BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 24-01-017

DRAFT 2025 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLAN OF MARIN CLEAN ENERGY

PUBLIC VERSION

Sai Powar
Policy Analyst
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
(415) 464-6044
spowar@mcecleanenergy.org

Dated: June 30, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 24-01-017

DRAFT 2025 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLAN OF MARIN CLEAN ENERGY

PUBLIC VERSION

In accordance with the California Public Utilities Commission's ("Commission" or "CPUC") April 17, 2025, *Assigned Commissioner and Assigned Administrative Law Judges' Ruling Identifying Issues and Schedule of Review for 2025 Renewables Portfolio Standard Procurement Plans* ("ACR"), Marin Clean Energy ("MCE" or "Agency"), hereby submits this Draft 2025 Renewables Portfolio Standard Procurement Plan ("RPS Procurement Plan"). As directed by the ACR, this RPS Procurement Plan includes responses for the issues expressed in ACR sections 6.1-6.15.

MCE notes that certain issues and requests in these ACR sections apply to the other retail sellers (electrical corporations and electric service providers), and do not extend to Community Choice Aggregators ("CCAs"). MCE is nevertheless voluntarily responding to these ACR sections in the interest of transparency and in order to collaborate with the Commission. However, the submission of this RPS Procurement Plan pursuant to the ACR should not be construed as a waiver of the right to assert that components of Senate Bill ("SB") 790 (2012) or that Commission decisions and rulings on RPS Procurement Plan submittals do not extend to CCAs. MCE reserves the right to challenge any such assertion of jurisdiction over these matters.

In reviewing this RPS Procurement Plan, MCE encourages the Commission to consider the differences between California's investor-owned utilities ("IOUs") and other retail sellers, including CCAs. Differing levels of detail, procedure, complexity, and coordination within the planning documents submitted by these organizations are appropriate.

I. Summary of Major Changes to RPS Plan

This Section describes the most significant changes between MCE's Draft 2024 RPS Procurement Plan (which was deemed final by Decision 24-12-035) and its Draft 2025 RPS Procurement Plan. A redline of this Draft 2025 RPS Plan against MCE's Draft 2024 RPS Plan is included as Appendix A. The table below provides a list of key differences between MCE's 2024 and 2025 RPS Procurement Plans.

Table 1: Key Changes to MCE's RPS Procurement Plan

Plan Reference	Plan Section	Summary/Justification of Change
2025 RPS Procurement Plan: Section IV	Assessment of RPS Portfolio Supplies and Demand	Updated to provide latest information on MCE's progress towards meeting the requirements of Mid-Term Reliability Decision, D.21-06-035, D.23-02-040, and potential RPS planning implications.
2025 RPS Procurement Plan: Section I.V.B.2	Curtailment Frequency, Forecasting, Costs	Updated information regarding historical curtailments in Calendar Year 2024 and Calendar Year 2025 to date.
2025 RPS Procurement Plan: Section V	Project Development Status Updates	Updated the project development status template, Appendix D, to reflect the recent progress of renewable

		generating projects that have yet to achieve commercial operation. Updated narrative to describe projects, including status of delays and contract online dates.
2025 RPS Procurement Plan: Section IV.C	Portfolio Optimization	Updated to reflect how MCE is optimizing existing resources and future procurement to meet new CPUC reliability goals.
2025 RPS Procurement Plan: Section VII	Risk Assessment	Updated to include further detail on how MCE evaluates risk, especially in light of Mid-Term Reliability Decisions, D.21-06-035 and D.23-02-040.
2025 RPS Procurement Plan: Section VIII	Renewable Net Short Calculation	Updated the Renewable Net Short template, Appendix C, to reflect actual data through 2024 and updated projections through 2035.
2025 RPS Procurement Plan: Section XIV	Cost Quantification	Updated Cost Quantification template, Appendix E, to reflect updated cost projections associated with actual and planned RPS procurement through 2034.

II. Executive Summary Key Issues

In this Draft 2025 RPS Procurement Plan, MCE provides information and updates regarding its progress in meeting applicable renewable energy planning and procurement targets, as well as additional detail in response to the expanded requirements set forth in the ACR.

MCE, California's first CCA, is a not-for-profit public agency that began service in 2010 with a mission to confront the climate crisis by eliminating fossil free greenhouse gas emissions, producing renewable energy, and creating equitable community benefits. In 2024, MCE served approximately 585,000 customer accounts in 37 communities across Contra Costa, Marin, Napa, and Solano counties, with annual retail sales of approximately 5,500 gigawatt hours. In 2025, MCE expanded its service area to 38 communities with the inclusion of the City of Hercules. MCE offers its customers a 60% renewable default service ("Light Green"), as well as two 100% renewable energy service options ("Deep Green" and "Local Sol").

MCE is governed by a Board of Directors ("Board") comprised of 36 locally elected officials. The Board sets policy for the Agency and oversees its operations. Depending upon the issue, representatives from MCE's governing Board and committees generally convene two to three times per month with advance public notice provided in compliance with the Brown Act.

MCE updates its biennial Integrated Resource Plan ("IRP") mandated by SB 350 (2015). The IRP submitted to the Commission biennially has been primarily oriented towards supporting California's achievement of its 2030 Greenhouse Gas ("<u>GHG</u>") reduction targets. MCE's internal commitment to clean energy has resulted in a default supply portfolio that reached 60% renewable in 2017, thirteen years ahead of the statewide procurement mandate. MCE is also attentive to applicable long-term renewable energy contracting requirements and has secured 65% of its <u>total</u> projected 2025 RPS requirements (relative to California's interim annual RPS procurement mandate) via numerous long-term contracts, exceeding pertinent long-term contracting requirement established by SB 350 (2015). MCE observes that it has also procured over 100% of its voluntary, internally adopted renewable energy need, which, in aggregate, approximates 76% of projected retail load. MCE is also fully compliant with all CPUC Resource Adequacy ("<u>RA</u>")

requirements, to support the reliability needs of the state.

MCE maintains its clean, balanced portfolio by closely monitoring ongoing market conditions, including but not limited to curtailment, customer demand, and policy changes. MCE also monitors unanticipated market events, such as inflationary and supply chain pressures and their impacts on both the supply and demand sides of the market. In optimizing its portfolio, MCE prioritizes the maintenance of a balanced, diverse, and reliable portfolio; adhering to its commitment to clean energy and suppressing customer costs to the greatest practical extent.

MCE's commitment to clean energy has led to the exploration of opportunities to mitigate the impacts of air pollution in regions of the state where communities have been disproportionately affected by the existing generating fleet, as well as the need to bring economic benefits to communities with high levels of poverty and unemployment. To address this concern, MCE continues to evaluate the procurement of "clean resource adequacy" ("Clean RA") and the feasibility (both technological and economic) of transitioning to increased use of carbon-free capacity sources to meet statewide reserve capacity mandates.

MCE's RPS Procurement Plan details its current solicitations and its bid review and selection processes. The Plan also describes how MCE applies the Least-Cost Best Fit concept to its portfolio to support its priorities as an agency created to provide clean energy, amongst other customer- and community-focused service offerings and programs.

MCE continues to closely monitor its exposure to a variety of risk factors, as discussed more fully below in Section VII. MCE continues to find that its thorough analysis of both portfolio- and project- level risks, combined with its significant margin of over-procurement relative to statewide RPS goals, renders a quantitative risk assessment model unnecessary at this time. This noted, MCE continues to assess the need for such a model and may employ additional analytical tools in the future.

III. Compliance with Recent Legislation and Impact of Regulatory Changes

This RPS Procurement Plan addresses the requirements of relevant legislation and the Commission's regulatory framework and describes how this RPS Procurement Plan demonstrates that MCE meets these requirements.

SB 350 was signed by the Governor on October 7, 2015. SB 350 set a new RPS procurement target of 50% by December 31, 2030. On December 20, 2016, the Commission issued Decision ("D.") 16-12-040, which partially implemented the increased targets of SB 350 by establishing new compliance periods and procurement quantity requirements. On July 5, 2017, the Commission issued D.17-06-026, which implemented some of the key remaining elements of SB 350, including adopting new minimum procurement requirements for long-term contracts and owned resources, as well as revising the excess procurement rules. As discussed in greater detail in Section IV.A.1, MCE projects that 96% of its total projected 2025 RPS procurement target will be met with long-term contracts; MCE further expects that nearly 87% of mandated RPS purchases related to Compliance Period 4 will be fulfilled via deliveries from long-term renewable energy contracts.

SB 100 was signed by the Governor on September 10, 2018, and became effective on January 1, 2019. SB 100 increased the RPS procurement requirements to 44% by December 31, 2024, 52% by December 31, 2027, and 60% by December 31, 2030. On June 6, 2018, the Commission issued D.18-05-026, which implemented changes made by SB 350 to the RPS waiver process and reaffirmed the existing RPS penalty scheme. In July 2018, the Commission instituted Rulemaking ("R.") 18-07-003 to continue the implementation of the RPS program. On June 28, 2019, the Commission issued D.19-06-023, which continues to use a straight-line method to calculate compliance period procurement quantity requirements. The current RPS procurement targets are incorporated in MCE's Renewable Net Short ("RNS") Calculation Table as further described in Section VIII below and attached hereto as Appendix C. On a projected basis, MCE's current RPS procurement is sufficient to exceed applicable, internally adopted renewable energy procurement targets through 2025, including the minimum margin of over-procurement based on MCE's risk assessment, as further described in Sections VII and IX.

Additional RPS procurement efforts remain ongoing, and MCE intends to augment existing RPS contracts with additional supply to promote statutory compliance, as well as the achievement of internal RPS targets, in 2026 and beyond.

SB 901, signed by Governor Brown on September 21, 2018, added Public Utilities Code Section 8388, which requires any IOU, publicly owned electric utility, or CCA with a biomass contract meeting certain requirements to seek to amend the contract to extend the expiration date to be five years later than the expiration date that was operative as of 2018. MCE does not have a contract with a biomass facility that is covered by Public Utilities Code Section 8388.

In accordance with SB 255 (Bradford, 2019), D.22-04-035 revises the Commission's Supplier Diversity Program set forth in General Order ("GO") 156 to incorporate CCAs, Energy Service Providers ("ESPs"), and smaller utilities with certain revenue thresholds. MCE is committed to supporting sustained and fairly compensated local job opportunities through participation in the clean energy industry. To the extent allowed by state law, MCE seeks to create market incentives and partnerships to encourage diversity and a sustainable workforce through its support for:

- Fair compensation in direct hiring, renewable development projects, customer programs, internships, and procurement services;

- Development of locally generated renewable energy within the MCE service area;
- Direct use of union members from multiple trades;
- Quality training, apprenticeship, and pre-apprenticeship programs;
- Direct use of businesses local to the MCE service area;
- Development of California-based job opportunities;
- Business and workforce initiatives located in low-income and disadvantaged communities;
- Direct use of Disabled Veteran-owned Business Enterprises and LGBT-owned Business Enterprises;
- Direct use of green and sustainable businesses; and
- Use of direct hiring practices that promote diversity in the workplace.

