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Date: November 6, 2025
Witness(es): Various

# PACIFIC GAS AND ELECTRIC COMPANY

# 2026 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION

# ERRATA TO FALL UPDATE TESTIMONY

# (CLEAN VERSION)

PACIFIC GAS AND ELECTRIC COMPANY
2026 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
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# PACIFIC GAS AND ELECTRIC COMPANY
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## A. Introduction

In compliance with the Assigned Commissioner's Scoping Memo and Ruling,[1] Pacific Gas and Electric Company (PG&E or the Utility) submits to the California Public Utilities Commission (CPUC or Commission) and the parties in this proceeding PG&E's update to its Prepared Testimony (Fall Update). This Fall Update reflects market conditions closer to the time when 2026 rates will go into effect and updates to the forecasted year-end balancing account balances. As described further below, PG&E's Fall Update incorporates updated market and load information, changes to PG&E's portfolio, and updates to Market Price Benchmarks (MPB) used in calculations including the Power Charge Indifference Adjustment (PCIA), Ongoing Competition Transition Charge (CTC), and other Non-Bypassable Charges (NBC).[2]

## B. Background

On May 15, 2025, PG&E filed its Application (A.) 25-05-011 (hereinafter collectively referred to as Application or A.25-05-011) and served supporting Prepared Testimony seeking Commission approval of PG&E's 2026 Energy Resource Recovery Account (ERRA) and Generation NBC Forecast and Greenhouse Gas (GHG) Forecast Revenue Return and Reconciliation and adoption of its forecasted 2026 electric sales and peak load forecasts, revenue requirements and rate proposals, GHG allowance revenue return proposal, and the reasonableness review of GHG Administrative and Outreach (A&O) costs incurred in 2024 and forecasted for 2026. Preceding this Fall Update, PG&E served an errata to Prepared Testimony on August 18, 2025. Prepared

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1 "Assigned Commissioner's Scoping Memo and Ruling," issued July 31, 2025 (Scoping Memo).

2 A.25-09-015 PG&E's ERRA Trigger Application is considered in the year-end balancing account balances presented here and illustrative rates.

Testimony has preliminarily been marked as Exhibit (PGE-01) and PG&E's evidentiary motions will follow the service of this Fall Update.

On September 23, 2025, PG&E served Rebuttal Testimony addressing issues and recommendations brought forth in the testimony of Brian Dickman on behalf of the California Community Choice Association (CalCCA) and James Wilson on behalf of the Small Business Utility Advocates. PG&E's Rebuttal Testimony has preliminarily been marked as Exhibit (PGE-04).

PG&E submitted a Tier 1 Advice Letter (AL or Advice) on July 30, 2025 informing the Commission that the ERRA Trigger Balance surpassed the four percent trigger amount based on recorded balances for the June 2025 business cycle accounting close.[3] Specifically, the ERRA Trigger Balance surpassed the trigger amount for the June 2025 accounting close, and was forecast to self-correct within 120 days, anticipating that the August 2025 accounting close would constitute self-correction, and that the balance would eventually be reduced to 0.8 percent by the end of 2025.[4]

Consistent with Decision (D.) 08-08-011, PG&E later filed an ERRA Trigger Application on September 30, 2025 (A.25-09-015) because the Utility was no longer forecasting self-correction below the ERRA Trigger within 120 days.[5] In that ERRA Trigger Application, PG&E requested that timely amortization of the ERRA Trigger Balance be efficiently and expeditiously accomplished through the 2026 ERRA Forecast Application process. Subsequently, a ruling was issued in this proceeding on October 2, 2025, directing PG&E to, among other things, "incorporate all analysis related to A.25-09-015 in its Fall Update in A.25-05-011."[6] Consistent with that Ruling, PG&E's Fall Update incorporates analysis related to A.25-09-015 in its revenue requirement presentation, illustrative rates, and supporting workpapers. The Commission will hold a prehearing conference on October 20, 2025

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**3** PG&E AL 7663-E, available at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7663-E.pdf (last visited October 14, 2025).

**4** See AL 7663-E, pp. 2-3.

**5** *Id.* at pp. 3, 4. The Trigger Application is A.25-09-015.

**6** "E-Mail Ruling Addressing Trigger Application," issued by Administrative Law Judge (ALJ) Fox on October 2, 2025.

### C. Update of the 2026 Forecast Revenue Requirements

In this Fall Update, PG&E has updated its 2026 ERRA Forecast Application to a total revenue requirement of $3,261 million in addition to a revenue requirement of $1,250 million approved by the Commission in other proceedings or ALs. The inclusion of such Commission-approved costs is necessary to adopt a forecast of PG&E's electric procurement costs revenue requirement for rate setting purposes of $4,511 million. These forecast revenue requirements are presented in Table 1-1 below. Based on PG&E's assumptions as of the date of this Fall Update, PG&E's total 2026 electric procurement forecast for rate setting purposes consists of the following revenue requirements (rounded): Cost Allocation Mechanism (CAM) forecast revenue requirement of $373 million, administration/labor costs in the Voluntary Allocation Market Offer Memorandum Account (VAMOMA) of $654 thousand, PCIA forecast revenue requirement of $1,098 million,[7] Ongoing CTC forecast revenue requirement of $34 million, and an ERRA forecast revenue requirement of $2,952 million. PG&E also requests approval to recover through the Public Purpose Charge Procurement (PPCP) subaccount a forecasted revenue requirement credit of $1.7 million, the Tree Mortality Non-Bypassable Charge (TMNBC) revenue requirement of $42 million and the Bioenergy Market Adjusting Tariff (BioMAT) revenue requirement of $14 million. The Modified Cost Allocation Mechanism Balancing Account (MCAMBA) revenue requirement will not be recovered in this proceeding, until 2027, per Advice 6654-E-A.

These forecast revenue requirements currently represent PG&E's 2026 ERRA Forecast Application total revenue requirement of $4,511 million and the revenue requirement for rate-setting purposes approved by the Commission in other proceedings of $1,250 million, as shown below in Table 1-1.

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[7] This is inclusive of a $780 million overcollection comprised of PG&E's ERRA Trigger Balance as discussed Section D of this testimony.

**TABLE 1-1**
**SUMMARY OF 2026 FORECAST ENERGY PROCUREMENT REVENUE REQUIREMENTS**
**(THOUSANDS OF DOLLARS)**

| Line No. | Description | 2026 Revenue Requirement |
|---|---|---|
| 1 | CAM | $372,790 |
| 2 | Ongoing CTC | 33,736 |
| 3 | PCIA | 1,098,402 |
| 4 | VAMOMA | 654 |
| 5 | ERRA | 2,951,883 |
| 6 | PPCP | (1,723) |
| 7 | TMNBC | 41,579 |
| 8 | BioMat | 13,763 |
| 9 | Revenue Requirement for Rate Setting | $4,511,083 |
| 10 | Adjustments from Other Proceedings | |
| 11 | UOG-Related Costs | $(1,231,267) |
| 12 | RUBA-E | (19,119) |
| 13 | Adjustments from Other Proceedings | $(1,250,386) |
| 14 | 2026 ERRA Application Revenue Requirement Request | $3,260,697 |

As described in Section D below, PG&E's 2026 revenue requirements described above include PG&E's forecasted 2025 year-end balancing account balances, which utilize recorded balances through August 2025[8] and a forecast of balancing account activity from September through December 2025. Included as part of PG&E's year-end balancing account balances considered as part of the forecast 2026 revenue requirements is the ERRA Trigger over-collected balance of $700 million. To ensure that 2026 rates reflect the best estimate of year-end balances, PG&E requests permission to update all year-end balancing account forecasts presented in this Fall Update prior to implementation through the electric Annual Electric True-Up (AET) process to utilize the most recently available recorded balances. By doing so, PG&E would implement more accurate rates to take effect on January 1, 2026, which would have improved accuracy for recovering the actual year-end balances over the 2026 calendar year.

As a result of revenue requirements requested for approval in this application and PG&E's ratemaking requests, including the ERRA Trigger, the system average bundled rate—including the impact of the change in GHG

8 Including updated 2025 Final Renewables Portfolio Standard (RPS) and Resource Adequacy (RA) Adders provided by the Commission on October 1, 2025.

revenue return—would *decrease* by approximately 3.9 cents/kilowatt-hour (kWh), or 11.0 percent, to a total rate of 31.3 cents per kWh, when compared to the currently effective system average bundled rate of 35.2 cents/kWh. The system average rate for Community Choice Aggregator (CCA) and Direct Access (DA) customers, whose average rates exclude commodity charges that are provided by other service providers, would *increase* by approximately 2.9 per kWh, or 14.6 percent, to a total rate of 22.6 cents per kWh, when compared to the currently effective system average rate for DA and CCA customers of 19.7 cents per kWh.

## D. PG&E's Fall Update Compared to Prepared Testimony

PG&E's Fall Update provides refreshed System, Bundled, CCA and DA load forecasts, updated rate forecasts for the Green Tariff Shared Renewables (GTSR) Program, a revised Utility-Owned Generation (UOG)-related revenue requirement based on final Commission decisions, refreshed forward gas and electricity market prices, generation portfolio updates, Final 2025 MPBs, and Forecast 2026 MPBs for certain NBCs, updated GHG Forecast Revenue Return and Reconciliation information, and an updated estimate of year-end balancing account balances. Of note, due to changes in 2026 load forecast assumptions, PG&E is no longer able to reflect incremental data center demand as a line item on PG&E's load forecast tables. As described below, this is because the 2026 load forecast of data center demand is decreased, relative to the forecast presented in Prepared Testimony. As further described below, this forecast also reflects changes to PG&E's Slice-of-Day (SoD) consistent with PG&E's Rebuttal Testimony.

### 1. System and Bundled Sales Forecasts[9]

This Fall, the System Forecast update extended beyond the General Rate Case (GRC) Settlement requirements for agriculture sales and accounts, which are the only class forecasts generally updated between Spring and Fall. The economic outlook was especially fluid this year, and changes in data center outlook, further described below, coincided with

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9 Attached to this Fall Update testimony are witnesses' updated Statements of Qualifications correcting typographical errors concerning sections of testimony each PG&E witness sponsored in connection to the system and bundled sales forecast presentation.

lower than expected sales in the first third of 2025; consequently, in this Fall Update PG&E updated all four customer class models using the most current available information. Sales and account data were appended with data through April of 2025 and the economic drivers were obtained from the most current Moody's data delivery of April 2025 (see Table 2-1 below). PG&E re-estimated all customer class models to produce a more complete forecast update than in previous years where only the Palmer Drought Severity Index (PDSI)-related variables in the System forecast were updated. The updated information resulted in a reduction in base forecast of several percent, depending on class. In addition, an updated data center forecast was included in the final system forecast. The end result was (in some cases minor) decreases in all four customer class energy forecasts and a system sales forecast decrease of about 3.5 percent, as compared to the sales forecast set forth in Prepared Testimony.

**a. Agricultural Sales Update**

The agricultural sales forecast has been updated for the PDSI and lagged PDSI variables in accordance with a settlement from the 2020 GRC Phase II (A.19-11-019), consistent with the last few years. Further, consistent with the overall re-estimation mentioned above, the models were refitted using sales and account data through April 2025. The net result was a decrease of about 2.1 percent, relative to the Spring agricultural forecast. Table 2-3 has been updated to reflect this change.

**b. Coronavirus Effects**

PG&E notes that its commercial and residential adjustment for the novel coronavirus (COVID-19) effects has been implemented using dummy variables and a gradual return to a long-term new normal extrapolated from the dummy variable coefficient values. Consistent with the Prepared Testimony, the forecast COVID-19 effect follows an exponential recovery trajectory with constant term fitted to the coefficient values of the dummy variables. The values of this adjustment vary over time and fluctuate with recent history but generally decline as more post-COVID history (now about 5 years) is reflected in the historical record, reducing the need for such adjustment. The variables describing the recovery trajectory and the corresponding resulting percentage effects on the 2026 commercial forecast are provided in the updated workpapers supporting Table 2-3.

**c. Data Center Forecast Update**

The data center forecast was updated for the Fall Update with the best available data. While a Fall Update is not standard for load modifier forecasts, new data on the data center interconnection application queue in addition to uncertainty associated with the nascent field of data center forecasting[10] led PG&E to update the data center forecast for the 2026 load forecast. The Fall Update also addresses some questions raised in Intervenor Testimony served September 2, 2025.

Interconnection application information available to PG&E's forecast team as of July 2025[11] was used in this Fall Update, compared to data as of November 2024 used in the Prepared Testimony submitted in May. Additionally, relative to the data center forecast from PG&E's Prepared Testimony, a new constraint was introduced for this updated forecast: limiting forecasted load only to projects in the interconnection queue that had reached an advanced level of maturity. Specifically, PG&E's Prepared Testimony assumed new data center load from projects with an active application and completed or in-progress engineering studies. In contrast, PG&E's Fall Update only assumes new data center load from projects for which PG&E has identified a Business Case Customer Required Operative Date (BC CRODT) by year-end 2026. The BC CRODT is the date that PG&E has agreed to in the business case with the customer to put the project in service. Depending on the specific project, the customer is either the project sponsor or the third party requesting the interconnection. The

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**10** To the point of data center forecasting nascency: prior to this Fall Update, PG&E had only produced a data center forecast once. Similarly, the California Energy Commission (CEC) has only produced a data center forecast once.

**11** Based on the information available to the load forecasting team as of October 14, 2025, the list of projects with BC CRODTs has not changed since July 2025.

BC CRODT can be interpreted as the deadline that PG&E and the customer have agreed upon for energization. It represents our best professional judgement of energization date within the ERRA timeline (i.e., by year-end 2026). With this approach, PG&E no longer applies an application conversion factor, but all other data center forecast assumptions and methodologies to translate data center projects into sales and peak impacts (e.g., project-specific capacity ramp schedules, capacity utilization, load factor, seasonality, load shape) were unchanged from the Prepared Testimony served in May. As in PG&E's Prepared Testimony, for forecasting data center capacity in an individual year, PG&E uses the data center's expected capacity ramp schedule rather than the data center's final project capacity.

Regarding the October 6, 2025 ALJ Ruling Requiring Additional Information, PG&E wants to address the use of the data submitted in response to Question 2.d. of the ALJ's initial September 9, 2025 Ruling Requiring Additional Information. The data provided in 2.d. Attachment A in response to the September 9 ALJ Ruling—representing certain aspects of the data center interconnection application queue as of September 9, 2025—is not recommended for use in load forecasting. PG&E outlines below the primary limitations with such an approach.

1) Application Conversion Rate Calculation: The application conversion rate used in PG&E's Prepared Testimony represents the percent of applications that result in completed projects. In mathematical terms, the application conversion rate can be expressed as follows:

   *completed projects / (completed projects + withdrawn projects)*

   The Excel file known as Attachment A that was submitted in response to Question 2.d. of the ALJ's September 9 Ruling does not contain the information needed to perform the above calculation. While the Excel file contains withdrawn projects, it does not contain completed projects. The September 9th ALJ Ruling requested PG&E to produce a list of projects in the interconnection queue, which in preparing a response, PG&E interpreted as excluding completed projects because those projects are no longer in the interconnection queue.

To calculate an application conversion rate, rather than examining PG&E's pipeline of incomplete projects, it would be preferable to examine PG&E's historical list of completed data center projects and the historical list of withdrawn projects over a comparable timeframe. PG&E does not have the information to calculate such a rate at this time.

2) Interconnection Dates: For the ERRA Forecast Fall Update, the load forecasting team did not use the estimated interconnection date data from 2.d. Attachment A of the ALJ's September 9th Ruling. As mentioned in PG&E's response to Question 2.d., these dates often come from the customer directly or from the Preliminary Engineering Study (PES). Both data sources would represent interconnection dates that we consider less useful compared to the BC CRODT dates (mentioned above), which are generally later than the customer-provided and PES dates shown in 2.d. Attachment A. Note that many projects with 2026 interconnection dates in 2.d. Attachment A are in the Preliminary Engineering stage, implying a limited maturity level. Considering the 2026 ERRA Forecast year and the work and time required to plan for, engineer for, procure for, and interconnect these large load customers, it is our expectation that many of the estimated interconnection dates listed in the workpaper are earlier than the dates the projects are likely to materialize, especially in the 2026 ERRA Forecast timeframe (this, also, is mentioned in PG&E's written response to Question 2.d. of the ALJ's initial September 9, 2025 Ruling Requiring Additional Information).

3) Data Center Capacity: PG&E notes that the capacity addition data in 2.d. Attachment A from the response to the September 9th ALJ Ruling represents final capacity that a data center customer requested (i.e., when the data center is fully online and operational). Data centers typically ramp, or gradually increase, their load over a period of years. Ramp schedules (i.e., a time series of MW of

capacity per year) are needed to deduce the portion of that final capacity requested to be online in a given year.

For these reasons, the data in 2.d. Attachment A from the response to the September 9th ALJ Ruling was not used in developing the data center forecast for the Fall Update of PG&E's 2026 ERRA Forecast Application. We believe the methodology and data that we used instead, described in the previous paragraphs, will result in a more accurate load forecast than the approach described in the October 6, 2025 ALJ Ruling Requiring Additional Information.

As part of its updated forecast, PG&E did not change its assumptions surrounding backup generation or load flexibility at data centers as PG&E is not aware of any backup generation operations at data centers that would affect its 2026 ERRA load forecast. PG&E clarifies that, for forecasting purposes, it is standard practice in California to consider event-based Demand Response as a supply-side resource rather than a load modifying, demand-side resource. Supply-side resources, including Demand Response, are addressed in Chapter 5 of PG&E's Prepared Testimony. Backup generation running during power failure events has no impact on PG&E sales or peak as, by definition, PG&E cannot serve electricity during the power failure.

The updated data center forecast is lower than that from PG&E's Prepared Testimony because of:

1) Changes to the data center interconnection application queue and the added maturity constraint mentioned above. The result is a reduction in the number of data center applications that PG&E forecasts for 2026.
2) A better understanding of the current load of some data center projects. As the data center forecast is incremental to 2024, an increase in data center load in 2024 (compared to what was assumed in Prepared Testimony) reduces the amount of forecasted load.

The two points mentioned above reduce the data center forecast to the point that explicitly sharing data center forecast data would not comply with the "15/15" Rule first adopted in CPUC D.97-10-031.

Specifically, the data center forecast for the Fall Update is based on fewer than 15 customer applications and multiple customers represent greater than 15 percent of the total load. This was not the case for the data center forecast used in the Prepared Testimony submitted in May. Consequently, no data center forecast results are shared here nor in Table 2-3 (i.e., lines 7 and 39 are left blank), in order to protect private customer information. Instead, PG&E includes forecasted data center load in the unmitigated retail sales (line 2) and unmitigated retail peak (line 32) data in Table 2-3. Additionally, note that forecasted data center load is classified as industrial customer class.

**2. System and Bundled Peak Forecasts**

Similar to prior Fall Updates, the peak forecast model regression coefficients were not recalculated from the Prepared Testimony. As a result, the data center forecast update was the only driver modifying the system peak demand. The bundled peak tracks the system peak, but is also affected by shifts in the bundled energy share of system. The resulting updated system peak demand and bundled peak forecasts for 2026 have each declined by less than 1 percent from the May Prepared Testimony. These changes are reflected in the updated system and bundled peak forecasts for 2026 shown in Table 2-3.

**3. Departing Load Forecast**

**a. Municipal, Split-Wheeling, Customer Generation, and New Western Area Power Administration Forecasts**

In PG&E's Prepared Testimony, Table 2-2 included historical Departing Load (DL) data through the first quarter of 2024 in five categories,[12] excluding CCA and DA customers, with a note that the information in the table would be updated in PG&E's Fall Update. Table 2-2 has been updated to include recorded data through the first quarter of 2025.

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[12] The five DL types that rely on historical annual sales estimates include: (1) Transferred Municipal, (2) New Municipal, (3) Customer Generation, (4) New Western Area Power Administration, and (5) Split-Wheeling.

### b. CCA and DA Forecasts

CCA and DA forecasts have been updated with new information regarding CCA load from the Fall Meet and Confer process with CCAs.[13] PG&E has accepted the sales forecasts of all CCAs for this Fall Update.

Relative to PG&E's May Prepared Testimony, departing load changes that are captured in PG&E's ERRA Fall Update include:

1) Changes in CCAs' own load forecasts. Also, as mentioned above, PG&E accepted the sales forecasts of all CCAs as opposed to 11 in the Prepared Testimony.
2) Compared to the Prepared Testimony, a reduction in CCA data center load and the number of CCAs with data center load, as a result of the system-level reduction in data center load (discussed in Section 1.c.). Additionally, CCAs started reflecting some data center growth in their territories. With data center growth now being incorporated in CCA's forecasts, PG&E's and CCA's load forecasts are now more aligned.
3) Some data center growth occurs on sites that are currently served by Energy Service Providers (ESP). In the 2026 ERRA Forecast, all of these sites considered are currently in CCA territories. In the Prepared Testimony filed in May, no data center growth was associated with ESPs.

Regarding the third point, PG&E's Fall Update assumes that data center growth on sites that are currently served by ESPs will continue to be served by ESPs in 2026. Due to the data center load growth on sites currently serviced by ESPs, total DA load forecast in 2026 totals 11,414 gigawatt-hours (GWh)—slightly above the current cap of 11,393 GWh. Given the current DA cap, PG&E welcomes further guidance from the CPUC to clarify rules regarding future data center growth on existing ESP sites. Tables 2-2 and 2-3 have been updated to reflect all the departing load changes discussed in this section.

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[13] See, Decision D.16-12-038, Ordering Paragraph (OP) 3 (establishing a collaboration process between PG&E and CCAs in PG&E's service territory).

### 4. Modification to the Slice-of-Day RA Position Calculation Framework

In its Prepared Testimony, PG&E proposed a SoD framework for calculating the bundled portfolio's position across each of the 24-hourly slices in a month. This framework incorporates a storage heuristic designed to optimize the charging and discharging of energy storage resources across all hours, aiming to minimize the SoD open positions while satisfying RA charging sufficiency requirements. However, since the PCIA ratemaking process ultimately requires a single annual retained RA position and the application of a single annual MPB, PG&E introduced a method necessary to collapse the hourly positions into monthly values. In Prepared Testimony, PG&E proposed a weighting scheme based on the CEC's California Independent System Operator (CAISO) load forecast, which is also used to derive individual Load Serving Entities' SoD requirements.

In response to concerns raised by CalCCA regarding the level of retained RA under PG&E's initial proposal, primarily for battery storage resources, PG&E's Rebuttal Testimony introduced an alternative weighting scheme that places a weight of 100 percent on the portfolio's SoD position during the peak hour and 0 percent on the other 23 SoD hours. For the purposes of the Fall Update, PG&E applied this peak-hour weighting approach to calculate the retained RA volumes used in determining the PCIA revenue requirement.

While PG&E's revised proposal determines the amount of RA retained based on PG&E's storage optimized SoD position during the CAISO peak hour of each month, embedded within the single monthly values that result from the weighting calculation are PG&E's 24 SoD positions in each month that are presented in Tables 4-6 through Table 4-17 and Tables 5-4 through 5-15 presented in this Fall Update. That means while PG&E's revised proposal determines the retained RA quantities based on PG&E's SoD position during the CAISO peak hour of each month, the result from that weighting captures the SoD position volumes for all of the other 23 SoD positions in each month since the resources being retained during the

CAISO peak hour are also delivering RA supply across all of the SoD hours.[14]

**5. Renewables Portfolio Standard Sales**

PG&E's Prepared Testimony submitted in May reflected 2,300,000 megawatt-hours (MWh) of Renewable Energy Credit (REC) sales for 2026 delivery from PG&E's Voluntary Allocation share. PG&E's recent REC solicitation resulted in 250,000 MWh of sales for 2026 delivery. In AL 7681-E, PG&E determined these sales would be delivered from PG&E's overall PCIA Renewables Portfolio Standard (RPS)-Eligible portfolio, not from its own Voluntary Allocation share. Thus, in this Fall Update, sales revenues from the transactions approved by AL 7681-E will result in credit to costs recorded to Portfolio Allocation Balancing Account (PABA), and not ERRA. PG&E determined selling from the overall PCIA RPS-Eligible portfolio would reduce risk to bundled customers driven by MPB volatility.

**6. Voluntary Allocation Market Offer and Request for Information Processes and Revenue Requirement**

In this Fall Update, PG&E is updating the Voluntary Allocation Market Offer (VAMO)-related tables to present recorded costs from September 2024 through August 2025 to $645,770. The VAMOMA contains accrued costs that PG&E seeks to recover and the breakdown of the costs by month and year can be found in Tables 12-6.

The main areas that had increases since the Prepared Testimony was submitted are: (1) continuation of Information Technology (IT) and systems workstreams focused on ongoing maintenance as needed to ensure the implementation of VA and MO processes, (2) ongoing back-office work related to contract management, settlement invoicing, calculations and

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[14] Certain resource types may deliver zero SoD RA supply in certain hours (e.g., solar) while battery storage resources effectively contribute negative supply in terms of their charging requirement.

reconciliations, and (3) inclusion of the accrued PG&E Attorney costs through March 2025.[15]

PG&E has also updated its forecasted VAMO volumes to reflect updated 2026 Load-Serving Entity load shares and updated generation forecast volumes.

**7. Updated Electric and Gas Prices, Generation Portfolio, Hedging Costs, and Collateral Costs**

PG&E refreshed the economic dispatch modeling—described in its Prepared Testimony Chapter 4, Section B—using electric and gas price forwards calculated within 45 days of PG&E's service of the Fall Update. For this Fall Update, PG&E is using August 27, 2025 forward electricity and natural gas prices, which are summarized by month in Table 4-1.

Consistent with prior Fall Updates, PG&E has updated its generation portfolio to reflect actual and expected contract additions, as well as changes to resources in the existing portfolio. PG&E also updated hedging and collateral cost forecasts included in Tables 5-1 and 5-2. PG&E's forecasted 2026 hedging transactions are consistent with its Hedging Plan as approved in Resolution (Res.) E-5146.

Since Prepared Testimony was served in May, PG&E has executed additional RPS sales outside of the VAMO process for delivery in 2026. These sales are in accordance with the strategy laid out in PG&E's 2025 Draft RPS Plan.[16] Executed RPS sales will deliver 250 GWh in 2026. VAMO, as well as the above RPS sales, have contributed to an RPS Compliance short position of [redacted], which has been captured in PG&E's updated Minimum Retained RPS forecast for 2026.

PG&E has also executed sales of its Bundled customer share of generation from large hydroelectric resources. These sales amount to

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**15** VAMOMA expenses shown here are reconciled costs known at the time of the Fall Update. Future requests could include prior period adjustments should further reconciliations identify valid uncollected costs for the period of August 2024 through September 2025.

