) 14, and subsequently modified by D.02-12-074. ERRA was substantially modified by D.18-10-019, which addressed the Power Charge Indifference Adjustment (PCIA) in rulemaking R.17-06-026.[1] The revised ERRA records power costs applicable solely to PG&E's bundled customers while power costs incurred on behalf of both bundled and departing load customers are recorded in the Portfolio Allocation Balancing Account (PABA), or one of the other five non-bypassable charge balancing accounts.[2]

---

1 PG&E submitted Advice Letter (AL) 5440-E on December 10, 2018, which was approved May of 2019 with an effective date of January 1, 2019. PG&E implemented the changes authorized in AL 5440-E during the June 2019 business close.

2 The other non-bypassable charge balancing accounts include: The Modified Transition Cost Balancing Account, the New System Generation Balancing Account (NSGBA), the Tree Mortality Non-Bypassable Charge Balancing Account, the Public Purpose Charge Balancing Account (PPCBA), and the Bioenergy Market Adjusting Tariff (BioMAT) Non-Bypassable Charge Balancing Account.

### 1. Overview of ERRA Entries

The ERRA records net generation revenues and net costs attributable to bundled customers, except for bundled customers served under the Green Tariff Shared Renewables Program (GTSR) rate schedules E-GT and E-ECR.[3] The ERRA revenue and costs are described below:

- Customer Revenues: PG&E records bundled customers' net billed generation revenues to ERRA, excluding the following components as defined in PG&E's Electric Preliminary Statement I, "Rate Schedule Summary": (1) PCIA rates that are recorded to the PABA vintage subaccounts, (2) Power Charge Collection Balancing Account, and (3) California Department of Water Resources Franchise Fees. In addition, PG&E records an estimate of revenues earned from providing electricity to customers that has not yet been billed to customers, in accordance with Generally Accepted Accounting Principles. For a more complete discussion of this process, please refer to Chapter 12, Section C.1., "Revenues from Customers."
- Retained Portfolio Attribute Value: There are four entries that record the portfolio value for Renewable Energy Credit attributes and Resource Adequacy (RA) attributes associated with PG&E's PCIA-eligible resource portfolio. The value of these attributes used for bundled customers' compliance with the Renewable Portfolio Standard (RPS) Program as defined in PG&E's RPS plan and with the RA requirements implemented through the Commission's RA Program are transferred from the various recovery accounts (i.e., PABA, Modified Transition Cost Balancing Account, BioMAT Non-Bypassable Charge Balancing Account, Public Purpose Charge Balancing Account (PPCBA), and Tree Mortality Non-Bypassable Charge Balancing Account) to ERRA for recovery from bundled customers.[4] Two of the entries are for use throughout the year on the initial forecast market price benchmark. The

---

[3] Costs for the GTSR Program are recorded to the Green Tariff Shared Renewables Memorandum Account (GTSRMA) and Green Tariff Shared Renewables Balancing Account (GTSRBA) and are recovered from bundled customers that are on the E-GT and E-ECR rates schedules. The GTSRMA and GTSRBA are presented in Chapter 11.

[4] Please see Chapter 12, Section C.2 for further discussion of PG&E's RPS Program activity. PG&E's RA Program activity is discussed in Chapter 8.

other two entries are used to record an annual true-up when a final market price benchmark is issued by the Energy Division each Fall.

- Reliability Order Instituting Rulemaking (OIR) Supply and Demand: D.21-03-056 directs PG&E to prepare for potential extreme weather to meet the peak and net peak demand by increasing the peak and net peak supply to prevent the need for rotating outages like the events occurring in Summer 2020. Resource costs associated with the Reliability OIR (R. 20-11-003) are recovered through the Cost Allocation Mechanism (CAM) methodology, which is recorded in NSGBA. However, there are three types of transactions within ERRA associated with Reliability OIR supply: (1) transfer of an allocated portion of costs for import capacity rights from ERRA to NSGBA in the event PG&E uses existing PG&E-owned import capacity rights to meet such system reliability procurement targets; (2) transfer of RA value of procurement originally used to meet such system reliability targets that are instead used to meet PG&E's bundled service RA compliance requirements from NSGBA to ERRA; and (3) transfer of excess RA or unsold RA from ERRA to NSGBA when used to meet such system reliability procurement targets. The three transactions are included in tariff lines 5.g., 5.h., and 5.i. to ERRA's subledger. Reliability OIR demand costs recovered in ERRA includes customer education expenses related to PG&E's Critical Peak Pricing Program for Reliability OIR Demand. The amount is capped at $635,000.[5]
- Energy Supply Administration (ESA): There is one entry to record bundled customers' share of the ESA costs which are authorized in Phase 1 of PG&E's General Rate Case and embedded within the annual authorized revenue requirements associated with PG&E's owned generation.[6]

5 Reliability OIR Demand costs are recorded under ERRA's miscellaneous costs under tariff 5.ab.

6 ESA costs are portfolio-wide costs that are now proportionally allocated to the generation-related balancing accounts pursuant to the approval of AL 5440-E.

- California Independent System Operator (CAISO) Charges and Revenues: There are five entries to record CAISO charges and revenues, three of which record load-related charges or revenues: generation-related charges and revenues in the day ahead and real-time markets, ancillary services markets for generation resources recovered in ERRA, and miscellaneous charges/revenues for load and generation.[7] The other two entries recover costs and revenues associated with congestion revenue rights and convergence bidding.[8] Included in these entries is CAISO activity associated with GTSR dedicated resources, recorded into ERRA. Additionally, a credit transfer of ($26.4 million) in net CAISO revenues ($11 million from 2021 and $15.4 million from 2022) associated with GTSR interim pool resources was transferred to ERRA from PABA, as approved by Resolution E-5218.[9] This transfer was recorded upon the approval of AL 6677-E, which approved a modification to ERRA's tariff line items 5.k and 5.l.[10]
- Fuel Costs: There is one entry to record fuel costs, fuel transportation, and miscellaneous costs for contracts recovered through ERRA.
- Contract Costs: There are three entries to record short-term contracts related to bilateral, renewable contracts, or Qualifying Facility/Combined Heat and Power (QF/CHP) Program contracts that are not eligible for recovery through the PCIA or other non-bypassable charges. The ERRA also includes one entry to record the transfer of QF/CHP contract costs and Marsh Landing costs to the NSGBA. Additionally, pursuant to D.19-11-016, to reduce the potential for system RA shortages beginning in 2021, the Commission required PG&E to procure additional

---

**7** Generation resource costs recovered in ERRA exclude resources that are recovered through PG&E's generation-related non-bypassable charges including, the Ongoing Competition Transition Charge, PCIA, New System Generation Charge, Tree Mortality Non-Bypassable Charge, and BioMAT Non-Bypassable Charge.

**8** For further discussion of PG&E's CAISO settlements and monitoring activity, please see Chapter 10.

**9** Based on D.21-12-036 PG&E identified 20 resources used as borrowed GTSR pool to meet the projected over-subscription load. The resource pool was filed as part of Advice Letter 6451-E, as approved by Resolution E-5218, dated June 23, 2022.

**10** AL-6677-E was filed to modify both ERRA and PABA's tariff lines to allow the transfer of GTSR interim pool resources. The AL was approved in November 2022.

incremental RA capacity.[11] Lastly, per PG&E's interim cost recovery request in AL 5826-E, 93.7 percent of the contract costs were recorded in ERRA and 6.3 percent were recorded in the Incremental Resource Adequacy Procurement Memorandum Account (IRAPMA) during the Record Period.[12] The ERRA portion of these contracts is recorded in the entry related to short-term bilateral contracts.[13]

- Greenhouse Gas (GHG) Costs: There is one entry to record costs associated with physically settled greenhouse compliance instruments for contracts. During 2022, there were no direct GHG compliance costs associated with contracts recorded in ERRA.
- Miscellaneous Costs: There are seven entries to record costs incurred for bundled customers, including: forward hedges, net energy metering payments, and energy storage evaluation program funding. PG&E is also authorized to recover other indirect costs that support PG&E's management of its procurement/generation resource portfolio. These costs include: credit and collateral, Western Renewable Energy Generation Information System certificates, and third-party independent evaluator reviews. See Testimony Chapter 12, PABA, Section C.11. *Miscellaneous Costs* for a detailed discussion of how these costs are assigned and allocated among PABA, ERRA, and the NSGBA. Finally, this category includes other power procurement costs related to

---

[11] List of contracts can be found on AL 5826-E.

[12] As approved in D.22-05-002 and included in PG&E's 2023 ERRA Forecast Application approved in D.22-12-044, PG&E will begin recovering bundled customers' share of these costs in PABA Vintage 2019 instead of ERRA beginning January 1, 2023. In AL 6654-E-A, PG&E requested associated tariff updates to implement the directives in D.22-05-022, which was approved January of 2023. Thus, the transfer of these costs to Vintage 2019 was not recorded in 2022 and instead will be implemented during the February 2023 Accounting close.