These commitments, made prior to the passage of SB 255, align with SB 255's direction for CCAs to take steps to increase procurement from small, local, and diverse businesses in all procurement categories.

MCE has submitted annual supplier diversity reports to the CPUC since 2020, the first year SB 255 was in effect.[1] These reports follow the same timeline and reporting structure that applies to the other entities that report to the CPUC annually under GO 156, adjusted to account for MCE's status as a public agency subject to Proposition 209.[2] MCE and other CCAs have been working with the CPUC's Supplier Diversity staff since the passage of SB 255 to ensure reporting

[1] *See* https://mcecleanenergy.org/wp-content/uploads/2024/06/MCE_Supplier-Diversity-Report_FINAL.pdf for MCE's 2024 Supplier Diversity report

[2] Proposition 209 was approved by voters in 1996 and amended the California Constitution to prohibit the state, including local government agencies, from discriminating or granting preferential treatment on the basis of race, sex, color, ethnicity, or national origin in the operation of public employment, public education, and public contracting.

requirements for CCAs are appropriate and conform to SB 255, and will continue to do so on an ongoing basis, as set forth in D.22-04-035.

Assembly Bill ("AB") 843 (Aguiar-Curry, 2021) authorizes CCAs to submit eligible bioenergy projects for cost recovery pursuant to the Bioenergy Market Adjusting Tariff ("BioMAT") program. The BioMAT program is a feed-in tariff program for small bioenergy renewable generators less than 5 megawatts ("MW") in size, offering 250 MW total to eligible projects through a fixed price standard contract to export electricity to California's IOUs and CCAs. Electricity generated through the BioMAT program counts towards RPS targets. MCE engaged with the California Community Choice Association ("CalCCA"), the CPUC, and the IOUs to establish program implementation details to facilitate CCA participation in the program; however, MCE does not participate in this program currently. SB 1109 (Caballero, 2022) and AB 2750 (Gallagher, 2023) require entities, including CCAs, with a contract to procure electricity generated from biomass that expires or expired on or before December 31, 2028, to amend or establish a new contract that includes an expiration date five years later than the expiration date in the contract that was operative in 2022. MCE does not have any contracts that fit this requirement.

SB 1020 (Laird, 2022) sets interim targets for renewable and zero-carbon energy in California, requiring 90% of all retail sales of electricity be zero-carbon by December 31, 2035, and 95% of all retail sales of electricity be zero-carbon by December 31, 2040. MCE's most recent Operational Integrated Resource Plan ("OIRP") adopted interim targets that are more stringent than what is required for SB 1020,[3] therefore, MCE expects to meet these goals. Additionally,

[3] MCE's Light Green service option is expected to be 95% GHG-free by 2023 and is expected to reach 85% renewable energy by 2029. https://www.mcecleanenergy.org/wp-content/uploads/2021/11/MCE-Operational-Integrated-Resource-Plan_2022.pdf.pdf.

MCE is working with state partners to understand the requirements of SB 1020 for other agencies and exploring how to support those other agencies in meeting SB 1020 goals. In the interim, MCE notes that state agency accounts may enroll in MCE's 100% renewable energy service option, Deep Green, to immediately receive zero-carbon retail energy service.

AB 1373 (Garcia, 2023) authorizes the CPUC to request that the Department of Water Resources ("DWR") act as a central procurement entity ("CPE") to conduct procurement of certain eligible long lead-time resources ("LLT") on behalf of customers of all LSEs under the CPUC's IRP purview. On August 22, 2024, the CPUC issued D.24-08-064 making an initial need determination of up to 10.6 gigawatts ("GW") of nameplate capacity of the following emerging technologies: offshore wind (up to 7.6 GW), enhanced geothermal systems (up to 1 GW), multi-day long duration energy storage ("LDES") (up to 1 GW), and LDES with a discharge period of at least 12 hours (up to 1 GW). Using the most recent vintage of the demand forecast, CPUC will allocate CPE procurement benefits to LSEs and recover costs from all customers. DWR will tentatively begin development of solicitation plans and materials in 2025 and conduct pre-bid activities in early 2026 for LDES. MCE will continue to engage with the CPUC as the CPE mechanism is developed and incorporate the consideration of CPE resources, if procured, in its procurement strategy in future IRPs.

AB 1373 (Garcia, 2023) also requires the CPUC to include cost-effective resource diversity in its integrated resource planning processes. The bill permits CCAs to satisfy their portion of the CPUC's resource diversity requirements so long as the CCA's proposal promotes the efficient achievement of state energy policy objectives and does not result in incremental costs to bundled customers. The CPUC is currently in the process of developing a new IRP framework, the Reliable and Clean Power Procurement Program ("RCPPP"). In March 2025, the CPUC put forth its proposal on RCPPP that included reliability procurement and GHG reduction target frameworks for stakeholder consideration MCE is engaging in R.20-05-003 and working with CalCCA to facilitate effective design of the new program and establish reasonable implementation details. MCE will address requirements set forth in the RCPPP after the program's adoption and tentative implementation in 2027.

AB 2368 (Petrie-Norris, 2024) requires the CPUC to ensure that the RA program can reasonably maintain a standard measure of reliability, such as a 1-in-10 loss of load expectation ("LOLE") metric, and use it for planning purposes. The bill also adds midterm procurement, along with short term and long term, to IRP requirements. MCE will address these requirements as they are implemented by the CPUC.

IV. Assessment of RPS Portfolio Supplies and Demand

IV.A. Portfolio Supply and Demand

(i) Assessment of Portfolio Supply and Demand through 2035

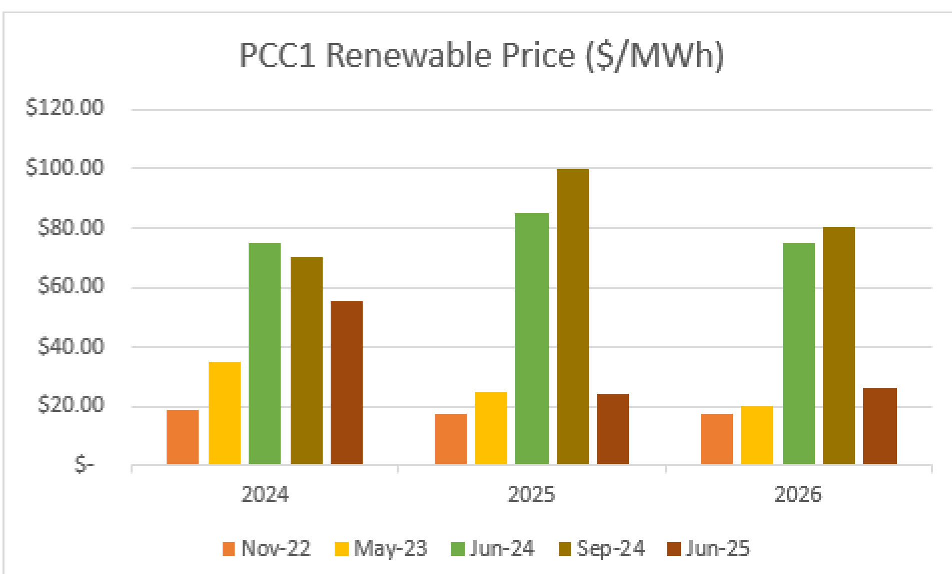
MCE continues to project that it will meet or exceed applicable RPS procurement obligations over the long-term planning horizon (through 2035, which reflects the final year of the planning period addressed in this document). The exact characteristics of MCE's renewable supply portfolio are expected to vary over the planning horizon based on a variety of considerations, including market developments and RPS product availability, policy changes, technological improvements, Agency preferences, and/or other factors.

Of note, due to apparent RPS supply constraints, which affected Portfolio Content Category 1 ("PCC1")[4] product availability and pricing in 2024 and 2025, MCE observes that

[4] A resource which is either located within California, or directly delivers to California without substituting energy from another source.

PCC1 prices increased more than 400% during the 18-month period between November 2022 and June 2024. While the full scope of circumstances contributing to this pricing runup remains unclear, many retail sellers, including MCE, were subjected to substantial budgetary impacts in meeting adopted portfolio objectives. The unexpected rise in RPS prices and the associated changes in regional short-term renewable energy markets impact how MCE can balance customer affordability with achieving environmental objectives that generally exceed statewide mandates. Between June 2024 and June 2025, PCC1 prices declined for product vintages to be delivered in 2026 and beyond, and while such prices have yet to return to "historical norms," there has been budgetary relief for load serving entities ("LSE") needing to procure incremental RPS supply thus far in Compliance Period 5. The previously described PCC1 pricing volatility is reflected in the following bar chart, which identifies average historical prices observed by MCE for index-plus PCC1 transactions over the past approximate 18-month term. MCE observes that "historically normal" PCC1 levels during the several years leading up to late 2022 were generally at/below $20/megawatt hours ("MWh") for index-plus transactions.

Figure 1: MCE's PCC1 Renewable Price 2024-2026



This recent price volatility highlighted a relatively new, but significant, risk facing buyers of short-term renewable energy products which, for several years, had experienced relatively low levels of pricing variability. State procurement directives, including the mid-term reliability and supplemental mid-term reliability programs, have had the effect of multiple buyers entering the market at the same time due to the universally applicable schedule of compliance deadlines assigned through such processes. Additionally, recent tariff discussions have introduced the risk of substantive cost increases for certain projects. These factors have exerted upward pressure and considerable uncertainty on certain technology/project types, which may play meaningful roles in California meeting its eventual RPS goals – particularly in a way that balances affordability for ratepayers. MCE continues to assess the best approach for dealing with these risks which may be subject to considerable iteration. For example, taking on additional long-term contracts, which can often promote increased price stability within an RPS contract portfolio (even though overall costs associated with such contracts can be higher than prices identified in short-term markets) could mitigate exposure to the occasional volatility experienced in short-term RPS markets. However, disproportionately high levels of long-term contracting could reduce planning flexibility, including a retail seller's ability to take advantage of emerging technologies, adapt to policy changes, and react to periodic market fluctuations.

In the near term, MCE expects budgetary and rate-related impacts associated with addressing prior (2024 and 2025) and projected (2026 and 2027) RPS open positions, but MCE remains committed to fulfilling its internally adopted RPS targets as planned. Due to prudent planning, MCE is well resourced for the early stages of Compliance Period 5, so short-term RPS procurement efforts will be predominantly focused on outstanding needs in 2026 and 2027, years in which prices have recently subsided. Over the long-term planning horizon, MCE believes that its disciplined and diversified approach to RPS procurement will lead to average portfolio costs that are manageable and considerate of customer rate sensitivities as well as statewide planning needs.

As previously noted, MCE's internally adopted renewable energy procurement targets have been set in excess of state-imposed mandates, creating a natural compliance buffer. For example, approximately 74% of MCE's aggregate supply portfolio was comprised of RPS-eligible renewable energy in 2024, an amount exceeding the state's interim annual procurement mandate by nearly 68%. Similar to previous years, this significant level of over-procurement would have accommodated massive fluctuations in annual retail sales and/or anticipated renewable energy deliveries before triggering potential compliance risks for MCE. Given the significance of MCE's internally established 60% renewable target (which persists through 2025 before increasing thereafter), past success exceeding applicable compliance mandates, existing supply commitments and ongoing planning/procurement efforts focused on RPS-eligible energy, MCE does not foresee any issues fulfilling future renewable supply commitments.