**16** Executed RPS energy and REC sales will be sold from the entirely of the PCIA-eligible portfolio.

200 GWh to be delivered in 2026 and such transactions are reflected in this Fall Update.

### 8. Generation NBCs

PG&E updated the 2026 forecast revenue requirements associated with the following Generation NBCs that were impacted by updated UOG-related costs and MPBs: Chapter 7 (CAM), Chapter 8 (PCIA and Ongoing CTC), Chapter 10 (BioMAT), and Chapter 11 (ERRA). The tables and forecasts for the revenue requirements reflected in the above chapters have been updated to reflect the following changes from the May Prepared Testimony:

a) The final MPBs for 2025 and the 2026 forecast MPBs for the Energy Index, RA Adder, and RPS Adder provided by Energy Division on October 1, 2025, are applied as authorized in D.19-10-001, modified in D.22-01-023, and D.25-06-049 in the calculations for PCIA, Ongoing CTC, BioMAT, ERRA, and PPCP; and

b) Included the electric generation revenue requirement associated with 2022 WMCE A.22-12-009, authorized by the Commission in D.25-09-008.

### 9. Updated MPBs

The updated MPBs provided by the CPUC's Energy Division are provided below, along with a description of each.

**TABLE A**
**2025 FINAL PCIA ADDERS FOR PG&E**

| Line No. | Description | Benchmarks |
|---|---|---|
| 1 | Resource Adequacy ($/kilowatt (kW)-month) | |
| 2 | System RA | $11.21 |
| 3 | Local RA – PG&E | $11.21 |
| 4 | Local RA – Southern California Edison Company (SCE) | $11.21 |
| 5 | Local RA – San Diego Gas & Electric Company (SDG&E) | $11.21 |
| 6 | Flexible RA | $11.21 |
| 7 | Renewables ($/MWh) | |
| 8 | RPS | $63.86 |

**TABLE B**
**2026 FORECAST PCIA ADDERS FOR PG&E**

| Line No. | Description | Benchmarks |
|---|---|---|
| 1 | <u>Energy Index ($/MWh)</u> | |
| 2 | On Peak | $50.20 |
| 3 | Off Peak | $52.31 |
| 4 | <u>Resource Adequacy ($/kW-month)</u> | |
| 5 | System RA | $11.53 |
| 6 | Local RA – PG&E | $11.53 |
| 7 | Local RA – (SCE) | $11.53 |
| 8 | Local RA – (SDG&E) | $11.53 |
| 9 | Flexible RA | $11.53 |
| 10 | <u>Renewables ($/MWh)</u> | |
| 11 | RPS | $62.45 |

<u>Energy Index</u>

- Separate values for each Investor-Owned Utility (IOU) based on Platts average peak- and off-peak market indices for North of Path-15 and South of Path-15.

<u>RA Adder</u>

- <u>*System* RA</u> – Single price for all IOUs based on transacted RA not used for local or flexible RA purposes;
- <u>*Local* RA</u> – Separate prices for each IOU Transmission Access Charge area based on transacted RA to fulfill local RA requirements; and
- <u>*Flexible* RA</u> – Single value for all IOUs calculated using transacted flexible RA not used for local RA requirements.

<u>RPS Adder</u>

- Single value for all IOUs based on index-plus Portfolio Content Category-1 RPS energy transactions.

**10. Updated 2025 End-of-Year Balancing Account Forecasts**

PG&E has updated the recorded data through August 2025 and the balance of year forecast for September through December 2025, as reflected in Table 12-1. The following sections provide additional details regarding the forecast balances of the PABA and ERRA, as well as ERRA Trigger-related updates.

### a. 2025 Forecast Year-End PABA

The 2025 year-end PABA balance, before balance transfers from other balancing accounts is forecast to be under-collected by $2,240 million.[17] The primary drivers for the undercollection are presented in Table 12-3, as follows.

[17] See Table 12-1, line 5, Column D.

**TABLE 12-3**
**PRIMARY DRIVERS FOR PABA UNDERCOLLECTION SUMMARY**
**(MILLIONS OF DOLLARS)**

| Line No. | Description | | Approximate Impact (Over)/Under Collection |
|---|---|---|---|
| 1 | Lower Expected CAISO Revenues | | |
| | (a) Lower Market Electricity Prices | $430 | |
| | (b) Less Generation From PCIA eligible Resources | 105 | |
| | | | $535 |
| 2 | Greater Net Procurement Costs | | |
| | (a) Lower Net RA Transaction Revenues | 545 | |
| | (b) Higher Energy Storage Contract Costs | 80 | |
| | (c) Lower Natural Gas Fired Generator Costs | (85) | |
| | (d) Procurement Related Credits not in the Forecast | (110) | |
| | | | 430 |
| 3 | Lower Retained RPS Value | | |
| | (a) Lower 2025 final RPS adder | 65 | |
| | (b) Lower Retained RPS quantity | 120 | |
| | | | 185 |
| 4 | Lower Retained RA Value | | |
| | (a) Lower 2025 final RA adder | 630 | |
| | (b) Lower Retained RA quantity | 415 | |
| | | | 1,045 |
| 5 | Higher/(Lower) recorded balances brought forward from 2024 | | |
| | (a) PABA | 80 | |
| | (b) ERRA | (70) | |
| | | | 10 |
| 6 | Balancing Account Interest | | 40 |
| 7 | Other | | (6) |
| **8** | **Forecast 2025 year-end PABA balance, before Balance Transfers** | | **$2,240** |

### 1) Lower Expected CAISO Revenues

The lower expected CAISO revenue of approximately $535 million is attributable to the following:

#### a) Lower Market Electricity Prices

Average 2025 CAISO market electricity prices for PG&E's PCIA eligible resources are expected to be approximately 25 percent lower than the 2025 Energy Benchmark (brown power), resulting in a reduction of CAISO revenues of approximately $430 million. The decrease in CAISO electricity prices is partially driven by lower-than-expected natural gas prices, which have been approximately 20 percent lower on average than the 2025 PG&E Citygate forward prices adopted in D.24-12-038 for January through August and are projected to be approximately 25 percent lower on average for September through December.

#### b) Less Generation From PCIA-Eligible Resources

Generation from PCIA eligible resources is forecasted to be approximately 2,100 GWh less than the forecast adopted in D.24-12-038. The reduction is primarily driven by lower-than-expected generation from solar resources for January through August. This net decrease in generation represents an approximately $105 million decrease in CAISO market revenues.

### 2) Greater Net Procurement Costs

#### a) Lower Net RA Transaction Revenue

RA sales revenues (net of cost) are approximately $545 million lower than expected, primarily due to lower RA sale prices than forecasted in D.24-12-038.

#### b) Higher Energy Storage Contract Costs

The expected costs for Energy Storage contracts are higher by approximately $80 million, compared to what was forecasted in D.24-12-038, primarily due to a reduction in forecasted net benefits related to CAISO wholesale market power prices.

**c) Lower Natural Gas-Fired Generator Costs**

Fuel costs for natural gas-fired resources in PG&E's electric portfolio are approximately $85 million lower than expected, primarily due to lower PG&E Citygate natural gas prices compared to the prices forecasted in D.24-12-038.

**d) Procurement Related Credits Not Included in the 2025 Forecast**

Credits related to procurement that were not included in the forecast authorized by the Commission in D.24-12-038 are as follows:

- $43 million related to outages at the Diablo Canyon Power Plant, as authorized in the 2022 ERRA Compliance Decision (D.25-06-045);
- $36 million in delay damage fees collected from counterparties due to developing projects missing contractual milestones;
- Approximately $30 million of available excess RA that was transferred to the System Reliability Incremental Procurement Subaccount of New System Generation Balancing Account (NSGBA) and used to contribute towards PG&E's effective Planning Reserve Margin to provide additional summer reliability that was adopted in D.23-06-029; and

**3) RPS Market Value**

**a) Lower 2025 Final RPS Adder**

Pursuant to D.19-10-001, PG&E updated the imputed RPS market value based on the Final RPS Adder provided by the Commission on October 1, 2025. The Final RPS Adder is $63.86/MWh, or 10 percent lower than the Forecast RPS Adder authorized in D.24-12-038. This resulted in an overcollection in the retained REC and Minimum Retained RPS value of approximately $65 million.

**b) Lower Retained RPS Volume**

Lower than expected generation from RPS eligible resources resulted in an approximately $120 million undercollection in PABA retained REC value.

**4) RA Market Value**

**a) Lower 2025 Final RA Adder**

Pursuant to D.19-10-001, PG&E updated the RA Market Value to be calculated based on the Final RA Adders provided by Commission on October 1, 2025. The Final RA Adders ranged between 16 and 72 percent lower than the Forecast RA Adders authorized in D.24-12-038. This resulted in an overcollection of retained RA value of approximately $630 million.

**b) Lower Retained RA Quantity**

Retained RA value decreased approximately $415 million, primarily due to lower volumes retained from battery storage projects. The reduction is driven by both project development delays for new battery storage resources as well as the forecast volumes based on projected Effective Flexible Capacity (EFC) volumes for projects that are not located in local transmission capacity areas.[18]

**5) Higher Net Recorded PABA Undercollection Brought Forward From 2024**

The recorded net PABA undercollection, after offsetting the overcollection from ERRA, brought forward from 2024 was approximately $10 million higher than forecasted in 2025 rates primarily due to lower than forecasted customer revenue, partially offset by lower net CAISO market cost (after deducting CAISO revenues) and procurement cost.

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[18] In its 2026 ERRA Forecast, PG&E will begin limiting retained EFC forecast volumes to the maximum available Net Qualifying Capacity for battery storage resources.

#### 6) Balancing Account Interest

The primary reason for the accumulation of the $40 million Balancing Account Interest[19] was due to the higher-than-expected undercollections in PABA.

### b. 2025 Forecast Year-End ERRA

The 2025 year-end ERRA balance, before the balance transfers to/or from other balancing accounts, is forecast to be over-collected by $1,853 million. The primary drivers for the overcollection are presented in Table 12-4, as follows.

**TABLE 12-4**
**PRIMARY DRIVERS FOR ERRA OVERCOLLECTION SUMMARY**
**(MILLIONS OF DOLLARS)**

| Line No. | Description | | Approximate Impact (Over)/Under Collection |
|---|---|---|---|
| 1 | Lower Customer Revenues | | $105 |
| 2 | Lower Expected CAISO Costs | | |
| | (a) Lower Market Electricity Prices | (385) | |
| | (b) Lower Bundled Load Requirement | (275) | |
| | | | (660) |
| 3 | Greater Net Procurement Costs | | 125 |
| 4 | Retained RPS and RA | | |
| | (a) Lower Retained RPS Value | (190) | |
| | (b) Lower Retained RA Value | (1,200) | |
| | | | (1,390) |
| 5 | Balancing Account Interest | | (30) |
| 6 | Other | | (3) |
| 7 | Forecast 2025 year-end ERRA-Main balance, before Balance Transfers | | ($1,853) |

19 The recording of Balancing Account Interest is authorized by the Commission in PG&E’s Electric Preliminary Statement Part HS, line 5.ao.

**1) Lower Customer Revenues**

Customer revenue is expected to be approximately $105 million undercollected primarily due to lower recorded revenues for January through August, compared to the forecast in rates.

**2) Lower Expected Net CAISO Costs**

The lower expected net CAISO cost of approximately $660 million is attributable to the following:

**a) Lower Market Electricity Prices**

The average price for procuring bundled customer load in the CAISO energy market is approximately 25 percent lower than expected, resulting in lower CAISO costs of approximately $385 million.

**b) Lower Bundled Load Requirement**

Approximately 4,550 GWh reduction in bundled CAISO load, which reduces the CAISO procurement costs by approximately $275 million.

**3) Higher Procurement Costs**

Net impact from higher costs related to firm energy import contracts and Western Systems Power Pool (WSPP), Inc. bilateral purchase contracts,[20] partially offset by higher than forecast non-RPS-eligible hydro sales.

**4) Retained RA and RPS Market Value**

The net Retained RA and RPS Market Value overcollection of $1,390 million is primarily caused by differences between the forecast and final MPBs, which have a corresponding impact to ERRA as discussed in the drivers for PABA undercollection above.

[20] The WSPP, Inc. bilateral contract terms are less than 12 months.

**5) Balancing Account Interest**

The primary reason for the accumulation of the $30 million Balancing Account Interest is due to the higher-than-expected recorded and forecast overcollections in ERRA during the year.[21]

**c. Authorized Balance Transfers**

Consistent with prior years' ERRA Forecasts, PG&E anticipates the following balance transfers to ERRA and PABA as follows:

**1) Residential Uncollectibles Balancing Account Authorized in D.20-06-003**

As of August 2025, PG&E has recorded $19 million in the Residential Uncollectibles Balancing Account (RUBA-E).[22] As such, PG&E is expected to transfer $19 million to ERRA for recovery, authorized in PG&E's AL 4334-G-A/6001-E-A.

**2) Transfer of 2025 Forecast Year-End ERRA Balances to PABA**

After accounting for RUBA-E balance transfers discussed above, the final 2025 year-end ERRA overcollection is $1,834 million,[23] which PG&E anticipates transferring to PABA Vintage 2025 Subaccount as authorized in D.22-01-023, OP 4.

**d. ERRA Trigger**[24]

On September 30, 2025, PG&E submitted its 2025 expedited ERRA Trigger Application (A.25-09-015) informing the Commission that the Utility's ERRA balance, net of the relevant forecasted bundled service customer PABA balance (the "ERRA Trigger Balance"), is more than five percent over-collected. PG&E further stated that its ERRA Trigger Balance is not forecasted to self-correct below the four percent trigger

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[21] The recording of Balancing Account Interest is authorized by the Commission in PG&E's Electric Preliminary Statement Part CP, line 5.ak.

[22] See Table 12-1, line 7, Column D.

[23] The $1,834 million comprises of $1,853 million ERRA overcollection, less $19 million balance transfers from RUBA-E. Plus, an allowance of Revenue Fees and Uncollectibles (RF&U), the ERRA balance to be transferred to PABA is $1,857 million as reflected in Table 13-1, Column D.

[24] Calculated based on 2025 Billing Determinants authorized by the Commission in D. 24-12-038.

point within 120 days, and will be remain over-collected by December 2025.

A ruling on A.25-09-015 was issued by the ALJ on October 2, 2025 as follows:

> Given the concurrent timing and the overlapping issues in A.25-05-011 and A.25- 09-015, PG&E is directed to incorporate all analysis related to A.25-09-015 in its Fall Update in A.25-05-011. In addition, parties are directed to address any matters from A.25-09-015 in hearings and/or briefs for A.25-05-011.

Below, is an update to PG&E's ERRA Trigger Analysis based on the current forecast.

**TABLE C**
**ERRA TRIGGER UNDER-/(OVER)-COLLECTED BALANCE**
**(MILLIONS OF DOLLARS)**

| Line No. | Business Cycle Close | Bundled Share of ERRA and PABA | Dec-24 Forecast Balance Amortize in Rates | ERRA Trigger Balance | 5% Threshold Amount | Percent of prior year recorded generation revenues, excluding DWR | |
|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C)=(A)-(B) | (D) | (E)=(C)/(D/5%) | |
| 1 | Jan-25 | 117 | 112 | 5 | 216 | 0.1% | Recorded [1/] |
| 2 | Feb-25 | 133 | 104 | 29 | 258 | 0.6% | Recorded [1/] |
| 3 | Mar-25 | 42 | 94 | (52) | 258 | -1.0% | Recorded [1/] |
| 4 | Apr-25 | (6) | 87 | (93) | 258 | -1.8% | Recorded [1/] |
| 5 | May-25 | (73) | 77 | (150) | 258 | -2.9% | Recorded [1/] |
| 6 | Jun-25 | (177) | 67 | (244) | 258 | -4.7% | Recorded [1/] |
| 7 | Jul-25 | (207) | 52 | (259) | 258 | -5.0% | Recorded [1/] |
| 8 | Aug-25 | (235) | 38 | (273) | 258 | -5.3% | Recorded [1/] |
| 9 | Sep-25 | (205) | 27 | (233) | 258 | -4.5% | Revised Forecast |
| 10 | Oct-25 | (594) | 18 | (612) | 258 | -11.9% | Revised Forecast |
| 11 | Nov-25 | (676) | 10 | (686) | 258 | -13.3% | Revised Forecast |
| 12 | Dec-25 | (700) | 0 | (700) | 258 | -13.6% | Revised Forecast |

Note:

[1/] Recorded based on the monthly Activity Reports submitted to the Energy Division

The ERRA Trigger overcollection forecast in Table C above for December 2025 reaches -13.6 percent,[25] compared to -6.3 percent[26] in PG&E's expedited ERRA Trigger Application (A.25-09-015). This change is primarily driven by the current revised forecast being based on the Final RPS and RA Adders provided by the Commission on October 1, 2025, as described in PABA undercollection[27] and ERRA over-collection[28] drivers above. These adders were not available when PG&E submitted A.25-09-015 on September 30, 2025.

In A.25-09-015, PG&E did not propose to change its rates so close to the end of the year. Instead, PG&E proposed to address the overcollection as part of this 2026 ERRA Forecast Application, through the 2026 AET.[29] Pursuant to D.22-01-023, OP 4, PG&E will transfer the over-collected ERRA to the PABA Vintage 2025 Subaccount for consolidation with the balance of the PABA vintages for recovery in the bundled PCIA rates. To minimize the number of rate changes in 2026 and to provide a smoother customer rate experience, PG&E continues to propose in this Fall Update to amortize the ERRA Trigger Balance consistent with other balancing accounts through the end of 2026.

**e. Request to Update Recorded Balancing Account Balances Prior to Rate Implementation**

The forecasted 2025 year-end balancing account balances presented in this Fall Update utilize recorded balances through August 2025 and a forecast of balancing account activity from September through December 2025. PG&E has requested that the revenue requirements presented in this Application be effective January 1, 2026, concurrent with its AET. In order to implement rates that most closely tie to the actual recorded 2025 year-end balances, PG&E requests authority to update all year-end balancing account

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**25** Table C, line 12, Column E

**26** See A.25-09-015, p. A-3, Table 1, line 12, Column E.

**27** Section 10.a.4.a.

**28** Section 10.b.4.

**29** See A.25-09-015, pp. 7 and 9.

forecasts presented in this Fall Update prior to implementation through the AET process to utilize the most recently available recorded balances. PG&E proposes to continue utilizing the balancing account forecast presented in this Fall Update for months where recorded balances are not yet available. By doing so, PG&E would implement more accurate rates effective January 1, 2026, which would have a higher likelihood to recover the actual year-end balances over the course of the 2026 calendar year.

## 11. Illustrative Electric Rates

### a. Introduction

In this Fall Update, PG&E has updated the illustrative rates presented in Chapter 13 of its Prepared Testimony to incorporate changes to the electric load forecast presented in Tables 2-2 and 2-3 and to incorporate the revenue requirements presented in Table 13-1.

### b. PCIA Rates

#### 1) Proposed PCIA Rates

The PCIA revenue requirement presented in this Fall Update results in changes to base PCIA rates for all customer vintages and rate groups. As mentioned in Section 10.d of this Fall Update, PG&E's ERRA Trigger Balance is driven by an over-collection in its forecasted year-end ERRA balance, which is partially offset by the bundled service customer PABA balance. In A.25-09-015, PG&E proposed to address this over-collected ERRA balance by means of its 2026 ERRA Forecast Application through the 2026 AET. In compliance with OP 4 of D.22-01-023 and consistent with recent ERRA Forecast Applications, in this Fall Update PG&E has proposed the transfer of the forecast 2025 year-end ERRA balance to the 2025 vintage subaccount in PABA. Transferring the forecasted ERRA over-collection to the 2025 vintage subaccount in

PABA will decrease PCIA rates for vintage 2025, as shown in Table 13-2.[30]

**TABLE 13-2**
**IMPACT OF AMORTIZATION OF THE FORECASTED 2025 YEAR-END OVER-COLLECTED ERRA AND BUNDLED SHARE OF ACCUMULATED PABA BALANCES**
**(DOLLARS PER kWh)**

| Line No. | PCIA Rate Element | Average PCIA Rate Impact |
|---|---|---|
| 1 | Vintage 2025 PCIA Rate Resulting From Transfer of ERRA Overcollection to PABA | $(0.06896) |
| 2 | Vintage 2025 PCIA Rate Resulting From Bundled Share of PABA Undercollections | $0.04508 |
| 3 | Net Vintage 2025 PCIA Rate for Bundled Customers | $(0.02388) |

Table 13-3 shows PCIA rates. The PCIA rates for the 2026 vintage are applicable to bundled service customers. The California Department of Water Resources Franchise fees are included in each table.

Table 13-4 summarizes the PCIA revenues allocated to bundled and DA/CCA customers.

**TABLE 13-4**
**PCIA REVENUES ALLOCATION SUMMARY**
**(THOUSANDS OF DOLLARS)**

| Line No. | Description | Expected PCIA Revenues From PCIA Rates |
|---|---|---|
| 1 | Bundled Customers | $(362,845) |
| 2 | DA/CCA Customers | 1,461,901 |
| 3 | Total Revenues | $1,099,056 |

30 Table 13-2 has been modified to show the joint impact of the over-collected ERRA Balance, as well as the under-collections in PABA, in order to align with the instruction to include all analysis on A.25-09-015 in the Fall Update. Rate calculations shown in Table 13-2 are based on the 2026 Billing Determinant Forecast presented for approval in this Fall Update.

**c. Generation Rates**

Table 13-5 presents illustrative average generation rates based on the revenue requirements presented in Table 13-1 effective January 1, 2026. To remain consistent with the generation rates that will appear in rate schedule tariffs the generation rates presented in Table 13-5 do not include Bundled PCIA.

**d. Changes to Total Rates**

Attachment A to this Fall Update shows a comprehensive list of illustrative proposed revenues for bundled, DA, and CCA customers and the associated average present and proposed rates by schedule and functional rate component. Attachment A1 presents average rates with the impact of the GHG revenue return, while Attachment A2 presents average rates, excluding the impact of the GHG revenue return.

As a result of revenue requirements requested for approval in this Application and PG&E's ratemaking requests, the system average bundled rate—including the impact of the change in GHG revenue return—would *decrease* by approximately 3.9 ¢/kWh, or 11.0 percent, to a total rate of 31.3 ¢/kWh, when compared to the currently effective system average bundled rate of 35.2 ¢/kWh. The system average rate for DA and CCA customers, whose average rates exclude commodity charges that are provided by other service providers, would *increase* by approximately 2.9 ¢/kWh, or 14.6 percent, to a total rate of 22.6 ¢/kWh, when compared to the currently effective system average rate for DA and CCA customers of 19.7 ¢/kWh.

**12. GHG Administrative and Outreach Expenses**

In this Fall Update, PG&E has revised its 2026 forecast and 2024 recorded expenses for GHG Administrative and Outreach activities to reflect the most current information available.

As shown in Table 16-5, PG&E's 2026 A&O forecast has increased by $0.113 million, from $0.812 million in May Prepared Testimony to $0.925 million. This increase is attributed to the following changes:

a) The program administrative forecast was increased by $0.043 million to support critical modernization of the California Industry Assistance attestation site's Content Management System. This initiative involves a full system migration aimed at enhancing security, improving performance, and implementing accessibility upgrades in alignment with the Web Content Accessibility Guidelines (WCAG) and the Americans with Disabilities Act (ADA), as required by the United States Department of Justice (U.S. DOJ).[31]

b) The IT and billing system forecast was increased by $0.056 million to continue enhancements to the Small Business Climate Credit Program. These enhancements will enable PG&E to automate the distribution of credits to eligible customers, such as identification and extraction of eligible accounts, calculating the credit and applicable taxes, improving reporting capabilities, and implementing Res.E-5339's directive to exclude entities with 100 or more eligible accounts.

c) The customer outreach forecast was increased by $0.014 million to support potential Climate Credit outreach modifications, including the rebranding of Cap-and-Trade to Cap-and-Invest, as mandated by Assembly Bill (AB) 1207 (2025-2026)[32] that may result from the Commission's Order Instituting Rulemaking (OIR) to Improve the California Climate Credit.[33] This increase also reflects PG&E's outreach to inform eligible customers of their opportunity to attest to their qualification for California Industry Assistance[34] for Compliance Period 6—an activity that was inadvertently omitted from PG&E's Prepared Testimony.

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**31** WCAG Version 2.1, Level AA compliance is required under the U.S. DOJ's final rule issued in April 2024, pursuant to Title II of the ADA. The rule mandates that state and local government entities with populations of 50,000 or more must ensure their websites and mobile applications meet these accessibility standards by April 26, 2026.

**32** AB 1207 adopted modifications to California Public Utilities Code (Pub. Util. Code) Section 748.5 (b)(2) requiring the Commission to require electrical corporations to make modification to the customer outreach plan including a customer bill statement concerning savings attributable to the Cap-and-Invest Program.

**33** Rulemaking (R.) 25-07-013 (issued July 28, 2025), p. 6 includes as part of its preliminary scope "If changes are made to the Climate Credit allocation or distribution, how should these changes be communicated to customers?"

**34** Res.E-4716, OP 5.

### 13. Low Income and Disadvantaged Community Solar Programs Funded in Whole or in Part From the GHG Allowance Revenues

PG&E currently has three Clean Energy and Energy Efficiency (CEEE) programs funded in whole or in part from the sales of GHG allowances: (1) Solar on Multi-Family Affordable Housing (SOMAH); (2) Disadvantaged Community Single-Family Affordable Solar Housing (DAC-SASH); and (3) Disadvantaged Community Green Tariff (DAC-GT). Through 2024, the Community Solar – Green Tariff (CS-GT) Program was also funded in part by the sale of GHG allowances. However, D.24-05-065 issued on May 30, 2024 discontinued the CS-GT Program. Additionally, PG&E also funds the DAC-GT (and previously CS-GT) programs offered by CCAs, as applicable.

Furthermore, AB 1207, effective September 19, 2025, renders inoperative the statutory provision authorizing the Commission to allocate 15 percent of electrical corporation allowance revenue toward CEEE programs as of July 1, 2026.[35] As filed in PG&E's Opening Comments in R.25-07-013, PG&E recommends that the Commission evaluate the impact and implications of legislative changes, including those affecting funding for the CEEE programs, within the aforementioned Rulemaking.[36] PG&E anticipates that in future ERRA Forecast Applications, true-ups and/or balancing account transfers consistent with the Commission's implementation of AB 1207 may need to occur. Since the Commission has not yet implemented AB 1207, PG&E requests funding for the 2026 full program year for DAC-SASH and for PG&E and the CCAs' DAC-GT programs. Funding for the SOMAH Program is requested only for a partial year, as its scheduled conclusion is June 30, 2026, as detailed below.

In this section, PG&E uses rounded amounts in the narrative description, however, actual requested dollar amounts are reflected in the accompanying tables.

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[35] AB 1207 Section 13 (amending Section 748.5 (c) to render inoperative the Commission's authority to allocate electrical corporation allowance revenues to fund CEEE programs as of July 1, 2026).

[36] R.25-07-013, Opening Comments of PG&E (U 39 M) to OIR to Improve the California Climate Credit, filed September 26, 2025, p. 10 and p. 11.