[13] The 6.3 percent recorded in IRAPMA represents costs related to the incremental RA contracts and related administrative costs incurred on behalf of opt-out Load-Serving Entities, and is not subject to this proceeding. Further Commission determination in Rulemaking R.20-05-003 occurred in D.22-05-002 and will be implemented in 2023 as approved by Resolution E-5239, adopting AL 6654-E-A.

resources that are the sole responsibility of bundled customers and authorized to be recovered through ERRA.[14]

### 2. NSGBA-Resource Costs

D.06-07-029 and D.07-09-044 approved guidelines for allocation of costs and benefits for resources authorized for the CAM, which recovers the net capacity costs for resources providing RA benefits. D.10-12-035 subsequently authorized recovery of net capacity costs for certain contracts arising from the QF/CHP Settlement. Both CAM and QF/CHP resource types (NSGBA Resources) are recovered through the CAM rate and recorded to the NSGBA. The Commission authorized the CAM effective January 1, 2012.[15] Net capacity costs that are eligible for recovery through the CAM are credited out of ERRA and recovered through the NSGBA.

### 3. PCIA Financing Subaccount

In D.18-10-019 the Commission established a cap for the PCIA rate increase by vintage at no more than 0.5 cents per kilowatt-hour, and directed major electric utilities to file a Tier 2 AL to establish an under-collection balancing account that would track the accrued PCIA-obligation when the 0.5 cent cap is reached. In December 2019, AL 5624-E was approved to establish this account as well as other consistent balancing account modifications. One such modification included the establishment of a new PCIA Financing Subaccount to track the amount financed by bundled customers related to the revenue shortfall associated with capped PCIA rates for departing load customers. In D.20-12-038, the Commission directed the PCIA Financing Subaccount, to be reimbursed from 2021 to 2023 based on the incremental rate adder included in the amortization of the forecast 2020 balance. As established in D.22-02-002, the PCIA Financing Subaccount is to be transferred to PABA Vintage 2020 each year until fully returned in rates, thereby reimbursing all customers who helped finance the additional PCIA shortfall during the 2020 record period.

---

**14** Including customer education expenses related to PG&E’s Critical Peak Pricing Program for Reliability OIR Demand, as mentioned earlier under in this section.

**15** D.11-12-031, OP 1.

### 4. Recorded Balances

In OP 19 of D.02-12-074, the Commission directed the three California Investor-Owned Utilities (IOU) to submit ERRA balancing account activity reports (ERRA activity reports) each month to the Energy Division no later than 20 days following the end of the month. These monthly reports provide the Commission with an opportunity to review monthly transactions in advance of the annual ERRA Compliance Review application.[16] As of December 31, 2022, the balance in the ERRA is under collected at $560.1 million. This balance includes the balance of ERRA's PCIA Financing subsidiary account for the amount of $82.6M, which tracks the amount financed by bundled customers related to the revenue shortfall associated with capped PCIA rates for departing load customers[17] and $642.8 million under-collected in ERRA's main account. Table 13-2 summarizes the monthly accounting entries made to the ERRA from January 1 through December 31, 2022.

## C. PG&E's Internal Audit of 2021 Activity in the ERRA

On January 16, 2014, the Commission issued D.14-01-011, which among other things approved a Settlement Agreement (SA) between PG&E and the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), formerly called the Office of Ratepayer Advocates.[18] Section 2.4.3 of the SA provided that PG&E perform an accounting audit of the ERRA at least once every four years. The first two audits covered the periods of January 1, 2013 to December 31, 2013 and the January 1, 2017 to December 31, 2017 record periods, respectively. The most recent audit of ERRA is 2021 record period and was performed in 2022.

In June 2022, PG&E's Internal Auditing (IA) Department finalized an audit of the 2021 activity recorded in the ERRA balancing account. The internal audit

---

**16** A full set of these 2021 reports are included in PG&E's confidential response to Cal Advocates Master Data Request #1.3.1. Please see attachments to ERRA-2021-PGE-Compliance_DR_CalAdvocates_MDR001-Q26.docm.

**17** Please see PG&E's Preliminary Statement Part CP at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_CP.pdf, Section 6, "PCIA Financing Subaccount."

**18** OP 1 of D.14-01-011 approved the SA.

evaluated PG&E's processes and controls over the recording and reporting of costs and revenues to ERRA. IA concluded that costs and recorded revenues flowing through ERRA in 2021 were accurate. There are no additional journal entry adjustments needed when the internal audit was concluded. Additionally, PG&E's process and controls to support accurate revenue and costs recording and reporting is adequate. However, IA noted a low-risk observation[19] related to improving the quality of supporting documentation recorded to ERRA.

Accounting acknowledged the low-risk observation and has implemented additional lead schedules, which itemizes various journal entries recorded to a specific tariff line item shown in ERRA's balancing account. Also, Accounting had simplified calculation formulas to allow for journal entry data to be easily traceable. The process for improving general journal entry preparation and documentation recorded to ERRA is still an ongoing process. PG&E will continue to improve the quality of support recorded to ERRA.

## D. PG&E's Solar Choice Program

The GTSR Program became effective January 1, 2016. Consistent with the legislative requirement that non-participating customers remain rate indifferent to the GTSR Program, the Commission determined that each IOU is required to establish a balancing account to track the costs and revenues of the program. ERRA accounting procedures 5.ac, 5.ad, 5.ae, and 5.af enable the transfer of costs between ERRA and the GTSR balancing accounts. In addition, the IOUs are required to establish a memorandum account to track the program administrative and marketing costs. Chapter 11 of PG&E's Prepared Testimony includes a presentation of administrative and marketing costs incurred in the GTSR Memorandum Account in 2022 that are subject to reasonableness review in this proceeding and includes a showing of the GTSRBA entries for the record period.

## E. Other Cost Recovery

The RPSCMA was established to track third-party consultant costs incurred by the CPUC and paid by PG&E in connection with the CPUC's implementation and administration of the RPS, as authorized in D.06-10-050. The CPUC's

---

[19] Low-risk observations are for informational purposes only; IA does not require or track management action plans for these items.

Energy Division reviews and approves invoices it receives from independent consultants. PG&E pays the invoiced amount and records the costs in the RPSCMA, and D.06-10-050 authorizes PG&E to request recovery in rates through the ERRA application or other proceeding as authorized by the Commission. In 2022, the Energy Division staff did not submit any invoices to PG&E for payment of consulting services and therefore there were no entries to the RPSCMA during the record period.

**F. Variance Analysis**

In Table 13-1, PG&E provides a summary of the ERRA procurement costs recorded in the current record period, compared to the forecast included in its 2022 ERRA Forecast November Update Application, approved by the Commission in D.22-02-002.

**TABLE 13-1**
**2022 ACTUAL RECORDED COSTS COMPARED TO APPROVED FORECAST**
**(MILLIONS OF DOLLARS)**

| Line # | Description | Recorded | Forecast | Variance |
|---|---|---|---|---|
| | | ERRA | $M | $M |
| 1 | Contract Costs (a) | [redacted] | [redacted] | [redacted] |
| 1a | Contract Costs (CAM) | [redacted] | [redacted] | [redacted] |
| 1b | Contract Costs, Non-Vintage Modified CAM | [redacted] | [redacted] | [redacted] |
| 2 | Contract Costs, System Reliability D.19-11-016 | [redacted] | [redacted] | [redacted] |
| 3 | UOG Costs (GRC Costs) | [redacted] | [redacted] | [redacted] |
| 4 | Market Purchases & CAISO Cost (b) | [redacted] | [redacted] | [redacted] |
| 5 | Hedging Costs | [redacted] | [redacted] | [redacted] |
| 6 | Collateral and interest Expense | [redacted] | [redacted] | [redacted] |
| 7 | Retained RA | [redacted] | [redacted] | [redacted] |
| 8 | Retained RPS | [redacted] | [redacted] | [redacted] |
| 9 | Green Tariff Shared Renewable (GTSR), excluding PCIA Program Charges | [redacted] | [redacted] | [redacted] |
| 10 | **Total Procurement Costs in ERRA Forecast Proceeding** | [redacted] | [redacted] | [redacted] |
| | | - | - | |

(a) Contract line includes true-up between imputed fuel and trasport costs to actual costs for CAM contracts
(b) CAISO line includes CAM related CAISO costs/revenue not included in the forecast.

As Table 13-1 indicates, PG&E's procurement costs recorded across the portfolio contains both higher-than-forecasted and lower-than-forecasted amounts. This includes higher-than-forecast CAISO net market purchases, which were driven by higher-than-forecast market prices. This is primarily due to higher forward energy prices. Contract costs were higher than forecast due to an increase in costs to short-term contracts. The higher-than-forecasted Retained RAs was due to the final adder value being higher than the forecast RA adder authorized in D.22-02-002 with lower RA sales. A lower-than-forecast in Retained RPS was driven by higher RPS sales. A more detailed variance analysis of forecasted and actual amounts is included in PG&E's confidential workpapers for Chapter 13.

## G. Conclusion

PG&E has complied with the Commission's directives and has appropriately recorded entries to the ERRA. PG&E requests that upon verification and review of the costs and revenues recorded to the ERRA the Commission find the recorded entries in ERRA for the record period are appropriate, correctly stated, and in compliance with Commission decision.