MCE continues to monitor the prospective impacts to its customer base associated with California's direct access market due to SB 237 (2018) and D.19-05-043. Should there be material changes to direct access availability for non-residential accounts, or direct access is expanded in the future, MCE will accordingly reflect such an outcome in its planning process. With this in mind, MCE's analysis shall remain ongoing and may result in future adjustments to MCE's load forecast and related renewable energy procurement obligations, which would be expected to decrease if MCE load migrates to direct access providers.

Additionally, MCE is aware that supply chain impacts continue to exist, and for renewable energy projects that have yet to achieve commercial operation, MCE will closely monitor progress in case such issues impact expected online dates. Federal policy changes regarding Tax Credits and imposition of significantly increased tariffs that could be applied to certain renewable and battery storage infrastructure is another important concern being monitored by MCE, as such risk is often being addressed by "price reopener" provisions inserted in various renewable energy contracts. These provisions not only create the potential for budgetary uncertainty but also the reality that extreme price increases may compromise the prospect of project completion (via contract termination), leaving the affected retail seller to search for project alternatives that may be necessary to backfill vacated supply. Regarding demand side impacts, these are often more challenging to isolate, as normal variations in usage caused by weather may obscure otherwise atypical variations in consumption. With current monetary policy focused on controlling inflation, MCE will be attentive to potential changes in customer usage that may result from ongoing policy adaptations, particularly those intended to control persistent inflationary pressures. Based on available data and related analyses conducted to date, impacts to MCE's overall load and sales appear to be relatively modest.

(ii) Assessment of Need for RPS Resources with Specific Deliverability Characteristics

MCE regularly analyzes and assesses its renewable portfolio mix to identify supply, fit, and compliance needs. While compliance with the RPS program has not been an issue of concern, as California increases its renewable and carbon free targets, there is a need for MCE to continue diversifying its resource mix. Resources with diverse deliverability characteristics help in mitigating risk exposure to market forces while providing grid reliability. Peaking dispatchable resources, such as storage paired with solar or wind, are critical in meeting high demand periods in the future. However, this requires having baseload resources like geothermal to allow for the flexibility to dispatch marginal resources as load shifts. Reliance on intermittent resources like solar and wind alone exposes one to congestion and potential curtailment risks. This risk continues to grow with the accelerated adoption of solar and wind on the grid. MCE is aware of these factors and continues to pursue a diverse set of renewable resources to not only meet its RPS obligations but also maintain operational flexibility while contributing to overall system reliability.

(iii) Experience Managing Exposure to Negative Market Prices

MCE closely monitors twelve separate locations that are indicative of renewable energy resources that are exposed to market prices and potential curtailment. Resources at those locations are bid into the CAISO markets and are curtailed when prices fall below individual resource's threshold prices. Weighted average prices for the generation at those locations are compared to weighted average prices at Pacific Gas and Electric's ("PG&E") Default Load Aggregation Point ("DLAP") to assess the impact of congestion on the resource's performance. In addition, the MWh of curtailment are logged.

These two metrics - weighted average price of the resources compared to that of the DLAP and MWh curtailed - are used to assess effectiveness of the resources in meeting MCE's RPS obligations at cost effective prices. If the resource's weighted average price is near the DLAP and it has been curtailed, then the reason for curtailment is system over-supply. If the resource's weighted average price diverges from the DLAP and it has been curtailed, then the reason for curtailment is local overgeneration that is contributing to congestion. This information is valuable feedback to MCE in locating potential future resources. If congestion and local oversupply is significant in certain areas, then MCE can determine by reviewing the CAISO's transmission planning documents whether transmission upgrades are planned to mitigate congestion that is observed with existing resources.

If curtailment is caused by congestion, the impact can be somewhat mitigated by obtaining CAISO Congestion Revenue Rights ("CRRs"), which MCE has done. However, CRRs are not a perfect hedge against congestion and cannot be relied upon to mitigate congestion and subsequent economic curtailment entirely. MCE will continue to monitor and plan for managing exposure to negative market prices.

(iv) Assessment of how the Renewable Net Short Quantitative Analysis Supports the Assessment of Portfolio Supply and Demand

As reflected in MCE's RNS appendix, MCE aims to procure sufficient quantities of renewable energy that: 1) meaningfully exceed statewide procurement mandates via internally adopted RPS procurement targets that range from 10.7% to 25.0% above the state's interim annual RPS procurement targets throughout the planning period (2025-2035); and 2) reflect a 10% planning reserve (in excess of projected, internally adopted RPS targets that meaningfully exceed statewide mandates) to ensure that production from intermittent resources, curtailments, potential project delays or failures, and/or other unexpected circumstances that could otherwise reduce anticipated renewable energy deliveries, do not adversely impact MCE's ability to fulfill publicly communicated renewable energy portfolio goals. These planning decisions serve as formidable protections against renewable energy delivery shortfalls.

(v) Assessment of how Procurement or Allocations are Consistent with the Evaluation of Supply and Demand

MCE has assembled a broadly diverse renewable energy contract portfolio, meaning that MCE's portfolio is attentive to technological diversity, temporal diversity, geographic diversity, and supplier diversity. These planning considerations, coupled with MCE's voluntary procurement targets that meaningfully exceed statewide mandates, minimize sources of planning vulnerability and prevent the risk of RPS compliance shortfalls. In terms of serving customer energy requirements, MCE's diverse portfolio, which includes baseload, peak, off-peak, seasonal, and dispatchable delivery profiles, is generally complementary to the manner in which MCE's customers use electric power. Dispatchable renewable resources, specifically co-located solar and battery infrastructure, allow for the shaping of certain renewable deliveries to promote improved alignment between supply and demand. Over time, MCE will continue to evaluate customer energy requirements and usage patterns relative to how its renewable resource portfolio delivers power and will pursue incremental procurement opportunities to better align supply and demand at least cost.

IV.A.1. Long-Term Procurement

(i) Assessment of How Current and Planned Procurement Meets 65 Percent Long-Term Contracting Procurement Requirement Through 2035.

MCE has been committed to supporting new, California-based renewable resource development since its inception, and has supported numerous generating assets via execution of long-term contracts. MCE has already executed long-term renewable contracts that are expected to yield approximately 96% of its total RPS/statutory renewable energy requirements (or 147% of MCE's expected RPS-related long-term renewable energy requirements) in 2025. Further, most of the renewable energy supply solicited under MCE's Open Season is intended for projects with proposed delivery terms between ten and twenty years, which bolsters MCE's proportionate use of long-term renewable energy over time.

(ii) Quantitative Assessment of MCE's Long Term RPS Positions

The table below relates projected deliveries under MCE's existing long-term RPS supply contracts to interim annual RPS procurement targets and related long-term contracting requirements.

Table 2: Projected RPS Deliveries

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Proportionate Long-Term RPS Purchases Relative to Interim Annual Statutory Procurement Mandate	96%	95%	105%	118%	114%	108%	105%	102%	90%	85%	83%
Proportionate Long-Term RPS Purchases Relative to Interim Annual Statutory Long-Term Contracting Requirement	147%	146%	162%	182%	176%	166%	161%	157%	139%	131%	127%

MCE's substantial, ongoing commitment to long-term RPS contracting has created significant projected long-term RPS surpluses. As a result of such surpluses, there is an exceptionally low risk of MCE falling short of this aspect of the RPS compliance program.

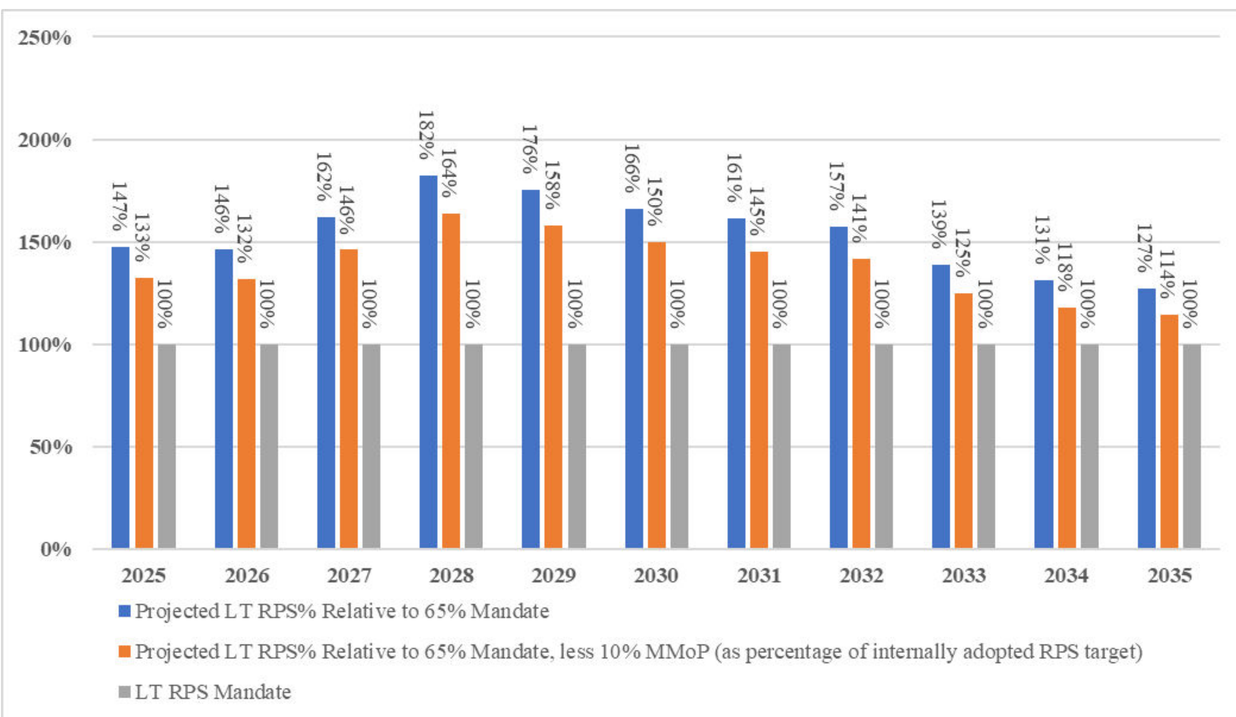
Figure 2 depicts the relationship between California's currently effective long-term RPS contracting mandates and projected deliveries related to MCE's existing long-term RPS contracts, for calendar years 2025 through 2035. The rightmost bar in each grouping reflects California's 65 percent RPS contracting mandate as 100 percent of the total long-term contracting requirement. MCE has included two additional bars in each grouping:

1) An unadjusted projection of MCE's expected annual long-term contract deliveries, relative to the 65 percent mandate. This bar represents the proportionate relationship between MCE's long-term contract deliveries and the statewide procurement mandate. For example, MCE projects that it will surpass the state's long-term contracting requirement

by 47 percent in 2025 and is not expecting to fall below 100 percent of its long-term contracting requirement during the current planning period; and

2) An adjusted projection of MCE's expected annual long-term contract deliveries relative to the 65 percent procurement mandate. This bar represents the proportionate relationship between MCE's long-term contract deliveries (including an annual reduction in such deliveries equivalent to MCE's established Minimum Margin of Over Procurement ("MMoP"), which reflects the potential impacts of delivery shortfalls related to resources intermittency, delays in commercial operation, resource curtailment, supply chain issues, and/or other operational issues) and the statewide mandate. MCE believes that this scenario represents a relatively extreme stress case. Nonetheless, MCE would expect to meet or exceed California's long-term contracting mandate throughout the planning period.