As shown in table 17-8, PG&E's 2026 SOMAH set aside amount is $19.88 million, which is unchanged from PG&E's May application. Pursuant to D.22-09-009, if the IOUs'[37] combined forecasted GHG revenue exceeds $1 billion, the IOUs are to set aside their annual proportionate share limit of $100 million, which is $39.76 million for PG&E for a full program year.[38] However, D.20-04-012 stipulates that, through its ERRA forecast proceeding, PG&E should propose funding for the SOMAH Program until June 30, 2026. Therefore, as shown in Table 17-3 below, since the three large IOUs' combined forecasted GHG proceeds for 2026 easily exceed $1 billion, PG&E's 2026 proposed set aside for SOMAH is $19.88 million, which is half of a full program year. For simplicity, PG&E has not included the smaller IOUs. As noted, their GHG proceeds will be included in the upcoming SOMAH True-Up AL—where it is needed to calculate 2025 true-ups.

**TABLE 17-3**
**IOU GHG PROCEEDS TO DETERMINE SOMAH SHARE METHODOLOGY**

| Line No. | IOU | 2024 Recorded GHG Proceeds | 2025 Forecasted GHG Proceeds[(a)] | 2026 Forecasted GHG Proceeds |
|---|---|---|---|---|
| 1 | PG&E | $576,556,216 | $593,068,333 | $704,046,796 |
| 2 | SCE | 819,525,252 | 638,360,474 | 682,213,540 |
| 3 | SDG&E | 223,553,623 | 198,958,067 | 207,853,428 |
| 4 | Total | $1,619,635,091 | $1,430,386,874 | $1,594,113,764 |

(a) 2025 Forecasted GHG Proceeds includes partial year actual recorded values, plus forecast for later months for PG&E, SCE, and SDG&E, as reported to PG&E on September 29, 2025. The final 2025 Recorded GHG Proceeds for all IOUs, including PacifiCorp and Liberty, will be updated in the True Up AL to be filed by March 1, 2026.

Pursuant to D.20-04-012, Table 17-4 below shows a true-up of the prior years' authorized SOMAH set-aside amounts compared to actual auction revenues, presented in the same format as the untitled table in D.20-02-047 at p. 20. The amounts presented for 2025 include a forecast for the

37 IOUs include: PG&E, SCE, SDG&E, Liberty Utilities (CalPeco Electric), PacifiCorp dba Pacific Power (PacifiCorp).

38 D.22-09-009, Table 2, p. 11 and OP 3, p. 14.

remainder of 2025 and are presented for informational purposes. The final 2025 true-up will be presented in the true-up AL to be submitted by March 1, 2026, as described below.

**TABLE 17-4**
**SOMAH SET ASIDE AMOUNTS**

| Line No. | Year | Recorded GHG Allowance Revenues | Set Aside Based on 10% of Recorded GHG Revenue or $100 million limit | Actual Set Aside[a] | Difference (Actual Set Aside – 10% Set Aside or $100 million Limit)[e] |
|---|---|---|---|---|---|
| 1 | 2016[b] | $301,670,155 | $15,083,508 | $15,083,508 | – |
| 2 | 2017 | 345,513,934 | 34,551,393 | 34,551,393 | – |
| 3 | 2018 | 348,098,763 | 34,809,876 | 34,809,876 | – |
| 4 | 2019 | 389,040,958 | 38,904,096 | 38,904,096 | – |
| 5 | 2020 | 385,893,957 | 38,589,396 | 38,589,396 | – |
| 6 | 2021 | 384,773,215 | 34,518,517 | 34,518,517 | – |
| 7 | 2022 | 486,243,930 | 34,816,563 | 34,816,563 | – |
| 8 | 2023 | 544,616,174 | 34,626,367 | 34,626,367 | – |
| 9 | 2024[c] | 576,556,216 | 35,074,821 | 39,757,379 | $4,682,558 |
| 10 | 2025[d] | 593,068,333 | 40,856,720 | 39,757,379 | (1,099,341) |
| 11 | Total | $4,355,475,636 | $341,831,257 | $345,414,474 | $3,583,217 |

Note: Totals may not add exactly to line items due to rounding.

(a) Years 2016 through 2023 include already-executed true ups: Years 2016-2018 include true-ups for previous under-collections, which were collected in 2020 ($29.52 million) per D.20-02-047 and 2021 ($4.45 million) per D.20-12-038. Year 2019 includes the true-up ($1.17 million under-collected), which was collected in 2019. Year 2020 includes the true-up ($187 thousand over-collected) which was netted in 2022 per D.22-02-002. Year 2021 includes the true-up ($2.91 million over-collected), which was netted in 2023 per D.22-12-044. Year 2022 includes the true-up ($11.59 million over-collected), which was netted in 2024 per D.23-12-022. Year 2023 includes the true-up ($5.13 million over-collected), which was netted in 2025 per D.24-12-038. Year 2024 is the actual set aside performed quarterly in 2024 based on the forecast approved in D.23-12-022. Year 2025 is the actual set aside performed quarterly in 2025 based on the forecast approved in D.24-12-038.

(b) AB 693 implemented SOMAH mid-way through 2016; therefore, GHG Revenue and set aside amounts are pro-rated 50 percent and totals reflect the pro-rated amounts.

(c) Based on 2024 recorded GHG allowance revenues and the IOU $100 million cap, PG&E over-forecasted the 2024 set aside by $4.68 million per AL 7521-E-B. PG&E requests to enact the true-up in 2026 by netting the 2024 over-collection of $4.68 million from the 2026 SOMAH set aside request.

(d) 2025 line is preliminary: 2025 Recorded GHG Allowance Revenue includes January through August recorded, plus September through December forecast. The 2025 set aside based on the $100 million limit is $39,757,379. Pursuant to D.20-04-012 and D.22-09-009, the IOUs will submit a Tier 1 AL that includes the true-up amount including the final four months of 2025 by March 1, 2026. Based on the final 2025 true up amount, PG&E will enact the 2025 true up in its 2027 ERRA Forecast filing.

(e) To align with the format of AL 7251-E-B this column displays an over-collection in the SOMAH Program as a positive and an under-collection as a negative. This differs from Table 17-8, where an over-collection is presented as a negative and an under-collection is presented as a positive.

Pursuant to D.20-04-012 and D.22-09-009, by March 1, 2026, the IOUs will submit a Tier 1 AL that includes the true-up amount for the final four months of 2025. If, as expected, SOMAH funding based on 10 percent of actual GHG proceeds from all five IOUs exceed $100 million, PG&E will perform the true-up based on its proportionate share of allowance sale proceeds over the previous four quarters.[39]

There are no changes to the DAC-SASH or DAC-GT set aside from PG&E's May 2025 Prepared Testimony. However, summary information and tables associated with PG&E and the CCAs' DAC-GT and CS-GT 2026 funding requests and 2024 true-ups are incorporated below for consistency and completeness.

As described in PG&E AL 6308-E,[40] the California Air Resources Board (CARB) prohibits using GHG funds to deliver volumetric discounts. Beginning with its 2022 ERRA Forecast filing, generation costs are funded from GHG proceeds and all other costs (bill discounts and administration) are funded from Public Purpose Program (PPP) funds for both PG&E and the CCAs' DAC-GT programs. PG&E intends to put into 2026 rates the budget requests from PPP funds, in accordance with approved budget ALs, in its upcoming AET.[41]

PG&E filed its DAC-GT budget for Program Year (PY) 2026 and prior year (2024) true-ups for DAC-GT and CS-GT in AL 7554-E,[42] as shown in Table 17-5 below. In 2024, in response to the Commission's discontinuation of CS-GT in D.24-05-065, PG&E ended the CS-GT Program. By the end of Q3 2025, PG&E completed its closure of the CS-GT balancing account. This included transferring a net amount of $(9 million) as follows: $(3.3 million) of unspent PPP funding went to the DAC-GT balancing

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**39** D.17-12-022, OP 7, pp. 69-70.

**40** This is consistent with PG&E AL 6308-E, available at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6308-E.pdf (last accessed October 14, 2025).

**41** PG&E's AET AL establishing rates for January 1, 2026 will reflect final Commission decisions in effect as of the end of 2025. PG&E's preliminary AET will be submitted on November 15, 2025.

**42** See PG&E AL 7554-E, available at: ELEC_7554-E.pdf (last accessed October 14, 2025).

account in Q3 2025, and $(5.8 million) of unspent GHG auction revenue went back to the GHG revenue balancing account earlier in Q1 2025.

**TABLE 17-5**
**FUNDING REQUESTS FOR PG&E'S DAC-GT AND CS-GT PROGRAMS**

| | | PPP | | GHG | | |
|---|---|---|---|---|---|---|
| Line No. | PG&E Program | 2024 True-Up[(a)] | 2026 Funding[(b)] | 2024 True-Up[(a)] | 2026 Set Aside | Total |
| 1 | DAC-GT | $(1,663,347) | $12,312,335 | $2,174,665 | $11,334,222 | $24,157,875 |
| 2 | CS-GT[(c)] | – | | (5,938,644) | | (5,938,644) |
| 3 | Total | $(1,663,347) | $12,312,335 | $(3,763,979) | $11,334,222 | $18,219,231 |

(a) The 2024 DAC-GT PPP and GHG true-ups are final actuals-based as described in the approved PG&E Budget AL 7554-E-A.

(b) This is a sum of the five budget line items (20 percent bill discount, program management costs, IT costs, program evaluator costs, and CCA integration costs) in AL 7554-E to be funded from PPP. This does not include any CCA PPP True-Up costs.

(c) The 2024 CS-GT PPP True-Up resulted in an overcollection of ($87,230). Since the CS-GT Program concluded in 2024, and consistent with the 2026 budget AL filed on April 1, 2025, both the ($87,230) 2024 CS-GT PPP overcollection and the 2023 CS-GT PPP overcollection of ($2,215,431), totaling ($2,302,662), are deducted from the 2026 DAC-GT PPP funding request. Therefore, the 2024 CS-GT PPP True-Up is shown as $0 above. Based upon the approval of the budget AL, PG&E transferred all of the remaining CS-GT PPP balance to the DAC-GT balancing account.

Under D.18-06-027, CCAs may choose to offer their own versions of the DAC-GT Program. In PG&E's service territory, there are five CCAs with DAC-GT Programs. All have submitted 2026 budget ALs for DAC-GT.[43] DAC-GT PY 2026 funding requests and 2024 true-ups are shown in the table below for the five participating CCAs.

43 The CCAs include San Jose Clean Energy (SJCE), Peninsula Clean Energy (PCE), Clean Power San Francisco (CPSF), Marin Clean Energy (MCE), and Ava.

**TABLE 17-6**
**FUNDING REQUESTS FOR CCA PROGRAMS**

| | | PPP | | GHG | | |
|---|---|---|---|---|---|---|
| Line No. | CCA | 2024 True-Up | 2026 Funding[(a)] | 2024 True-Up | 2026 Set Aside | Total |
| 1 | MCE | $152,929 | $1,980,832 | $(426,718) | $921,536 | $2,628,579 |
| 2 | Ava | (256,746) | 2,576,901 | 622,374 | 4,326,339 | 7,268,868 |
| 3 | SJCE | (137,118) | 384,838 | (2,217) | 183,751 | 429,254 |
| 4 | PCE | 78,520 | 957,428 | 210,618 | 1,229,386 | 2,475,953 |
| 5 | CPSF | (75,561) | 449,011 | (225,895) | 256,250 | 403,805 |
| 6 | Total | $(237,976) | $6,349,010 | $178,162 | $6,917,262 | $13,206,459 |

(a) This is the sum of the bill discount, program administration subtotal, and the Marketing, Evaluation, and Outreach subtotal in the CCAs' budget ALs to be funded from PPP.

To provide a complete picture of the program funding requests, Table 17-7 below reflects the forecasted funding for CEEE programs to be recovered through PPP as described previously, which include all costs except generation costs for the DAC-GT Program for PG&E and the CCAs. PG&E intends to put into rates $16.05 million, plus associated RF&U from PPP funds in 2026 via the upcoming AET.

**TABLE 17-7**
**FORECASTED PPP FUNDING FOR CEEE PROGRAMS**

| Line No. | CEEE Program PPP Funding Request[a] | 2025 | 2026 |
|---|---|---|---|
| 1 | PG&E's DAC-GT | $6,872,838 | $12,312,335 |
| 2 | PG&E's CS-GT | – | – |
| 3 | PG&E's DAC-GT 2023 True-Up | 2,750,370 | – |
| 4 | PG&E's CS-GT 2023 True-Up[b] | – | – |
| 5 | PG&E's DAC-GT 2024 True-Up | – | (1,663,347) |
| 6 | PG&E's CS-GT 2024 True-Up[b] | – | – |
| 7 | CCAs' DAC-GT and CS-GT | 6,068,943 | 6,349,010 |
| 8 | CCAs' DAC-GT and CS-GT 2023 True-Up | 332,928 | – |
| 9 | CCAs' DAC-GT and CS-GT 2024 True-Up | – | (237,976) |
| 10 | 2023 CCA Disbursement Reconciliation to PG&E | 34,195 | – |
| 11 | 2024 CCA Disbursement Reconciliation to PG&E | – | (714,507) |
| 12 | Total PPP Funds | $16,059,274 | $16,045,516 |

(a) DAC-GT and CS-GT costs except generation costs are funded from PPP.

(b) The 2023 and 2024 CS-GT PPP true-ups resulted in an overcollection of ($2,215,431) and ($87,230), respectively. Since the CS-GT Program concluded in 2024, and consistent with the 2026 budget AL filed on April 1, 2025, both overcollections, totaling ($2,302,662), are deducted from the 2026 DAC-GT PPP funding request. Therefore, the 2023 and 2024 CS-GT PPP true-ups are shown as $0 above. Based upon the approval of the budget AL, PG&E transferred all of the remaining CS-GT PPP balance to the DAC-GT balancing account.

Table 17-8 below lists the program-by-program 2025 and 2026 set-aside amounts from GHG funding. PG&E’s and the CCAs’ DAC-GT and CS-GT set asides from GHG funds include generation resource costs only.

**TABLE 17-8**
**FORECASTED GHG FUNDING FOR CEEE PROGRAMS**

| Line No. | CEEE Program GHG Set Aside[a] | 2025 | 2026 |
|---|---|---|---|
| 1 | SOMAH | $39,757,379 | $19,878,689 |
| 2 | SOMAH 2023 True-Up[b] | (5,131,012) | – |
| 3 | SOMAH 2024 True-Up[c] | – | (4,682,558) |
| 4 | DAC-SASH | 4,370,000 | 4,370,000 |
| 5 | PG&E's DAC-GT | 4,742,848 | 11,334,222 |
| 6 | PG&E's CS-GT | – | – |
| 7 | PG&E's DAC-GT 2023 True-Up | (2,883,049) | – |
| 8 | PG&E's CS-GT 2023 True-Up | (5,818,644) | – |
| 9 | PG&E's DAC-GT 2024 True-Up | – | 2,174,665 |
| 10 | PG&E's CS-GT 2024 True-Up | – | (5,938,644) |
| 11 | CCAs' DAC-GT and CS-GT | 3,944,204 | 6,917,262 |
| 12 | CCAs' DAC-GT and CS-GT 2023 True-Up | (679,154) | – |
| 13 | CCAs' DAC-GT and CS-GT 2024 True-Up | – | 178,162 |
| 14 | Total GHG Funds | $38,302,572 | $34,231,799 |

(a) DAC-GT and CS-GT GHG set asides will be used for generation resource costs only.

(b) Pursuant to Table 17-4, PG&E's proportional share of 2023 SOMAH funding was $34.63 million, resulting in an over-collection of $5.13 million. This $5.13 million credit amount is not included in the CEEE allowance cap calculation for 2025 in Table 17-9.

(c) Pursuant to Table 17-4, PG&E's proportional share of 2024 SOMAH funding was $35.10 million, resulting in an over-collection of $4.68 million. This $4.68 million credit amount is not included in the CEEE allowance cap calculation for 2026 in Table 17-9.

PG&E requests to set aside $34.23 million from GHG allowance revenues for CEEE programs in 2026. This includes 2024 true-ups for the SOMAH Program, PG&E’s and the CCAs’ DAC-GT programs’ generation costs. PG&E excludes these true-ups from the 15 percent cap calculation for 2026 since they are associated with prior years. Instead, PG&E has confirmed that these 2024 true-up amounts are within the 15 percent cap as applied in the relevant year.

Total available CEEE funds for 2026 based on 15 percent of forecasted GHG allowance revenues are $105.61 million. Excluding prior year true-ups and carryovers, the forecasted set asides from GHG revenues for PY 2026 total $42.50 million, which is below the CEEE cap of $105.61 million for 2026. Table 17-9 below reflects the CEEE 15 percent cap for GHG funds.

**TABLE 17-9**
**GHG ALLOWANCE FOR CEEE PROGRAMS**

| Line No. | Clean Energy and Energy Efficiency Program Set Aside | 2024[b] | 2025 | 2026 |
|---|---|---|---|---|
| 1 | CEEE 15 Percent Allowance From GHG Funds[a] | $86,483,432 | $88,960,250 | $105,607,019 |
| 2 | SOMAH | 35,074,821 | 39,757,379 | 19,878,689 |
| 3 | DAC-SASH | 4,370,000 | 4,370,000 | 4,370,000 |
| 4 | PG&E's DAC-GT | (2,174,665) | 4,742,848 | 11,334,222 |
| 5 | PG&E's CS-GT | (5,938,644) | – | – |
| 6 | CCAs' DAC-GT and CS-GT | 2,399,586 | 3,944,204 | 6,917,262 |
| 7 | CEEE Programs Funds Subtotal | $38,080,428 | $52,814,431 | $42,500,173 |
| 8 | Remaining CEEE Funds (line 1 – line 7) | $48,403,004 | $36,145,819 | $63,106,846 |

(a) 15 percent of line 5 in Table 17-1.

(b) 2024 is the only year that is fully trued-up: includes true-ups for SOMAH and PG&E's and the CCAs' DAC-GT and CS-GT programs.

For 2026, it is forecasted that $63.11 million remain available for CEEE programs funded from GHG proceeds.

### 14. Forecast 2026 GHG Revenue Return Calculation

PG&E revised its forecasted 2026 GHG Allowance Revenue Return and Distribution to customers as follows:

1) Updated its 2026 forecast proxy GHG allowance price to reflect the August 27, 2025 settlement price of the Intercontinental Exchange California Carbon Allowance futures contract with a 2026 vintage year;
2) Updated the amount set aside to cover the GHG A&O expenses described in Section 12 above;
3) Updated its Clean Energy and EE Funds set aside to reflect the amounts described in Section 13 above;
4) Updated its year-end forecast balance to GHG Revenues Sub Account, within the GHG Revenue Balancing Account, to reflect the recorded balance through August 31, 2025 and a forecast revenue and cost for the balance of the year;
5) Pursuant to the GHG Climate Credits OIR (R.20-05-002), the allocation of Emissions-Intensive and Trade-Exposed (EITE) returns will be given to all EITE-eligible customers until the CARB takes over the distribution to the large customers it manages; and

6) Pursuant to Res.E-5339, recipients with 100 or more eligible accounts are no longer eligible to receive the Small Business California Climate Credit (CCC) on any account.

The revised total GHG allowance revenue return available for amortization in rates over the 2026 calendar year is updated to $475 million. The semi-annual residential and small business CCC is updated to $36.18.

## E. Confidentiality

In Appendix B of the Prepared Testimony, PG&E submitted declarations attesting to the confidentiality of data presented therein. PG&E requested that the confidential information in PG&E's testimony be kept confidential, pursuant to D.06-06-066, D.14-10-033, and Pub. Util. Code Sections 454.5(g) and 583, as identified in PG&E's matrix identifying the justification for confidential treatment by chapter.

This Fall Update contains identical confidential information that is the subject of PG&E's confidentiality matrix and covered by the original declarations. PG&E asks that the same confidential treatment requested with its Prepared Testimony, apply to the information marked confidential in this Fall Update. PG&E is also proposing to redact certain third-party proprietary information.

## F. Conclusion

PG&E requests that the Commission:

1) Adopt PG&E's total 2026 electric procurement forecast of 3,261 million. When combined with $1,250 million of revenue requirements already adopted by the Commission in other proceedings, this results in a total revenue requirement for rate setting of $4,511 million. The revenue requirement for rate setting purposes consists of the following: $373 million for CAM, $654 thousand for VAMOMA, $1,098 million for PCIA, inclusive of the ERRA Trigger Balance, $34 million for Ongoing CTC, $2,952 million for ERRA, -$1.7 million for PPCP, $42 million for TMNBC, and $14 million for BioMAT. These revenue requirements will be further updated to incorporate any additional Commission adopted revenue requirements as well as forecast year-end balances with the latest available recorded actuals as of the date of the AET;
2) Adopt PG&E's 2026 electric sales and load forecast;

3) Adopt a $475 million[44] 2026 forecast GHG allowance revenue return amount, including the 2026 Semi-Annual Residential/Small Business CCC amount per household/customer of $36.18;

4) Adopt PG&E's 2026 forecast GHG A&O expenses of $0.925 million;

5) Approve PG&E's 2024 recorded GHG utility A&O expenses of $0.708 million as reasonable;

6) Approve PG&E's proposal to dispose the RUBA through the ERRA as authorized in D.20-06-003 and thereafter accumulate with the ERRA, to the PABA Vintage 2025 Subaccount in pursuant to D.22-01-023; and

7) Determine that the revenue requirements for the Fall Update adopted by the Commission, including the ERRA Trigger Balance to be credited to vintage 2025 PABA, subject to updated recorded year-end balancing account balances available as of the date of the AET are to be consolidated with other approved electric revenue requirements and rate changes through the AET process, to become effective in rates on or after January 1, 2026.

## G. Tables Appearing in Exhibit (PGE-01) Updated for the Fall Update

Consistent with prior years' filings, PG&E provides a complete set of tables in this section updated to reflect revised assumptions for this Fall Update and also provides supporting workpapers.[45]

**TABLE 2-1**
**SERVICE AREA ECONOMIC INDICATORS**

| Line No. | Economic Indicator | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|
| 1 | Real Gross Product ($ Billions) | [redacted] | | | |
| 2 | % Change | | | | |
| 3 | Total Employment (Thousands) | | | | |
| 4 | % Change | | | | |
| 5 | Real Personal Income ($ Billions) | | | | |
| 6 | % Change | | | | |

44 Inclusive of $750 thousand GHG A&O amount set-aside to true-up recorded and forecast GHG expenses (see Table 17-2).

45 For the purpose of table references, PG&E maintains consistency with its Prepared Testimony.

**TABLE 2-2**
**2026 DEPARTED LOAD SALES ESTIMATE BY CATEGORY**
**(MWh)**

| Line No. | Departing Load Category | Total DL | Ongoing CTC | PCIA | NSGC |
|---|---|---|---|---|---|
| 1 | Transferred Municipal DL[(a)] | 645,728 | 522,969 | Exempt | Exempt |
| 2 | New Municipal DL | 256,936 | – | Exempt | Exempt |
| 3 | Customer Generation DL | 15,827,629 | 217,610 | Exempt | Exempt |
| 4 | New WAPA DL | 52,586 | 2,493 | – | 2,493 |
| 5 | Split Wheeling DL | 6,527 | 6,527 | – | 6,527 |
| 6 | Direct Access less Continuous D.12-04-012 | 11,185,161 | 11,185,161 | 7,055,330 | 11,185,161 |
| 7 | Continuous DA D.12-04-012 | 228,722 | 228,722 | Exempt | 228,722 |
| 8 | Total Direct Access | 11,413,882 | 11,413,882 | 7,055,330 | 11,413,882 |
| 9 | CCA | 38,806,077 | 38,806,077 | 38,806,077 | 38,806,077 |
| 10 | Total Departing Load | 67,009,367 | 50,969,558 | 45,861,407 | 50,228,980 |

(a) Includes a de-minimus amount of non-exempt, vintaged NSGC-eligible load that does not impact ratemaking.

# TABLE 2-3
# 2026 ENERGY (GWh) AND PEAK DEMAND (MW) REQUIREMENTS

2026 ENERGY REQUIREMENTS (GWh)

| Line No. | Description | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Energy Load (GWh) | | | | | | | | | | | | | |
| 2 | Unmitigated Retail Sales (incl Large Data Centers) | [redacted] | | | | | | | | | | | | 89,500 |
| 3 | Conservation and Energy Efficiency [1] | (102) | (93) | (106) | (106) | (121) | (134) | (148) | (146) | (130) | (120) | (100) | (101) | (1,406) |
| 4 | Distributed Generation | | | | | | | | | | | | | |
| 5 | Solar | (670) | (796) | (1,215) | (1,445) | (1,639) | (1,684) | (1,710) | (1,636) | (1,415) | (1,204) | (845) | (715) | (14,973) |
| 6 | Non-PV DG | (255) | (223) | (247) | (240) | (244) | (237) | (245) | (246) | (238) | (241) | (234) | (243) | (2,891) |
| 7 | Large Data Centers | | | | | | | | | | | | | |
| 8 | Storage | 11 | 10 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 10 | 10 | 10 | 129 |
| 9 | Electric Vehicles | 333 | 307 | 347 | 343 | 361 | 357 | 376 | 383 | 378 | 398 | 392 | 412 | 4,386 |
| 10 | Building Electrification | 29 | 25 | 23 | 21 | 18 | 17 | 17 | 17 | 17 | 20 | 24 | 31 | 260 |
| 11 | Retail Sales | [redacted] | | | | | | | | | | | | 75,004 |
| 12 | Direct Access | | | | | | | | | | | | | |
| 13 | Direct Access | (934) | (883) | (893) | (880) | (908) | (970) | (1,045) | (1,061) | (1,020) | (1,000) | (915) | (904) | (11,414) |
| 14 | Community Choice Aggregation | | | | | | | | | | | | | |
| 15 | Marin Clean Energy | [redacted] | | | | | | | | | | | | |
| 16 | Sonoma Clean Power | [redacted] | | | | | | | | | | | | |
| 17 | Clean Power San Francisco | [redacted] | | | | | | | | | | | | |
| 18 | Peninsula Clean Energy | [redacted] | | | | | | | | | | | | |
| 19 | Silicon Valley Clean Energy | [redacted] | | | | | | | | | | | | |
| 20 | Redwood Coast Energy Authority | [redacted] | | | | | | | | | | | | |
| 21 | Pioneer Community Energy | [redacted] | | | | | | | | | | | | |
| 22 | Central Coast Community Power | [redacted] | | | | | | | | | | | | |
| 23 | Ava Community Energy | [redacted] | | | | | | | | | | | | |
| 24 | San Jose Clean Energy | [redacted] | | | | | | | | | | | | |
| 25 | Valley Clean Energy | [redacted] | | | | | | | | | | | | |
| 26 | King City Community Power | [redacted] | | | | | | | | | | | | |
| 27 | Community Choice Aggregation Total | (3,453) | (3,026) | (3,115) | (2,851) | (2,951) | (3,132) | (3,508) | (3,504) | (3,299) | (3,182) | (3,195) | (3,591) | (38,806) |
| 28 | UFE, Transmission & Distribution Losses | [redacted] | | | | | | | | | | | | 2,316 |
| 29 | Total Requirement | [redacted] | | | | | | | | | | | | 27,101 |
| 30 | Retail Sales excludes BART energy requirements. | | | | | | | | | | | | | |

# TABLE 2-3
# 2026 ENERGY (GWH) AND PEAK DEMAND (MW) REQUIREMENTS
# (CONTINUED)

2026 PEAK REQUIREMENTS (MW)

| Line No. | Description | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 31 | Peak Load (MW) | | | | | | | | | | | | |
| 32 | Unmitigated Retail Peak (incl Large Data Centers) | [redacted] | | | | | | | | | | | |
| 33 | Conservation and Energy Efficiency [1] | (150) | (151) | (160) | (162) | (269) | (295) | (343) | (286) | (249) | (186) | (161) | (155) |
| 34 | Distributed Generation | | | | | | | | | | | | |
| 35 | Solar | 0 | 0 | 0 | 0 | (30) | (144) | (907) | (564) | (90) | 0 | 0 | 0 |
| 36 | Non-PV DG | (342) | (331) | (332) | (334) | (328) | (329) | (329) | (330) | (331) | (324) | (325) | (326) |
| 37 | Electric Vehicles | 302 | 308 | 332 | 378 | 351 | 358 | 340 | 347 | 353 | 359 | 392 | 372 |
| 38 | Building Electrification | 61 | 57 | 50 | 40 | 34 | 31 | 32 | 31 | 30 | 35 | 51 | 64 |
| 39 | Large Data Centers | | | | | | | | | | | | |
| 40 | Storage | (332) | (333) | (341) | (344) | (339) | (358) | (359) | (364) | (364) | (330) | (330) | (327) |
| 41 | Retail Peak with distribution losses | [redacted] | | | | | | | | | | | |
| 42 | Direct Access with distribution losses | (1,544) | (1,604) | (1,577) | (1,622) | (1,719) | (2,101) | (2,176) | (2,168) | (1,838) | (1,901) | (1,596) | (1,485) |
| 43 | Community Choice Aggregation with dist losses | (6,942) | (6,627) | (6,490) | (6,437) | (7,313) | (8,131) | (8,537) | (8,530) | (8,349) | (7,103) | (6,525) | (7,167) |
| 44 | UFE & Transmission Losses | [redacted] | | | | | | | | | | | |
| 45 | Puget Sound Power & Light (Return) | [redacted] | | | | | | | | | | | |
| 46 | Total Requirement | [redacted] | | | | | | | | | | | |
| 47 | Retail Peak excludes BART demand requirements. | | | | | | | | | | | | |

Notes:

Distributed generation, storage, and EV impacts are cumulative, whereas energy efficiency, building electrification, and data center impacts are incremental to end-of-year 2024.