**TABLE 13-2**
**FOR THE YEAR ENDING DECEMBER 31, 2022**

| Tariff Line Item | DR/CR | Tariff Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | FY 2022 YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Billed Revenue** | | | | | | | | | | | | | | | |
| 5.a. | **CR** | A credit entry equal to the revenue from the ERRA rate component from bundled customers during the month, excluding the allowance for Revenue Fees and Uncollectible (RF&U) Accounts expense. | [redacted] | | | | | | | | | | | | (3,381,368,398.93) |
| 5.b. | **CR** | A credit entry equal to revenues received from Schedule TBCC (Transitional Bundled Commodity Cost); | | | | | | | | | | | | | (15,836,579.90) |
| **Retained RPS and RA Value** | | | | | | | | | | | | | | | |
| 5.c. | **DR** | A debit entry equal to the Retained Renewable Portfolio Standard (RPS) Value, determined using the most current Commission-adopted RPS Adder, multiplied by Actual Retained RPS quantities. A corresponding credit entry equal the Retained RPS Value is recorded in PABA, MTCBA, BNBCBA, and MGBA. | | | | | | | | | | | | | 190,092,116.46 |
| 5.d. | **DR/CR** | A debit or credit entry to true-up the Retained RPS Value, determined using the Forecast RPS Adder to the Retained RPS Value using the Final RPS Adder. A corresponding credit or debit entry equal to the true-up of the Retained RPS Value is recorded in PABA, MTCBA, and the BNBCBA. | | | | | | | | | | | | | (5,060,361.71) |
| 5.e. | **DR** | A debit entry equal to the Retained Resource Adequacy (RA) Value, determined using the most current Commission-adopted RA Adder, multiplied by the Actual Retained RA quantities. A corresponding credit entry equal to the Retained RA Value is recorded in PABA, MTCBA, BNBCBA, and MGBA. | | | | | | | | | | | | | 544,741,841.30 |
| 5.f. | **DR/CR** | A debit or credit entry to true-up the Retained RA Value, determined using the Forecast RA Adder to the Retained RA Value using the Final RPS Adder. A corresponding credit or debit entry equal to the true-up of the Retained RA Value is recorded in PABA, MTCBA, and the BNBCBA. | | | | | | | | | | | | | 79,076,457.00 |
| **Summer Reliability** | | | | | | | | | | | | | | | |
| 5.g. | **DR/CR** | A credit entry to transfer an allocated portion of the cost for import capacity rights to the NSGBA if PG&E uses existing PGE-owned import allocation rights to meet the procurement targets pursuant to D.21-02-028 or D.21-03-056. The credit entries will be based on either the average price PG&E received for sales of its excess maximum import capability or, if not available or representative of market value, another reasonable market benchmark. | | | | | | | | | | | | | (2,117,721.49) |
| 5.h. | **DR/CR** | A debit entry to reflect the resource adequacy (RA) value of procurement originally directed in the Emergency Reliability proceeding, Rulemaking 20-11-003, including resources procured pursuant to D.21-02-028 and D.21-03-056, that is transferred to ERRA to meet bundled service RA compliance requirements. The contract costs and energy benefits of the Emergency Reliability procurement, if any, will continue to be allocated to all benefitting customers through the NSGBA. | | | | | | | | | | | | | - |
| 5.i. | **CR** | A credit entry equal to the value of RA that is excess or unsold RA capacity and that is transferred to the System Reliability Incremental Procurement Subaccount of NSGBA in order to meet the procurement targets pursuant to D.21-03-056, after having made reasonable attempts to sell excess capacity to other load-serving entities to meet their 15% planning reserve margin. The credit entry will use the most current market price benchmark for system RA, which is approved in the annual ERRA Forecast, and used to value RA capacity in the PCIA calculation. | | | | | | | | | | | | | - |
| **UOG Costs** | | | | | | | | | | | | | | | - |
| 5.j. | **DR/CR** | A debit or credit entry, as appropriate, to record ESA costs associated with bundled customer portfolio/procurement activity (which is embedded in the annual authorized revenue requirements associated with PG&E's owned generation). | | | | | | | | | | | | | 43,047,263.87 |
| **ISO Related Charges/ Revenues** | | | | | | | | | | | | | | | - |
| 5.k. | **DR/CR** | A debit or credit entry equal to the net charges or revenues for energy associated with load and generating resources recovered in ERRA and the New System Generation Balancing Account (NSGBA), and net charges or revenue for a proportional share of energy associated with the interim pool of RPS resources used to support the GTSR program | | | | | | | | | | | | | 2,909,120,962.25 |
| 5.l. | **DR/CR** | A debit or credit entry equal to the net charges or revenues for miscellaneous CAISO charges/credits associated with load and generating resources recovered in ERRA and NSGBA, and net charges or revenue for a proportional share of for miscellaneous CAISO charges/ credits associated with the interim pool of RPS resources used to support the GTSR program | | | | | | | | | | | | | 175,632,986.11 |
| 5.m. | **DR/CR** | A debit or credit entry equal to the net charges or revenues for ancillary services associated with load and generating resources recovered in ERRA and the NSGBA | | | | | | | | | | | | | 37,834,324.59 |
| 5.n. | **DR/CR** | A credit or debit entry equal to the revenues or costs related to Congestion Revenue Rights; | | | | | | | | | | | | | (78,149,475.33) |
| 5.o. | **DR/CR** | A credit or debit entry equal to the revenues or costs related to convergence bidding; | | | | | | | | | | | | | - |

# TABLE 13-2
# FOR THE YEAR ENDING DECEMBER 31, 2022
# (CONTINUED)

| Tariff Line Item | DR/CR | Tariff Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | FY 2022 YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Fuel Costs** | | | [redacted] | | | | | | | | | | | | - |
| 5.p. | **DR** | A debit entry equal to fuel and related transportation and miscellaneous costs for contracts recovered through ERRA. | [redacted] | | | | | | | | | | | | (247,142.75) |
| **Contract Costs** | | | [redacted] | | | | | | | | | | | | - |
| 5.q. | **DR** | A debit entry equal to short-term bilateral contract obligations. | [redacted] | | | | | | | | | | | | 246,991,384.34 |
| 5.r. | **DR/CR** | A debit or credit entry equal to short-term renewable contract obligations, and fees associated with participating in WREGIS | [redacted] | | | | | | | | | | | | 66,551.56 |
| 5.s. | **DR** | A debit entry equal to the short-term capacity and energy costs for QF/CHP Program contracts | [redacted] | | | | | | | | | | | | 12,826,989.98 |
| 5.t. | **CR** | A credit entry equal to the net capacity costs recorded in the QF/CHP Program and Marsh Landing subaccounts of the New System Generation Balancing Account (NSGBA). | [redacted] | | | | | | | | | | | | (120,366,362.19) |
| **GHG Costs** | | | [redacted] | | | | | | | | | | | | - |
| 5.u. | **DR** | A debit entry equal to greenhouse gas costs related with physically settled compliance instruments associated with contracts. | [redacted] | | | | | | | | | | | | - |
| **Miscellaneous Costs** | | | [redacted] | | | | | | | | | | | | - |
| 5.v. | **DR** | A debit entry equal to financial hedging contract obligations. | [redacted] | | | | | | | | | | | | 13,478,162.95 |
| 5.w. | **DR/CR** | A debit or credit entry equal to pre-payments and credit and collateral payments, including all associated fees, for procurement purchase and, if applicable, reimbursements of prepayments, credit and collateral payments; | [redacted] | | | | | | | | | | | | 4,655,022.30 |
| 5.x. | **DR** | A debit entry equal to any other power costs associated with procurement. | [redacted] | | | | | | | | | | | | 160,426.88 |
| 5.y. | **DR** | A debit entry equal to the incremental IE costs through 2010 related to RFOs seeking terms of less than five years. After 2010, a debit entry equal to all IE costs related to all RFOs and other IE and third-party reviewer costs approved by the Commission | [redacted] | | | | | | | | | | | | 232,840.76 |
| 5.z. | **DR** | A debit entry equal to power purchase payments provided to eligible Net Energy Metering customers for energy produced by on-site generation in excess of consumption over a 12-month period. Power purchase payments may include additional compensation for renewable attributes where applicable. | [redacted] | | | | | | | | | | | | 14,633,345.18 |
| 5.aa. | **DR** | A debit entry equal the authorized energy storage procurement evaluation program fund amount authorized in D.14-10-045 | [redacted] | | | | | | | | | | | | - |
| 5.ab. | **DR** | A debit entry to record customer education expenses associated with PG&E's Critical Peak Pricing Program for Summer Reliability 2021 and 2022, as authorized in D.21-03-056, which is capped at $635,000. | [redacted] | | | | | | | | | | | | 597,085.59 |
| 5.ag. | **DR/CR** | A debit/credit entry to record the transfer of the revenues financed by bundled customers related to the revenue shortfall associated with capped PCIA rates for departing load customers. A corresponding credit/debit entry is reflected in Accounting Procedure 6a below. | [redacted] | | | | | | | | | | | | (12,837,180.07) |
| 5.ah. | **DR/CR** | A debit or credit entry equal, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC. | [redacted] | | | | | | | | | | | | (283,122,655.37) |
| **Green Tariff Shared Renewables Program Accounting Procedures** | | | [redacted] | | | | | | | | | | | | - |
| 5.ac. | **DR/CR** | A credit or debit entry to reflect the generation-related Program Charge expense associated with the GTSR Program, excluding the PCIA expense and marketing and administrative expenses, for customers taking service under Schedule E-GT, equal to the Program Charge rate, multiplied by the kWh delivered under the program to the E-GT customers for the month, and/or entry to reflect any subsequent true-up of the Program Charge components' expense to actual costs. | [redacted] | | | | | | | | | | | | (23,485,911.71) |
| 5.ad. | **DR/CR** | A credit or debit entry to reflect generation-related Program Charge expense associated with the GTSR Program, excluding the PCIA expense and marketing and administration expenses, for customers taking service under Schedule E-ECR, equal to the Program Charge rate, multiplied by the subscription level of the EECR customer in kWh, and/or entry to reflect any subsequent trueup of the Program Charge components' expense to actual costs. | [redacted] | | | | | | | | | | | | - |
| 5.ae. | **DR/CR** | A debit or credit entry equal to expenses associated with the GTSR Program's Enhanced Community Solar (ECR) option resources that is unsubscribed. | [redacted] | | | | | | | | | | | | - |
| 5.af. | **DR/CR** | A debit or credit entry to transfer expenses from the GTSRBA for renewable resources procured to serve customers taking service under Schedule E-GT that are in excess of the E-GT program subscription pursuant to the backstop provision in Pub. Util. Code §2833(s) | [redacted] | | | | | | | | | | | | - |
| | | **Total Monthly Activity Before Interest** | **111,606,138.97** | **26,615,491.97** | **(314,719,910.41)** | **(16,991,885.55)** | **9,222,073.50** | **23,684,028.30** | **(161,065,047.80)** | **44,119,698.50** | **321,813,177.73** | **(46,775,093.79)** | **67,684,696.15** | **285,402,604.10** | **350,595,971.68** |
| | | | | | | | | | | | | | | | |