Figure 2: MCE's Projected Long-Term RPS Contracting Progress: 2025-2035



Note that the data underlying this bar chart has been compiled annually, which means that the percentages do not reflect the additional compliance flexibility related to California's multi-year compliance periods. For example, if MCE exceeds the long-term procurement mandate by 47% in 2025, it could absorb meaningful delivery shortfalls in the other years encompassing Compliance Period 5 before any compliance deficits arise. Unadjusted projections of MCE's long-term contracting progress suggest that MCE is expected to exceed applicable mandates through the current planning period. Likewise, adjusted projections also suggest that MCE will similarly exceed applicable mandates, even under a relatively extreme stress case such as the one reflected in the previous bar chart. MCE expects to engage in additional long-term contract efforts, which will further increase its long-term RPS positions as well as the compliance buffer already in place.

(iii) Summary of Current and Planned Long-Term RPS Procurement

MCE maintains a diverse set of long-term power purchase agreements to meet its long-term procurement needs. This includes multiple geothermal, solar, wind, small hydro and solar plus storage resources. These contracts are staggered in nature, spanning 10 to 30 years in length. In addition, MCE is engaged in negotiations to add more generating and storage resources to the existing fleet. MCE does not anticipate any issues meeting its long-term requirements.

(iv) Timeline Meeting 65 Percent Long Term Procurement Requirement.

MCE did not receive an SB 155 letter and does not expect any issues in meeting its long-term RPS contracting obligations, as described elsewhere in this Plan.

IV.B. Portfolio Diversity and Reliability

(i) Description of How Portfolio Diversity is Considered.

As part of MCE's forecasting and procurement processes, MCE considers the deliverability characteristics of its resources including the expected delivery profile, available capacity and dispatchability attributes, if any, associated with each of its generating resource and/or supply agreements and reviews the respective risks associated with short- and long-term purchases. These efforts lead to a more diverse resource mix, address grid integration issues, and provide value to MCE's member communities, including reduced costs and support in achieving planned procurement objectives for the period addressed in this RPS Procurement Plan. A quantitative description of MCE's forecast is attached in Appendix C.

(ii) Description of How Planned RPS Portfolio Diversity will Contribute to System Reliability.

With respect to system reliability, MCE is aware of the planning challenges faced by retail sellers with internally adopted renewable energy targets that exceed RPS mandates. In particular, such retail sellers must often bear increased costs for renewable resources with diverse and complementary delivery profiles, as well as comparatively high levels of energy storage infrastructure to allow for the reshaping of renewable energy deliveries to better align with load.

For example, renewable energy procurement efforts that may initially focus on relatively low-cost solar resources will often necessitate subsequent investments in co-located energy storage infrastructure and/or higher-cost baseload renewable generating technologies, such as those using geothermal, biomass and landfill gas fuel sources. These baseload renewable technologies are often priced at three-to-four times the level of in-state photovoltaic ("PV") solar generation but generally provide increased capacity value due to the more predictable, baseload generating profiles of such resources, and related reliability enhancements.

Despite the adverse budgetary impacts, MCE continues to pursue resource acquisitions that will promote increased alignment between supply and demand as well as the increased use of locally situated renewable generating resources. Currently, low-cost, long-term solutions are incredibly challenging to identify, as ongoing increases in California's RPS procurement mandates and technological limitations often create the need for near-term investments to balance the achievement of compliance mandates with generalized grid reliability.

Nonetheless, MCE remains committed to pursuing a conscientious planning process that balances grid reliability, compliance demonstration, and customer cost impacts. Again, there are no easy solutions in addressing this dilemma, but MCE's commitment to pursuing alignment of supply and demand as well as general resource diversity should contribute to grid reliability, reducing related risks for MCE's customers and the system at large. In consideration of MCE's diverse contractual commitments for requisite renewable energy supply and ongoing focus on the identification of RPS-eligible and complementary technologies that will mitigate reliability impacts associated with increased use of intermittent generating resources throughout the state, overall risks to system reliability associated with MCE's RPS Procurement Plan were determined to be low.

(iii) Description of How Portfolio Diversity will Maximize Ratepayer Value While Minimizing Costs and Risks.

MCE is interested in emerging and viable technologies to meet the state's reliability needs. MCE's commitment to innovation and the advancement of renewable technologies continues to drive strategic opportunities for the inclusion of emerging technologies within its supply portfolio. The extent to which such technologies will be successful in mitigating conditions of oversupply, production variability and misalignments between energy production and customer use will be monitored over time to ensure that such contractual commitments are promoting desired outcomes.

MCE will continue to procure renewable and other GHG-free and conventional energy products, as necessary, to ensure that the future energy needs of its customers are met in a clean, reliable, and cost-effective manner. MCE has established proportionate procurement targets for overall GHG-free energy content, including subcategories for renewable energy and other carbon-free products, including related planning reserves.

In 2020, MCE also implemented an "equivalent carbon-free" portfolio metric, which considers the total emissions associated with each supply source relative to a target annual emission factor for its entire supply portfolio. For example, MCE's 95% carbon-free equivalent goal in 2024 contributed to the achievement of an overall portfolio emission factor less than 1% of the California Air Resources Board's ("CARB") assigned emission factor for energy imports and system power, which is currently set at 0.428 metric tons of carbon dioxide equivalent per megawatt hour ("MT CO_2e"). Expressed differently, the 95% carbon-free equivalent goal limited, on a voluntary basis, MCE's emissions to an overall portfolio emission factor of 0.021 MT CO_2e/MWh. As reflected in its current 2024 Power Source Disclosure ("PSD") report for Light Green service,[5] MCE's actual 2024 emission factor of 0.001 MT CO_2e/MWh was below the organization's 95% carbon-free equivalent emission target (reflecting a virtual 100% carbon-free equivalency for the Light Green portfolio. The emission factors for Deep Green, Local Sol and Green Access service, as reflected in MCE's 2024 PSD report, were also zero.

As certain renewable generating technologies are known to have relatively low levels of emissions, such as certain geothermal generating technologies, MCE's equivalent carbon-free metric captures such impacts, along with any other use of carbon-emitting supply, including

[5]The 2024 Power Source disclosure Report was submitted by June 1, 2025.

system power and CARB-certified Asset Controlling Supply, to derive its proportionate use of carbon-free generation. To the extent that MCE's energy needs are not fulfilled using renewable or other GHG-free generating resources, it should be assumed that such supply will be sourced from conventional energy sources, such as natural gas generating technologies or system power purchases. MCE also plans to maintain its carbon-free equivalent metric at 95% of total supply in 2025 and beyond, meaning it will be further constrained in utilizing <u>any</u> carbon-emitting sources, including certain renewable generating technologies. As such, MCE will continue to creatively address the exercise of resource planning and portfolio composition to meet or exceed the aforementioned carbon-free equivalency metric.

MCE uses a portfolio risk management approach in its power purchasing program, seeking low-cost supply (based on then-current market conditions) as well as diversity among technologies, production profiles, project sizes and locations, counterparties, lengths of contract, and timing of market purchases. These factors are taken into consideration when MCE engages the market and pursues related procurement activities.

A key component of this process relates to the analysis and consideration of MCE's forward load obligations and existing supply commitments with the objectives of closely balancing supply and demand, cost/rate stability, and overall budgetary impacts, while leaving some flexibility to take advantage of market opportunities and/or technological improvements that may arise over time. MCE's long-term load forecast is a projection of the energy (reflected in MWh) that its customers will consume annually. MCE's long-term load forecast is driven primarily by the number and types of customers that MCE expects to serve, in conjunction with weather projections. Hourly class-specific load profiles are then used to break down the monthly energy forecast into more granular time-of-use and peak demand values. MCE's long-term load forecast also incorporates the load-modifying effects of electric vehicles, behind-the-meter solar and/or storage (via net energy metering), and energy efficiency.

MCE monitors its open positions separately for each renewable generating technology as well as GHG-free resources, conventional resources, and its aggregate supply portfolio. MCE maintains portfolio coverage targets of up to 100% of expected customer energy requirements in the near term (0 to 2 years) and typically leaves gradually larger open positions in the mid- to long-term, consistent with generally accepted industry practices. However, those larger open positions are continuously monitored for weather, market changes, and resource availabilities, and filled in a non-linear fashion as determined by MCE management. For example, MCE may fill residual summer positions ahead of the spring season or through procurements administered during the previous calendar year.

MCE prefers zero emission generating technologies, but within this preference MCE is largely technology-agnostic, subject to the previously discussed carbon-free equivalency metric.[6] MCE's supply preferences are intended to exhibit diversity across a broad range of renewable technologies that will deliver energy in a profile that is generally consistent with MCE's anticipated load shape. MCE is aware that significant use of intermittent renewable generating technologies has the potential to create misalignments between customer energy consumption and related power production; however, MCE regularly evaluates customer usage in light of expected renewable deliveries to reduce such risks and inform future procurement decisions. Furthermore, MCE continues to consider procurement opportunities with renewable generating facilities that will utilize storage technology, which can materially re-shape the typical delivery profile

[6] As mentioned above, MCE has a policy of not pursuing resource-specific nuclear power purchases.

associated with intermittent renewable generating assets, providing the opportunity for MCE to more accurately balance supply and changing customer demand, particularly due to the potential expansion of transportation electrification. MCE is also considering stand-alone energy storage opportunities to "recontour" purchased energy volumes in a manner that better matches changing customer usage patterns. MCE has determined that such projects are comparatively costly due to infrastructure costs and, in the case of battery storage projects, losses stemming from the common charge/discharge cycle of such projects.