EE data represents savings from additional achievable energy efficiency programs and codes & standards incremental to 2024, based on the CPUC's Potential and Goals study. Importantly, this does not include committed savings from energy efficiency programs and codes & standards. Additionally, PG&E develops a simplified "daytype" forecast for energy efficiency hourly impacts, rather than a comprehensive 8760 forecast. This data reflects the peak daytype from said daytype forecast (compared to non-peak weekday and weekend daytypes).

## TABLE 4-1
## 2025 FORWARD ELECTRIC PRICES AND NATURAL GAS PRICES

| Line No. | Description | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Ave.* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Energy ($/MWh) | [redacted] | | | | | | | | | | | | |
| 2 | On Peak | | | | | | | | | | | | | |
| 3 | Off Peak | | | | | | | | | | | | | |
| 4 | Natural Gas ($/MMBtu) | | | | | | | | | | | | | |
| 5 | Citygate | | | | | | | | | | | | | |

Note: Forward Energy and Natural Gas Prices were derived from August 27, 2025 broker quotes. Ave.* is simple average of monthly prices.

# TABLE 4-3
# 2026 ENERGY SUPPLY
# (GWh)

| Line No. | Description | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Energy Supply (GWh) | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | |
| 4 | Energy Storage | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | |
| 9 | Energy Storage | | | | | | | | | | | | | |
| 10 | QF | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | | | | | | | | | | | | | |
| 14 | Nuclear | [redacted] | | | | | | | | | | | | |
| 15 | Hydro | | | | | | | | | | | | | |
| 16 | Fossil | | | | | | | | | | | | | |
| 17 | Solar | 12 | 19 | 28 | 31 | 35 | 34 | 34 | 33 | 28 | 25 | 17 | 16 | 313 |
| 18 | Fuel Cell | [redacted] | | | | | | | | | | | | |
| 19 | Energy Storage | | | | | | | | | | | | | |
| 20 | Pre-2003 Contracted Resources | | | | | | | | | | | | | |
| 21 | QF | | | | | | | | | | | | | |
| 22 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 23 | RPS Eligible | | | | | | | | | | | | | |
| 24 | RPS-Eligible Contracts | 691 | 778 | 1,074 | 1,231 | 1,417 | 1,414 | 1,402 | 1,302 | 1,120 | 960 | 743 | 625 | 12,756 |
| 25 | RPS-Eligible Contracts - Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | RPS-Eligible Future Contracts | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 27 | RPS-Eligible Future Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 28 | Other Bilateral Contracts | [redacted] | | | | | | | | | | | | |
| 29 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | |
| 30 | Fossil Contracts - CHP | | | | | | | | | | | | | |
| 31 | Large Hydro | | | | | | | | | | | | | |
| 32 | Non-RPS-Eligible Hydro Sales | | | | | | | | | | | | | |
| 33 | Energy Storage | | | | | | | | | | | | | |
| 34 | Future Imports | | | | | | | | | | | | | |
| 35 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | |
| 36 | Pre-2002 Contracted Resources | | | | | | | | | | | | | |
| 37 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | |
| 38 | MWD Etiwanda | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 39 | Puget Sound Power & Light Contract (N | [redacted] | | | | | | | | | | | | |
| 40 | QF | | | | | | | | | | | | | |
| 41 | Public Policy Charge Procurement (PPCP) | | | | | | | | | | | | | |
| 42 | QF | [redacted] | | | | | | | | | | | | |
| 43 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | |
| 44 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 45 | RPS Eligible | | | | | | | | | | | | | |
| 46 | RPS-Eligible Contracts | 8 | 7 | 7 | 9 | 10 | 10 | 11 | 12 | 11 | 10 | 12 | 11 | 120 |
| 47 | Tree Mortality Non-Bypassable Charge (TMNBC) | | | | | | | | | | | | | |
| 48 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 49 | RPS Eligible | | | | | | | | | | | | | |
| 50 | RPS-Eligible Contracts | 55 | 55 | 53 | 38 | 59 | 54 | 59 | 62 | 44 | 37 | 40 | 44 | 600 |
| 51 | RPS-Eligible Contracts - Sales | (33) | (30) | (30) | (33) | (39) | (31) | (36) | (41) | (43) | (42) | (35) | (37) | (430) |
| 52 | RPS-Eligible Future Contracts | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 53 | RPS-Eligible Future Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 54 | Modified Cost Allocation Mechanism (MCAM) | | | | | | | | | | | | | |
| 55 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 56 | Other Bilateral Contracts | [redacted] | | | | | | | | | | | | |
| 57 | Energy Storage | | | | | | | | | | | | | |
| 58 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | |
| 59 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 60 | Other Bilateral Contracts | | | | | | | | | | | | | |
| 61 | Future Non-RPS-Eligible Hydro Sales | [redacted] | | | | | | | | | | | | |
| 62 | Non-RPS-Eligible Hydro Sales | | | | | | | | | | | | | |
| 63 | Imports | | | | | | | | | | | | | |
| 64 | RA Contracts | | | | | | | | | | | | | |
| 65 | Energy Storage | | | | | | | | | | | | | |
| 66 | Utility-Owned Generation | | | | | | | | | | | | | |
| 67 | Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 68 | Energy Storage | [redacted] | | | | | | | | | | | | |
| 69 | Total Supply | | | | | | | | | | | | | |

Note: Totals may not add due to rounding.

# TABLE 4-4
# 2025 RPS ENERGY SUPPLY
# (GWh)

| Line No. | Description | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Energy Supply (GWh) | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | |
| 4 | Energy Storage | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | |
| 9 | Energy Storage | | | | | | | | | | | | | |
| 10 | QF | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | | | | | | | | | | | | | |
| 14 | Nuclear | [redacted] | | | | | | | | | | | | |
| 15 | Hydro | 86 | 77 | 71 | 70 | 80 | 75 | 55 | 57 | 54 | 62 | 49 | 61 | 799 |
| 16 | Fossil | [redacted] | | | | | | | | | | | | |
| 17 | Solar | 12 | 19 | 28 | 31 | 35 | 34 | 34 | 33 | 28 | 25 | 17 | 16 | 313 |
| 18 | Fuel Cell | [redacted] | | | | | | | | | | | | |
| 19 | Energy Storage | | | | | | | | | | | | | |
| 20 | Pre-2003 Contracted Resources | | | | | | | | | | | | | |
| 21 | QF | | | | | | | | | | | | | |
| 22 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 23 | RPS Eligible | | | | | | | | | | | | | |
| 24 | RPS-Eligible Contracts | 845 | 911 | 1,246 | 1,411 | 1,605 | 1,585 | 1,565 | 1,455 | 1,285 | 1,132 | 901 | 771 | 14,713 |
| 25 | RPS-Eligible Contracts - Sales | [redacted] | | | | | | | | | | | | |
| 26 | RPS-Eligible Future Contracts | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 27 | RPS-Eligible Future Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 28 | Other Bilateral Contracts | | | | | | | | | | | | | |
| 29 | Fossil Contracts - Non-CHP | [redacted] | | | | | | | | | | | | |
| 30 | Fossil Contracts - CHP | | | | | | | | | | | | | |
| 31 | Large Hydro | | | | | | | | | | | | | |
| 32 | Non-RPS-Eligible Hydro Sales | | | | | | | | | | | | | |
| 33 | Energy Storage | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | |
| 37 | MWD Etiwanda | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 38 | Puget Sound Power & Light Contract (N | [redacted] | | | | | | | | | | | | |
| 39 | QF | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PPCP | | | | | | | | | | | | | |
| 41 | QF | | | | | | | | | | | | | |
| 42 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | |
| 43 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 44 | RPS Eligible | | | | | | | | | | | | | |
| 45 | RPS-Eligible Contracts | 8 | 7 | 7 | 9 | 10 | 10 | 11 | 12 | 13 | 12 | 14 | 13 | 127 |
| 46 | Tree Mortality Non-Bypassable Charge (TMNBC) | | | | | | | | | | | | | |
| 47 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 48 | RPS Eligible | | | | | | | | | | | | | |
| 49 | RPS-Eligible Contracts | 55 | 55 | 53 | 38 | 59 | 54 | 59 | 62 | 44 | 37 | 40 | 44 | 600 |
| 50 | RPS-Eligible Contracts - Sales | (33) | (30) | (30) | (33) | (39) | (31) | (36) | (41) | (43) | (42) | (35) | (37) | (430) |
| 51 | RPS-Eligible Future Contracts | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 52 | RPS-Eligible Future Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 53 | Modified Cost Allocation Mechanism (MCAM) | | | | | | | | | | | | | |
| 54 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 55 | Other Bilateral Contracts | | | | | | | | | | | | | |
| 56 | Energy Storage | [redacted] | | | | | | | | | | | | |
| 57 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | |
| 58 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 59 | Other Bilateral Contracts | | | | | | | | | | | | | |
| 60 | QF | [redacted] | | | | | | | | | | | | |
| 61 | Energy Storage | | | | | | | | | | | | | |
| 62 | RPS-Eligible Future Contracts | | | | | | | | | | | | | |
| 63 | Utility-Owned Generation | | | | | | | | | | | | | |
| 64 | Solar | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 65 | Energy Storage | [redacted] | | | | | | | | | | | | |
| 66 | Total Supply | | | | | | | | | | | | | |

Note: Totals may not add due to rounding.

## TABLE 4-5
## 2026 PROCUREMENT COSTS
## (THOUSANDS OF DOLLARS)

| Line No. | Description | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Energy Supply / Demand Procurement Costs ($) | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | | | | | | | | | | | | | |
| 4 | Energy Storage | [redacted] | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | [redacted] | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | [redacted] | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | [redacted] | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | [redacted] | | | | | | | | | | | | |
| 9 | Energy Storage Contracts | [redacted] | | | | | | | | | | | | |
| 10 | QF | [redacted] | | | | | | | | | | | | |
| | Future RA Contracts | [redacted] | | | | | | | | | | | | |
| 11 | Imports | [redacted] | | | | | | | | | | | | |
| 12 | CPE Administrative | 186 | 186 | 191 | 193 | 203 | 208 | 208 | 208 | 191 | 289 | 180 | 188 | 2,431 |
| 13 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | |
| 14 | Utility-Owned Generation | | | | | | | | | | | | | |
| 15 | Nuclear | [redacted] | | | | | | | | | | | | |
| 16 | Hydro | [redacted] | | | | | | | | | | | | |
| 17 | Fossil | [redacted] | | | | | | | | | | | | |
| 18 | Solar | [redacted] | | | | | | | | | | | | |
| 19 | Fuel Cell | [redacted] | | | | | | | | | | | | |
| 20 | Energy Storage | [redacted] | | | | | | | | | | | | |
| 21 | Pre-2003 Contracted Resources | [redacted] | | | | | | | | | | | | |
| 22 | QF | [redacted] | | | | | | | | | | | | |
| 23 | Post-2002 Contracted Resources | [redacted] | | | | | | | | | | | | |
| 24 | RPS Eligible | [redacted] | | | | | | | | | | | | |
| 25 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | |
| 26 | RPS-Eligible Contracts - Sales | [redacted] | | | | | | | | | | | | |
| 27 | RPS-Eligible Future Contracts | [redacted] | | | | | | | | | | | | |
| 28 | RPS-Eligible Future Sales | [redacted] | | | | | | | | | | | | |
| 29 | Other Bilateral Contracts | [redacted] | | | | | | | | | | | | |
| 30 | Fossil Contracts - Non-CHP | [redacted] | | | | | | | | | | | | |
| 31 | Fossil Contracts - CHP | [redacted] | | | | | | | | | | | | |
| 32 | Large Hydro | [redacted] | | | | | | | | | | | | |
| 33 | Energy Storage Contracts | [redacted] | | | | | | | | | | | | |
| 34 | Future RA Contracts | [redacted] | | | | | | | | | | | | |
| 35 | RA Contracts - Sales | [redacted] | | | | | | | | | | | | |
| 36 | Non-RPS-Eligible Hydro Sale | [redacted] | | | | | | | | | | | | |
| 37 | Ongoing Competition Transition Charge (CTC) | [redacted] | | | | | | | | | | | | |
| 38 | Pre-2002 Contracted Resources | [redacted] | | | | | | | | | | | | |
| 39 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | |
| 40 | MWD Etiwanda | [redacted] | | | | | | | | | | | | |
| 41 | Puget Sound Power & Light Contract (Net) | [redacted] | | | | | | | | | | | | |
| 42 | QF | [redacted] | | | | | | | | | | | | |
| 43 | Public Policy Charge Procurement (PPCP) | [redacted] | | | | | | | | | | | | |
| 44 | QF | [redacted] | | | | | | | | | | | | |
| 45 | Bioenergy Market Adjusting Tariff (BioMAT) | [redacted] | | | | | | | | | | | | |
| 46 | Post-2002 Contracted Resources | [redacted] | | | | | | | | | | | | |
| 47 | RPS Eligible | [redacted] | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | |
| 49 | Tree Mortality Non-Bypassable Charge (TMNBC) | [redacted] | | | | | | | | | | | | |
| 50 | Post-2002 Contracted Resources | [redacted] | | | | | | | | | | | | |
| 51 | RPS Eligible | [redacted] | | | | | | | | | | | | |
| 52 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | |
| 53 | RPS-Eligible Contracts - Sales | [redacted] | | | | | | | | | | | | |
| 54 | RPS-Eligible Future Contracts | [redacted] | | | | | | | | | | | | |
| 55 | RPS-Eligible Future Sales | [redacted] | | | | | | | | | | | | |
| 56 | RA Contracts - Sales | [redacted] | | | | | | | | | | | | |
| 57 | Modified Cost Allocation Mechanism (MCAM) | [redacted] | | | | | | | | | | | | |
| 58 | Post-2002 Contracted Resources | [redacted] | | | | | | | | | | | | |
| 59 | Other Bilateral Contracts | [redacted] | | | | | | | | | | | | |
| 60 | Energy Storage Contracts | [redacted] | | | | | | | | | | | | |
| 61 | Energy Resource Recovery Account (ERRA) | [redacted] | | | | | | | | | | | | |
| 62 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | |
| 63 | Energy Storage | [redacted] | | | | | | | | | | | | |
| 64 | Other Bilateral Contracts | [redacted] | | | | | | | | | | | | |
| 65 | Future Non-RPS-Eligible Hydro Sales | [redacted] | | | | | | | | | | | | |
| 66 | Non-RPS-Eligible Hydro Sales | [redacted] | | | | | | | | | | | | |
| 67 | QF | [redacted] | | | | | | | | | | | | |
| 68 | RA Contracts | [redacted] | | | | | | | | | | | | |
| 69 | RPS-Eligible Future Contracts | [redacted] | | | | | | | | | | | | |
| 70 | RPS-Eligible Future Sales | [redacted] | | | | | | | | | | | | |
| 71 | Total Costs | 199,872 | 162,647 | 169,729 | 181,925 | 203,570 | 284,773 | 285,839 | 274,996 | 252,128 | 195,676 | 164,548 | 180,439 | 2,556,141 |

# TABLE 4-6
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (JAN)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Recei | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PPCP) | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 10 | 19 | 24 | 26 | 26 | 25 | 23 | 16 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 49 | DCPP Extended Operations (DCPP_NBC_CA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-7
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (FEB)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment ([redacted] | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Receiv[redacted] | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (P[redacted] | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account ([redacted] | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 8 | 33 | 42 | 43 | 41 | 40 | 40 | 40 | 34 | 18 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
| 49 | DCPP Extended Operations (DCPP_NB[redacted] | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-8
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (MAR)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Recei | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PP | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 20 | 38 | 42 | 39 | 40 | 40 | 37 | 34 | 31 | 22 | 5 | 0 | 0 | 0 | 0 | 0 | 0 |
| 49 | DCPP Extended Operations (DCPP_NBC_CA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-9
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (APR)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Recei | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PPCP) | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 0 | 0 | 0 | 0 | 0 | 1 | 19 | 42 | 47 | 47 | 47 | 48 | 48 | 47 | 48 | 46 | 41 | 19 | 1 | 0 | 0 | 0 | 0 | 0 |
| 49 | DCPP Extended Operations (DCPP_NBC | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-10
## 2026 BUNDLED PORTFOLIO SYSTEM RA
## (MAY)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Receive) | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PPCP) | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 49 | DCPP Extended Operations (DCPP_NBC_CA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-11
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (JUN)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Recei | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PP | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 4 | 4 | 4 | 4 | 4 | 14 | 40 | 53 | 58 | 59 | 59 | 60 | 60 | 59 | 59 | 57 | 53 | 40 | 14 | 4 | 4 | 4 | 4 | 4 |
| 49 | DCPP Extended Operations (DCPP_NBC_CA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-12
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (JULY)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Recei | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PPC | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (ER | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 4 | 4 | 4 | 4 | 4 | 8 | 33 | 51 | 57 | 58 | 59 | 59 | 59 | 58 | 58 | 55 | 51 | 36 | 11 | 4 | 4 | 4 | 4 | 4 |
| 49 | DCPP Extended Operations (DCPP_N | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-13
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (AUG)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Receiv [redacted] | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PPC [redacted] | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 6 | 6 | 6 | 6 | 6 | 7 | 23 | 46 | 55 | 57 | 58 | 58 | 58 | 58 | 57 | 53 | 45 | 23 | 7 | 6 | 6 | 6 | 6 | 6 |
| 49 | DCPP Extended Operations (DCPP_NBC_CA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-14
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (SEPT)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Receiv [redacted] | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PP [redacted] | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 6 | 6 | 6 | 6 | 6 | 6 | 16 | 44 | 54 | 56 | 56 | 56 | 56 | 56 | 56 | 53 | 36 | 12 | 6 | 6 | 6 | 6 | 6 | 6 |
| 49 | DCPP Extended Operations (DCPP_NBC_CA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-15
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (OCT)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Recei | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PPCP) | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 6 | 6 | 6 | 6 | 6 | 6 | 9 | 31 | 48 | 50 | 49 | 48 | 48 | 49 | 48 | 41 | 18 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| 49 | DCPP Extended Operations (DCPP_NBC_CA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-16
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (NOV)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioM | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Recei | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PPC | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (E | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 16 | 36 | 42 | 41 | 40 | 41 | 42 | 39 | 27 | 8 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| 49 | DCPP Extended Operations (DCPP_N | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

# TABLE 4-17
# 2026 BUNDLED PORTFOLIO SYSTEM RA
# (DEC)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Imports | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | Hydro | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | Fossil | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | Pre-2003 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | RPS-Eligible Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | RPS-Eligible Future Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | Other Bilateral Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | Fossil Contracts - CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | Large Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | Energy Storage | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | RA Contracts - Sales | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | Future RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | | | | | | | | | | | | | |
| 31 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 32 | RPS Eligible | | | | | | | | | | | | | | | | | | | | | | | | |
| 33 | RPS-Eligible Contracts | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | Pre-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | MWD Etiwanda | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | QF | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | Puget Sound Power & Light (Recei | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | Public Policy Charge Procurement (PPCP) | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | QF | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | Utility-Owned Generation | | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | Energy Storage | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | Post-2002 Contracted Resources | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | RA Contracts | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | GTSR | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | RPS-Eligible Contracts | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 8 | 19 | 28 | 33 | 34 | 34 | 33 | 30 | 20 | 7 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| 49 | DCPP Extended Operations (DCPP_NBC_CA) | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | Nuclear | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |

**TABLE 5-1**
**2025 FORECAST OF NATURAL GAS AND ELECTRIC HEDGE TRANSACTION COSTS**
**(THOUSANDS OF DOLLARS)**

| Line No. | Description | Jan-26 | Feb-26 | Mar-26 | Apr-26 | May-26 | Jun-26 | Jul-26 | Aug-26 | Sep-26 | Oct-26 | Nov-26 | Dec-26 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Costs Incurred at Trade Execution | [redacted] | | | | | | | | | | | | |
| 2 | Exchange and Broker Fees | | | | | | | | | | | | | |
| 3 | Option Premiums | | | | | | | | | | | | | |
| 4 | Total Costs Incurred at Trade Execution | | | | | | | | | | | | | |
| 5 | Costs Incurred at Trade Settlement | | | | | | | | | | | | | |
| 6 | Mark-to-market of Futures as of August 27, 2025 | | | | | | | | | | | | | |
| 7 | Mark-to-market of Futures as of August 27, 2025 | | | | | | | | | | | | | |
| 8 | Total Costs Incurred at Trade Settlement | | | | | | | | | | | | | |
| 9 | Net Hedging Cost | | | | | | | | | | | | | |

**TABLE 5-2**
**SUMMARY OF 2026 FORECAST COLLATERAL COSTS**
**(THOUSANDS OF DOLLARS)**

| Line No. | Collateral Costs | Amount |
|---|---|---|
| 1 | Collateral on Physical and Financial Transactions | $7,020 |
| 2 | GHG Inventory Carrying Costs | 1,159 |
| 3 | Net Interest Paid on Collateral Posted to PG&E | (515) |
| 4 | Total | $7,664 |

## TABLE 5-4
## 2026 SYSTEM RA OPEN POSITION
## (JAN)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustment | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

## TABLE 5-5
## 2026 SYSTEM RA OPEN POSITION
## (FEB)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustme | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

## TABLE 5-6
## 2026 SYSTEM RA OPEN POSITION
## (MAR)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustme | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

## TABLE 5-7
## 2026 SYSTEM RA OPEN POSITION
## (APRIL)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustme | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / ( | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

**TABLE 5-8**
**2026 SYSTEM RA OPEN POSITION**
**(MAY)**

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustment | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

**TABLE 5-9**
**2026 SYSTEM RA OPEN POSITION**
**(JUN)**

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustment | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

## TABLE 5-10
## 2026 SYSTEM RA OPEN POSITION
## (JULY)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustment | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

## TABLE 5-11
## 2026 SYSTEM RA OPEN POSITION
## (AUG)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustment | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

**TABLE 5-12**
**2026 SYSTEM RA OPEN POSITION**
**(SEPT)**

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjus | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

**TABLE 5-13**
**2026 SYSTEM RA OPEN POSITION**
**(OCT)**

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustment | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

## TABLE 5-14
## 2026 SYSTEM RA OPEN POSITION
## (NOV)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustment | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

## TABLE 5-15
## 2026 SYSTEM RA OPEN POSITION
## (DEC)

| Line No. | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustment | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | | | | | | | | | | | | | |

**TABLE 5-16**
**2026 BUNDLED RPS OPEN POSITION**

| Line No. | Description | Total | Reference |
|---|---|---|---|
| 1 | Bundled Load (MWh) - RPS Customer | 24,784,495 | |
| 3 | RPS Req. % | 49% | |
| 4 | RPS Req (MWh) | 12,226,191 | |
| 5 | RPS Sales (MWh) | (4,988,814) | |
| 6 | Unsold RPS | - | |
| 7 | Net RPS Generation* | 11,239,000 | Table 4-4, Row 66 |
| 8 | Expected RPS Open Position* * | [redacted] | Table 8-3 |

**Net RPS Generation is derived from PG&E's deterministic modeling.*

***Expected RPS Open Position is dervived from PG&E's RPS Stochastic model and will not tie to deterministic volumes presented above.*

## TABLE 5-17
## 2025 SYSTEM RA OPEN POSITION
## (MW)

| Line No. | Description | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Peak ERRA Load (MW) | | | | | | | | | | | | |
| 2 | PG&E Bundled Peak load Forecast | [redacted] | | | | | | | | | | | |
| 3 | CPUC RA Compliance Requirement Adjustment | | | | | | | | | | | | |
| 4 | Reserve Requirement | | | | | | | | | | | | |
| 5 | Demand Response | | | | | | | | | | | | |
| 6 | Portfolio Reserve | | | | | | | | | | | | |
| 7 | Total ERRA Capacity Requirement | | | | | | | | | | | | |
| 8 | Total Net Supply | | | | | | | | | | | | |
| 9 | Position Before Adjustment for Unsold Long / (Short) | | | | | | | | | | | | |
| 10 | Unsold Capacity | | | | | | | | | | | | |
| 11 | Position after Adjustment for Unsold | | | | | | | | | | | | |

## TABLE 5-18
## 2026 SYSTEM RA RESIDUAL TRANSACTION REVENUES

| Line No. | Description | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residual RA Transaction Revenues | [redacted] | | | | | | | | | | | | |