## TABLE 13-2
## FOR THE YEAR ENDING DECEMBER 31, 2022
## (CONTINUED)

| Tariff Line Item | DR/CR | Tariff Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | FY 2022 YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Interest Expense and Other | | | | | | | | | | | | | | | |
| 5.ai. | DR/CR | An entry equal to interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor; | [redacted] | | | | | | | | | | | | 4,469,183.06 |
| | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| | | **Beginning Balance** | 287,698,560.22 | 399,332,083.81 | 425,975,580.70 | 111,239,320.98 | 94,356,114.77 | 103,618,797.92 | 127,370,291.74 | (33,781,867.92) | 10,393,357.43 | 332,906,822.06 | 286,636,725.79 | 354,991,075.52 | 287,698,560.22 |
| | | | | | | | | | | | | | | | |
| | | **ERRA Ending Balance** | **399,332,083.81** | **425,975,580.70** | **111,239,320.98** | **94,356,114.77** | **103,618,797.92** | **127,370,291.74** | **(33,781,867.92)** | **10,393,357.43** | **332,906,822.06** | **286,636,725.79** | **354,991,075.52** | **642,763,714.96** | **642,763,714.96** |
| **6. POWER CHARGE INDIFFERENCE (PCIA)FINANCING SUBACCOUNT** | | | | | | | | | | | | | | | |
| | | **Beginning Balance** | (188,060,443.59) | (180,729,929.15) | (175,036,993.59) | (78,795,922.71) | (81,171,310.39) | **(81,232,253.09)** | **(81,263,866.49)** | **(81,159,857.14)** | **(81,380,518.36)** | **(81,942,998.12)** | (81,712,182.40) | (81,609,653.77) | (188,060,443.59) |
| 6.a. | DR/CR | A credit/debit entry to record the transfer of the revenues financed by bundled customers related to the revenue shortfall associated with capped PCIA rates for departing load customers. A corresponding debit/credit entry is reflected in Accounting Procedure 5ac above. | [redacted] | | | | | | | | | | | | 12,837,180.07 |
| 6.b. | DR/CR | A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, upon approval by the CPUC. | | | | | | | | | | | | | 94,030,221.79 |
| 6.c. | DR/CR | A monthly entry equal to interest on the average balance in the subaccount at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor. | | | | | | | | | | | | | (1,379,030.53) |
| | | | | | | | | | | | | | | | |
| | | **PCIA Financing Subaccount Ending Balance** | **(180,729,929.15)** | **(175,036,993.59)** | **(78,795,922.71)** | **(81,171,310.39)** | **(81,232,253.09)** | **(81,263,866.49)** | **(81,159,857.14)** | **(81,380,518.36)** | **(81,942,998.12)** | **(81,712,182.40)** | **(81,609,653.77)** | **(82,572,072.25)** | **(82,572,072.25)** |
| | | | | | | | | | | | | | | | |
| | | **TOTAL ERRA Ending Balance** | **218,602,154.66** | **250,938,587.11** | **32,443,398.27** | **13,184,804.38** | **22,386,544.82** | **46,106,425.24** | **(114,941,725.07)** | **(70,987,160.93)** | **250,963,823.93** | **204,924,543.39** | **273,381,421.74** | **560,191,642.71** | **560,191,642.71** |

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 14

# MAXIMUM POTENTIAL DISALLOWANCE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 14
MAXIMUM POTENTIAL DISALLOWANCE

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 14
# MAXIMUM POTENTIAL DISALLOWANCE

## A. Introduction

The purpose of this chapter is to present the maximum potential disallowance calculation for Standard of Conduct 4 (SOC4) violations for the January 1 – December 31, 2022 record period. SOC4 states that:

> …the utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner.[1]

Pacific Gas and Electric Company (PG&E) agreed to provide this chapter in its Settlement Agreement (SA) with the California Public Advocates Office (formerly known as Office of Ratepayer Advocates) in the 2014 Energy Resource Recovery Account Compliance proceeding (Application (A.) 15-02-023).[2] By providing this testimony, PG&E is not explicitly or implicitly indicating that there were any SOC4 violations during the January 1 – December 31, 2022 record period. Rather, PG&E does not believe that there were any SOC4 violations but is providing this calculation consistent with the SA.

## B. Calculation Methodology for Maximum Potential Disallowance

PG&E's SOC4 is limited to the administration of electric procurement contracts and generation resources and to the dispatch of energy in a least-cost manner. Expenses that are included under SOC4 include the following: contract negotiation and management; dispatch of Utility-Owned Generation (UOG) and third-party resources; and fuel costs to UOG facilities. There are other costs at issue in this proceeding that do not fall under the purview of SOC4, such as the costs for UOG replacement energy.

SOC4 is limited in scope and, accordingly, the potential for disallowance is also limited. In Decision (D.) 02-12-074, the California Public Utilities Commission (Commission) adopted a limit for potential disallowances for SOC4

---

1 D.02-10-062, pp. 50-52.

2 SA, § 3.8. The SA was approved at the Commission on December 20, 2016 in D.16-12-045.

violations in Ordering Paragraph (OP) 25. The maximum potential disallowance risk is equal to two times PG&E's annual procurement administrative expenditures.[3] The Commission further defined that "annual procurement administrative expenditures" include costs related to "utility-related generation, renewables, Qualifying Facilities, demand-side resources, and any other procurement resources."[4] In D.03-06-067, the Commission modified OP 25 to state that the specific dollar amounts for each utility shall be reviewed in each General Rate Case (GRC) or cost of service proceeding.[5]

### C. Calculation of Maximum Potential Disallowance

In 2018, PG&E filed its 2020 GRC Application. The Commission approved application (A.18-12-009) in D.20-12-005, finding the settlement amount of $36.584 million for EPP costs reasonable.[6]

As described above, the maximum potential disallowance risk is based on PG&E's procurement-related administrative expenses and is determined by the most recently adopted GRC decision.

For this Compliance proceeding, PG&E calculated the 2022 Imputed Regulatory Values of the four Major Work Categories (MWC) that support expenses for the Energy Policy and Procurement organization in compliance with D.20-12-005. The 2022 Imputed Regulatory Values are shown in Table 14-1.

**TABLE 14-1**
**2022 IMPUTED REGULATORY VALUES**
**2020 GRC SETTLMENT DECISION**
**(THOUSANDS OF DOLLARS)**

| Line No. | MWC | MWC Description | 2022 Imputed Regulatory Values |
|---|---|---|---|
| 1 | CT | Acquire and Manage Electric Supply | $24,019 |
| 2 | CV | Acquire and Manage Gas Supply | 2,151 |
| 3 | AB | Misc. Expense/Support | 505 |
| 4 | CY | Manage Electric Grid Operations (GII) | 11,109 |
| 5 | Total | | $37,784 |

---

3 D.02-12-074, pp. 77-78, OP 25.

4 *Id.*, p. 55.