Additionally, MCE offers several programs to manage its load shapes and better align MCE's supply resources with hourly demand. For example, MCE currently offers a managed EV charging app, MCE Sync, which helps customers automate EV charging and shift consumption away from peak periods.[7] Additional programs to help better align supply and demand include but are not limited to: MCE's Peak FLEXmarket;[8] Time of Use ("TOU") rates;[9] and MCE's revised Feed-In-Tariff ("FIT") Plus program,[10] that requires the addition of storage equal to 180% of the generator's nameplate capacity and enables generation to be shifted outside of normal solar production hours to better align MCE resources to match the hourly load.[11]

Recent market data continues to indicate that midday peak resources are likely to comprise a larger proportion of California's renewable supply portfolio due to the rapid decline in wholesale prices for solar PV generation and the abundance of such projects in operation and under development. Additions to MCE's portfolio during the Planning Period will likely be more heavily

---

[7] *See* https://www.mcecleanenergy.org/mce-sync/.
[8] *See* https://mcecleanenergy.org/peak-flex-market/.
[9] *See* https://mcecleanenergy.org/what-is-the-time-of-use-rate-plan/.
[10] *See* https://www.mcecleanenergy.org/feed-in-tariff/.
[11] *See* Agenda Item #06 from MCE's December 2, 2021, Technical Committee Meeting, available at https://www.mcecleanenergy.org/wp-content/uploads/2021/11/MCE-Technical-Committee-Packet-December_2021.pdf.

weighted toward energy resources – dispatchable, shaped during non-solar or ramping periods, or otherwise – that complement competitively priced solar already under contract or pair new solar projects with storage technologies to avoid exacerbating midday over-supply. MCE may also engage in purchases from as-available renewable generation (*e.g.*, wind) to the extent that such supply is competitively priced or otherwise provides electricity during time of day when existing supply commitments are currently lacking. Additionally, MCE is working with developers of its solar projects already under contract to add storage to those existing resources to increase the number of dispatchable resources in its portfolio. In regard to project location, MCE places the greatest value on locally-sited renewable generating and storage projects, particularly those located in its service area or within approximately 100 miles thereof. In general terms, the next highest preference related to resource selection are projects sited within the California Independent System Operator's ("CAISO") North of Path 15 Zone (generally, Northern California), followed by projects elsewhere in California, and lastly, out-of-state resources. This procurement strategy has led MCE to achieve its desired clean energy portfolio objectives as well as cost-competitive customer rates.

(iv) Description of How Energy Storage and Emerging Technologies are Addressed in Reliability and Diversity Planning.

Regarding new and emerging technologies, MCE has a particular interest in using offshore wind, long duration battery storage, and green hydrogen storage for building a carbon free portfolio for its customers and providing reliability to the grid. These technologies provide opportunities to shape MCE's hourly portfolio to match the hourly demand. MCE has provided several letters of intent with the potential to get into long term agreements once the technology is commercially viable to developers of new and emerging technologies. MCE intends to continue this approach in the future.

IV.B.1. Forecasting for Increased Transportation Electrification

A key component of the long-term load forecast includes the projections for transportation electrification load, the methodology for developing this forecast is described as follows:

MCE's load forecast is adjusted for expected increases due to electric vehicle ("EV") adoption. In order to estimate the impact of EV adoption on MCE's load forecast, MCE utilizes the California Energy Commission's ("CEC") Integrated Energy Policy Report as the basis for the estimates. MCE utilizes the state's mid-demand scenario, adjusting the forecasted EV load based upon two factors: 1) EV adoption rates within MCE's service territory and 2) Participation rates within MCE's service territory. California Department of Motor Vehicle registration data is utilized to estimate the territory's share of the state's forecasted EV load growth and internal customer data sources are utilized to adjust for MCE participation rates. MCE's EV load growth forecast does not segment by vehicle types but rather adjusts the state's total EV load based upon penetration levels.

Table 3: Transportation Electrification Load Forecast (2025-2035)

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
MCE Annual EV Load Forecast (GWh)	683	737	785	833	884	937	990	995	1,000	1,005	1,010

IV.B.2. Curtailment Frequency, Cost, and Forecasting

This Section responds to the questions presented in Section 4 of the ACR[12] and describes MCE's strategies and experience in managing the Agency's exposure to negative pricing events, overgeneration, and economic curtailment for MCE's region and portfolio of renewable resources.

[12] ACR at 19-20.

IV.B.2.(a) Factors Having the Most Impact on the Projected Increases in Incidences of Overgeneration and Negative Market Price Hours

Due in large part to the rapid increase in the amount of wind and solar generation coming online throughout the western United States, the CAISO Balancing Authority Area ("BAA") has experienced an increasing frequency and magnitude of curtailment and negative pricing events. The U.S. Energy Information Agency ("EIA") estimates that as of March 2025, California has 41,262 MW of total installed solar capacity, with 18,706 MW of that total being behind-the meter solar.[13] The CAISO reports that it has approximately 21,240 MW of utility-scale solar and 8,373 MW of utility-scale wind currently installed within its BAA.[14] This capacity results in discrete periods where the majority of load in the CAISO is served by solar and wind resources. The monthly maximum load served by wind and solar in the CAISO has averaged 87.5% over the past 5 years (April 2020 to April 2025), and the monthly maximum load served by wind and solar exceeded 142%.[15]

To address the resulting instances of over-supply, the amount of curtailment of wind and solar in the CAISO has significantly increased each year from 2015 through 2022, totaling 187,000 MWh in 2015, 308,000 MWh in 2016, 358,000 MWh in 2017, 461,000 MWh in 2018, 961,000 MWh in 2019, 1,587,497 MWh in 2020, 1,504,803 in 2021, 2,449,248 in 2022 2,659,526 MWh in 2023, and 3,423,376 in 2024. As of June 12, 2025, the total curtailment of solar and wind year to date is 2,290,000 MWh. Curtailment is typically the highest during the months of March, April,

---

[13] EIA, Electric Power Monthly, *Table 6.2.B. Net Summer Capacity Using Primarily Renewable Energy Sources and by State, March 2025 and 2024 (Megawatts)*, available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_02_b..
[14] CAISO, What are we doing to green the grid?, updated April, 2024, *at* https://www.caiso.com/about/our-business/managing-the-evolving-grid
[15] https://www.caiso.com/documents/monthly-renewables-performance-report-april-2025.html CAISO, Monthly Renewables Performance Report, April 2025, available at https://www.caiso.com/documents/monthlyrenewablesperformancereport-feb2024.html

and May when hydroelectric generation is historically at its highest and California load is at its lowest. Years in which there is an above-average snowpack results in higher-than-average hydroelectric generation which exacerbates renewable generation curtailment. The table below summarizes solar and wind curtailment from January 2025 through April 2025

Table 4: Summary of CAISO Solar and Wind Curtailment January-April 2025

2025 Data	**Wind Curtailment (MWh)**	**Solar Curtailment (MWh)**
January	15,300	114,970
February	22,890	479,630
March	61,840	857,180
April	51,480	686,710
Total Curtailment	151,510	2,138,490
Curtailment %	2.02 %	13.68%
No. of Intervals Curtailed	14,841	16,728
Pct. of Intervals Curtailed	34.14	38.48
Annual Curtailment (MWh)		
	Wind	Solar
2018	28,686	432,357
2019	43,557	921,684
2020	90,276	1,497,220
2021	78,477	1,426,326
2022	128,990	2,320,258
2023	150,604	2,508,916
2024	230,765	3,192,612

2025 (Partial Year*)	151,510	2,138,490
Annual Curtailment (% of Specific Generation)		
2018	0.17%	1.56%
2019	0.27%	3.22%
2020	0.56%	4.99%
2021	0.41%	4.19%
2022	0.70%	6.26%
2023	0.72%	6.10%
2024	1.03%	6.29%
2025 (Partial Year*)	2.02%	13.68%
Average	0.55%	4.66%
Annual Curtailment (% of Load)		
2018	0.013%	0.190%
2019	0.020%	0.420%
2020	0.041%	0.680%
2021	0.036%	0.650%
2022	0.057%	1.030%
2023	0.069%	1.148%
2024	0.103%	1.419%
2025 (Partial Year*)	0.227%	3.210%
Average	0.071%	1.093%

*Through April 2025

The CAISO notes that the majority of renewable resource curtailment is "a result of economic downward dispatch, rather than self-schedule curtailment," and that "[m]ost renewable generation dispatched down in the ISO were solar resources, rather than wind, because solar resources typically bid more economic downward capacity than wind resources".[16] That means that curtailment happened in response to congestion and was mitigated by supply that was willing to reduce its output based on price signals from the CAISO market.

CAISO system-wide 2025 curtailment percentages are higher than forecasted by MCE to date. Thus far in 2025 through May, MCE has experienced 85,404 MWh of curtailment, which is over 11.2% of MCE's RPS portfolio. This percentage will likely decrease as the summer season progresses. Curtailment to MCE's RPS portfolio is predominantly composed of the Little Bear Solar resources, which is 93.3% of MCE's curtailment volume. MCE has been in discussions with the CAISO regarding local network upgrades required and the potential for adding a battery to the project to alleviate Little Bear Solar curtailment.

IV.B.2.(b). Written Description of Quantitative Analysis of Forecast of the Number of Hours Per Year of Negative Market Pricing for the Next 10 Years

MCE's scheduling coordinator agent, ZGlobal, has the capability to perform production cost analyses based on various input assumptions through 2035 to derive hourly market prices for energy and ancillary services. PLEXOS Integrated Energy Model is a commercial optimization engine that can simulate the economic commitment and dispatch used by the CAISO's day-ahead

[16] CAISO, 2020 Annual Report on Market Issues and Performance Report, published January 20, 2022, page 41, available at http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf.

market processes which simultaneously optimizes energy dispatch and ancillary services capacity awards across the CAISO grid. In this way, the simulation will determine locational marginal prices and ancillary service marginal prices in the same manner the CAISO day-ahead market sets prices. ZGlobal has developed models using input assumptions that are based on common case inputs and planning guidelines from Western Electricity Coordinating Council, CAISO, Commission and CEC.

The key assumptions considered for the assessment included the impact of higher California renewable energy standards (60% RPS by 2030), planned gas-fired and nuclear generation retirements and adopted CEC demand forecasts which consider energy efficiency programs and increased behind-the-meter solar generation. Results are highly dependent upon input assumptions, primarily the level of new RPS generation, deployment of energy storage facilities, upgrades to CAISO-controlled transmission facilities and the ability to export energy from the CAISO to external balancing areas.

In California, electricity prices are typically set by gas-fired resources operating on the margin. However, as increasing supplies of renewable energy are added to the system, there are periods where marginal prices are being set by zero or even negatively-priced resources. Market prices have been trending downward, especially during seasons and periods of the day when loads are low and solar output is high with the influx of renewable energy resources. The modeling shows that during solar hours, prices are low during the middle of the day, driven by solar resources and their willingness to curtail and increasing in the morning and evening when gas-fired resources are needed to meet peak loads outside of the solar supply period. In short, prices as reflected by the CAISO's duck curve are expected to continue, with the amplitude of the valley and ramps dictated by the amount of energy storage available to smooth out the net supply.

IV.B.2.(c) Experience, to Date, With Managing Exposure to Negative Market Prices and/or Lessons Learned from Other Retail Sellers in California

MCE's experience and process for managing exposure to negative market prices has been addressed above in Section IV.A.(*iii*).

IV.B.2.(d) Direct Costs Incurred, to Date, for Incidences of Overgeneration and Associated Negative Market Prices

For calendar year 2025 through May, MCE's RPS portfolio has been exposed to negative market prices and experienced curtailment as summarized in the table below.