# TABLE 5-19
# 2026 BUNDLED MONTHLY WEIGHTED-AVERAGE SYSTEM CAPACITY

| Line No. | Description | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Capacity Supply (MW) | | | | | | | | | | | | |
| 2 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | |
| 3 | Utility-Owned Generation | [redacted] | | | | | | | | | | | |
| 4 | Energy Storage | [redacted] | | | | | | | | | | | |
| 5 | Post-2002 Contracted Resources | [redacted] | | | | | | | | | | | |
| 6 | Other Bilateral Contracts | [redacted] | | | | | | | | | | | |
| 7 | Fossil Contracts - Non-CHP | [redacted] | | | | | | | | | | | |
| 8 | Fossil Contracts - CHP | [redacted] | | | | | | | | | | | |
| 9 | QF | [redacted] | | | | | | | | | | | |
| 10 | Energy Storage | [redacted] | | | | | | | | | | | |
| 11 | Imports | [redacted] | | | | | | | | | | | |
| 12 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | |
| 13 | Utility-Owned Generation | [redacted] | | | | | | | | | | | |
| 14 | Nuclear | [redacted] | | | | | | | | | | | |
| 15 | Hydro | [redacted] | | | | | | | | | | | |
| 16 | Fossil | [redacted] | | | | | | | | | | | |
| 17 | Solar | [redacted] | | | | | | | | | | | |
| 18 | Pre-2003 Contracted Resources | [redacted] | | | | | | | | | | | |
| 19 | QF | [redacted] | | | | | | | | | | | |
| 20 | Post-2002 Contracted Resources | | | | | | | | | | | | |
| 21 | RPS Eligible | | | | | | | | | | | | |
| 22 | RPS-Eligible Contracts | 210 | 264 | 330 | 477 | 544 | 2,007 | 2,849 | 1,229 | 1,846 | 835 | 175 | 211 |
| 23 | RPS-Eligible Future Contracts | [redacted] | | | | | | | | | | | |
| 24 | Other Bilateral Contracts | [redacted] | | | | | | | | | | | |
| 25 | Fossil Contracts - CHP | [redacted] | | | | | | | | | | | |
| 26 | Fossil Contracts - Non-CHP | [redacted] | | | | | | | | | | | |
| 27 | Large Hydro | [redacted] | | | | | | | | | | | |
| 28 | Energy Storage | [redacted] | | | | | | | | | | | |
| 29 | RA Contracts - Sales | [redacted] | | | | | | | | | | | |
| 30 | RA Contracts | [redacted] | | | | | | | | | | | |
| 31 | Bioenergy Market Adjusting Tariff (BioMAT) | | | | | | | | | | | | |
| 32 | Post-2002 Contracted Resources | | | | | | | | | | | | |
| 33 | RPS Eligible | | | | | | | | | | | | |
| 34 | RPS-Eligible Contracts | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 12 | 16 | 16 | 16 |
| 35 | Ongoing Competition Transition Charge (CTC) | | | | | | | | | | | | |
| 36 | Pre-2002 Contracted Resources | | | | | | | | | | | | |
| 37 | Irrigation District & Water Agency | [redacted] | | | | | | | | | | | |
| 38 | MWD Etiwanda | [redacted] | | | | | | | | | | | |
| 39 | QF | [redacted] | | | | | | | | | | | |
| 40 | Puget Sound Power & Light (Receiv [redacted] | [redacted] | | | | | | | | | | | |
| 41 | Public Policy Charge Procurement (PPCP) | | | | | | | | | | | | |
| 42 | QF | [redacted] | | | | | | | | | | | |
| 43 | Energy Resource Recovery Account (ERRA) | | | | | | | | | | | | |
| 44 | Utility-Owned Generation | [redacted] | | | | | | | | | | | |
| 45 | Energy Storage | [redacted] | | | | | | | | | | | |
| 46 | Post-2002 Contracted Resources | [redacted] | | | | | | | | | | | |
| 47 | RA Contracts | [redacted] | | | | | | | | | | | |
| 48 | GTSR | | | | | | | | | | | | |
| 49 | RPS-Eligible Contracts | 0 | 0 | 0 | 1 | 0 | 40 | 51 | 23 | 36 | 18 | 6 | 6 |
| 49 | DCPP Extended Operations (DCPP_NBC_CA) | | | | | | | | | | | | |
| 50 | Nuclear | [redacted] | | | | | | | | | | | |
| 51 | Total Net Supply | [redacted] | | | | | | | | | | | |

## TABLE 5-20
## 2026 CAISO AND OTHER PROCUREMENT COSTS

| Line No. | Description | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | CAISO Costs | | | | | | | | | | | | | |
| 2 | Grid Management Charges | [redacted] | | | | | | | | | | | | |
| 3 | CTC | | | | | | | | | | | | | |
| 4 | ERRA | | | | | | | | | | | | | |
| 5 | PCIA | | | | | | | | | | | | | |
| 6 | TMNBC | | | | | | | | | | | | | |
| 7 | BIOMAT | | | | | | | | | | | | | |
| 8 | PPCP | | | | | | | | | | | | | |
| 9 | Bundled Load Requirement (ERRA) | | | | | | | | | | | | | |
| 10 | Other Load (ERRA) | | | | | | | | | | | | | |
| 11 | Interstate Gas Transportation Costs | | | | | | | | | | | | | |
| 12 | Cost Allocation Mechanism (CAM) | | | | | | | | | | | | | |
| 13 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 14 | Other Bilateral Contracts | | | | | | | | | | | | | |
| 15 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | |
| 16 | Fossil Contracts - CHP | | | | | | | | | | | | | |
| 17 | Power Charge Indifference Adjustment (PCIA) | | | | | | | | | | | | | |
| 18 | Utility-Owned Generation | | | | | | | | | | | | | |
| 19 | Fossil | | | | | | | | | | | | | |
| 20 | Fuel Cell | | | | | | | | | | | | | |
| 21 | Post-2002 Contracted Resources | | | | | | | | | | | | | |
| 22 | Other Bilateral Contracts | | | | | | | | | | | | | |
| 23 | Fossil Contracts - Non-CHP | | | | | | | | | | | | | |
| 24 | **Total Costs** | | | | | | | | | | | | | |

Note: Totals may not add due to rounding.

## TABLE 6-1
## CPE PROCUREMENT COST FORECAST FOR CAM

| Line No. | Description | 1/1/2026 | 2/1/2026 | 3/1/2026 | 4/1/2026 | 5/1/2026 | 6/1/2026 | 7/1/2026 | 8/1/2026 | 9/1/2026 | 10/1/2026 | 11/1/2026 | 12/1/2026 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Compensated Self-Shown RA Capacity | [redacted] | | | | | | | | | | | | [redacted] |
| 2 | Compensated Bundled RA Capacity | | | | | | | | | | | | | |
| 3 | Compensated Bundled RA with Energy Settlement | | | | | | | | | | | | | |
| 4 | Total CPE Procurement | | | | | | | | | | | | | |

Notes:

Totals may not add due to rounding.

1

**TABLE 6-2**
**2026 CPE ADMINISTRATIVE COST FORECAST FOR CAM**
**(THOUSANDS OF DOLLARS)**

| Line No. | Cost Element | 2026 Cost | Description | 2026 Headcount |
|---|---|---|---|---|
| 1 | Solicitation and Procurement | $1,565 | Manage all processes related to the CPE's annual solicitation requirement, including the preparations of solicitation materials, communication with the market, processing, and evaluation of offers, preparation of contracts, negotiation and execution of transactions, and development of all required annual and monthly CPUC and CAISO Local RA filings. Includes costs related to the required use of an Independent Evaluator for all CPE solicitations. | 8 |
| 2 | Contract Management and Settlements | 443 | Contract administration and settlements of CPE agreements. | 3.5 |
| 3 | Compliance | 17 | Includes oversight of all CPE-related compliance activities including the development of CPE Annual Compliance Report and coordination of all Procurement Review Group meetings. | 0.1 |
| 4 | Regulatory | 17 | Augmented regulatory expertise to manage filings and communication related to CPE transactional volume. | 0.1 |
| 5 | Credit/Risk and Treasury | 17 | Additional expertise to perform credit calculations and monitor and maintain adequate protections and documentation for CPE transactions. | 0.1 |
| 6 | Information Technology (IT) | 180 | Personnel required to maintain systems and functionality related to CPE operations. | 0.5 |
| 7 | Accounting | 17 | Personnel required to address accounting operations for additional CPE transactions. | 0.1 |
| 8 | Legal | 75 | Provide regulatory and commercial legal support to the CPE for its annual solicitation process. Includes the potential use of external counsel. | 0.25 |
| 9 | IT Systems | 100 | Includes annual cost of additional system licensing needs for CPE personnel and any system updates needed to accommodate changes driven by the CPUC and/or CAISO. | – |
| 10 | Total CPE-Admin Cost | $2,431 | | 12.65 |

Note: Totals may not add due to rounding.

**TABLE 7-1**
**2026 CAM REVENUE REQUIREMENT**
**(THOUSANDS OF DOLLARS)**

| Line No. | Description | Revenue Requirement |
|---|---|---|
| 1 | Total CAM-eligible Contract, UOG and CPE Costs | [redacted] |
| 2 | CAISO Market Revenues | |
| 3 | Net Costs | $241,246 |
| 4 | RF&U @ 0.01252 | 3,020 |
| 5 | Total Revenue Requirement | $244,266 |

**TABLE 8-1**
**AUTHORIZED UOG-RELATED COSTS AND**
**RECOVERY OF AUTHORIZED UOG-RELATED COSTS**
**(THOUSANDS OF DOLLARS)**

| Line No. | Description | Authorization | Total |
|---|---|---|---|
| 1 | Authorized UOG-Related Costs | | |
| 2 | 2023 GRC + 2024 to 2026 Attrition | D.23-11-069 | $1,205,338 |
| 3 | Cost of Capital and Debt Adjustment | Advice 5042-G/7535-E | 19,893 |
| 4 | Hydro Sales | Advice 5042-G/7535-E | (8,866) |
| 5 | Pension | Advice 5042-G/7535-E | 30,252 |
| 6 | Gain on Sale of SFGO | D.21-08-027 | (21,028) |
| 7 | Purchase of Oakland General Office | D.24-08-009 | 9,286 |
| 8 | Non-Wildfire Self Insurance Adjustment | D.25-03-008 | (8,350) |
| 9 | 2022 WMCE | D.25-09-008 | 4,742 |
| 10 | Total | | $1,231,267 |

| | | |
|---|---|---|
| 11 | <u>Recovery of Authorized UOG-Related Costs</u> | |
| 12 | PCIA | $1,185,531 |
| 13 | ERRA | (737) |
| 14 | CAM | 46,474 |
| 15 | Total | $1,231,267 |

**TABLE 8-2**
**ANNUAL AVAILABLE COMPLIANCE PERIOD RPS GENERATION**

| Line No. | (A) Delivery Year | (B) Bundled Sales (MWH) | (C) Annual RPS Compliance Target (%) | (D) = (B*C) Annual RPS Compliance Target (MWh) | (E) Net Physical RPS Position (MWH) | (F) Expected Net Open (MWH) | (G) Unsold RPS (MWH) | (H) Excess RPS (MWH) | (I) = ( F - G - H) Net Available Compliance Period RPS Generation (MWH) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 2013 | 75,705,039 | 20% | 15,141,008 | 17,069,488 | 1,928,480 | - | - | 1,928,480 |
| 2 | 2014 | 74,546,865 | 22% | 16,176,670 | 20,156,687 | 3,980,017 | - | - | 3,980,017 |
| 3 | 2015 | 72,112,848 | 23% | 16,802,294 | 21,284,772 | 4,482,478 | - | - | 4,482,478 |
| 4 | 2016 | 68,440,794 | 25% | 17,110,199 | 22,489,623 | 5,379,425 | - | - | 5,379,425 |
| 5 | 2017 | 61,397,214 | 27% | 16,577,248 | 20,281,522 | 3,704,274 | - | - | 3,704,274 |
| 6 | 2018 | 48,832,111 | 29% | 14,161,312 | 18,934,717 | 4,773,405 | - | - | 4,773,405 |
| 7 | 2019 | 35,956,100 | 31% | 11,146,391 | 10,444,565 | (701,826) | - | - | (701,826) |
| 8 | 2020 | 35,838,070 | 33% | 11,826,563 | 12,271,881 | 445,318 | - | - | 445,318 |
| 9 | 2021 | 33,149,379 | 36% | 11,850,903 | 17,250,635 | 5,399,732 | - | - | 5,399,732 |
| 10 | 2022 | 30,307,095 | 39% | 11,668,232 | 12,990,684 | 1,322,452 | - | - | 1,322,452 |
| 11 | 2023 | 26,017,569 | 41% | 10,732,247 | 10,144,199 | (588,048) | 3,409,455 | - | (3,997,503) |
| 12 | 2024 | 26,722,965 | 44% | 11,758,105 | 6,690,397 | (5,067,708) | 349,104 | - | (5,416,812) |
| 13 | 2025 | 24,784,000 | 47% | 11,566,693 | [redacted] | [redacted] | - | - | [redacted] |
| 14 | 2026 | 24,784,495 | 49% | 12,226,191 | [redacted] | [redacted] | - | - | [redacted] |

*(E) Net Physical RPS position is RPS generation less RPS Sales. Value is dervived from PG&E's deterministic model.*
(F) Expected Net Open is dervived from PG&E's RPS Stochastic model for 2025 and 2026 and will not tie to the deterministic volumes.

**TABLE 8-3**
**HISTORICAL MINIMUM RETAINED RPS ENTRIES**

| Line No. | (A) Delivery/ Vintage Year | Vintage Credited | (B) Net Available Compliance Period RPS Generation (MWH) | (C) * Applied Prior Years Minimum RPS Entry | (D) Adjusted Net RPS Position |
|---|---|---|---|---|---|
| **1** | 2013 | [redacted] | 1,928,480 | [redacted] | [redacted] |
| **2** | 2014 | [redacted] | 3,980,017 | [redacted] | [redacted] |
| **3** | 2015 | [redacted] | 4,482,478 | [redacted] | [redacted] |
| **4** | 2016 | [redacted] | 5,379,425 | [redacted] | [redacted] |
| **5** | 2017 | [redacted] | 3,704,274 | [redacted] | [redacted] |
| **6** | 2018 | [redacted] | 4,773,405 | (4,773,405) | - |
| **7** | 2019 | [redacted] | (701,826) | 701,826 | - |
| **8** | 2020 | [redacted] | 445,318 | [redacted] | [redacted] |
| **9** | 2021 | | 5,399,732 | (5,399,732) | - |
| **10** | 2022 | | 1,322,452 | (1,322,452) | - |
| **11** | 2023 | | (3,997,503) | 3,997,503 | - |
| **12** | 2024 | | (5,416,812) | 5,416,812 | - |
| **13** | 2025 | [redacted] | [redacted] | [redacted] | [redacted] |
| 14 | Total | [redacted] | [redacted] | [redacted] | [redacted] |

**No minimum retained RPS entry was needed related to 2021 and 2022 since both years RPS generation exceeded the respective annual RPS targets resulting in a surplus.*

**TABLE 8-4**
**2026 MINIMUM RETAINED RPS ENTRY**

| Line No. | (A) Delivery Year | Vintage Credited | (B) Pre-2026 Adjusted Net RPS Position | (C) Minimum 2026 Entry | (D) = (B + C) Post-2026 Adjusted Net RPS Position |
|---|---|---|---|---|---|
| 1 | 2013 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2 | 2014 | [redacted] | [redacted] | [redacted] | [redacted] |
| 3 | 2015 | [redacted] | [redacted] | [redacted] | [redacted] |
| 4 | 2016 | [redacted] | [redacted] | [redacted] | [redacted] |
| 5 | 2017 | [redacted] | [redacted] | [redacted] | [redacted] |
| 6 | 2018 | | - | - | - |
| 7 | 2019 | | - | - | - |
| 8 | 2020 | [redacted] | [redacted] | [redacted] | [redacted] |
| 9 | 2021 | | - | - | - |
| 10 | 2022 | | - | - | - |
| 11 | 2023 | | - | - | - |
| 12 | 2024 | | - | - | - |
| 13 | 2025 | | - | - | - |
| 14 | 2026 | | [redacted] | [redacted] | - |
| 15 | Total | | [redacted] | - | [redacted] |

## TABLE 8-5
## SUMMARY OF INDIFFERENCE AMOUNT REVENUE REQUIREMENT
## (THOUSANDS OF DOLLARS)

| Line No. | Rate Component | Revenue Requirement |
|---|---|---|
| 1 | Ongoing CTC | ($3,374) |
| 2 | PPCP (PPP) | (1,086) |
| 3 | PCIA | 687,196 |
| 4 | Total | $682,737 |

## TABLE 8-6
## IOU TOTAL PORTFOLIO SUMMARY
## PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019 AND D.21-03-051

| Line No. | | Ongoing CTC-Eligible Portfolio | PPCP | UOG Legacy and Vintaged PCIA Portfolio | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | UOG Legacy | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
| 1. | CRS Eligible Portfolio Costs [(a)] ($000) | $59,635 | $989 | $823,271 | $1,426,439 | $430,874 | $126,577 | $159,474 | $49,142 | $3,670 | $6,118 | $1,764 |
| 2. | CRS Eligible Non-Renewable Supply at Generation Meter (GWh) | 627 | 0 | 8,261 | 7,288 | -244 | 421 | 746 | 341 | 64 | 114 | 11 |
| 3. | CRS Eligible Renewable Supply at Generation Meter (GWh) | 88 | 17 | 380 | 3,435 | 3,339 | 905 | 1,079 | 578 | 29 | 45 | 27 |
| 4. | CRS Eligible Total Net Qualifying Capacity (MW) | | | | | | | | | | | |
| 5. | CRS Eligible System NQC (System only, No flex or local) | 88 | 2 | 244 | 291 | 73 | 41 | 43 | 42 | 3 | 0 | 0 |
| 6. | CRS Eligible Local NQC - PG&E (System and local, with or without flex) | 90 | 0 | 1,240 | 516 | 64 | 27 | 76 | 4 | 1 | 1 | 2 |
| 7. | CRS Eligible Local NQC - SCE (System and local, with or without flex) | 0 | 0 | 0 | 0 | 21 | 0 | 4 | 0 | 2 | 9 | 0 |
| 8. | CRS Eligible Local NQC - SDG&E (System and local, with or without flex) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | CRS Eligible Flexible NQC (System and flex only, No local) | 0 | 0 | 246 | 663 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**TABLE 8-6**
**IOU TOTAL PORTFOLIO SUMMARY**
**PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019 AND D.21-03-051**
**(CONTINUED)**

| Line No. | | UOG Legacy and Vintaged PCIA Portfolio | | | | | | | | | | IOU Total Portfolio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | |
| 1. | CRS Eligible Portfolio Costs [(a)] ($000) | $9,165 | $60 | $37,874 | $0 | $158,684 | ($0) | $19,443 | $384 | $577 | $0 | $3,314,141 |
| 2. | CRS Eligible Non-Renewable Supply at Generation Meter (GWh) | 58 | 0 | 0 | 0 | -514 | 0 | 0 | 0 | 0 | 0 | 17,172 |
| 3. | CRS Eligible Renewable Supply at Generation Meter (GWh) | 121 | 0 | 0 | 0 | 865 | 0 | 16 | 6 | 8 | 0 | 10,941 |
| 4. | CRS Eligible Total Net Qualifying Capacity (MW) | | | | | | | | | | | |
| 5. | CRS Eligible System NQC (System only, No flex or local) | 7 | 0 | -21 | 0 | 6 | 0 | 1 | 0 | 1 | 0 | 821 |
| 6. | CRS Eligible Local NQC - PG&E (System and local, with or without flex) | 22 | 0 | 95 | 0 | 120 | 0 | 0 | 0 | 0 | 0 | 2,258 |
| 7. | CRS Eligible Local NQC - SCE (System and local, with or without flex) | 0 | 0 | 60 | 0 | 115 | 0 | 0 | 0 | 0 | 0 | 212 |
| 8. | CRS Eligible Local NQC - SDG&E (System and local, with or without flex) | 0 | 0 | 42 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 42 |
| 9. | CRS Eligible Flexible NQC (System and flex only, No local) | 9 | 0 | 62 | 0 | 480 | 0 | 52 | 0 | 0 | 0 | 1,513 |

**TABLE 8-7**
**INDIFFERENCE CALCULATION INPUTS AND SOURCES**
**PURSUANT TO D.17-08-026, AND**
**MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019 AND D.21-03-051, AND D.23-06-066**

| Line No. | Description | Source of Data | Value |
|---|---|---|---|
| 1. | On Peak Energy Index ($/MWh) | 2026 forecast Benchamrk | $50.20 |
| 2. | Off Peak Energy Index ($/MWh) | 2026 forecast Benchamrk | $52.31 |
| 3. | On Peak Time Weight (%) | Based on 2026 Calendar and NERC Holiday Schedule | 56.1% |
| 4. | Off Peak Time Weight (%) | Based on 2026 Calendar and NERC Holiday Schedule | 43.9% |
| 5. | Portfolio Weights | 2022-2024 PCIA revenue less the actual average NP15 | 0.89 |
| 6. | Load Weighted Average Price ($/MWh) | (line 1 x line 3 + line 2 x line 4) x line 5 | $45.75 |
| 7. | Green/RPS Adder ($/MWh) | 2026 forecast Benchmark | $62.45 |
| 8. | Green Benchmark ($/MWh) | line 6 + line 7 | $108.20 |
| 9. | System RA Benchmark ($/kW-Year) | 2026 forecast Benchamrk ($11.53 kW-Month x 12) | $138.36 |
| 10. | Local RA Benchmark ($/kW-Year) - PG&E | 2026 forecast Benchamrk ($11.53 kW-Month x 12) | $138.36 |
| 11. | Local RA Benchmark ($/kW-Year) - SCE | 2026 forecast Benchamrk ($11.53 kW-Month x 12) | $138.36 |
| 12. | Local RA Benchmark ($/kW-Year) - SDG&E | 2026 forecast Benchamrk ($11.53 kW-Month x 12) | $138.36 |
| 13. | Flexible RA Benchmark ($/kW-Year) | 2026 forecast Benchamrk ($11.53 kW-Month x 12) | $138.36 |
| 14. | Revenue Fee and Uncollectible Factor | Advice 4989-G/7419-E | 0.012520 |

**TABLE 8-8**
**INDIFFERENCE AMOUNT CALCULATION**
**PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019 AND D.21-03-051, AND D.23-06-066**

| Line | | | | Ongoing | PPCP | UOG Legacy and Vintaged PCIA | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Description | Equation | Unit | CTC-Eligible | | UOG Legacy | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| | **Cost of Portfolio** | | | | | | | | | | | | |
| 1. | Portfolio Total Cost | | $000 | $59,635 | $989 | $823,271 | $1,426,439 | $430,874 | $126,577 | $159,474 | $49,142 | $3,670 | $6,118 |
| 2. | CRS Eligible Non-Renewable Supply at Generation Meter | | GWh | 627 | 0 | 8,261 | 7,288 | -244 | 421 | 746 | 341 | 64 | 114 |
| 3. | CRS Eligible Renewable Supply at Generation Meter | | GWh | 88 | 17 | 380 | 3,435 | 3,339 | 905 | 1,079 | 578 | 29 | 45 |
| 4. | CRS Eligible System NQC | | MW | 88 | 2 | 244 | 291 | 73 | 41 | 43 | 42 | 3 | 0 |
| 5. | CRS Eligible Local NQC - PG&E | | MW | 90 | 0 | 1,240 | 516 | 64 | 27 | 76 | 4 | 1 | 1 |
| 6. | CRS Eligible Local NQC - SCE | | MW | 0 | 0 | 0 | 0 | 21 | 0 | 4 | 0 | 2 | 9 |
| 7. | CRS Eligible Local NQC - SDG&E | | MW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8. | CRS Eligible Flexible NQC | | MW | 0 | 0 | 246 | 663 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | **Portfolio Unit Cost** | **Line 1 / (Line 2 + Line 3)** | **$/MWh** | **$83.35** | **$57.77** | **$95.27** | **$133.03** | **$139.19** | **$95.44** | **$87.38** | **$53.46** | **$39.58** | **$38.47** |
| 10. | **Market Value of Portfolio** | | | | | | | | | | | | |
| 11. | **Market Value of Brown Portfolio** | | | | | | | | | | | | |
| 12. | Non-Renewable Energy | | GWh | 627 | 0 | 8,261 | 7,288 | -244 | 421 | 746 | 341 | 64 | 114 |
| 13. | Weighted Average Brown Benchmark | | $/MWh | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 |
| 14. | **Market Value of Brown Portfolio** | **Line 12 x Line 13** | **$000** | **$28,697** | **$0** | **$377,922** | **$333,418** | **($11,153)** | **$19,252** | **$34,136** | **$15,592** | **$2,930** | **$5,204** |
| 15. | **Market Value of Green Portfolio** | | | | | | | | | | | | |
| 16. | Renewable Energy | | GWh | 88 | 17 | 380 | 3,435 | 3,339 | 905 | 1,079 | 578 | 29 | 45 |
| 17. | Weighted Average Green Benchmark | | $/MWh | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 |
| 18. | **Market Value of Green Portfolio** | **Line 16 x Line 17** | **$000** | **$9,544** | **$1,853** | **$41,166** | **$371,667** | **$361,328** | **$97,975** | **$116,739** | **$62,583** | **$3,105** | **$4,902** |
| 19. | **Capacity Adder** | | | | | | | | | | | | |
| 20. | Average Monthly System NQC | | MW | 88 | 2 | 244 | 291 | 73 | 41 | 43 | 42 | 3 | 0 |
| 21. | System RA Benchmark | | $/kW-Year | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 |
| 22. | Average Monthly Local Area NQC - PG&E | | MW | 90 | 0 | 1,240 | 516 | 64 | 27 | 76 | 4 | 1 | 1 |
| 23. | Local RA Benchmark - PG&E | | $/kW-Year | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 |
| 24. | Average Monthly Local Area NQC - SCE | | MW | 0 | 0 | 0 | 0 | 21 | 0 | 4 | 0 | 2 | 9 |
| 25. | Local RA Benchmark - SCE | | $/kW-Year | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 |
| 26. | Average Monthly Local Area NQC - SDG&E | | MW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 27. | Local RA Benchmark - SDG&E | | $/kW-Year | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 |
| 28. | Average Monthly Flexible NQC | | MW | 0 | 0 | 246 | 663 | 0 | 0 | 0 | 0 | 0 | 0 |
| 29. | Flexible RA Benchmark | | $/kW-Year | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 |
| 30. | **Market Value of Capacity** | | **$000** | **$24,727** | **$209** | **$239,470** | **$203,552** | **$21,922** | **$9,419** | **$16,934** | **$6,323** | **$677** | **$1,406** |
| 31. | **Portfolio Market Value** | **Line 14 + Line 18 + Line 30** | $000 | **$62,968** | **$2,062** | **$658,559** | **$908,637** | **$372,097** | **$126,646** | **$167,809** | **$84,498** | **$6,711** | **$11,511** |
| 32. | **Indifference Amount** | | | | | | | | | | | | |
| 33. | **Portfolio Total Cost** | **Line 1** | $000 | **$59,635** | **$989** | **$823,271** | **$1,426,439** | **$430,874** | **$126,577** | **$159,474** | **$49,142** | **$3,670** | **$6,118** |
| 34. | **Portfolio Market Value** | **Line 31** | $000 | **$62,968** | **$2,062** | **$658,559** | **$908,637** | **$372,097** | **$126,646** | **$167,809** | **$84,498** | **$6,711** | **$11,511** |
| 35. | **Total Indifference Amount (Unadjusted)** | **Line 33 - Line 34** | $000 | **($3,332)** | **($1,072)** | **$164,713** | **$517,802** | **$58,777** | **($69)** | **($8,335)** | **($35,355)** | **($3,041)** | **($5,393)** |
| 36. | **Other Adjustments** | | $000 | | | | | | | | | | |
| 37. | **Adjusted Indifference Amount** | **Line 35 + Line 36** | $000 | **($3,332)** | **($1,072)** | **$164,713** | **$517,802** | **$58,777** | **($69)** | **($8,335)** | **($35,355)** | **($3,041)** | **($5,393)** |
| 38. | **Revenue Franchise Fees & Uncollectibles (RF&U)** | **Advice 4989-G/7419-E** | $000 | **($42)** | **($13)** | **$2,062** | **$6,483** | **$736** | **($1)** | **($104)** | **($443)** | **($38)** | **($68)** |
| 39. | **Adjusted Indifference Amount with RF&U** | **Line 37 + Line 38** | $000 | **($3,374)** | **($1,086)** | **$166,775** | **$524,285** | **$59,513** | **($70)** | **($8,440)** | **($35,798)** | **($3,079)** | **($5,461)** |
| 40. | **Cummulative Adjusted Indifference Amount with RF&U** | | $000 | **($3,374)** | **($1,086)** | **$166,775** | **$691,060** | **$750,573** | **$750,503** | **$742,063** | **$706,266** | **$703,187** | **$697,726** |