5 D.03-06-067, p. 23, OP 3a.

6 D.20-12-005, p. 145.

### D. Conclusion

PG&E requests that the Commission approve its 2022 calculation of the maximum potential disallowance of $75.567 million, which is two times $37.784 million.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 15

# REVIEW ENTRIES RECORDED IN THE DISADVANTAGED COMMUNITY – SINGLE-FAMILY AFFORDABLE SOLAR HOMES BALANCING ACCOUNT AND THE DISADVANTAGED COMMUNITY – SINGLE-FAMILY AFFORDABLE SOLAR HOMES MEMORANDUM ACCOUNT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 15
REVIEW ENTRIES RECORDED IN THE
DISADVANTAGED COMMUNITY – SINGLE-FAMILY AFFORDABLE SOLAR HOMES BALANCING ACCOUNT
AND THE DISADVANTAGED COMMUNITY – SINGLE-FAMILY AFFORDABLE SOLAR HOMES MEMORANDUM ACCOUNT

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 15
# REVIEW ENTRIES RECORDED IN THE DISADVANTAGED COMMUNITY – SINGLE-FAMILY AFFORDABLE SOLAR HOMES BALANCING ACCOUNT AND THE DISADVANTAGED COMMUNITY – SINGLE-FAMILY AFFORDABLE SOLAR HOMES MEMORANDUM ACCOUNT

## A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents for review its 2022 Disadvantaged Community – Single-Family Affordable Solar Homes (DAC SASH) funding and administrative costs recorded to the DAC SASH subaccount in the Public Policy Charge Balancing Account (referred as Disadvantaged Community – Single-Family Affordable Solar Homes Balancing Account (DACSASHBA) in this chapter) and the Disadvantaged Community – Single-Family Affordable Solar Homes Memorandum Account (DACSASHMA), as directed by the California Public Utilities Commission (Commission) in Decision (D.) 18-06-027, the *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*.

Assembly Bill 327 required the Commission to develop alternatives to increase the adoption and growth of renewable generation in disadvantaged communities. D.18-06-027 adopted the DAC SASH Program, along with the Disadvantaged Community Green Tariff and Community Solar Green Tariff programs, as discussed in Chapter 5.

## B. DACSASHBA

### 1. Funding of the DAC SASH Program and Transfer to Balancing Account

Pursuant to Ordering Paragraph (OP) 8 of D.18-06-027, the annual budget of $10 million for the program is funded first through Greenhouse Gas (GHG) allowance proceeds. If such funds are exhausted, the program will be funded through the Public Purpose Charge component of the Public Purpose Program funds. PG&E's proportionate share of the

$10 million per year is 43.7 percent, or $4.37 million per year.[1] In the 2022 Energy Resource Recovery Account (ERRA) Forecast proceeding (Application 21-06-001), PG&E stated that its proportionate share of $4.37 million for DAC SASH funding could be wholly covered by GHG allowance proceeds for the 2022 record year. In February 2022, the Commission approved this use of GHG allowance proceeds in D.22-02-002 and the $4.37 million was transferred from GHG Revenue Balancing Account to DACSASHBA.[2]

**2. Expenses of the DAC SASH Program Recorded to Balancing Account**

An overview of the expenses recorded in 2022 to the DACSASHBA[3] are shown in Table 15-1 below.

**TABLE 15-1**
**DACSASHBA RECORDED EXPENSES IN 2022**

| Line No. | Description | Amount |
|---|---|---|
| 1 | PG&E Program Management | $44,306 |
| 2 | Independent Evaluation Contract Expenses | 131,048 |
| 3 | Program Administrator (PA) Administrative Expenses | 696,467 |
| 4 | Incentives | 3,866,544 |
| 5 | Total | $4,738,365 |

PG&E incurred $44,306 in internal PG&E Program Management expenses to the DACSASHBA during 2022. Activities associated with this work included:

- Reviewing and approving administration and incentive invoices;
- Ensuring compliance with all regulatory requirements;

---

1 D.18-06-027, Appendix A, p. A-6.

2 Advice Letter (AL) 5363-E, the DACSASHBA Implementation AL, was approved on January 24, 2019 and effective as of September 19, 2018. Interest on the account balance is calculated and recorded based on the average balance in this account at the beginning and the end of the month, at a rate equal to one-twelfth of the interest rate on the three-month Commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

3 Interest on the account balance is calculated and recorded based on the average balance in this account at the beginning and the end of the month, at a rate equal to one-twelfth of the interest rate on the three-month Commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

- Drafting, reviewing, and responding to regulatory filings;
- Financial planning and analysis for the program;
- Responding to data requests from the independent program evaluator;
- Monthly meetings with GRID Alternatives on increasing program referrals from the Energy Savings Assistance Program and general program updates;
- Generating and transmitting data items to GRID Alternatives;[4] and
- Co-marketing activities involved in a targeted email campaign to customers.

For the Independent Evaluation Contract Expenses, there is a co-funding agreement between the Investor-Owned Utilities (IOUs) which is managed by San Diego Gas and Electric Company (SDG&E). In 2022, PG&E did not receive any invoices from SDG&E. Using the best information available, PG&E accrued $131,048 to account for PG&E's share of the estimated expense from the independent evaluator's work performed in 2022.

For the Program Administrative Expenses incurred by GRID Alternatives, there is a co-funding agreement between the IOUs which is managed by Southern California Edison Company. In 2022, PG&E paid four invoices totaling $696,467 for PG&E's share of the administrative costs for GRID Alternatives. In 2022, PG&E paid incentive invoices to GRID Alternatives totaling $3,866,544 for completed DAC SASH projects.

### 3. Recovery of 2022 PG&E Administrative Costs

OP 6 of D.20-12-003 authorizes the IOUs to submit Tier 2 ALs with proposed annual budgets for reasonable administrative costs needed to support the DAC SASH program, starting with the 2021 proposed PG&E budget. PG&E filed AL 6491-E for the proposed 2022 budget of $80,000 for the DAC SASH program, which was effective March 3, 2022.[5] OP 7 of D.20-12-003 authorizes PG&E to seek recovery of its approved administration costs through its DACSASHBA and to include such costs in

---

4 Per OP 2 of D.20-12-003, PG&E must annually transmit the data items listed in Appendix A to GRID Alternatives.

5 PG&E AL 6491-E can be accessed: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6491-E.pdf.

its annual ERRA proceedings for reasonableness review. PG&E requests approval and seeks recovery of $44,306 for the PG&E expenses incurred in 2022 to the DACSASHBA in this ERRA Compliance proceeding.

### C. DACSASHMA

In the 2019 ERRA Compliance Testimony, PG&E defined startup costs as expenses incurred from January 2019 to the launch of the DAC SASH Program (September 2019). No additional start-up costs were incurred in 2021 or 2022, and no additional expenses are anticipated for the memorandum account (DACSASHMA)[6]. All start-up costs were requested and approved in the 2019 ERRA Compliance decision, D.21-07-013. PG&E does not make any requests related to the DACSASHMA because PG&E requested to retire to the DACSASHMA in the 2021 ERRA Compliance proceeding, which is pending a final decision.

### D. Conclusion

In this chapter, PG&E described its 2022 funding and recorded expenses for the DAC SASH Program. PG&E requests that the Commission find DAC SASH expenses incurred in 2022 to be reasonable and approve cost recovery of PG&E's 2022 program management expenses incurred and recorded in the DACSASHBA.

---

6 AL 5361-E, the DACSASHMA Implementation AL approved on December 14, 2018 and effective as of August 20, 2018. Interest on the account balance is calculated and recorded based on the average balance in this account at the beginning and the end of the month, at a rate equal to one-twelfth of the interest rate on the three-month Commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

# PACIFIC GAS AND ELECTRIC COMPANY

# CHAPTER 16

# CENTRAL PROCUREMENT ENTITY ENTRIES RECORDED TO THE CENTRALIZED LOCAL PROCUREMENT SUB-ACCOUNT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 16
CENTRAL PROCUREMENT ENTITY ENTRIES RECORDED TO THE CENTRALIZED LOCAL PROCUREMENT SUB-ACCOUNT

TABLE OF CONTENTS

# PACIFIC GAS AND ELECTRIC COMPANY
# CHAPTER 16
# CENTRAL PROCUREMENT ENTITY ENTRIES RECORDED TO THE CENTRALIZED LOCAL PROCUREMENT SUB-ACCOUNT

## A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents its administrative costs recorded to the Centralized Local Procurement Sub-Account (CLPSA) and contract management issues related to Central Procurement Entity (CPE) agreements.

In Decision (D.) 20-06-002 (CPE Decision), issued June 17, 2020, the California Public Utilities Commission (CPUC or Commission) ordered PG&E to serve as the CPE for PG&E's distribution service area for the multi-year local Resource Adequacy (RA) program. Starting with the 2023 RA compliance year, the CPE is responsible for procuring the total local RA requirement for all local areas in PG&E's distribution service area on behalf of Commission-jurisdictional Load Serving Entities. The CPE Decision established that both procurement costs and administrative costs incurred in serving the central procurement function shall be recoverable under the Cost Allocation Mechanism and directed PG&E to submit the administrative costs in the Energy Resource Recovery Account Forecast and Compliance proceedings[1] in addition to any contract management issues associated with CPE agreements.[2]

The CPUC approved Advice Letter (AL) 5919-E, effective September 16, 2020, which established the CLPSA in the New System Generation Balancing Account for recording procurement and administrative costs associated with PG&E's role as the CPE.