Table 5: Summary of MCE RPS Resources Curtailment January-May 2025

Location	Day-Ahead Negative Prices	Real-Time Negative Prices	Curtailment (MWh)	Cost of Curtailment ($)
South P26	-$10.79	-$16.59	1,711	$69,151
Fresno 1	-$36.83	-$43.49	79,701	$3,798,396
Fresno 2	-$18.78	-$24.52	997	$48,777
North P26	-$11.77	-$16.52	2,995	$110,174
Total	**-$22.41**		**85,404**	**$4,026,499**

The Day-Ahead and Real-Time Negative Price columns represent averages of negative prices by RPS geographic area when prices are negative for solar hours for solar resources and all hours for wind resources. The prices are averages based on resources within the area. Curtailment MWh is the amount of energy that MCE RPS resources in the areas were curtailed from January 1 through May 31, 2025. "Cost of Curtailment" is the subsequent market cost of the curtailed energy.

IV.B.2.(e) An Overall Strategy for Managing the Overall Cost Impact of Increasing Incidences of Overgeneration and Negative Market Prices

While curtailment is a viable renewable integration strategy that is generally more cost-effective than other options, there are potential negative consequences from excessive curtailment. Curtailment of solar and wind represents a lost opportunity to generate zero-GHG electricity, and excessive curtailment could impact the ability of the state to meet its environmental and energy policy goals. Additionally, these over-supply situations expose ratepayers to increased costs because their load serving entities must either economically curtail the generating resource (and often pay for the electricity that was not generated) or generate power and be exposed to negative prices.

MCE considers the impact of curtailment and negative pricing on its portfolio and factors potential curtailment into its long-term planning. Due to the difficulty in accurately forecasting curtailment, MCE will review the historical data on curtailment and negative pricing within regions where MCE may contract for generating resources. When MCE is evaluating new procurement opportunities, the potential amount of future curtailment is one factor that MCE considers. While MCE has not yet developed an individualized forecast of future curtailment, MCE will factor potential curtailment into its minimum margin of procurement (described in Section IX) and may also factor this consideration in future iterations of its Risk Assessment (Section VII). To the extent that MCE is engaged in renewable supply agreements which include curtailment provisions, it will take actions to limit the impacts of curtailment on its customers. During its current and future renewable contracting efforts, MCE will pursue contract terms that recognize and limit the potential financial impacts of negative pricing and give MCE greater flexibility to direct economic curtailment, if this becomes necessary.

IV.B.2.(f)Contract Terms Included in RPS Contracts Intended to Reduce the Likelihood of Curtailment or Protect Against Negative Prices.

MCE negotiates the right in its long-term Power Purchase Agreements ("PPA") to economically curtail deliveries to a certain number of hours up to which there is no seller compensation. MCE also has a strong preference to be the scheduling coordinator so that it can adjust its bidding strategies to protect against negative pricing in the Day Ahead and Real Time markets.

IV.C. Portfolio Optimization

MCE plans for and secures commitments from a diverse portfolio of generating resources to reliably serve the electricity supply requirements of its customers over near-term, mid-term and long-term planning horizons. MCE's goal is to meet organizational policies and statewide mandates in a manner that is cost effective, achieves internally adopted clean energy objectives, promotes grid reliability, and generally supports a well-balanced and diversified resource portfolio. Portfolio optimization strategies can help reduce costs and should facilitate alignment of MCE's portfolio of resources with its forecasted needs. This noted, MCE continues to pursue its renewable energy procurement goals through the exclusive use of PCC1 products but remains aware of the diminished availability of this supply during Compliance Period 5. If alternative RPS-eligible products become necessary to meet MCE's near-term portfolio objectives, MCE will consider these alternatives as appropriate. MCE's preference for PCC1 RPS products is expected to minimize portfolio emission impacts that would otherwise accrue using Portfolio Content Category 2 ("PCC2") and Portfolio Content Category 3 ("PCC3") product options, both of which are ascribed emissions under California's current emissions calculation methodology. While this approach is more costly it promotes the achievement of MCE's GHG-related objectives. This noted, MCE may procure small quantities of RPS supply from clean and specified PCC2 resources if unexpected delivery shortfalls are higher than expected retail sales and/or prevailing market conditions necessitate such purchases. MCE anticipates such purchases to be rare, if purchased at all. This flexibility to purchase PCC2 resources ensures that MCE can fulfill adopted portfolio commitments to its customers. MCE will advise the Commission if the Agency anticipates any deviations from the aforementioned resource preferences.

To support its RPS planning and procurement goals, MCE considers the following strategies:

- Joint Solicitations: Joint solicitations can expand the procurement opportunities available to a CCA, as well as provide procedural efficiencies, economies of scale, and overall cost savings for participating organizations. MCE is closely networked with other CCAs through its membership in the CalCCA, the trade organization representing California's CCA sector, and regularly coordinates with other CCAs regarding prospective procurement opportunities and portfolio balancing activities.
- Purchases from Retail Sellers: Purchases of RPS-eligible renewable energy from other retail sellers can provide a cost-effective way of meeting short-term resource needs or filling in gaps in procurement while long-term projects are under development. MCE will evaluate solicitations offered by other retail sellers, as necessary.
- Sales Solicitations: As MCE continues to manage its growing portfolio of renewable resources, it will also consider administering sales solicitations (serving as a renewable energy seller) for the benefit of other retail sellers. Such solicitations are expected to be rare and relatively small in scale. MCE may also engage in bilateral sales discussions with certain retail sellers, including CCAs, if/when divesting relatively small amounts of surplus renewable energy supply is deemed necessary to rebalance MCE's renewable portfolio

relative to internally established procurement targets. MCE has completed such processes in the past and expects to do so in the future as well. Selling excess renewable supply is an effective way for all LSEs to reduce unnecessary renewable energy expenses while providing valuable renewable energy products to other market participants.

- Optimizing Existing Procurement: As MCE considers its long-term resource needs, it may evaluate options in its future PPAs to increase the output of existing generating facilities through technological upgrades. This can be accomplished by adding new capacity to an existing generator or by adding energy storage infrastructure to an existing renewable generator. Expanding existing facilities may provide additional generation at reduced costs with a lower risk of project failure because the need for distribution system upgrades and permitting may be minimized or eliminated. Adding energy storage infrastructure to an existing renewable generator enhances grid reliability and the value of electric energy produced by the generating facility. Such enhancements allow pre-storage energy delivery profiles to be shifted to: 1) better align MCE's supply with customer demand; or 2) create more value for MCE customers by shifting electric energy deliveries to a time of day when market revenues (related to such energy deliveries) would be greater than normal. In terms of reliability impacts related to the addition of energy storage infrastructure, MCE expects that such enhancements would meaningfully increase the proportionate level of RA capacity that could be derived from an intermittent renewable generating resource. It is well documented that without such storage infrastructure, there will be reductions to the Net Qualifying Capacity ("NQC") of intermittent renewable generating resources, resulting in very little capacity benefits from solar-only generating projects. In considering these sorts of enhancements, MCE will be mindful of the need to coordinate with its resource owners/operators to evaluate potential planning constraints (*e.g.,* generator interconnection processes and limitations) before determining that the addition of energy storage infrastructure at an existing generating facility would be a viable option.

MCE launched a Request for Information ("RFI") for Long-term Offers on April 14, 2025.[17] The results of the RFI will inform MCE's approach to its typical Open Season solicitation process. Open Season provides a competitive, objectively administered opportunity for qualified suppliers of various energy products (including renewable and storage technologies) to fulfill MCE's future resource requirements and compliance obligations. Open Season is typically administered on an annual basis for purposes of soliciting offers for new-build renewable energy and storage resources and capacity that meet the procurement targets set forth in IRP. The 2025 Open Season will focus on soliciting resources that will provide the best value and best fit for MCE load shapes, in addition to supporting MCE's compliance with regulatory procurement requirements.

As part of the Open Season solicitation process, MCE provides a Procedural Overview and Instructions document that describes the Open Season process, schedule, and requirements for submitting a conforming offer. MCE also provides an offer form and term sheets that must be submitted along with the offer.

During this year's RFI, MCE sought information from qualified suppliers of renewable energy, energy storage products and RA to inform MCE's formal long-term offer solicitation in 2025. MCE's procurement team launched an RFI as an initial step in its long-term procurement efforts in 2025. MCE believed that this new approach would streamline procurement efforts for all participants. MCE sought information for prospective full-toll agreements (all applicable

[17] *See* https://www.mcecleanenergy.org/energy-procurement/.

products) with a minimum contract term length of at least five (5) years from Renewable Energy (PCC1-eligible) projects, Renewable Energy Paired with Energy Storage projects, and Standalone Energy Storage projects. Projects were to be no less than 5 MW for 24x7 load profiles or no less than 25 MW for intermittent resources. Beyond these categories, responses were not limited in any other respect. Due to numerous headwinds in the market for grid-scale projects, including interconnection delays and process reforms, permitting challenges, and federal tax credit and tariff uncertainty, MCE sought a new approach to its long-term procurement in 2025. The procurement team believed a streamlined RFI process would provide an indication of the current landscape for projects in all stages of development. The Procurement team worked closely with MCE's Public Affairs team, leveraged external stakeholders, including CalCCA, and communicated with an extensive network of developers to draw participation in the RFI. MCE will continue to evaluate the RFI results and may pursue a formal Request for Offers ("RFO") from qualified respondents.

When an offer is received, MCE first reviews an offer for completeness relative to the RFO eligibility criteria. MCE then conducts a quantitative analysis focused on the value of each conforming offer, in addition to a qualitative review evaluating non-quantitative offer details, like interconnection status, in more depth. MCE selects the strongest offers on a rolling basis, in parallel to completing evaluations of other offers as they are submitted. To ensure that favorable opportunities are not "lost" to other buyers, MCE works with the 3rd party to enter into an Exclusivity Agreement once an offer has been short-listed.

Once an Exclusivity Agreement is executed, Staff will begin contract negotiations with the shortlisted projects. The resulting PPAs and Energy Storage Agreement(s) ("ESA") are reviewed by MCE's Executive Management team before review and approval by MCE's Board. Contract execution occurs after the agreements are approved by the Board.