## TABLE 8-8
## INDIFFERENCE AMOUNT CALCULATION
## PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019 AND D.21-03-051, AND D.23-06-066
## (CONTINUED)

| Line No. | Description | Equation | Unit | UOG Legacy and Vintaged PCIA 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Cost of Portfolio** | | | | | | | | | | | | | |
| 1. | Portfolio Total Cost | | $000 | $1,764 | $9,165 | $60 | $37,874 | $0 | $158,684 | ($0) | $19,443 | $384 | $577 | $0 |
| 2. | CRS Eligible Non-Renewable Supply at Generation Meter | | GWh | 11 | 58 | 0 | 0 | 0 | -514 | 0 | 0 | 0 | 0 | 0 |
| 3. | CRS Eligible Renewable Supply at Generation Meter | | GWh | 27 | 121 | 0 | 0 | 0 | 865 | 0 | 16 | 6 | 8 | 0 |
| 4. | CRS Eligible System NQC | | MW | 0 | 7 | 0 | -21 | 0 | 6 | 0 | 1 | 0 | 1 | 0 |
| 5. | CRS Eligible Local NQC - PG&E | | MW | 2 | 22 | 0 | 95 | 0 | 120 | 0 | 0 | 0 | 0 | 0 |
| 6. | CRS Eligible Local NQC - SCE | | MW | 0 | 0 | 0 | 60 | 0 | 115 | 0 | 0 | 0 | 0 | 0 |
| 7. | CRS Eligible Local NQC - SDG&E | | MW | 0 | 0 | 0 | 42 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8. | CRS Eligible Flexible NQC | | MW | 0 | 9 | 0 | 62 | 0 | 480 | 0 | 52 | 0 | 0 | 0 |
| 9. | **Portfolio Unit Cost** | **Line 1 / (Line 2 + Line 3)** | **$/MWh** | **$46.94** | **$51.28** | **$0.00** | **$0.00** | **$0.00** | **$451.06** | **$0.00** | **$1,200.46** | **$67.15** | **$69.17** | **$0.00** |
| 10. | **Market Value of Portfolio** | | | | | | | | | | | | | |
| 11. | **Market Value of Brown Portfolio** | | | | | | | | | | | | | |
| 12. | Non-Renewable Energy | | GWh | 11 | 58 | 0 | 0 | 0 | -514 | 0 | 0 | 0 | 0 | 0 |
| 13. | Weighted Average Brown Benchmark | | $/MWh | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 | $45.75 |
| 14. | **Market Value of Brown Portfolio** | **Line 12 x Line 13** | **$000** | **$484** | **$2,631** | **$0** | **$0** | **$0** | **($23,499)** | **$0** | **$0** | **$0** | **$0** | **$0** |
| 15. | **Market Value of Green Portfolio** | | | | | | | | | | | | | |
| 16. | Renewable Energy | | GWh | 27 | 121 | 0 | 0 | 0 | 865 | 0 | 16 | 6 | 8 | 0 |
| 17. | Weighted Average Green Benchmark | | $/MWh | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 | $108.20 |
| 18. | **Market Value of Green Portfolio** | **Line 16 x Line 17** | **$000** | **$2,923** | **$13,117** | **$0** | **$0** | **$0** | **$93,640** | **$0** | **$1,752** | **$618** | **$903** | **$0** |
| 19. | **Capacity Adder** | | | | | | | | | | | | | |
| 20. | Average Monthly System NQC | | MW | 0 | 7 | 0 | (21) | 0 | 6 | 0 | 1 | 0 | 1 | 0 |
| 21. | System RA Benchmark | | $/kW-Year | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 |
| 22. | Average Monthly Local Area NQC - PG&E | | MW | 2 | 22 | 0 | 95 | 0 | 120 | 0 | 0 | 0 | 0 | 0 |
| 23. | Local RA Benchmark - PG&E | | $/kW-Year | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 |
| 24. | Average Monthly Local Area NQC - SCE | | MW | 0 | 0 | 0 | 60 | 0 | 115 | 0 | 0 | 0 | 0 | 0 |
| 25. | Local RA Benchmark - SCE | | $/kW-Year | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 |
| 26. | Average Monthly Local Area NQC - SDG&E | | MW | 0 | 0 | 0 | 42 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 27. | Local RA Benchmark - SDG&E | | $/kW-Year | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 |
| 28. | Average Monthly Flexible NQC | | MW | 0 | 9 | 0 | 62 | 0 | 480 | 0 | 52 | 0 | 0 | 0 |
| 29. | Flexible RA Benchmark | | $/kW-Year | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 | $138.36 |
| 30. | **Market Value of Capacity** | | **$000** | **$331** | **$5,247** | **$0** | **$32,893** | **$0** | **$99,712** | **$0** | **$7,354** | **$44** | **$201** | **$0** |
| 31. | **Portfolio Market Value** | **Line 14 + Line 18 + Line 30** | $000 | **$3,737** | **$20,994** | **$0** | **$32,893** | **$0** | **$169,854** | **$0** | **$9,106** | **$662** | **$1,104** | **$0** |
| 32. | **Indifference Amount** | | | | | | | | | | | | | |
| 33. | **Portfolio Total Cost** | **Line 1** | $000 | **$1,764** | **$9,165** | **$60** | **$37,874** | **$0** | **$158,684** | **($0)** | **$19,443** | **$384** | **$577** | **$0** |
| 34. | **Portfolio Market Value** | **Line 31** | $000 | **$3,737** | **$20,994** | **$0** | **$32,893** | **$0** | **$169,854** | **$0** | **$9,106** | **$662** | **$1,104** | **$0** |
| 35. | **Total Indifference Amount (Unadjusted)** | **Line 33 - Line 34** | $000 | **($1,973)** | **($11,829)** | **$60** | **$4,981** | **$0** | **($11,170)** | **($0)** | **$10,337** | **($278)** | **($527)** | **$0** |
| 36. | **Other Adjustments** | | $000 | | | | | | | | | | | |
| 37. | **Adjusted Indifference Amount** | **Line 35 + Line 36** | $000 | **($1,973)** | **($11,829)** | **$60** | **$4,981** | **$0** | **($11,170)** | **($0)** | **$10,337** | **($278)** | **($527)** | **$0** |
| 38. | **Revenue Franchise Fees & Uncollectibles (RF&U)** | **Advice 4989-G/7419-E** | $000 | **($25)** | **($148)** | **$1** | **$62** | **$0** | **($140)** | **($0)** | **$129** | **($3)** | **($7)** | **$0** |
| 39. | **Adjusted Indifference Amount with RF&U** | **Line 37 + Line 38** | $000 | **($1,998)** | **($11,977)** | **$61** | **$5,043** | **$0** | **($11,310)** | **($0)** | **$10,466** | **($282)** | **($533)** | **$0** |
| 40. | **Cummulative Adjusted Indifference Amount with RF&U** | | $000 | **$695,728** | **$683,751** | **$683,812** | **$688,855** | **$688,855** | **$677,545** | **$677,545** | **$688,011** | **$687,730** | **$687,196** | **$687,196** |

**TABLE 9-1**
**2026 TMNBC REVENUE REQUIREMENT**
**(THOUSANDS OF DOLLARS)**

| Line No. | Description | Table Cross Reference | Revenue Requirement |
|---|---|---|---|
| 1 | Tree Mortality Non-Bypassable Charge (TMNBC) | | |
| 2 | Post-2002 Contracted Resources | | |
| 3 | RPS-Eligible | | |
| 4 | RPS-Eligible Contracts | Table 4-5, line 56 | [redacted] |
| 5 | RPS-Eligible Contracts Sales | Table 4-5, line 57 | [redacted] |
| 6 | RPS-Eligible Future Contracts | Table 4-5, line 58 | [redacted] |
| 7 | RPS-Eligible Future Sales | Table 4-5, line 59 | [redacted] |
| 8 | Resource Adequacy Sales | Table 4-5, line 60 | [redacted] |
| 9 | CAISO Costs (GMCs) | Table 5-20, line 6 | [redacted] |
| 10 | CAISO Revenues | | [redacted] |
| 11 | Net Costs | | $33,929 |
| 12 | RF&U @ 0.01252 | | 425 |
| 13 | Total Revenue Requirement | | $34,354 |

**TABLE 10-1**
**2026 BIOMAT REVENUE REQUIREMENT**
**(THOUSANDS OF DOLLARS)**

| Line No. | Description | Table Cross Reference | Revenue Requirement |
|---|---|---|---|
| 1 | Bioenergy Market Adjustment Tariff (BioMAT) | | |
| 2 | Post-2002 Contracted Resources | | |
| 3 | RPS-Eligible | | |
| 4 | RPS-Eligible Contracts | Table 4-5, line 51 | [redacted] |
| 5 | Grid Management Charges | Table 5-20, line 7 | [redacted] |
| 6 | CAISO Revenues | | [redacted] |
| 7 | REC Market Value | | (7,500) |
| 8 | RA Capacity Market Value | | (1,520) |
| 9 | Net Costs | | $10,035 |
| 10 | RF&U @ 0.01252 | | 126 |
| 11 | Total Revenue Requirement | | $10,160 |

**TABLE 11-1**
**2026 ERRA REVENUE REQUIREMENT**
**(THOUSANDS OF DOLLARS)**

| Line No. | Description | Table Cross Reference | Revenue Requirement |
|---|---|---|---|
| 1 | Energy Resource Recovery Account (ERRA) | | |
| 2 | Bundled Load Requirement | Table 5-20, line 9 | [redacted] |
| 3 | Other Load | Table 5-20, line 10 | [redacted] |
| 4 | Grid Management Charges | Table 5-20, line 4 | [redacted] |
| 5 | Utility-Owned Generation | | [redacted] |
| 6 | Energy Storage | Table 4-5, line 69 | [redacted] |
| 7 | Other Bilateral Contracts | | [redacted] |
| 8 | Future Non-RPS-Eligible Hydro Sales | Table 4-5, line 71 | [redacted] |
| 9 | Non-RPS-Eligible Hydro Sales | Table 4-5, line 72 | [redacted] |
| 10 | QF | Table 4-5, line 73 | [redacted] |
| 11 | RA Contracts | Table 4-5, line 74 | [redacted] |
| 12 | RPS-Eligible Future Contracts | Table 4-5, line 75 | [redacted] |
| 13 | Hedging Costs | Table 5-1, line 9 | [redacted] |
| 14 | Collateral & Interest Expense | See Note (a) | 9,524 |
| 15 | UOG-Related Costs | See Note (b) | (728) |
| 16 | CAISO Revenues | | [redacted] |
| 17 | Resource RA and REC Market Benchmark Value | | |
| 18 | PCIA REC Value | Table 8-8 calculations | 676,686 |
| 19 | PCIA RA Value | Table 8-8 calculations | 645,482 |
| 20 | CTC REC Value | Table 8-8 calculations | 5,508 |
| 21 | CTC RA Value | Table 8-8 calculations | 24,727 |
| 22 | PPCP REC Value | Table 8-8 calculations | 1,070 |
| 23 | PPCP RA Value | Table 8-8 calculations | 209 |
| 24 | BioMAT REC Value | Table 10-1, line 7 | 7,500 |
| 25 | BioMAT RA Value | Table 10-1, line 8 | 1,520 |
| 26 | Net Costs | | $2,915,382 |
| 27 | RF&U @ 0.01252 | | 36,501 |
| 28 | Total Revenue Requirement | | $2,951,883 |

(a) The Collateral Interest Expense of $7.6 million in Table 5-2 is allocated between ERRA and PABA.

(b) The UOG-Related Cost amount in this table excludes RF&U. The revenue requirement including RF&U is shown in Table 8-1.

**TABLE 12-1**
**2026 FORECAST YEAR-END BALANCES**
**(THOUSANDS OF DOLLARS)**

| Line No. | | August Recorded Balance | Forecast Customer Revenue | Forecast Cost and Interest | Forecast Year End Balance | Balance Transfers of RUBA to ERRA authorized in D. 20-06-003 | Balance Transfers of ERRA to PABA authorized in D. 22-01-023 | RF&U per Advice 4889-G/ 7419-E 0.01252 | Forecast Year End Balance after Balance Transfers, including RF&U | The Recorded/Forecast Year End Balance (including RF&U) as presented in Table 13-1, for amortization in 2026 Rates comprises: Recorded/ Forecast Year End Balance with RF&U | The Recorded/Forecast Year End Balance (including RF&U) as presented in Table 13-1, for amortization in 2026 Rates comprises: Balance Transfers of RUBA to ERRA authorized in D. 20-06-003 | The Recorded/Forecast Year End Balance (including RF&U) as presented in Table 13-1, for amortization in 2026 Rates comprises: Balance Transfers of ERRA to PABA authorized in D. 22-01-023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D)= Σ (A..C) | (E) | (F) | (G) | (H)= Σ (D..G) | (I) | (J) | (K) |
| 1 | Non-PPP | | | | | | | | | | | |
| 2 | NSGBA | $140,345 | ($107,115) | $93,705 | $126,935 | | | $1,589 | $128,524 | $128,524 | $0 | |
| 3 | MTCBA | (13,906) | 17,054 | 33,503 | 36,651 | | | 459 | 37,110 | 37,110 | | |
| 4 | PABA | 972,898 | 98,431 | 1,168,546 | 2,239,875 | | (1,833,754) | 5,085 | 411,206 | 2,267,918 | 0 | (1,856,712) |
| 5 | VAMOMA | 646 | | | 646 | | | 8 | 654 | 654 | | |
| 6 | ERRA | (678,672) | (1,423,420) | 249,456 | (1,852,636) | 18,882 | 1,833,754 | 0 | 0 | (1,875,831) | 19,119 | 1,856,712 |
| 7 | RUBA-E | 18,882 | | | 18,882 | (18,882) | | 0 | 0 | 19,119 | (19,119) | |
| 8 | Subtotal (Non-PPP) | $440,192 | ($1,415,049) | $1,545,210 | $570,353 | $0 | $0 | $7,141 | $577,494 | $577,494 | $0 | $0 |
| 9 | PPP | | | | | | | | | | | |
| 10 | PPCP | ($1,296) | $668 | ($2) | ($630) | | | ($8) | ($638) | ($638) | | |
| 11 | TMNBCBA | 8,821 | (15,477) | 13,792 | 7,136 | | | 89 | 7,225 | 7,225 | | |
| 12 | BNBCBA | (1,270) | 1,308 | 3,520 | 3,558 | | | 45 | 3,602 | 3,602 | | |
| 13 | Subtotal (PPP) | $6,255 | ($13,501) | $17,310 | $10,064 | $0 | $0 | $126 | $10,190 | $10,190 | $0 | $0 |
| **14** | **Total (Non-PPP and PPP)** | **$446,447** | **($1,428,551)** | **$1,562,520** | **$580,417** | **$0** | **$0** | **$7,267** | **$587,684** | **$587,684** | **$0** | **$0** |

Totals may not add due to rounding

## TABLE 12-2
## 2026 FORECAST YEAR-END VINTAGED PABA BALANCES
## (THOUSANDS OF DOLLARS)

| Line No. | | Legacy UOG Subaccount | Vintage Subaccounts | | | | | | | | | | | | | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Vin 2009 | Vin 2010 | Vin 2011 | Vin 2012 | Vin 2013 | Vin 2014 | Vin 2015 | Vin 2016 | Vin 2017 | Vin 2018 | Vin 2019 | Vin 2020 | Vin 2021 | Vin 2022 | Vin 2023 | Vin 2024 | Vin 2025 | |
| 1 | Recorded from January to August (a) | | | | | | | | | | | | | | | | | | | |
| 2 | Recorded Beginning Balance as of January | $295,082 | $466,462 | $100,052 | $50,688 | $69,475 | $36,501 | $1,130 | $2,298 | $2,256 | ($2,039) | ($67,821) | ($3,716) | ($4,262) | $16,243 | ($3,764) | ($44,532) | $0 | $0 | $914,052 |
| 3 | PCIA Customer Revenue | (136,561) | (335,153) | (32,452) | (5,544) | 4,677 | 12,714 | 4,303 | 1,948 | 2,571 | 12,929 | 113,912 | 73,850 | 2,757 | 423,475 | 4,087 | 50,212 | 97,171 | (71,450) | 223,444 |
| 4 | Portfolio Costs | 1,063,135 | 825,513 | 201,553 | 59,833 | 72,444 | 30,718 | 7,058 | 11,685 | 1,090 | 88 | (133) | 508 | (380) | 14,482 | 23 | (1,275) | (22) | 0 | 2,286,322 |
| 5 | Energy Value | (563,452) | (93,968) | (33,372) | (16,913) | (16,979) | (9,914) | (1,394) | (2,271) | (416) | (2,584) | 0 | 0 | 0 | (588) | 0 | (61) | 0 | 0 | (741,912) |
| 6 | RPS Value | (2,278) | (153,188) | (120,460) | (33,516) | (34,035) | (29,331) | (6,264) | (10,406) | (1,198) | (5,875) | (69,592) | 0 | 0 | (4,933) | 0 | (233) | 0 | 69,592 | (401,718) |
| 7 | RA Value | (635,847) | (191,026) | (25,864) | (9,468) | (16,376) | (4,509) | (500) | (1,581) | (207) | (10,676) | 0 | (84,130) | 0 | (133,277) | 0 | (92) | 0 | 0 | (1,113,553) |
| 8 | One Time Adjustments | (18,533) | 13,963 | 1,309 | 1,100 | 1,441 | 50 | 9 | 15 | 1 | 7 | 0 | (0) | (3) | 6 | 0 | 0 | (210,595) | 0 | (211,231) |
| 9 | Interest | 446 | 12,705 | 2,703 | 1,397 | 2,105 | 1,098 | 97 | 79 | 96 | (122) | (1,551) | (118) | (91) | 4,186 | (167) | (849) | (4,596) | 73 | 17,492 |
| 10 | Recorded August Balance | $1,992 | $545,308 | $93,467 | $47,575 | $82,752 | $37,327 | $4,440 | $1,768 | $4,195 | ($8,272) | ($25,185) | ($13,606) | ($1,979) | $319,595 | $179 | $3,170 | ($118,043) | ($1,785) | $972,898 |
| 11 | Forecast from September to December (b) | | | | | | | | | | | | | | | | | | | |
| 12 | PCIA Customer Revenue | ($67,146) | ($169,277) | ($16,998) | ($2,572) | ($1,605) | $9,140 | $1,157 | $1,617 | $100 | $6,531 | $56,847 | $36,018 | $1,377 | $204,529 | $1,582 | $23,559 | $47,094 | ($33,521) | $98,431 |
| 13 | Portfolio Costs | 480,981 | 554,270 | 170,546 | 58,196 | 64,502 | 18,043 | 4,288 | 4,995 | 680 | 4,201 | 21 | 23,250 | 0 | 42,493 | (0) | 1,678 | 0 | 0 | 1,428,144 |
| 14 | Energy Value | (162,436) | (219,957) | (34,262) | (14,320) | (22,039) | (10,771) | (1,907) | (3,331) | (416) | (1,980) | 0 | 0 | 0 | (188) | 0 | (186) | 0 | 0 | (471,794) |
| 15 | RPS Value | (5,691) | (60,621) | (53,154) | (11,659) | (16,178) | (8,144) | (5,116) | (2,335) | (333) | (1,530) | (54,619) | 0 | (28,438) | (8,110) | 0 | (267) | 0 | 83,057 | (173,138) |
| 16 | RA Value | 279,892 | 34,353 | 5,736 | 3,272 | 1,926 | 1,088 | (187) | (283) | 2 | 2,358 | 0 | 8,083 | 0 | 24,510 | 0 | (290) | 0 | 0 | 360,461 |
| 17 | One Time Adjustments | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | Interest | 4,479 | 9,330 | 2,168 | 1,047 | 1,468 | 611 | 203 | 34 | 60 | (39) | (206) | 341 | (68) | 6,489 | 14 | 218 | (1,314) | 38 | 24,873 |
| 19 | Forecast transactions from September to December | $530,079 | $148,099 | $74,036 | $33,963 | $28,074 | $9,965 | ($1,561) | $696 | $93 | $9,540 | $2,042 | $67,692 | ($27,128) | $269,724 | $1,596 | $24,713 | $45,780 | $49,574 | $1,266,978 |
| 20 | Forecast Year End Balance (c) = (a) + (b) | | | | | | | | | | | | | | | | | | | |
| 21 | Recorded Beginning Balance as of January | $295,082 | $466,462 | $100,052 | $50,688 | $69,475 | $36,501 | $1,130 | $2,298 | $2,256 | ($2,039) | ($67,821) | ($3,716) | ($4,262) | $16,243 | ($3,764) | ($44,532) | $0 | $0 | $914,052 |
| 22 | PCIA Customer Revenue | (203,707) | (504,430) | (49,450) | (8,116) | 3,072 | 21,853 | 5,460 | 3,565 | 2,671 | 19,460 | 170,759 | 109,868 | 4,134 | 628,004 | 5,669 | 73,771 | 144,265 | (104,971) | 321,876 |
| 23 | Portfolio Costs | 1,544,116 | 1,379,784 | 372,099 | 118,030 | 136,946 | 48,761 | 11,346 | 16,680 | 1,771 | 4,288 | (112) | 23,758 | (380) | 56,975 | 23 | 403 | (22) | 0 | 3,714,466 |
| 24 | Energy Value | (725,888) | (313,924) | (67,634) | (31,234) | (39,018) | (20,685) | (3,301) | (5,602) | (832) | (4,565) | 0 | 0 | 0 | (776) | 0 | (247) | 0 | 0 | (1,213,706) |
| 25 | RPS Value | (7,968) | (213,808) | (173,615) | (45,176) | (50,213) | (37,475) | (11,380) | (12,741) | (1,531) | (7,405) | (124,211) | 0 | (28,438) | (13,043) | 0 | (500) | 0 | 152,649 | (574,856) |
| 26 | RA Value | (355,955) | (156,674) | (20,128) | (6,196) | (14,450) | (3,421) | (686) | (1,863) | (205) | (8,318) | 0 | (76,047) | 0 | (108,767) | 0 | (382) | 0 | 0 | (753,091) |
| 27 | One Time Adjustments | (18,533) | 13,963 | 1,309 | 1,100 | 1,441 | 50 | 9 | 15 | 1 | 7 | 0 | (0) | (3) | 6 | 0 | 0 | (210,595) | 0 | (211,231) |
| 28 | Interest | 4,925 | 22,036 | 4,870 | 2,443 | 3,573 | 1,709 | 300 | 113 | 157 | (161) | (1,757) | 223 | (158) | 10,676 | (153) | (631) | (5,910) | 111 | 42,365 |
| 29 | Forecast Year End Balance before Transfer | $532,071 | $693,407 | $167,503 | $81,539 | $110,826 | $47,292 | $2,879 | $2,464 | $4,287 | $1,267 | ($23,143) | $54,086 | ($29,108) | $589,319 | $1,775 | $27,883 | ($72,263) | $47,789 | $2,239,875 |
| 30 | Balance Transfers from ERRA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (1,833,754) | (1,833,754) |
| 31 | Forecast Year End Balance after Transfer from ERRA | $532,071 | $693,407 | $167,503 | $81,539 | $110,826 | $47,292 | $2,879 | $2,464 | $4,287 | $1,267 | ($23,143) | $54,086 | ($29,108) | $589,319 | $1,775 | $27,883 | ($72,263) | ($1,785,965) | $406,121 |
| 32 | RF&U per Advice 4839-G/7086-E @ 0.01252 | 6,662 | 8,681 | 2,097 | 1,021 | 1,388 | 592 | 36 | 31 | 54 | 16 | (290) | 677 | (364) | 7,378 | 22 | 349 | (905) | (22,360) | 5,085 |
| **33** | **Forecast Year End Balance after Transfer from ERRA (Including RF&U)** | **$538,733** | **$702,089** | **$169,600** | **$82,560** | **$112,213** | **$47,885** | **$2,915** | **$2,495** | **$4,341** | **$1,283** | **($23,432)** | **$54,763** | **($29,472)** | **$596,697** | **$1,797** | **$28,232** | **($73,167)** | **($1,808,325)** | **$411,206** |

Totals may not add due to rounding

**TABLE 12-6**
**VAMO ADMINISTRATIVE COSTS ACCRUED BALANCE SUMMARY**
**(BY MONTH)**

| Line No. | VAMO Order Number | Order Description | 2024 Sep | 2024 Oct | 2024 Nov | 2024 Dec | 2024 Total | 2025 Jan | 2025 Feb | 2025 Mar | 2025 Apr | 2025 May | 2025 Jun | 2025 Jul | 2025 Aug | 2025 Total | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 8202617 | VAMO Costs | $8,710.24 | $5,146.96 | $7,522.48 | $9,502.08 | $30,881.76 | $6,944.00 | $8,246.00 | $10,850.00 | $8,680.00 | $8,680.00 | $3,472.00 | $14,322.00 | $9,982.00 | $71,176.00 | $102,057.76 |
| 2 | 8203065 | VAMO RFI Process | 2,472.28 | 6,178.30 | 3,098.72 | 7,967.87 | 19,717.17 | 8,493.32 | | 2,674.66 | | | | | | 11,167.98 | 30,885.15 |
| 3 | 8203066 | VAMO Allocation and Market Offer (RFI/RFO) | 580.83 | | | 8,776.76 | 9,357.59 | | | | | | | | | 0.00 | 9,357.59 |
| 4 | 8203067 | VAMO Back Office Support | 9,378.36 | 10,813.57 | 9,996.99 | 7,101.83 | 37,290.75 | 8,191.75 | 8,598.65 | 42,966.03 | 46,899.13 | 29,105.14 | 32,929.76 | 30,325.76 | 28,861.02 | 227,877.24 | 265,167.99 |
| 5 | 8203068 | VAMO Compliance Support | 243.60 | | | | 243.60 | | | 767.58 | 639.65 | 255.86 | 511.72 | | | 2,174.81 | 2,418.41 |
| 6 | 8203069 | VAMO Law Support | | 112.38 | 1,198.72 | 1,086.34 | 2,397.44 | 2,555.68 | 439.26 | | | | | | | 2,994.94 | 5,392.38 |
| 7 | 8203073 | VAMO Systems/IT | 28,258.01 | 55,840.60 | 11,347.42 | | 95,446.03 | 4,589.60 | 7,572.84 | | 6,775.53 | 37,739.52 | 32,998.32 | 23,144.50 | 22,224.37 | 135,044.68 | 230,490.71 |
| 8 | | Grand Total | $49,643.32 | $78,091.81 | $33,164.33 | $34,434.88 | $195,334.34 | $30,774.35 | $24,856.75 | $57,258.27 | $62,994.31 | $75,780.52 | $69,911.80 | $67,792.26 | $61,067.39 | $450,435.65 | $645,769.99 |

# TABLE 13-1
# SUMMARY OF 2026 FORECAST ENERGY PROCUREMENT REVENUE REQUIREMENTS
# (THOUSANDS OF DOLLARS)

| Line No. | | 2026 Cost With Revenue Fees and Uncollectibles[(a)] | 2025 Year End Balance[(b)] | Authorized Transfers [(d)] | 2025 Year End transfers to PABA [(e)] | 2026 Revenue Requirements |
|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) = SUM (A..D) |
| 1 | Non-PPP | | | | | |
| 2 | CAM (NSGC) | $244,266 | $128,524 | $0 | | $372,790 |
| 3 | Ongoing CTC (MTCBA) | (3,374) | 37,110 | | | 33,736 |
| 4 | PCIA/PABA | 687,196 | 2,267,918 | 0 | (1,856,712) | 1,098,402 |
| 5 | VAMOMA [(c)] | | 654 | | | 654 |
| 6 | ERRA | 2,951,883 | (1,875,831) | 19,119 | 1,856,712 | 2,951,883 |
| 7 | RUBA-E | | 19,119 | (19,119) | | 0 |
| 8 | Non-PPP Subtotal | $3,879,971 | $577,494 | $0 | $0 | $4,457,465 |
| 9 | PPP | | | | | |
| 10 | PPCP | (1,086) | (638) | | | (1,723) |
| 11 | TMNBC | 34,354 | 7,225 | | | 41,579 |
| 12 | BioMat | 10,160 | 3,602 | | | 13,763 |
| 13 | PPP Subtotal | $43,428 | $10,190 | $0 | $0 | $53,618 |
| **14** | **Revenue Requirement for Rate Setting** | **$3,923,400** | **$587,684** | **$0** | **$0** | **$4,511,083** |
| 15 | Revenue Requirements authorized in other proceedings | | | | | |
| 16 | UOG-Related Costs [(g)] | (1,231,267) | | | | (1,231,267) |
| 17 | RUBA-E | | (19,119) | | | (19,119) |
| 18 | Subtotal | ($1,231,267) | ($19,119) | $0 | $0 | ($1,250,386) |
| **19** | **2026 ERRA Application Revenue Requirement Request** | **$2,692,132** | **$568,565** | **$0** | **$0** | **$3,260,697** |

Notes:

(a) Costs exclude GTSR Program Costs

(b) The year-end balaning account balances recovered in rates through the AET, and/or a subsequent rate change advice letter.