## B. Administrative Expenses Recorded to the CLPSA During the Record Period

In 2022, PG&E incurred administrative costs related to the operations and support of CPE procurement activities. The amounts recorded to the CLPSA during the record period are as follows:

---

1 D.20-06-022, pp. 55-56.

2 D.20-06-022, p. 62.

**TABLE 16-1**
**2022 PG&E CPE ADMINISTRATIVE COSTS**

| Line No. | Description | Amount ($) |
|---|---|---|
| 1 | CPE Implementation Team Cost | $1,215,939 |
| 2 | CPE Supporting Functions Costs | 306,152 |
| 3 | IE Cost | 100,454 |
| 4 | Total | $1,622,545 |

### 1. CPE Implementation Team and Supporting Functions

The CPE is tasked with a number of functions in the CPE Decision, including, but not limited to: (1) conducting one or more competitive, all-source solicitations for local RA procurement with specific requirements outlined in the CPE Decision, (2) evaluating and selecting bids in the solicitation in accordance with the all-source selection criteria, (3) complying with various regulatory requirements, and (4) contracting with counterparties for procurement of local RA. To ensure compliance with CPE competitive neutrality rules, PG&E established on October 1, 2020, a separate and walled-off CPE Implementation Team to lead the implementation of the CPE function and perform the commercial duties of the PG&E CPE.

All CPE-related work in 2022 was led primarily by the CPE Implementation Team with the support of shared functions both within and outside of PG&E's procurement department. These shared functions included, but were not limited to, Law, Credit Risk and Management, Energy Contract Management and Settlements, Energy Policy and Analysis, and Information Technology departments. These supporting departments were critical to the successful execution of CPE procurement activities. They supported critical processes and functions such as CPE contract development and review, solicitation management, credit management for CPE counterparties, CPE systems operations and maintenance, and CPE contract administration.

Costs for the CPE Implementation Team and CPE supporting functions totaled $1,522,091 for 2022.

### 2. 2022 CPE Activities

In April of 2022, PG&E CPE launched the 2022 CPE Local RA Request for Offers (RFO). Between the months of April and September, the PG&E CPE conducted negotiations with over 15 counterparties for procurement of local resources to meet its local reliability requirements for the 2023 through 2025 compliance period. After thorough evaluation of all offers, the CPE executed multiple CPE agreements in August of 2022. Consistent with Commission requirements, on September 19, 2022, the CPE filed its 2022 Annual Compliance Report to the Commission detailing its procurement process to demonstrate compliance with the CPE Decision as well as providing details of the agreements executed and the current CPE local RA position.

Upon the conclusion of the 2022 CPE Local RA RFO, the PG&E CPE also engaged in bilateral discussions with several counterparties looking for additional capacity in local areas where the CPE was short for the compliance period.

In October of 2022, PG&E CPE launched a second solicitation, the 2022 PG&E CPE Kern-Lamont Battery Energy Storage RFO ("Kern-Lamont RFO") pursuant to CPUC D.22-02-004, the 2021 Preferred System Plan Decision ("PSP Decision"). Through the PSP Decision, the PG&E CPE was required to issue a solicitation in 2022 and submit a Tier 2 AL to the Commission by the end of the year, detailing progress made in the procurement process. The Tier 2 AL was filed December 28, 2022, fulfilling the CPE's compliance requirement through the PSP Decision.

### 3. Independent Evaluator (IE) Costs

The CPE Decision requires the PG&E CPE to consult regularly with an IE on various aspects of the CPE procurement process including, but not limited to, development of the CPE Code of Conduct, development of CPE solicitation protocols and processes, and evaluation of bids and offers into the CPE solicitation. In 2022, PG&E engaged with Merrimack Energy Group to act as the IE for all CPE procurement activities, including the 2022 CPE Local RA RFO, the 2022 CPE Kern-Lamont Battery Energy Storage RFO, and all bilateral negotiations conducted by PG&E CPE. As IE, Merrimack Energy Group was responsible for monitoring all aspects of these solicitations including development of solicitation materials, attending and presenting at Procurement Review Group meetings, monitoring all counterparty negotiations, and authoring the IE Report for the CPE's Annual Compliance Report. Total expense for engagement with the IE in 2022 was $100,454.

### C. CPE Contract Management Issues During Record Period

Through the 2022 CPE Local RA RFO, PG&E CPE executed multiple agreements toward meeting its multi-year forward local reliability requirements. These agreements do not include deliveries prior to 2023. Further, there were no agreements executed through the 2022 CPE Kern-Lamont Battery Energy Storage RFO or via bilateral negotiations that would have required deliveries prior to 2023. As such, there are no contract management issues to report for the 2022 record period.

### D. Conclusion

The above testimony describes CPE administrative costs that were incurred during the record period and demonstrates that these costs were reasonable and prudently incurred. The above testimony also confirms no contract management activity for CPE agreements during the record period.

# PACIFIC GAS AND ELECTRIC COMPANY

## APPENDIX A

## STATEMENTS OF QUALIFICATIONS

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF MARIANNE AIKAWA

Q 1 Please state your name and business address.

A 1 My name is Marianne Aikawa, and my business address is Pacific Gas and Electric Company, 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Senior Manager of Risk and Compliance within the Contract Management, Settlements, and Reporting Department of PG&E's Energy Policy and Procurement (EPP) organization. In this position, I am responsible for managing EPP's compliance and risks programs and regulatory reporting associated with energy procurement.

Q 3 Please summarize your educational and professional background.

A 3 I joined PG&E in 1989 and have held various roles of increasing scope and responsibility. Most recently, I served as Interim Director in the Risk, Compliance and Reporting Department within Energy Policy Procurement, responsible for overseeing EPP's compliance with the California Public Utilities Commission, Federal Energy Regulatory Commission and North American Electric Reliability standards and obligations affecting its recovery of energy procurement costs. In addition, I was responsible for ensuring the organization's compliance with the Securities and Exchange Commission reporting requirements, Section 404 of the Sarbanes-Oxley Law, all internal audit recommendations, and plans for systems and process improvement.

Prior to joining Risk, Compliance and Reporting, I served in management roles supporting regulatory activities and policy development within the Long-Term Energy Policy Department in PG&E's Energy Policy and Procurement organization. Prior to joining Energy Policy and Procurement, I served in roles within the Corporate Accounting Department of Finance and the Revenue Requirements Department of Regulatory Affairs.

I received a Bachelor of Science degree in Biology from University of California, Berkeley and a Master of Arts degree in Economics from New Mexico University, Las Cruces.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 14, "Maximum Potential Disallowance."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF THOMAS R. BALDWIN

Q 1 Please state your name and business address.

A 1 My name is Thomas R. Baldwin, and my business address is Pacific Gas and Electric Company, Diablo Canyon Power Plant.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director of Nuclear Generation Business Operations, responsible for the Nuclear Generation functional area strategic and integrated planning, General Rate Case (GRC) activities, and matrixed organizations including business finance and supply chain.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from University of Colorado, Boulder, in 1984. I joined PG&E in 1985 as a Design Engineer in the Mechanical and Nuclear Engineering Department. I have since held positions as the Supervisor of Systems Engineering, Manager of Regulatory Services, Manager of Procedures Services, Operations Senior Reactor Operator (licensed by the Nuclear Regulatory Commission), Director of Site Services, and the Director of Business Planning for Generation. Additionally, I was a Witness in PG&E's 2023 GRC proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 4, "Utility-Owned Generation: Nuclear."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF DONNA L. BARRY

Q 1 Please state your name and business address.

A 1 My name is Donna L. Barry, and my business address is Pacific Gas and Electric Company, 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Regulatory Principal in Electric Rates Department within the Corporate Affairs organization. I am responsible for developing testimony and analysis to support proceedings filed at the California Public Utilities Commission on matters related to energy procurement and cost recovery.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Civil Engineering from Washington State University and a Master's degree in Business Administration from Santa Clara University.

I began my career with PG&E in 1989 as an Engineer in the Engineering and Construction Business Unit's Gas Construction Department managing gas distribution and pipeline replacement construction projects. From there, I took an assignment in the Gas Supply Business Unit in the Gas Engineering and Construction (GEC) Department as a Project Manager, managing three gas backbone transmission projects before joining the Gas Planning section in GEC where I analyzed the reliability of local transmission and distribution systems. I subsequently joined the Cost of Service section in the Rates Department where I performed Cost of Service studies and marginal cost analyses supporting various gas and electric rate applications.

I joined the Electric Restructuring Cost Recovery section of the Revenue Requirements Department in 2001 and Electric Energy Revenue and Analysis and Ratemaking section in 2002. I was a Principal Case Manager and Witness for the Energy Resource Recovery Account (ERRA) Forecast and ERRA Compliance Review proceedings between 2003 and 2014 responsible for case managing and testimony development. The department and section were renamed as the Energy Supply Proceedings Department in 2012. In 2014, I moved to the Revenue Requirements and

Analysis Department and moved to my current position in Electric Rates in 2017.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 11, "Review Entries Recorded in the Green Tariff Shared Renewables Memorandum Account and the Green Tariff Shared Renewables Balancing Account":
  - Sections A, B, D, and E.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF SHANNON CONNER

Q 1 Please state your name and business address.

A 1 My name is Shannon Conner, and my business address is Pacific Gas and Electric Company, Diablo Canyon Power Plant.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I manage the Nuclear Fuels Purchasing group for Diablo Canyon. I am responsible for contracts associated with the fabrication of nuclear fuel for Diablo Canyon and the purchase of feed materials (uranium, conversion services, and enrichment services).