MCE also considers allocations from PG&E in its portfolio optimization. Through the Power Charge Indifference Adjustment ("PCIA"), MCE customers (and other CCA and Direct Access customers) are required to pay their share of the above-market costs associated with PG&E's legacy resources such as its large hydroelectric fleet, PG&E's nuclear power plant, Diablo Canyon, and many PG&E PPAs including RPS PPAs. As nearly half of PG&E's customer load has departed for other LSEs, it has resulted in PG&E having excess resources in its portfolio. Accordingly, the Commission directed PG&E to offer a proportionate share allocation of output from hydroelectric and nuclear, GHG-free, resources at no additional cost on a voluntary basis to CCAs and Direct Access providers whose customers pay the PCIA for the years 2019 and 2020. ("Interim Allocation" The Interim Allocation was extended into 2021 by Resolution E-5111, in which the Commission also authorized PG&E to extend the interim approach to GHG-Free resources through December 31, 2023.). In Decision ("D.") 23-06-06 the Commission modified the PCIA methodology by allowing PG&E to elect to either offer an allocation of large hydro GHG-Free attributes or to retain the attributes and value them at a new market price benchmark. In Advice Letter 7005-E, PG&E notified LSEs of its intent to offer large hydro allocations for 2024, and in its 2025 Energy Resource Recovery Application PG&E notified parties of its intent to offer large hydro allocations for the 2025-2027 period as well. MCE's Board in late 2024, accepted the hydro allocations as well as 2025 nuclear allocations. MCE will use these allocations in meeting its internally adopted GHG-free targets. Additionally, MCE structured its Light Green portfolio to be approximately 95% GHG-free starting in 2023,[18] subject to market and/or regulatory changes. To structure such a clean Light Green portfolio by 2023, MCE procured three

[18] MCE's Operational Integrated Resource Plan, https://www.mcecleanenergy.org/wp-content/uploads/2022/11/MCE-Operational-Integrated-Resource-Plan_2023.pdf.

products: (1) RPS-eligible renewable energy; (2) large hydroelectric energy; and (3) Asset Controlling Supplier energy, the vast majority of which is attributable to large hydroelectric generating resources. To ensure grid reliability, MCE's contracting goals include 475 MW of stand-alone energy storage to be online by 2030, and to have approximately 153 MW of new energy storage paired with solar resources online by 2030.[19]

Disadvantaged Community Solar Green Tariff: In 2021, MCE launched its first solicitation for the Green Access ("Disadvantage Community – Green Tariff" or "DAC-GT") and Community Solar Connection ("DAC-CSGT") procurement process ("2021 Green Tariff"). The purpose of MCE's 2021 Green Tariff was to fulfill the requirements of AB 327, D.18-06-027, D.18-10-007, and Resolution E-4999 (collectively the "Green Tariff policy"). The Green Tariff policy is intended to promote the installation of renewable generation among residential customers in disadvantaged communities ("DACs"). MCE executed two contracts for the DAC-GT program. To comply with the Green Tariff policy, MCE has to procure under two programs: 1) Green Access and 2) Community Solar Connection. MCE fulfilled the requirements of the Green Access program through the selected projects from the 2021 solicitation. MCE held annual solicitations for the Community Solar Connection program in 2022 and 2023 and received no offers. MCE then opened the Community Solar Connection solicitation in 2024 on an open until filled basis with no offers received. On May 30, 2024, the CPUC issued D.24-05-065, which made several modifications to the DAC-GT program, including adopting changes to the cost cap for the program, and closing the Community Solar Connection program, rolling unused capacity into the DAC-GT program. MCE is currently evaluating and will likely release a solicitation addressing

[19] MCE's 2022 CPUC Integrated Resource Plan, https://www.mcecleanenergy.org/wp-content/uploads/2022/11/MCE-2022-Integrated-Resource-Plan_11012022.pdf.

both these elements.

On June 24, 2021, the Commission adopted D.21-06-035, which directed all retail sellers to collectively procure 11,500 MW of new NQC, including LLT resources to come online between 2023 and 2026. This decision assigned each retail seller a specific procurement responsibility based on its share of peak demand. In February 2023, the Commission issued D.23-02-040, which supplemented the initial Mid-Time Reliability ("MTR") order to require LSEs to procure an additional 4,000 MW of NQC and pushing out the online date for LLT resources to 2028. MCE's total obligation, resulting from these two CPUC decisions, is 454 MW of NQC by June 1, 2028. MCE's 454 MW requirement includes 72 MW of NQC from dispatchable, zero-emitting capacity, required to be online by June 1, 2025. As part of its 454 MW requirement, MCE must also procure at least 58 MW of LLT resources, including (1) 29 NQC MW from long duration storage resources by June 1, 2028; and (2) 29 NQC MW from firm, non-fossil fueled baseload generating resources by June 1, 2028.[20] MCE plans to meet its MTR obligations using a diverse set of resource technologies, some of which will be RPS-eligible. MCE has negotiated a number of ESAs and PPAs to meet its MTR obligations and has executed agreements for RPS-eligible resources related to MTR.[21] As discussed in Section V below, pursuant to the Commission's initial MTR order, MCE has eight executed contracts for projects under development that will be used to meet MTR mandates: Daggett, Golden Fields, Geysers, Humboldt House, Strauss Wind, Key, Cormorant, and Corby. MCE's RNS, Project Development Status, and Cost Quantification templates have also been updated to incorporate these eight projects.

[20] Pursuant to D.23-02-040, the Commission changed the required online dates for LLT resources from 2026 to 2028.
[21] *See* Renewable Net Short Template Row Fb.

Generally, the MTR decisions are aligned with MCE's internally adopted contracting goals, which are highlighted above. As noted above, MCE provided approximately 99% GHG-free and 69% renewable energy through its Light Green base product in 2024, as shown in MCE's 2024 PSD Report. All other MCE customers, including those participating in the Deep Green, Local Sol, and Green Access service options, received supply reflecting 100% renewable and zero carbon emissions in 2024.

MCE intends to use RPS-eligible resources acquired for the MTR procurement mandates to fill open positions relative to MCE's internal RPS goal.[22] MCE will continue to use procurement strategies such as joint contracting efforts, buying from other retail sellers, and optimizing existing procurement, as described earlier in this section, to meet the MTR procurement mandates and MCE's internal goals for RPS at the lowest cost to its customers.

IV.C.1 Conformance with the IRP Proceeding

The resources identified in this RPS Procurement Plan are consistent with the resources MCE expects to identify in MCE's 2025 IRP, which is currently required to be submitted to the Commission for certification by November 1, 2025.[23] MCE's RPS Procurement Plan is also consistent with the biannual MTR updates provided to the Commission addressing MCE's progress towards meeting procurement requirements under D.21-06-035 and D.23-02-040.[24] As required by the ACR,[25] specifically, Table 6below describes how MCE's 2025 RPS Procurement

[22] *See* Row Ga of the Renewable New Short Template.
[23] While Commission decision indicates that LSEs are to submit 2025 IRP to the Commission by November 1, 2025, Energy Division indicated via email on June 5, 2025 that the IRP timeline will be delayed.
[24] Since filing its 2022 Compliance IRP, MCE has filed six biannual MTR update filings on February 1, 2023, August 1, 2023, December 1, 2023, June 3, 2024, December 2, 2024, and June 2, 2025 respectively.
[25] ACR at 21-22.

Plan conforms with the determinations made in the IRP Proceedings (R.16-02-007 and R.20-05-003) and highlights the interrelationships of its RPS and IRP planning processes. The following table reflects MCE's current updates, as reflected in this RPS Procurement Plan, regarding RPS alignment with the 2024-2026 IRP process.

Table 6: RPS Alignment in MCE's IRP

IRP Section Subsection	RPS Alignment in IRP	
III. Study Results **A. Conforming and Alternative Portfolios**	Retail sellers should explain how the RPS resources they plan to procure, outlined in their RPS Plan, will align with each of their Conforming Portfolios being developed in their IRP Plans for Commission approval and certification. This explanation should include:	
	1. Existing RPS resources that the retail seller owns or contracts. *2. Existing RPS resources that the retail seller plans to contract with in the future.* *3. New RPS resources that the retail seller plans to invest in.* *4. New and existing resources that will be used to meet Mid-Term Reliability obligations adopted in D.21-06-035 and the supplemental procurement ordered in D.23-02-040.*	The Commission certified MCE's 2022 IRP per Ordering Paragraph 5 of D.24-02-047. Pursuant to D.24-02-047 and the *Assigned Commissioner's Amended Scoping Memo and Ruling Extending Statutory Deadline*, issued April 18, 2024, MCE's next full update to its 2022 Compliance IRP will be filed by November 1, 2025, although this filing date is subject to change due to delay in the Commission's issuance of filing materials and guidance. MCE's portfolio mix and planned procurement met the requirements of the 2022 IRP Preferred Conforming Portfolio ("PCP") in the last IRP cycle and met MCE's compliance and internal obligations and targets. Looking forward to the upcoming 2025 IRP, MCE anticipates that its planned procurement of a diverse set of renewable resources, as represented in its 2022 PCP and as supplemented and complemented with additional near-, mid-, and long-term procurement, will meet the Commission's

		mandated emissions targets and reliability metrics, including the balanced and diverse set of resources identified in the most recent (2023) preferred system plan adopted by the Commission. MCE's PCP procured to the lower emissions target that was adopted in the 2023 PSP. As such, MCE expects that its portfolio will comply with the emissions metrics of the current Preferred System Plan and the emissions metrics in the upcoming IRP cycle. However, MCE notes that until official guidance and requirements for the 2025 IRP cycle are issued by the Commission, MCE cannot state with certainty what its optimal long-term procurement plan will be. To remain resilient and flexible, MCE has not set a specific ratio on the characteristics or type of resources for its planned procurement. The right balance will depend on multiple factors including but not limited to; • Specific and final IRP requirements; • Availability of eligible resource types on the market; • Project development timelines; • Deliverability of available resources for contracting; • Price and affordability; • Location and congestion analysis; and • MCE Portfolio fit. • For reference, a description MCE's PCP is as follows: ● MCE's PCP achieves an overall portfolio GHG target below MCE's assigned share of the 2030 and 2035 emissions under both the 30 million metric tons ("MMT") and 25 MMT scenarios. ● Using the CPUC's embedded assumptions in the 25 MMT portfolio,

		MCE's emissions registered at 0.493 MMT relative to MCE's assigned share of 0.640 MMT in 2030 and 0.492 MMT relative to 0.504 MMT in 2035. ● MCE's PCP assumed the use of RPS resources that were reflected in MCE's supply portfolio at the time of the 2022 IRP filing. ● The planned RPS-eligible resources reflected in MCE's PCP included: 109 MW geothermal; 356 MW wind (consisting of in-state, out-of-state, and off-shore); and 222 MW solar o Of the aforementioned PCP resources, MCE anticipated the following new RPS-eligible capacity additions: new hybrid resources totaling 212 MW solar/ 153 MW battery storage, 109 MW of geothermal, and new wind resources totaling 265 MWs. ● MCE also continues to procure and develop projects (both renewable generation paired with storage and stand-alone storage) to meet its MTR requirements pursuant to D.21-06-035 and D.23-02-040 (MCE was assigned 332 MW of incremental Net Qualifying Capacity to meet its share of the state's MTR need pursuant to D.21-06-035 and was assigned an additional 122 MW of incremental NQC to be online by 2027 pursuant to D.23-02-040). MCE continues to actively procure to meet the initial MTR need, the supplemental MTR need, and RPS-related needs in compliance with the mandated timelines. All of this procurement contributes towards MCE's MTR- and IRP-related needs, and much, but not

		all, of the procurement will contribute towards MCE's RPS-related requirements. At the time of this filing, MCE's existing executed MTR agreements or new build RPS-eligible procurement include the following incremental capacity amounts: 27 MW of nameplate geothermal capacity; 100 MW nameplate solar paired with 92 MW of nameplate storage; and 110 MW of nameplate solar paired with 60 MW of nameplate storage, 93.35 MW of nameplate wind capacity, and 110 MW of nameplate solar paired with 110 MW of storage. Although not MTR-eligible, MCE has also procured and brought online 100 MW of energy-only solar capacity from a new-build solar facility. All of the referenced procurement contributes towards the diverse set of resources indicated in MCE's 2022 PCP, which portfolio will continue to be revised and supplemented to account for market conditions, regulatory requirements, and internal portfolio optimization needs. ● MCE is also taking action via its annual solicitation processes to identify additional projects that contribute towards MCE's MTR, RPS, and general IRP needs through formal RFIs and RFOs as well as pursuing bilateral opportunities with project developers as described in more detail in Section IV.C, above. MCE expects that some of this procurement will be eligible to contribute towards MCE's RPS needs; all of this procurement is expected to contribute towards MCE's existing MTR needs and existing and future IRP procurement obligations to support reliability and GHG reduction