(c) Pursuant to Electric Preliminary Statement Part JC, the VAMOMA blance approved by the Commission is recoverable through the PABA.

(d) The authorization of recovery of the RUBA-E is D.20-06-003 (as well as Advice 6001-E-A).

(e) Balance Transfers to PABA includes the transfer from ERRA balances as authorized in D.22-01-023.

## TABLE 13-3
## PROPOSED PCIA RATES BY CLASS AND VINTAGE
## (WITH DWR FRANCHISE FEE)
## (DOLLARS PER kWh)

| Line No. | Customer Class | 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 | 2023 Vintage | 2024 Vintage | 2025 Vintage | 2026 Vintage |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential | $0.02854 | $0.03196 | $0.03323 | $0.03485 | $0.03504 | $0.03504 | $0.03499 | $0.03503 | $0.03483 | $0.03429 | $0.03608 | $0.03515 | $0.05573 | $0.05580 | $0.05726 | $0.05444 | ($0.01514) | ($0.01514) |
| 2 | Small L&P | $0.02777 | $0.03110 | $0.03233 | $0.03391 | $0.03410 | $0.03409 | $0.03405 | $0.03408 | $0.03389 | $0.03337 | $0.03511 | $0.03420 | $0.05422 | $0.05429 | $0.05572 | $0.05297 | ($0.01473) | ($0.01473) |
| 3 | Medium L&P | $0.02926 | $0.03277 | $0.03408 | $0.03574 | $0.03593 | $0.03593 | $0.03588 | $0.03592 | $0.03572 | $0.03517 | $0.03700 | $0.03604 | $0.05715 | $0.05722 | $0.05872 | $0.05583 | ($0.01553) | ($0.01553) |
| 4 | E19 | $0.02776 | $0.03109 | $0.03232 | $0.03390 | $0.03409 | $0.03408 | $0.03404 | $0.03407 | $0.03388 | $0.03336 | $0.03510 | $0.03419 | $0.05421 | $0.05427 | $0.05570 | $0.05295 | ($0.01473) | ($0.01473) |
| 5 | Streetlights | $0.02331 | $0.02611 | $0.02715 | $0.02847 | $0.02863 | $0.02862 | $0.02858 | $0.02862 | $0.02845 | $0.02801 | $0.02948 | $0.02871 | $0.04552 | $0.04557 | $0.04677 | $0.04447 | ($0.01236) | ($0.01236) |
| 6 | Standby | $0.01958 | $0.02193 | $0.02280 | $0.02391 | $0.02404 | $0.02404 | $0.02401 | $0.02404 | $0.02390 | $0.02353 | $0.02476 | $0.02412 | $0.03823 | $0.03828 | $0.03928 | $0.03735 | ($0.01037) | ($0.01037) |
| 7 | Agriculture | $0.02635 | $0.02951 | $0.03069 | $0.03219 | $0.03236 | $0.03236 | $0.03231 | $0.03235 | $0.03217 | $0.03167 | $0.03332 | $0.03246 | $0.05146 | $0.05153 | $0.05288 | $0.05027 | ($0.01398) | ($0.01398) |
| 8 | B20/E20 T (Excluding FPP) | $0.02460 | $0.02754 | $0.02864 | $0.03004 | $0.03020 | $0.03020 | $0.03016 | $0.03019 | $0.03002 | $0.02956 | $0.03110 | $0.03029 | $0.04803 | $0.04808 | $0.04935 | $0.04692 | ($0.01304) | ($0.01304) |
| 9 | B20/E20 P (Excluding FPP) | $0.02508 | $0.02808 | $0.02920 | $0.03062 | $0.03079 | $0.03079 | $0.03075 | $0.03078 | $0.03061 | $0.03013 | $0.03171 | $0.03088 | $0.04896 | $0.04902 | $0.05031 | $0.04783 | ($0.01330) | ($0.01330) |
| 10 | B20/E20 S (Excluding FPP) | $0.02593 | $0.02903 | $0.03019 | $0.03166 | $0.03183 | $0.03183 | $0.03179 | $0.03182 | $0.03165 | $0.03115 | $0.03278 | $0.03193 | $0.05063 | $0.05069 | $0.05202 | $0.04946 | ($0.01375) | ($0.01375) |
| 11 | BEV1 | $0.02261 | $0.02533 | $0.02633 | $0.02762 | $0.02777 | $0.02777 | $0.02773 | $0.02776 | $0.02760 | $0.02717 | $0.02859 | $0.02785 | $0.04416 | $0.04421 | $0.04538 | $0.04314 | ($0.01200) | ($0.01200) |
| 12 | BEV2 | $0.02611 | $0.02924 | $0.03040 | $0.03188 | $0.03206 | $0.03206 | $0.03201 | $0.03205 | $0.03187 | $0.03137 | $0.03301 | $0.03215 | $0.05098 | $0.05104 | $0.05238 | $0.04980 | ($0.01385) | ($0.01385) |
| 13 | System Average PCIA Rate by Vintage | $0.02607 | $0.02897 | $0.03219 | $0.03306 | $0.03409 | $0.03451 | $0.03429 | $0.03430 | $0.03365 | $0.03379 | $0.03398 | $0.03425 | $0.05391 | $0.05335 | $0.05390 | $0.05059 | ($0.01480) | ($0.01480) |

**TABLE 13-4**
**PCIA REVENUES ALLOCATION SUMMARY**
**(THOUSANDS OF DOLLARS)**

| Line No. | Description | Expected PCIA Revenues From PCIA Rates |
|---|---|---|
| 1 | Bundled Customers | $(362,845) |
| 2 | DA/CCA Customers | 1,461,901 |
| 3 | Total Revenues | $1,099,056 |

**TABLE 13-5**
**PROPOSED 2026 AVERAGE TOTAL GENERATION RATES FOR BUNDLED CUSTOMERS**
**(DOLLARS PER kWh)**

| Line No. | Customer Class | Proposed Rate |
|---|---|---|
| 1 | Residential | $0.12349 |
| 2 | Small Commercial | $0.12015 |
| 3 | Medium Commercial | $0.12663 |
| 4 | Large Commercial | $0.12011 |
| 5 | Streetlights | $0.10085 |
| 6 | Standby | $0.08469 |
| 7 | Agriculture | $0.11403 |
| 8 | B20/E20 T | $0.10641 |
| 9 | B20/E20 P | $0.10849 |
| 10 | B20/E20 S | $0.11217 |
| 11 | BEV1 | $0.09785 |
| 12 | BEV2 | $0.11296 |

**TABLE 13-6**
**PROPOSED 2026 ONGOING CTC RATES**
**(DOLLARS PER kWh)**

| Line No. | Customer Class | Proposed Rate |
|---|---|---|
| 1 | Residential | $0.00046 |
| 2 | Small Commercial | $0.00045 |
| 3 | Medium Commercial | $0.00047 |
| 4 | Large Commercial | $0.00045 |
| 5 | Streetlights | $0.00038 |
| 6 | Standby | $0.00032 |
| 7 | Agriculture | $0.00043 |
| 8 | B20/E20 T | $0.00040 |
| 9 | B20/E20 P | $0.00041 |
| 10 | B20/E20 S | $0.00042 |
| 11 | BEV1 | $0.00045 |
| 12 | BEV2 | $0.00045 |

**TABLE 13-7**
**PROPOSED 2026 NSGC RATES**
**(DOLLARS PER kWh)**

| Line No. | Customer Class | Proposed Rate |
|---|---|---|
| 1 | Residential | $0.00685 |
| 2 | Small Commercial | $0.00449 |
| 3 | Medium Commercial | $0.00399 |
| 4 | Large Commercial | $0.00399 |
| 5 | Streetlights | $0.00391 |
| 6 | Standby | $0.00413 |
| 7 | Agriculture | $0.00433 |
| 8 | B20/E20 T | $0.00341 |
| 9 | B20/E20 P | $0.00341 |
| 10 | B20/E20 S | $0.00341 |
| 11 | BEV1 | $0.00449 |
| 12 | BEV2 | $0.00399 |

**TABLE 13-8**
**PROPOSED 2026 TREE MORTALITY NON-BYPASSABLE CHARGE RATES**
**(DOLLARS PER kWh)**

| Line No. | Customer Class | Proposed Rate |
|---|---|---|
| 1 | Residential | $0.00076 |
| 2 | Small Commercial | $0.00050 |
| 3 | Medium Commercial | $0.00044 |
| 4 | Large Commercial | $0.00044 |
| 5 | Streetlights | $0.00043 |
| 6 | Standby | $0.00046 |
| 7 | Agriculture | $0.00048 |
| 8 | B20/E20 T | $0.00034 |
| 9 | B20/E20 P | $0.00034 |
| 10 | B20/E20 S | $0.00034 |
| 11 | BEV1 | $0.00050 |
| 12 | BEV2 | $0.00044 |

**TABLE 13- 9**
**PROPOSED 2026 BIOENERGY MARKET ADJUSTING TARIFF RATES**
**(DOLLARS PER kWh)**

| Line No. | Customer Class | Proposed Rate |
|---|---|---|
| 1 | Residential | $0.00025 |
| 2 | Small Commercial | $0.00017 |
| 3 | Medium Commercial | $0.00015 |
| 4 | Large Commercial | $0.00015 |
| 5 | Streetlights | $0.00014 |
| 6 | Standby | $0.00015 |
| 7 | Agriculture | $0.00016 |
| 8 | B20/E20 T | $0.00011 |
| 9 | B20/E20 P | $0.00011 |
| 10 | B20/E20 S | $0.00011 |
| 11 | BEV1 | $0.00017 |
| 12 | BEV2 | $0.00015 |

**TABLE 13-10**
**PROPOSED 2026 PPCP RATES**
**(DOLLARS PER kWh)**

| Line No. | Customer Class | Proposed Rate |
|---|---|---|
| 1 | Residential | $(0.00002) |
| 2 | Small Commercial | $(0.00003) |
| 3 | Medium Commercial | $(0.00002) |
| 4 | Large Commercial | $(0.00002) |
| 5 | Streetlights | $(0.00003) |
| 6 | Standby | $(0.00001) |
| 7 | Agriculture | $(0.00003) |
| 8 | B20/E20 T | $(0.00001) |
| 9 | B20/E20 P | $(0.00001) |
| 10 | B20/E20 S | $(0.00001) |
| 11 | BEV1 | $(0.00003) |
| 12 | BEV2 | $(0.00002) |

**TABLE 14-1**
**GTSR PROGRAM RECORDED AND FORECAST SALES**

| Line No. | Description | Recorded | | | Forecast | |
|---|---|---|---|---|---|---|
| 1 | Fiscal Year | 2022 | 2023 | 2024 | 2025 | 2026 |
| 2 | Program Year | PY 7 | PY 8 | PY 9 | PY 10 | PY 11 |
| 3 | E-GT Sales (MWh/yr) | 440,481 | 375,231 | 316,358 | 187,606 | 162,208 |

**TABLE 14-3**
**GTSR PROGRAM – VINTAGE 2026**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | (1.514) | (1.473) | (1.473) | (1.553) | (1.473) | (1.236) | (1.398) | (1.304) | (1.330) | (1.375) | (1.200) | (1.385) |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **11.847** | **11.888** | **11.888** | **11.808** | **11.888** | **12.125** | **11.963** | **12.057** | **12.031** | **11.986** | **12.161** | **11.976** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **3.794** | **3.724** | **3.724** | **2.549** | **3.199** | **5.003** | **2.531** | **4.168** | **4.005** | **3.716** | **3.997** | **3.287** |

**TABLE 14-4**
**GTSR PROGRAM – VINTAGE 2025**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | (1.514) | (1.473) | (1.473) | (1.553) | (1.473) | (1.236) | (1.398) | (1.304) | (1.330) | (1.375) | (1.200) | (1.385) |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **11.847** | **11.888** | **11.888** | **11.808** | **11.888** | **12.125** | **11.963** | **12.057** | **12.031** | **11.986** | **12.161** | **11.976** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **3.794** | **3.724** | **3.724** | **2.549** | **3.199** | **5.003** | **2.531** | **4.168** | **4.005** | **3.716** | **3.997** | **3.287** |

**TABLE 14-5**
**GTSR PROGRAM – VINTAGE 2024**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | 5.444 | 5.297 | 5.297 | 5.583 | 5.295 | 4.447 | 5.027 | 4.692 | 4.783 | 4.946 | 4.314 | 4.980 |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **18.805** | **18.658** | **18.658** | **18.944** | **18.656** | **17.808** | **18.388** | **18.053** | **18.144** | **18.307** | **17.675** | **18.341** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **10.752** | **10.494** | **10.494** | **9.685** | **9.967** | **10.686** | **8.956** | **10.164** | **10.118** | **10.037** | **9.511** | **9.652** |

**TABLE 14-6**
**GTSR PROGRAM – VINTAGE 2023**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | 5.726 | 5.572 | 5.572 | 5.872 | 5.570 | 4.677 | 5.288 | 4.935 | 5.031 | 5.202 | 4.538 | 5.238 |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **19.087** | **18.933** | **18.933** | **19.233** | **18.931** | **18.038** | **18.649** | **18.296** | **18.392** | **18.563** | **17.899** | **18.599** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **11.034** | **10.769** | **10.769** | **9.974** | **10.242** | **10.916** | **9.217** | **10.407** | **10.366** | **10.293** | **9.735** | **9.910** |

**TABLE 14-7**
**GTSR PROGRAM – VINTAGE 2022**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | 5.580 | 5.429 | 5.429 | 5.722 | 5.427 | 4.557 | 5.153 | 4.808 | 4.902 | 5.069 | 4.421 | 5.104 |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **18.941** | **18.790** | **18.790** | **19.083** | **18.788** | **17.918** | **18.514** | **18.169** | **18.263** | **18.430** | **17.782** | **18.465** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **10.888** | **10.626** | **10.626** | **9.824** | **10.099** | **10.796** | **9.082** | **10.280** | **10.237** | **10.160** | **9.618** | **9.776** |

**TABLE 14-8**
**GTSR PROGRAM – VINTAGE 2021**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | 5.573 | 5.422 | 5.422 | 5.715 | 5.421 | 4.552 | 5.146 | 4.803 | 4.896 | 5.063 | 4.416 | 5.098 |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **18.934** | **18.783** | **18.783** | **19.076** | **18.782** | **17.913** | **18.507** | **18.164** | **18.257** | **18.424** | **17.777** | **18.459** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **10.881** | **10.619** | **10.619** | **9.817** | **10.093** | **10.791** | **9.075** | **10.275** | **10.231** | **10.154** | **9.613** | **9.770** |

**TABLE 14-9**
**GTSR PROGRAM – VINTAGE 2020**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | 3.515 | 3.420 | 3.420 | 3.604 | 3.419 | 2.871 | 3.246 | 3.029 | 3.088 | 3.193 | 2.785 | 3.215 |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **16.876** | **16.781** | **16.781** | **16.965** | **16.780** | **16.232** | **16.607** | **16.390** | **16.449** | **16.554** | **16.146** | **16.576** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **8.823** | **8.617** | **8.617** | **7.706** | **8.091** | **9.110** | **7.175** | **8.501** | **8.423** | **8.284** | **7.982** | **7.887** |

**TABLE 14-10**
**GTSR PROGRAM – VINTAGE 2019**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | 3.608 | 3.511 | 3.511 | 3.700 | 3.510 | 2.948 | 3.332 | 3.110 | 3.171 | 3.278 | 2.859 | 3.301 |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **16.969** | **16.872** | **16.872** | **17.061** | **16.871** | **16.309** | **16.693** | **16.471** | **16.532** | **16.639** | **16.220** | **16.662** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **8.916** | **8.708** | **8.708** | **7.802** | **8.182** | **9.187** | **7.261** | **8.582** | **8.506** | **8.369** | **8.056** | **7.973** |

**TABLE 14-11**
**GTSR PROGRAM – VINTAGE 2018**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | 3.429 | 3.337 | 3.337 | 3.517 | 3.336 | 2.801 | 3.167 | 2.956 | 3.013 | 3.115 | 2.717 | 3.137 |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **16.790** | **16.698** | **16.698** | **16.878** | **16.697** | **16.162** | **16.528** | **16.317** | **16.374** | **16.476** | **16.078** | **16.498** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **8.737** | **8.534** | **8.534** | **7.619** | **8.008** | **9.040** | **7.096** | **8.428** | **8.348** | **8.206** | **7.914** | **7.809** |

**TABLE 14-12**
**GTSR PROGRAM – VINTAGE 2017**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | 3.483 | 3.389 | 3.389 | 3.572 | 3.388 | 2.845 | 3.217 | 3.002 | 3.061 | 3.165 | 2.760 | 3.187 |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **16.844** | **16.750** | **16.750** | **16.933** | **16.749** | **16.206** | **16.578** | **16.363** | **16.422** | **16.526** | **16.121** | **16.548** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **8.791** | **8.586** | **8.586** | **7.674** | **8.060** | **9.084** | **7.146** | **8.474** | **8.396** | **8.256** | **7.957** | **7.859** |

**TABLE 14-13**
**GTSR PROGRAM – VINTAGE 2016**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | 3.503 | 3.408 | 3.408 | 3.592 | 3.407 | 2.862 | 3.235 | 3.019 | 3.078 | 3.182 | 2.776 | 3.205 |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **16.864** | **16.769** | **16.769** | **16.953** | **16.768** | **16.223** | **16.596** | **16.380** | **16.439** | **16.543** | **16.137** | **16.566** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **8.811** | **8.605** | **8.605** | **7.694** | **8.079** | **9.101** | **7.164** | **8.491** | **8.413** | **8.273** | **7.973** | **7.877** |

**TABLE 14-14**
**GTSR PROGRAM – VINTAGE 2015**
**E-GT OPTION**

| Line No. | | E1 cents/kwh | B1 cents/kwh | B6 cents/kwh | B10 cents/kwh | B19 cents/kwh | LS-3 cents/kwh | AG cents/kwh | B20 T cents/kwh | B20 P cents/kwh | B20 S cents/kwh | BEV1 cents/kwh | BEV2 cents/kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Charges** | | | | | | | | | | | | |
| 1 | **Solar Generation Price** | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 | 8.763 |
| 2 | PCIA | 3.499 | 3.405 | 3.405 | 3.588 | 3.404 | 2.858 | 3.231 | 3.016 | 3.075 | 3.179 | 2.773 | 3.201 |
| 3 | Renewable Integration | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Marketing & Administration | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 | 1.493 |
| 5 | Resource Adequacy | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 | 2.986 |
| 6 | CAISO Charges | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 | 0.118 |
| 7 | WREGIS Fees | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 |
| 8 | **Sub Total** | **16.860** | **16.766** | **16.766** | **16.949** | **16.765** | **16.219** | **16.592** | **16.377** | **16.436** | **16.540** | **16.134** | **16.562** |
| 9 | **Credits** | | | | | | | | | | | | |
| 10 | **Class Average Generation Rate** | 10.835 | 10.542 | 10.542 | 11.111 | 10.539 | 8.849 | 10.005 | 9.338 | 9.520 | 9.843 | 10.542 | 10.539 |
| 11 | Solar Value Adjustment | | | | | | | | | | | | |
| 12 | TOD | (3.630) | (3.226) | (3.226) | (2.700) | (2.698) | (2.575) | (1.421) | (2.297) | (2.342) | (2.421) | (3.226) | (2.698) |
| 13 | RA | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 | 0.848 |
| 14 | Other | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | **Subtotal** | 8.053 | 8.164 | 8.164 | 9.259 | 8.689 | 7.122 | 9.432 | 7.889 | 8.026 | 8.270 | 8.164 | 8.689 |
| 16 | **2026 Premium (cents/kwh)** | **8.807** | **8.602** | **8.602** | **7.690** | **8.076** | **9.097** | **7.160** | **8.488** | **8.410** | **8.270** | **7.970** | **7.873** |

## TABLE 15-1
## CONFIDENTIAL ANNUAL GHG EMISSIONS AND ASSOCIATED COSTS
## (TEMPLATE D-2)

| Line No. | Description | Forecast | Recorded | Final | Forecast | Recorded | Final | Forecast | Recorded | Final |
|---|---|---|---|---|---|---|---|---|---|---|
| 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 | | | | | | | | | |
| 9 | **Total Emissions (MT CO2e)** | **2,805,090** | **2,137,158** | **2,360,101** | **2,179,565** | **2,220,181** | **-** | **1,950,513** | **-** | **-** |
| 10 | Proxy GHG Price ($/MT) (a) | 39.62 | 38.65 | 39.14 | 37.58 | 29.52 | - | 30.58 | - | - |
| 11 | GHG Costs ($) | | | | | | | | | |
| 12 | Direct GHG Costs (b) | [redacted] | | | | | | | | |
| 13 | Direct GHG Costs - Financial Settlement | | | | | | | | | |
| 14 | Previous Year's Forecast Reconciliation (Line 21) | N/A | N/A | | (14,438,958) | (14,438,958) | | (10,396,609) | - | |
| 15 | **Total Costs ($)** | **89,829,621** | **75,390,663** | **84,025,499** | **65,645,983** | **46,614,538** | | **47,962,186** | **-** | |
| 16 | Forecast Variance ($) | N/A | (14,438,958) | 8,634,837 | N/A | (19,031,446) | | N/A | - | |

______________

(a) The difference between PG&E's confidential 2022 forecast GHG price and the 2022 forecast GHG proxy price is less than five percent.
(b) D.15-01-024 directs utilities to calculate recorded direct GHG Costs as the sum of each month's weighted average cost (WAC) of compliance instruments held in inventory multiplied by that month's actual GHG emissions. Recorded and Final Direct GHG Costs presented here are consistent with the requirements of D.15-01-024, including accounting true-ups and adjustments to reflect updated information.

## TABLE 15-2
## ILLUSTRATIVE ANNUAL GHG EMISSIONS AND ASSOCIATED COSTS
## (TEMPLATE D-2)

| Line No. | Description | Forecast | Recorded | Final | Forecast | Recorded | Final | Forecast | Recorded | Final |
|---|---|---|---|---|---|---|---|---|---|---|
| 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 | | | | | | | | | |
| 9 | **Total Emissions (MT CO2e)** | **2,805,090** | **2,137,158** | **2,360,101** | **2,179,565** | **2,220,181** | **-** | **1,950,513** | **-** | **-** |
| 10 | Proxy GHG Price ($/MT) (a) | 39.62 | 38.65 | 39.14 | 37.58 | 29.52 | - | 30.58 | - | - |
| 11 | GHG Costs ($) | | | | | | | | | |
| 12 | Direct GHG Costs (b) | [redacted] | | | | | | | | |
| 13 | Direct GHG Costs - Financial Settlement | | | | | | | | | |
| 14 | Previous Year's Forecast Reconciliation (Line 21) | N/A | N/A | | (14,438,958) | (14,438,958) | | (10,396,609) | - | |
| 15 | **Total Costs ($)** | **89,829,621** | **75,390,663** | **84,025,499** | **65,645,983** | **46,614,538** | | **49,250,074** | **-** | |
| 16 | Forecast Variance ($) | N/A | (14,438,958) | 8,634,837 | N/A | (19,031,446) | | N/A | - | |

______________

(a) The difference between PG&E's confidential 2022 forecast GHG price and the 2022 forecast GHG proxy price is less than five percent.
(b) D.15-01-024 directs utilities to calculate recorded direct GHG Costs as the sum of each month's weighted average cost (WAC) of compliance instruments held in inventory multiplied by that month's actual GHG emissions. Recorded and Final Direct GHG Costs presented here are consistent with the requirements of D.15-01-024, including accounting true-ups and adjustments to reflect updated information.