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in nuclear engineering from the University of Missouri – Rolla. I went on to receive a Master's of Science in Mechanical Engineering from University of Pittsburgh and a Master's of Business Administration from California State University – Monterey Bay. I have worked for PG&E at Diablo Canyon for over 8 years, in various roles in the engineering department. Prior to PG&E, I worked 10 years for Westinghouse Electric Company, primarily supporting startup testing services for various utilities worldwide.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 6, "Generation Fuel Costs and Electric Portfolio Hedging":
  - Sections A, E, and F; and
- Chapter 6, Attachment A, "Generation Fuel Costs."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF SEBASTIEN CSAPO

Q 1 Please state your name and business address.

A 1 My name is Sebastien Csapo, and my business address is Pacific Gas and Electric Company, 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Product Manager in the group supporting PG&E’s third-party Demand Response programs.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Accountancy and a Bachelor of Art degree in Economics from the University of Illinois at Urbana-Champaign; and a Master’s degree in Business Administration from San Jose State University. Also, I earned my Certified Public Accountant credential from the state of Illinois (inactive).

My work experience at PG&E covers a number of functional areas, including accounting, audit, regulatory and program management. Prior to PG&E, I worked for an agency within the United States Department of Treasury handling matters of compliance and enforcement.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E’s 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 9, “Contract Administration”:
  - Sections C.1.j and Section D.2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF KELLY A. EVERIDGE

Q 1 Please state your name and business address.

A 1 My name is Kelly A. Everidge, and my business address is Pacific Gas and Electric Company, 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Senior Director of the Contract Management, Settlements, and Reporting section of the Energy Policy and Procurement (EPP) Department, responsible for managing back office contract management and settlement operations associated with electric and gas procurement.

Q 3 Please summarize your educational and professional background.

A 3 I joined PG&E in 1997 and most recently served as the Chief of Staff for Electric Operations. I have served in several EPP roles such as the Director, Risk, Compliance, and Reporting, responsible for EPP's compliance and assurance programs and Director, Energy Contract Management and Settlements, responsible for contract management, settlement, payments, and financial reporting. Prior to EPP, I was responsible for managing the business planning function within Finance, including budget, forecasting, operational performance analysis, and strategic planning. I have also served in roles within the Risk Management and Finance organizations, and managed front, middle, and back office energy trading functions at PG&E's former subsidiary, the National Energy Group, headquartered in Bethesda, Maryland. I hold a Bachelor of Science degree in Finance from California State University, Sacramento and an Master of Business Administration from Golden Gate University.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 9, "Contract Administration"; and
- Chapter 10, "CAISO Settlements and Monitoring."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

## PACIFIC GAS AND ELECTRIC COMPANY
## STATEMENT OF QUALIFICATIONS OF ROBERT GOMEZ

Q 1 Please state your name and business address.

A 1 My name is Robert Gomez, and my business address is Pacific Gas and Electric Company, 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Manager in the Portfolio Management group in the Energy Policy and Procurement organization and am responsible for commercial activity and position management associated with products such as Resource Adequacy (RA) capacity, Greenhouse Gas (GHG), and energy.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Molecular and Cellular Biology from the University of Arizona in 1996, and a Master of Business Administration degree in Operations Management form the University of Arizona, The Eller School of Management, in 2001. I joined PG&E in 2002 as a Resource Planning Analyst developing forecast models and methodologies for various components of PG&E's portfolio for procurement planning purposes. Most recently, I am a Manager in the Portfolio Management group in the Energy Policy and Procurement organization at PG&E where I am responsible for commercial activity and position management associated with products such as RA capacity, GHG, and energy. Prior to my employment with PG&E, I worked for IBM as a Market Sector Analyst.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 8, "Resource Adequacy"; and
- Chapter 12, "Summary of Portfolio Allocation Balancing Account Entries for the Record Period":
  - Section D.3.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF TIFFANY HANSON

Q 1 Please state your name and business address.

A 1 My name is Tiffany Hanson, and my business address is Pacific Gas and Electric Company, 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Program Manager for low income solar programs in the Distributed Generation team under the Utility Partnerships and Innovation organization. In this role, I manage the administration for some of PG&E's solar incentive programs.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from University of California, San Diego and a Master's degree in Mechanical Engineering from Boston University. I joined PG&E in 2019 as a Program Manager for low income solar programs, including Solar on Multifamily Affordable Housing, Multifamily Affordable Solar Housing, Single-Family Affordable Solar Homes, Disadvantaged Community – Single-Family Solar Homes. Prior to PG&E, I worked as a Project Manager at a solar design company, and a solar design engineer at NRG Energy, Inc.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 15, "Review Entries Recorded in the Disadvantaged Community – Single-Family Affordable Solar Homes Balancing Account and the Disadvantaged Community – Single-Family Affordable Solar Homes Memorandum Account."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF JOSH HARMON

Q 1 Please state your name and business address.

A 1 My name is Josh Harmon, and my business address is Pacific Gas and Electric Company, 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Program Manager for Distributed Generation Programs in the Utility Partnerships and Innovation organization. In this role, I oversee the development and management of PG&E's customer-facing solar incentive and renewable energy programs. My focus in this role is management of the Green Tariff Shared Renewables Programs: Green Tariff and Enhanced Community Renewables.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Global Studies from the University of Illinois at Urbana-Champaign and a Master's degree in International Affairs from the George Washington University. I joined PG&E in 2018 as a Strategic Analyst and moved to the Distributed Generation team in 2019. Before working at PG&E, I worked at the George Washington University Solar Institute where I produced and directed short educational films on Solar Photovoltaic as part of the United States (U.S.) Department of Energy Sunshot Initiative. I have also interned in the Office of Energy Efficiency and Renewable Energy at the U.S. Department of Energy and worked as a consultant at a boutique advisory firm in Chicago.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 11, "Review Entries Recorded in the Green Tariff Shared Renewables Memorandum Account and the Green Tariff Shared Renewables Balancing Account":
  - Sections A through C, and E;
- Chapter 11, Attachment A, "GTSRMA Detail for Planning Year 2022."

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF KELLY JOHNSTON

Q 1 Please state your name and business address.

A 1 My name is Kelly Johnston, and my business address is Pacific Gas and Electric Company, 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Principal Portfolio Management Analyst in the Portfolio Management group in PG&E's Energy Policy and Procurement (EPP) organization and am responsible for greenhouse gas (GHG) commercial activity and position management.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Psychology from the University of California, Berkeley in 2007. I joined PG&E in 2014 as an Associate Contract Management Analyst on the EPP Contract Management team, performing contract administration duties for various power purchase agreements, including tolling, GHG, and RPS agreements. In 2018, I joined the Portfolio Management group in my current role. Prior to my employment with PG&E, I worked at UnitedHealthcare as a financial underwriter in its national accounts sector.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 7, "Greenhouse Gas Compliance Instrument Procurement."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF KEONI KANOA

Q 1 Please state your name and business address.

A 1 My name is Keoni Kanoa, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Program Manager for Distributed Generation Programs in the Utility Partnerships and Innovation organization. In this role, I oversee the development and management of PG&E's customer-facing solar incentive and renewable energy programs. My focus in this role is management of the Disadvantaged Community – Green Tariff and Community Solar – Green Tariff programs.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Business Administration from Whittier College. I also hold multiple project management certifications including a Project Management Professional certification from the Project Management Institute. I joined PG&E in 2022 as a Program Manager on the Distributed Generation team. Before working at PG&E, I worked at San Diego Gas & Electric Company in project management and marketing and communications focused on rate education and new rate implementation, and at the electric car company Rivian in program management for their service organization.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 5, "Review Entries Recorded in the Disadvantaged Community – Green Tariff Balancing Account and the Community Solar Green Tariff Balancing Account."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF GIA MILBRANDT

Q 1 Please state your name and business address.

A 1 My name is Gia Milbrandt, and my business address is Diablo Canyon Power Plant, San Luis Obispo, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Supervisor of Outage Hiring at PG&E, with knowledge of the Strategic Teaming and Resource Sharing (STARS) Alliance Management Council.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Theater from the University of California, Los Angles, in 1987. In 2011, I joined PG&E as an Executive Assistant supporting Senior Leaders at Diablo Canyon Power Plant (DCPP). After seven years, I supported Outage Management as a Sr. Work Week Manager for two and a half years. In addition, I assumed the role of STARS Management Council Representative from DCPP in June 2020. I assumed my current position in December 2020 and kept my role with STARS.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 6, "Generation Fuel Costs and Electric Portfolio Hedging":
  - Sections A and G; and
- Chapter 6, Attachment B, "Annual Report of Utility on the Activities of Stars Alliance, LLC.; Utility Savings/Avoided Costs by Stars Team/Project; and Independent Auditor's Report and Financial Statements."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

## PACIFIC GAS AND ELECTRIC COMPANY
## STATEMENT OF QUALIFICATIONS OF AMOL PATEL

Q 1 Please state your name and business address.

A 1 My name is Amol Patel, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 As Director, Central Procurement Entity Implementation, I oversee the Central Procurement Entity (CPE) department which focuses on the implementation of Local Resource Adequacy procurement processes for PG&E's role as the CPE for PG&E's distribution service area.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Biological Systems Engineering in 2000 from the University of California, Davis. I have worked in the energy industry for over 20 years, 17 of which have been for PG&E where I have held several leadership positions within the Energy Policy and Procurement organization, including positions within the Energy Contract Management and Settlements Department and my currently held position of Director, CPE Implementation.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 16, "Central Procurement Entity Entries Recorded to the Centralized Local Procurement Sub-Account."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF WILLIAM REINWALD

Q 1 Please state your name and business address.

A 1 My name is William Reinwald, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Analyst in the Risk and Compliance Department within the Energy Policy and Procurement organization. I am responsible for preparing, validating, and submitting energy procurement reports to state and federal regulatory agencies.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Nuclear Engineering in 1994 and a Master of Business degree in 2001, both from the University of Cincinnati.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 12, "Summary of Portfolio Allocation Balancing Account Entries for the Record Period":
  - Section C.2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF STEVE ROYALL

Q 1 Please state your name and business address.

A 1 My name is Steve Royall, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Director for Operations and Maintenance of PG&E's fossil, solar, and battery energy storage generation facilities in PG&E's Power Generation organization.

Q 3 Please summarize your educational and professional background.

A 3 I joined PG&E in 2007 as Director in the Generation Department, responsible for managing the Gateway Generating Station. Prior to PG&E, I worked at Northern California Power Agency, where I was the Assistant General Manager of Power Generation and the Manager of Gas Fired Generation. I have more than 38 years of experience working in power generation projects in the areas of operation, engineering, construction, and commissioning. I have been involved in projects that resulted in approximately 3,500 megawatts of new generation in California and Washington over the last 38 years, including PG&E's Gateway Generating Station, and Colusa Generating Station. Other former employers include: Calpine Corporation, Phillips Oil Company, and Freeport McMoRan Corporation. I am the Chairperson of the Electric Utility Cost Group Fossil committee and the former chairman of the Combined Cycle Users Group. I was a Witness in PG&E's 2014-2020 Energy Resource Recovery Account Compliance Review proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 3, "Utility-Owned Generation: Fossil and Other Generation”; and
- Chapter 6, “Generation Fuel Costs and Electric Portfolio Hedging”:
  - Sections A and C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF RYAN STANLEY

Q 1 Please state your name and business address.

A 1 My name is Ryan Stanley, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Manager in the Energy Accounting Department within the Corporate Accounting organization at PG&E. In this position, I am responsible for overseeing and advising on cost recovery. I am also responsible for leading various reporting activities on the monthly accounting entries made into the Energy Resource Recovery Account balancing account, in compliance with California Public Utilities Commission directives.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Business Administration, from the Walter A. Haas School of Business, University of California at Berkeley. I received my Master's in Business Administration from the Walter A. Haas School of Business, University of California at Berkeley.

I have over 14 years of regulated utility accounting, financial forecasting, and regulatory experience from having held positions of increasing responsibility at PG&E, in the Controller's and Regulatory Affairs organizations.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 5, "Review Entries Recorded in the Disadvantaged Community – Green Tariff Balancing Account and the Community Solar Green Tariff Balancing Account";
- Chapter 12, "Summary of Portfolio Allocation Balancing Account Entries for the Record Period";
- Chapter 12, Attachment A, "Final Joint Proposal on Potential Verification Method for PG&E's Greenhouse Gas Emissions and Weighted Average Costs (WAC) for Future ERRA Compliance Filing";
- Chapter 12, Attachment B, "GHG Emissions and Costs";

- Chapter 13, “Summary of Energy Resource Recovery Account Entries for the Record Period”; and
- Chapter 15, “Review Entries Recorded in the Disadvantaged Community – Single-Family Affordable Solar Homes Balancing Account and the Disadvantaged Community – Single-Family Affordable Solar Homes Memorandum Account.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF ALVA J. SVOBODA

Q 1 Please state your name and business address.

A 1 My name is Alva J. Svoboda, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 My position is Principal Analyst, Market Design Integration in the Short-Term Electric Supply Department at PG&E. I am responsible for supporting the optimization of short-term operations.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Mathematics from University of California, Santa Barbara in 1980; a Master of Science degree in Operations Research from University of California, Berkeley in 1984; and a Doctorate in Operations Research from University of California, Berkeley in 1992. I joined PG&E in 1997 and have worked in Short Term Electric Supply from that time to the present.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 1, "Least-Cost Dispatch and Economically-Triggered Demand Response":
  - Sections A, B, and D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF JOMO THORNE

Q 1 Please state your name and business address.

A 1 My name is Jomo Thorne, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Sr. Manager of Demand Response Operations and Programs. In this role I lead a team of Program Managers and support staff responsible for designing, marketing, and operating PG&E's Demand Response Program portfolio.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in History from Harvard University in Cambridge, Massachusetts. I also received a Master of Business Administration, and a Master of Public Policy from the University of Michigan. In 2008, I joined PG&E and have since held various positions of increasing responsibility, including Renewable Transactor where I negotiating renewable energy power purchase agreements with third-party developers; Manager of Renewable and Clean Energy Strategy in the run up to implementation of California's 33 percent Renewable Portfolio Standard law; Manager of Value Based Reliability via which I conducted a comprehensive review of power plant outage scheduling business processes, and governance, across merchant and operational lines of business and implemented broad change-management strategy; and Manager of Market Initiatives Implementation where I was charged with implementing California Independent System Operator initiatives that impact the design, policy, and operations of California's wholesale energy markets, as well as conducting all market monitoring functions.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 1, "Least-Cost Dispatch and Economically-Triggered Demand Response":
  - Sections A, C, and D.

- Chapter 1, Attachment A, “Summary of Triggered Dispatch From Demand Response Programs”;
- Chapter 1, Attachment B, “Summary of 2022 Capacity Bidding Program Events”; and
- Chapter 1, Attachment C, “Summary of Total Energy Dispatched From Demand Response Programs.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

## PACIFIC GAS AND ELECTRIC COMPANY
## STATEMENT OF QUALIFICATIONS OF JOHN ULLOA

Q 1 Please state your name and business address.

A 1 My name is John Ulloa, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 My current title is Manager, Electric Gas Supply in the Electric and Gas Acquisition Department, which is part of the Energy Policy and Procurement organization. I am responsible for physical and financial trading of gas in support of PG&E’s utility-owned generation plants and PG&E’s tolling agreements.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Economics and Business Administration from Saint Mary’s College of Moraga, in 1995. From 1998 to present, I have been employed by PG&E in various positions, including Financial Portfolio Manager in Electric Gas Supply, and currently Manager in the Electric Gas Supply Department.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 6, “Generation Fuel Costs and Electric Portfolio Hedging”:
  - Sections A and B; and
- Chapter 6, Attachment A, “Generation Fuel Costs.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

**PACIFIC GAS AND ELECTRIC COMPANY**
**STATEMENT OF QUALIFICATIONS OF ERIC A. VAN DEUREN**

Q 1 Please state your name and business address.

A 1 My name is Eric A. Van Deuren, and my business address is Pacific Gas and Electric Company (PG&E or the Company), 12840 Bill Clark Way, Auburn, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Senior Director of Hydro Operations and Maintenance (O&M) in PG&E's Power Generation department responsible for O&M of PG&E's hydro generation facilities. In this position, my responsibilities include leading the operating and maintenance of the Company's hydroelectric facilities.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science in Civil and Environmental Engineering from the University of Wisconsin, Madison, in 1990. I am a Licensed Professional Engineer in California. Prior to joining PG&E in 2013, I spent 23 years at Mead & Hunt, Inc., starting out as an entry-level Engineer in 1990, progressing to the position of Vice President and Group Leader of Water Resources, and serving on the Board of Directors for eight years. During my tenure at Mead & Hunt, I specialized in dam safety work; participated in, or acted as, the Federal Energy Regulatory Commission (FERC)-approved Independent Consultant for over 120 FERC Part 12 inspections; and performed engineering evaluations, and design, and on many dam and hydropower-related projects. I joined PG&E Power Generation in 2013, as Senior Manager of Project Engineering (including both project engineering and project management); moving into the role of Safety, Quality and Standards Director for Power Generation in 2015, moving into role of Director of Engineering for Power Generation in 2018, and moving to my current position as Senior Director of Hydro Operations and Maintenance in 2020.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 2, “Utility-Owned Generation:  Hydroelectric”;
- Chapter 2, Attachment A, “PG&E Powerhouses and Generating Units”; and
- Chapter 6, “Generation Fuel Costs and Electric Portfolio Hedging”:
  - Sections A and D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF ALAN WECKER

Q 1 Please state your name and business address.

A 1 My name is Alan Wecker, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Manager in the Energy Policy and Procurement Department. I am responsible for managing the financial position of PG&E's electric portfolio.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Psychology from Pitzer College, in 2008 and a Master's degree in Business Administration from the University of California, Davis in 2012. From 2014 to present, I have been employed by PG&E in various positions including Portfolio Management Analyst, Structured Energy Transactions Analyst, and Manager of Energy Transactions.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2022 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 6, "Generation Fuel Costs and Electric Portfolio Hedging":
  - Sections A, H, and I; and
- Chapter 6, Attachment A, "Generation Fuel Costs."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.