## TABLE 16-5
## DETAIL OF A&O EXPENSES 2024-2026
## (TEMPLATE D-3)
## (THOUSANDS OF DOLLARS)

| Line No. | Description | 2024 Forecast | 2024 Recorded | 2025 Forecast | 2025 Recorded* | 2026 Forecast | 2026 Recorded |
|---|---|---|---|---|---|---|---|
| 1 | Utility Administrative | | | | | | |
| 2 | General Program Management | 451 | 288 | 360 | 176 | 359 | Information not yet available |
| 3 | IT/Billing System Enhancements | 42 | 40 | 215 | 213 | 103 | |
| 4 | Customer Inquiry Support Cost | 172 | 215 | 180 | 126 | 230 | |
| 5 | Subtotal Administrative | 666 | 544 | 754 | 515 | 692 | |
| 6 | Utility Outreach | | | | | | |
| 7 | Marketing - Internal | | | | | | |
| 8 | Marketing - Contract/Consultant | | | | | | |
| 9 | Targetbase | | | | | | |
| 10 | Customer Outreach & Education | 177 | 164 | 193 | 78 | 233 | |
| 11 | Subtotal Outreach | 177 | 164 | 193 | 78 | 233 | |
| 12 | Utility Outreach and Administrative Expenses (line 5 + line 11) | 843 | 708 | 947 | 593 | 925 | |
| 13 | Additional (Non-Utility) Statewide Outreach | | | - | | - | |
| 14 | Total Outreach and Administrative Expenses (line 12 + line 13)** | 843 | 708 | 947 | 593 | 925 | |

*Recorded Expense reflect latest available data and includes actuals from January through August.
**Totals may not add up due to rounding.

# TABLE 17-1
# (TEMPLATE D-1)
# ANNUAL ALLOWANCE REVENUE RECEIPTS AND CUSTOMER RETURNS
# (THOUSANDS OF DOLLARS)

| | | 2024 | | 2025 | | 2026 | |
|---|---|---|---|---|---|---|---|
| Line | Description | Forecast [1] | Recorded | Forecast [1] | Recorded [2] | Forecast | Recorded |
| 1 | **Proxy GHG Price ($/MT)** | $39.62 | N/A | $37.58 | N/A | $30.58 | |
| 2 | **Allocated Allowances ('000 MT) [3]** | 16,757 | 16,364 | 21,426 | 21,070 | 23,023 | |
| 3 | **Revenues** | | | | | | |
| 4 | Prior Balance (From Line 31 of previous year) | (53,866) | (69,693) | 53,324 | 28,767 | 199,666 | |
| 5 | Allowance Revenue | (663,932) | (576,556) | (805,193) | (593,068) | (704,047) | |
| 6 | Interest | | (2,999) | | 3,782 | | |
| 7 | Revenue Franchise Fees and Uncollectibles (RF&U) | (7,394) | (7,244) | (8,016) | (9,030) | (5,877) | |
| 8 | **Subtotal Revenues** | (725,192) | (656,492) | (759,885) | (569,549) | (510,258) | |
| 9 | **Expenses** | | | | | | |
| 10 | Outreach and Administrative Expenses [4] | 808 | 695 | 817 | 674 | 934 | |
| 11 | RF&U | | | | | | |
| 12 | Interest | (112) | | (144) | | (183) | |
| 13 | **Subtotal Expenses** | 695 | 695 | 674 | 674 | 750 | |
| 14 | **Allowance Revenue Approved for Clean Energy or Energy Efficiency Programs** | 33,208 | 33,208 | 38,303 | 38,303 | 34,232 | |
| | (a) SOMAH including true-ups | 28,165 | 28,165 | 34,626 | 34,626 | 15,196 | Information not yet available |
| | (b) DAC-SASH | 4,370 | 4,370 | 4,370 | 4,370 | 4,370 | |
| | (c) DAC-GT and CS-GT including true-ups | 9,947 | 9,947 | 5,664 | 5,664 | 18,219 | |
| | (d) CCAs' DAC-GT and CS-GT including true-ups | 3,668 | 3,668 | 9,667 | 9,667 | 13,206 | |
| | (e) CCA Disbursement Reconciliation to PG&E | 812 | 812 | 34 | 34 | (715) | |
| | (f) Funding from Public Purpose Program (PPP) | (13,754) | (13,754) | (16,059) | (16,059) | (16,046) | |
| 15 | **Net GHG Revenues (Line 8 + Line 13 + Line 14)** | (691,289) | (622,590) | (720,909) | (530,572) | (475,276) | |
| 16 | **GHG Revenues to be Distributed in Future Years** | | | | | | |
| 17 | **Net GHG Revenues Available for Customers in Forecast Year(Line 15 + Line 16)** | (691,289) | (622,590) | (720,909) | (530,572) | (475,276) | |
| 18 | **GHG Revenue Returned to Eligible Customers** | | | | | | |
| 19 | EITE Customer Return | 43,242 | 41,916 | 42,978 | 52,307 | 51,257 | |
| 20 | Small Business Volumetric Return | 0 | 0 | 0 | 0 | 0 | |
| 21 | Residential Volumetric Return | 0 | 2 | 0 | 0 | 0 | |
| 22 | **Subtotal EITE + Volumetric Returns** | 43,242 | 41,918 | 42,978 | 52,307 | 51,257 | |
| 23 | **Semi-Annual Climate Credit [6]** | | | | | | |
| 24 | Number of Households Eligible for the California Climate Credit | | | | | | |
| 25 | Number of Eligible Residential Bundled Households | 1,973,235 | 1,863,785 | 1,868,362 | 1,868,362 | 1,878,608 | |
| 26 | Number of Eligible Residential Unbundled Households | 3,419,100 | 3,219,592 | 3,559,652 | 3,559,652 | 3,602,410 | |
| 27 | Number of Eligible Small Business Customers | 480,629 | 439,698 | 393,473 | 393,473 | 379,232 | |
| 28 | **Total Customers Eligible for Climate Credit (Sum 24..27)** | 5,872,964 | 5,523,075 | 5,821,487 | 5,821,487 | 5,860,251 | |
| 29 | **Per - Customer Semi-Annual Climate Credit (0.5 x (Line 17 + 22) ÷ Line 28)** | (55.17) | (55.17) | (58.23) | (58.23) | (36.18) | |
| 30 | **Total Revenue Distributed for the Climate Credit (2 x Line 28 x Line 29)** | (648,047) | (609,439) | (677,931) | (677,931) | (424,019) | |
| 31 | **Revenue Balance (Line 17 + Line 22 - Line 30)** | 0 | 28,767 | 0 | 199,666 | 0 | |
| | | | 0 | | | | |

Note 1 "Forecast" are derived from corresponding tables authorized by the Commission in D.23-12-022 and D. 24-12-038.

Note 2 2025 "Recorded" includes January through August 2025 recorded, plus forecast through the rest of the year.

Note 3 Forecast based on "Unofficial electronic version of the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms "

Note 4 2024 and 2025 "Recorded" columns for Lines 24 through 27 are calculated by dividing the recorded amounts distributed to Residential Bundled and Unbundled, as well as Small Business Customers over the authorized Per-Customers Semi-Annual Climate Credit (Line 29) as determined by the formula in the Template D-1, authorized in D. 15-01-024.

**TABLE 17-2**
**GHG A&O EXPENSES SET ASIDE**
**(THOUSANDS OF DOLLARS)**

| Line No. | Year | Authorization/ Application Request | Authorized Amount Set Aside | Recorded and Forecast GHG A&O Expenses [1] | GHG A&O Expenses Excess/ (Shortage) | Recorded Balancing Account Interest [2] | Total Excess/ (Shortage) including interest |
|---|---|---|---|---|---|---|---|
| | | | (A) | (B) | (C) = (A) +(B) | (D) | (E) = (C) + (D) |
| 1 | 2013 | D.13-12-041 | 3,520 | (1,360) | 2,160 | 0 | 2,160 |
| 2 | 2014 | D.13-12-041 | 4,156 | (2,695) | 1,461 | 1 | 1,463 |
| 3 | 2015 | D.14-12-054 | 1,380 | (1,083) | 298 | 6 | 303 |
| 4 | 2016 | D.15-12-022 | NIL | (1,022) | (1,022) | 17 | (1,005) |
| 5 | 2017 | D.16-12-038 | NIL | (1,052) | (1,052) | 23 | (1,029) |
| 6 | 2018 | D.18-01-009 | NIL | (901) | (901) | 29 | (873) |
| 7 | 2019 | D.19-02-023 | NIL | (426) | (426) | 18 | (408) |
| 8 | 2020 | D.20-02-047 | 1,206 | (598) | 608 | 8 | 616 |
| 9 | 2021 | D.20-12-038 | 189 | (560) | (371) | 1 | (371) |
| 10 | 2022 | D. 22-02-002 | 285 | (717) | (432) | 10 | (422) |
| 11 | 2023 | D. 22-12-044 | 482 | (528) | (46) | 31 | (15) |
| 12 | 2024 | D. 23-12-022 | 695 | (708) | (13) | 40 | 27 |
| 13 | 2025 | D. 24-12-038 | 674 | (947) | (273) | | (273) |
| 14 | 2026 | A. 24-05-0XX | | (925) | (925) | | (925) |
| 15 | Total | | 12,588 | (13,521) | (934) | 183 | (750) |

*Note 1:* *Recorded through 2024 is $11.649 million and Forecast 2024 and 2025 is $1.872 million, comprising of $0.947 million authroized in D.24-12-008 and $0.925 million PG&E's forecast budget for 2026 as presented in Table 17-5.*

*Note 2:* *A full year of 2025 recorded Balancing Account interest is not yet available*

# PACIFIC GAS AND ELECTRIC COMPANY

# APPENDIX A

# STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
2026 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
A.25-05-011

CORRECTIONS TO PG&E'S OCTOBER 15, 2025 FALL UPDATE TESTIMONY

DATED NOVEMBER 6, 2025

| Line Item | Fall Update Testimony Section | Page Number | Witness | Description of Errata | As Stated in Oct. 15, 2025 Fall Update Testimony | As Corrected in Nov. 6, 2025 Fall Update Errata |
|---|---|---|---|---|---|---|
| 1 | C | Page 3, line 3 | Angelia Vega | Correct 2026 ERRA Forecast Revenue Requirement | … a total revenue requirement of $3,044 million… | … a total revenue requirement of $3,261... |
| 2 | C | Page 3, line 7 | Angelia Vega | Correct 2026 Total Revenue Requirement | … revenue requirement for rate setting purposes of $4,294 million. | … revenue requirement for rate setting purposes of $4,511 million. |
| 3 | C | Page 3, line 14 | Angelia Vega | Correct PCIA forecast revenue requirement | PCIA forecast revenue requirement of $882 million | PCIA forecast revenue requirement of $1,098 million |
| 4 | C | Page 4 | Angelia Vega | Correct Table 1-1 | • Line 3: PCIA was stated as 881,696<br>• Line 9: Revenue Requirement for Rate Setting was stated as $4,294,377<br>• Line 14: 2026 ERRA Application Revenue Requirement Request was stated as $3,043,991 | • Line 3: PCIA is changed to 1,098,402<br>• Line 9: Revenue Requirement for Rate Setting is changed to $4,511,083<br>• Line 14: 2026 ERRA Application Revenue Requirement Request is changed to $3,260,697 |

PACIFIC GAS AND ELECTRIC COMPANY
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A.25-05-011

CORRECTIONS TO PG&E'S OCTOBER 15, 2025 FALL UPDATE TESTIMONY

DATED NOVEMBER 6, 2025

| Line Item | Fall Update Testimony Section | Page Number | Witness | Description of Errata | As Stated in Oct. 15, 2025 Fall Update Testimony | As Corrected in Nov. 6, 2025 Fall Update Errata |
|---|---|---|---|---|---|---|
| 5 | C | Page 4, line 7 | Angelia Vega | Correct ERRA Trigger over collected balance | Included as part of PG&E's year end balancing account balances considered as part of the forecast 2026 revenue requirements is the ERRA Trigger over collected balance of $780 million. | Included as part of PG&E's year end balancing account balances considered as part of the forecast 2026 revenue requirements is the ERRA Trigger over collected balance of $700 million. |
| 6 | C | Page 5, lines 1 through 7 | Mark Coughlan | Correct rate impact | …the system average bundled rate—including the impact of the change in GHG revenue return—would *decrease* by approximately 4.0 cents/kilowatt-hour (kWh), or 11.4 percent, to a total rate of 31.2 cents per kWh, when compared to the currently effective system average bundled rate of 35.2 cents/kWh.  The system average rate for Community Choice Aggregator (CCA) and Direct Access (DA) customers, whose average rates exclude commodity charges that are provided by other service providers, would *increase* by approximately 2.7 per kWh, or 13.8 percent, to a total rate of 22.4 cents per kWh… | "…the system average bundled rate—including the impact of the change in GHG revenue return—would *decrease* by approximately 3.9 cents/kilowatt-hour (kWh), or 11.0 percent, to a total rate of 31.3 cents per kWh, when compared to the currently effective system average bundled rate of 35.2 cents/kWh.  The system average rate for Community Choice Aggregator (CCA) and Direct Access (DA) customers, whose average rates exclude commodity charges that are provided by other service providers, would *increase* by approximately 2.9 per kWh, or 14.6 percent, to a total rate of 22.6 cents per kWh… |

PACIFIC GAS AND ELECTRIC COMPANY
2026 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
A.25-05-011

CORRECTIONS TO PG&E'S OCTOBER 15, 2025 FALL UPDATE TESTIMONY

DATED NOVEMBER 6, 2025

| Line Item | Fall Update Testimony Section | Page Number | Witness | Description of Errata | As Stated in Oct. 15, 2025 Fall Update Testimony | As Corrected in Nov. 6, 2025 Fall Update Errata |
|---|---|---|---|---|---|---|
| 7 | 10.a. | Page 18, line 4 | Angelia Vega | Correct forecast 2025 year end PABA balance, before balance transfers from other balancing accounts | The 2025 year end PABA balance, before balance transfers from other balancing accounts is forecast to be under collected by $2,026 million. | The 2025 year end PABA balance, before balance transfers from other balancing accounts is forecast to be under collected by $2,240 million. |
| 8 | 10.a. | Page 18 | Angelia Vega | Correct Table 12-3 | • Line 2 (e) Lower Net RPS Contract Cost was (210) and subtotal of section Line 2 was 220<br>• Line 7 Other was (9)<br>• Line 8 Forecast 2025 year-end PABA balance, before Balance Transfers was $2,026 | • Delete Line 2 (e) and subtotal of section Line 2 is changed to 430<br>• Line 7 Other is now (6)<br>• Line 8 Forecast 2025 year-end PABA balance, before Balance Transfers is changed to $2,240 |
| 9 | 10.a | Page 20, lines 24 through 27 | Angelia Vega | Delete sub-section "2)e) Greater Net RPS Transaction Revenue" | e) Greater Net RPS Transaction Revenue<br>Recorded RPS sales revenues have been greater than expected due to delayed settlement of 2024 RPS sales transactions recorded in 2025. | (Deleted) |
| 10 | 10.d. | Page 25 | Angelia Vega | Correct Table C | Delete the entire Table C | Replace with the new Table C |

PACIFIC GAS AND ELECTRIC COMPANY
2026 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
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CORRECTIONS TO PG&E'S OCTOBER 15, 2025 FALL UPDATE TESTIMONY

DATED NOVEMBER 6, 2025

| Line Item | Fall Update Testimony Section | Page Number | Witness | Description of Errata | As Stated in Oct. 15, 2025 Fall Update Testimony | As Corrected in Nov. 6, 2025 Fall Update Errata |
|---|---|---|---|---|---|---|
| 11 | 10.d. | Page 25, line 13 | Angelia Vega | Correct the ERRA Trigger overcollection forecast percent | The ERRA Trigger overcollection forecast in Table C above for December 2025 reaches -15.1 percent… | The ERRA Trigger overcollection forecast in Table C above for December 2025 reaches -13.6 percent… |
| 12 | 11.b | Page 28 | Mark Coughlan | Correct Table 13-2 | Delete entire Table 13-2 | Replace with the new Table 13-2 |
| 13 | 11.b | Page 28 | Mark Coughlan | Correct Table 13-4 | Delete entire Table 13-4 | Replace with the new Table 13-4 |
| 14 | 11.d | Page 29, lines 11 through 16 | Mark Coughlan | Correct rate impact | …the system average bundled rate—including the impact of the change in GHG revenue return—would *decrease* by approximately 4.0 cents/kilowatt-hour (kWh), or 11.4 percent, to a total rate of 31.2 cents per kWh, when compared to the currently effective system average bundled rate of 35.2 cents/kWh. The system average rate for Community Choice Aggregator (CCA) and Direct Access (DA) customers, whose average rates exclude commodity charges that are provided by other service providers, would *increase* by | …the system average bundled rate—including the impact of the change in GHG revenue return—would *decrease* by approximately 3.9 cents/kilowatt-hour (kWh), or 11.0 percent, to a total rate of 31.3 cents per kWh, when compared to the currently effective system average bundled rate of 35.2 cents/kWh. The system average rate for Community Choice Aggregator (CCA) and Direct Access (DA) customers, whose average rates exclude commodity charges that are provided by other service providers, would *increase* by |

PACIFIC GAS AND ELECTRIC COMPANY
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A.25-05-011

CORRECTIONS TO PG&E'S OCTOBER 15, 2025 FALL UPDATE TESTIMONY

DATED NOVEMBER 6, 2025

| Line Item | Fall Update Testimony Section | Page Number | Witness | Description of Errata | As Stated in Oct. 15, 2025 Fall Update Testimony | As Corrected in Nov. 6, 2025 Fall Update Errata |
|---|---|---|---|---|---|---|
| | | | | | approximately 2.7 per kWh, or 13.8 percent, to a total rate of 22.4 cents per kWh… | approximately 2.9 per kWh, or 14.6 percent, to a total rate of 22.6 cents per kWh… |
| 15 | F. 1) | Page 40, lines 21 through 26 | | Correct the following revenue requirements:<br>• 2026 ERRA Revenue Requirement<br>• 2026 Total Revenue Requirement<br>• PCIA Revenue Requirement | Adopt PG&E's total 2026 electric procurement forecast of 3,044 million. When combined with $1,250 million of revenue requirements already adopted by the Commission in other proceedings, this results in a total revenue requirement for rate setting of $4,294 million. The revenue requirement for rate setting purposes consists of the following: $373 million for CAM, $654 thousand for VAMOMA, $882 million for PCIA… | Adopt PG&E's total 2026 electric procurement forecast of 3,261million. When combined with $1,250 million of revenue requirements already adopted by the Commission in other proceedings, this results in a total revenue requirement for rate setting of $4,511million. The revenue requirement for rate setting purposes consists of the following: $373 million for CAM, $654 thousand for VAMOMA, $1,098 million for PCIA… |
| 16 | Table 6-2 | Page 73 | Mehul Patel | Correct Table 6-2 | Marked as confidential | Corrected to Public |
| 17 | Table 8-3 | Page 75 | Christa Hoffman | Correct Table 8-3 | Delete the entire Table 8-3 | Replace with new Table 8-3 |
| 18 | Table 8-4 | Page 76 | Christa Hoffman | Correct Table 8-4 | Delete the entire Table 8-4 | Replace with the new Table 8-4 |

PACIFIC GAS AND ELECTRIC COMPANY
2026 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
A.25-05-011

CORRECTIONS TO PG&E'S OCTOBER 15, 2025 FALL UPDATE TESTIMONY

DATED NOVEMBER 6, 2025

| Line Item | Fall Update Testimony Section | Page Number | Witness | Description of Errata | As Stated in Oct. 15, 2025 Fall Update Testimony | As Corrected in Nov. 6, 2025 Fall Update Errata |
|---|---|---|---|---|---|---|
| 19 | Table 8-6 | Page 77 to 78 | Angelia Vega | Correct Table 8-6 | Delete the entire Table 8-6 | Replace with the new Table 8-6 |
| 20 | Table 8-8 | Page 80 to 81 | Angelia Vega | Correct Table 8-8 | Delete the entire Table 8-8 | Replace with the new Table 8-8 |
| 21 | Table 12-1 | Page 84 | Angelia Vega | Correct Table 12-1 | Delete the entire Table 12-1 | Replace with the new Table 12-1 |
| 22 | Table 12-2 | Page 85 | Angelia Vega | Correct Table 12-2 | Delete the entire Table 12-2 | Replace with the new Table 12-2 |
| 23 | Table 13-1 | Page 87 | Angelia Vega | Correct Table 13-1 | Delete the entire Table 13-1 | Replace with the new Table 13-1 |
| 24 | Table 13-3 | Page 88 | Mark Coughlan | Correct Table 13-3 | Delete entire Table 13-3 | Replace with the new Table 13-3 |
| 25 | Table 13-4 | Page 89 | Mark Coughlan | Correct Table 13-4 | Delete entire Table 13-4 | Replace with the new Table 13-4 |
| 26 | Table 13-5 | Page 89 | Mark Coughlan | Correct Table 13-5 | Delete entire Table 13-5 | Replace with the new Table 13-5 |
| 27 | Table 14-3 | Page 92 | Akshay Mehmi | Correct Table 14-3 | Delete the entire Table 14-3 | Replace with the new Table 14-3 |
| 28 | Table 14-4 | Page 92 | Akshay Mehmi | Correct Table 14-4 | Delete the entire Table 14-4 | Replace with the new Table 14-4 |

PACIFIC GAS AND ELECTRIC COMPANY
2026 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION
NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS
FORECAST REVENUE RETURN AND RECONCILIATION
A.25-05-011

CORRECTIONS TO PG&E'S OCTOBER 15, 2025 FALL UPDATE TESTIMONY

DATED NOVEMBER 6, 2025

| Line Item | Fall Update Testimony Section | Page Number | Witness | Description of Errata | As Stated in Oct. 15, 2025 Fall Update Testimony | As Corrected in Nov. 6, 2025 Fall Update Errata |
|---|---|---|---|---|---|---|
| 29 | Table 14-5 | Page 93 | Akshay Mehmi | Correct Table 14-5 | Delete the entire Table 14-5 | Replace with the new Table 14-5 |
| 30 | Table 14-6 | Page 93 | Akshay Mehmi | Correct Table 14-6 | Delete the entire Table 14-6 | Replace with the new Table 14-6 |
| 31 | Table 14-7 | Page 94 | Akshay Mehmi | Correct Table 14-7 | Delete the entire Table 14-7 | Replace with the new Table 14-7 |
| 32 | Table 14-8 | Page 94 | Akshay Mehmi | Correct Table 14-8 | Delete the entire Table 14-8 | Replace with the new Table 14-8 |
| 33 | Table 14-9 | Page 95 | Akshay Mehmi | Correct Table 14-9 | Delete the entire Table 14-9 | Replace with the new Table 14-9 |
| 34 | Table 14-10 | Page 95 | Akshay Mehmi | Correct Table 14-10 | Delete the entire Table 14-10 | Replace with the new Table 14-10 |
| 35 | Table 14-11 | Page 96 | Akshay Mehmi | Correct Table 14-11 | Delete the entire Table 14-11 | Replace with the new Table 14-11 |
| 36 | Table 14-12 | Page 96 | Akshay Mehmi | Correct Table 14-12 | Delete the entire Table 14-12 | Replace with the new Table 14-12 |
| 37 | Table 14-13 | Page 97 | Akshay Mehmi | Correct Table 14-13 | Delete the entire Table 14-13 | Replace with the new Table 14-13 |
| 38 | Table 14-14 | Page 97 | Akshay Mehmi | Correct Table 14-14 | Delete the entire Table 14-14 | Replace with the new Table 14-14 |

PACIFIC GAS AND ELECTRIC COMPANY
2026 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
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CORRECTIONS TO PG&E'S OCTOBER 15, 2025 FALL UPDATE TESTIMONY

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| Line Item | Fall Update Testimony Section | Page Number | Witness | Description of Errata | As Stated in Oct. 15, 2025 Fall Update Testimony | As Corrected in Nov. 6, 2025 Fall Update Errata |
|---|---|---|---|---|---|---|
| 39 | Table 15-1 | Page 98 | Various | Correct Table 15-1 | Delete the entire Table 15-1 | Replace with the new Table 15-1 |
| 40 | Table 15-2 | Page 99 | Various | Correct Table 15-2 | Delete the entire Table 15-2 | Replace with the new Table 15-2 |
| 41 | Table 17-1 | Page 101 | Angelia Vega | Correct Table 17-1 | Delete the entire Table 17-1 | Replace with the new Table 17-1 |
| 42 | Attachment A | AtchA-1 through AtchA-8 | Mark Coughlan | Corrected Attachment A "Illustrative Rates" | Delete the entire Attachment A | Replace with the new Attachment A |
| 43 | Appendix B | NA | William Reinwald | Insertion of the Confidential Declaration of William Reinwald | Omitted | Inserted |
| 44 | Appendix B | NA | Ryan Stanley | Insertion of the Confidential Declaration of Ryan Stanley | Omitted | Inserted |

# PACIFIC GAS AND ELECTRIC COMPANY
# STATEMENT OF QUALIFICATIONS OF ANDREW KLINGLER

Q 1 Please state your name and business address.

A 1 My name is Andrew Klingler, 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 Data Scientist in our System Planning organization with responsibility for load forecasting and certain aspects of system forecasting and modeling.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor of Arts degree in Physics from the University of California, Berkeley; and a Doctor of Philosophy degree in Mathematics from the University of California, Santa Cruz. I have worked in various quantitative, programming, analytical, and managerial roles in the energy industry for about 20 years; I have been in the utility industry for most of that time. I left Dominion Virginia Power in 2007 to join PG&E, where I have worked as a Quantitative Analyst and then as a Manager in Market and Credit Risk, as a Manager in Rates, and currently as a Principal Data Scientist in System Planning.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Prepared Testimony: Chapter 2, "Sales and Peak Demand Forecast":
  - Sections A.1(a) and (b), A.3 and C; and
- Fall Update Testimony:
  - Sections D.1 (a & b) and 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 JORGE MERAZ**

Q 1 Please state your name and business address.

A 1 My name is Jorge Meraz, 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 Quantitative Analyst in the System Planning Department in PG&E's Strategy organization. I work on the peak, departing load, and behind-the-meter distributed generation forecasts.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor of Science degree in Environmental Science from Loyola University Chicago, and a Master of Science and PhD degree in Civil and Environmental Engineering from Stanford University.

I joined PG&E in January 2023 as an Analyst, where my primary responsibilities include developing various forecasts that inform PG&E's sales and peak demand, in addition to supporting in various regulatory proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Prepared Testimony: Chapter 2, "Sales and Peak Demand Forecast":
  - Sections A.1.c, A.2.a, A.2.e, B, and C; and
- Fall Update Testimony:
  - Sections D.2 and 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 DANIEL NELLI

Q 1 Please state your name and business address.

A 1 My name is Daniel Nelli, 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 an Expert Quantitative Analyst in the System Planning Department in PG&E's Strategy organization. I work on various load modifier forecasts including: electric vehicles, energy efficiency, building electrification, and data centers.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Science degree in Biophysics and a Master of Science in Civil and Environmental Engineering from Stanford University. I started my career at PG&E in February 2021 as an Analyst on my current team—Emerging Load Forecasting—where my primary responsibilities include developing energy impact forecasts of multiple emerging demand-side technologies.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Prepared Testimony: Chapter 2, "Sales and Peak Demand Forecast":
  - Sections A.2.b, A.2.c, A.2.d, and A.2.f; and
- Fall Update Testimony:
  - Section D.1.c.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.