		efforts. Through administration of MCE's RFI procurement process, MCE is seeking to reduce outstanding resource needs required to meet portfolio specifications reflected in its PCP, MTR requirements, as well as any other internal and state-mandated RPS or reliability procurement targets. To the extent additional resources are needed, MCE is conducting supplemental, smaller solicitations and pursuing bilateral negotiations. ● Separate from, and predating the RFI, MCE is also pursuing various new-build projects for wind capacity, additional geothermal capacity, and co-located solar and storage capacity that MCE expects to be under contact within the year or soon thereafter. ● In addition to the more formal solicitation processes, MCE also solicits offers for short-term PCC1 renewable energy purchases/sales for annual portfolio balancing. Additionally, MCE participated in the PG&E Voluntary Allocation and Market Offer ("VAMO") process and received an allocation of renewable energy from the PG&E's PCIA portfolio in 2024. MCE is no longer receiving allocations from this process.
Any IV. Action Plan **A. Proposed Activities**	Retail sellers should describe how they propose to use RPS resources to implement both Conforming Portfolios. Narratives should include:	
	1. Proposed RPS procurement activities as required by Commission decision or mandated procurement.	To ensure compliance with its IRP, GHG, reliability, and RPS targets, MCE plans to substantially rely on GHG-free and RPS-eligible resources while contributing to statewide reliability requirements and

	2. Procurement plans, potential barriers, and resource viability for each new RPS resource identified.	responsibly managing overall portfolio costs. As described above in the Study Results section, there is significant overlap among MCE's RPS-related procurement, IRP-related procurement, and MTR-related procurement. MCE has contracted for three co-located resources, which are expected to provide additional RPS- and MTR-eligible incremental capacity (one of which is online, the other two resources are expected to achieve commercial operation in August 2025 and April 2031, respectively). MCE's prior RPS procurement plan also indicated MCE had four contracts for geothermal capacity (3 of which were incremental, new build capacity; 1 is for 100 MW of existing geothermal capacity for a 10-year delivery period starting in 2027). As of this filing, and as has been previously reported to the Commission in prior RPS- or MTR-related filings, due to contract failure of one of the incremental geothermal projects, MCE now has three recently procured geothermal projects under contract (2 of which are incremental geothermal capacity eligible to count towards MTR requirements). All of the aforementioned geothermal procurement is under long-term contract. Of note, one of the aforementioned incremental projects (representing 7 MW of geothermal capacity) achieved commercial operation in June 2025 and is actively contributing towards MCE's reliability, emissions, and RPS needs. The other incremental geothermal project (representing 20 MW of nameplate capacity) has encountered a number of material delays due to interconnection and permitting. These delays will require material changes to critical contract milestones, including construction start

		and commercial operation, both of which MCE expects to be achieved before 2030. For more detailed descriptions of MCE's MTR procurement, please refer to MCE's biannual MTR update filings, the latest of which was filed on June 2, 2025. MCE is also actively pursuing various new-build projects for wind capacity, additional geothermal capacity, and co-located solar and storage capacity, as mentioned in the Study Results Section above and throughout this RPS Plan. MCE expects these resources to be under contact within the year or soon thereafter.
IV. Action Plan **B. Procurement Activities**	The retail seller should describe the solicitation strategies for the RPS resources that will be included in both Conforming Portfolios. This description should include:	
	1. The type of solicitation. *2. The timeline for each solicitation.* *3. Desired online dates.* *4. Other relevant procurement planning information, such as solicitation goals and objectives.*	MCE will issue future solicitations, as described above in Section X, on a timeline that is appropriate for the resource development plan that is: responsive to the anticipated needs for the upcoming 2025 IRP cycle; consistent with MTR procurement timelines and attributes; conducive to MCE meeting its internal and state-mandated RPS targets. As part of such processes, MCE may pursue additional resources that will be needed to fulfill resource specifications reflected in its own portfolio needs, to meet MTR requirements or future potential mandates or CPUC procurement program, upcoming IRP requirements. Responsive to current portfolio needs, and in anticipation of future needs, MCE's current RFI process is specifically targeting PCC 1-eligible renewable energy generating facilities that may be paired with energy storage and/or renewable baseload capacity. MCE is currently

		evaluating responses to this RFI and expects to launch a subsequent RFO and/or commence discussions with potential project developers bilaterally to try to secure projects that can meet MCE's current and anticipated RPS, IRP, and MTR needs. In addition to the more formal solicitation processes, MCE also solicits offers for short term PCC1 renewable energy purchases/sales for annual portfolio balancing.
IV. Action Plan C. Potential Barriers	Retail sellers should provide a summary of the potential barriers to implementing both Conforming Portfolios as they relate to RPS resources. The section should include:	
	1. Key market, regulatory, financial, or other resource viability barriers or risks associated with the RPS resources coming online in both retail sellers' Preferred Portfolios. *2. Key risks associated with the potential retirement of existing RPS resources on which the retail seller intends to rely in the future.*	MCE notes that even though a balanced, diverse RPS portfolio is desirable, the limited resource availability and lead time required for some technology types will necessitate planning flexibility. While MCE has a highly successful track record of contracting with new-build renewable resources, there is always a risk of project failure due to market and regulatory conditions beyond MCE's control. Of increasing concern to MCE is the backlogged interconnection queue and delays in processing the numbers of applications for interconnection studies and deliverability. Restrictions and uncertainty on this front increase risk and uncertainty for LSEs and can ultimately present a material barrier to LSEs bringing on new RPS resources that have sufficient deliverability to meet RPS program and reliability needs. Importantly, transmission and interconnection issues not only affect the viability of projects at the outset, but impact the on-going economics of projects once the generation is online – this is particularly relevant for non-dispatchable renewable projects that are subject to curtailment due to

		insufficient transmission. Adding to this constraint are lingering supply chain issues and permitting delays that impact timely development and interconnection of new resources. MCE also notes that potential changes to federal tax policy threaten to materially impact renewable energy development in California – the full impacts of which are yet to be determined.

IV.C.2. Response to Local and Regional Policies

(i) Responsiveness to Policies of MCE Governing Board

MCE is a local governmental agency that is subject to the control of its governing board and is directly accountable to the community that it serves. MCE strongly supports and is committed to meeting the state's GHG reduction and renewable procurement goals. As a member of CalCCA, MCE actively supported the passage of SB 100 (2018) and has fully incorporated the procurement requirements of the state's RPS program into its overall procurement strategy.

As previously noted, MCE's internally adopted renewable energy procurement target has been set at 60% (through 2025, increasing thereafter). All related renewable energy purchases will be sourced from CEC-certified generating facilities, which will be eligible for use under California's RPS Program. All of MCE's renewable energy purchases are expected to be sourced from products meeting the delivery requirements established for PCC1.

Furthermore, MCE's existing contractual commitments have secured the significant majority of its renewable energy requirements. Existing contracts continue to address the majority of MCE's renewable energy needs throughout the planning period addressed in this RPS Procurement Plan and are expected to account for 97% of statutorily mandated long-term renewable energy procurement requirements in 2035. MCE's planning and procurement process remains ongoing, which is expected to result in additional renewable energy acquisition, the substantial majority of which will be secured via long-term contracts.

Additionally, MCE policy, established by MCE's founding documents and directed on an ongoing basis by MCE's governing board, guides development of the resource plan and related procurement activities. MCE's key resource planning policies are as follows:

- Reduce GHG emissions and other pollutants within the electric power sector through increased use of renewable, GHG-free, and low-GHG energy resources;
- Maintain competitive electric rates and increase control over energy costs through management of a diversified resource portfolio;
- Benefit the local economy by offering competitive electricity rates and customer programs, and investing in local infrastructure, energy, and workforce-development programs within MCE's service area;
- Help customers reduce energy consumption and electric bills by supporting and administering enhanced customer energy efficiency, cost effective distributed generation, and other demand-side programs;
- Enhance system reliability through investments in supply- and demand-side resources;
- Actively monitor and manage operating risks to promote MCE's continued financial strength and stability; and
- Support supplier and workforce diversity as permitted by law.

MCE translates these broad policy objectives into more specific plans for the use of various types of electric resources, taking into consideration MCE's projected customer needs and MCE's existing resource commitments.

To enable MCE to meet its resource planning objectives, MCE's governing board has formally adopted the following policies related to resource planning and procurement:

(1) MCE's Sustainable Workforce and Diversity Policy:[26] MCE is committed to supporting sustained and fairly compensated local job opportunities through participation in the energy industry. To the extent allowed by state law, MCE seeks to create market incentives and partnerships to encourage diversity and a sustainable workforce through its support for:

- Fair compensation in direct hiring, renewable development projects, customer programs, internships, and procurement services;
- Development of locally generated renewable energy within MCE's service area;
- Direct use of union members from multiple trades;
- Quality training, apprenticeship, and pre-apprenticeship programs;
- Direct use of businesses local to MCE's service area;
- Development of California-based job opportunities;
- Business and workforce initiatives located in low-income and disadvantaged communities;
- Direct use of Disabled Veteran-owned Business Enterprises and LGBT-owned Business Enterprises;
- Direct use of green and sustainable businesses; and
- Use of direct hiring practices that promote diversity in the workplace.

(2) MCE's Energy Risk Management Policy:[27] MCE manages its energy resources and

---

[26] *See* Attachment A to Agenda Item #7 from MCE's November 16, 2017 Board Meeting, available at https://www.mcecleanenergy.org/wp-content/uploads/2020/05/MCE-Board-Meeting-Packet-November_2017.pdf.

[27] *See* Attachment to Agenda Item #7 from MCE's May 2, 2019, Technical Committee Meeting,

transactions for the purpose of providing its customers with low-cost renewable, carbon free and other energy, while at the same time minimizing risks. MCE procures energy and RA consistent with its Energy Risk Management Policy, which has been developed to ensure that MCE achieves its mission and adheres to policies established by the MCE Board of Directors, power supply and related contract commitments, good utility practice, and all applicable laws and regulations.

(ii) Responsiveness to Regional Policies

MCE is governed by a 36-member Board of Directors comprised of elected Councilmembers or Supervisors from its 38 member communities and is committed to benefiting its service area's economy through investments in local infrastructure and energy programs. Though several of MCE's member communities have adopted their own climate, transportation, and/or land use goals or policies, MCE is not aware of any specific policies that require MCE to alter its resource planning or procurement practices at this time, nor is MCE aware of local or regional policies that would affect MCE's risk of RPS compliance at this time. In part, this may be due to MCE's voluntary renewable procurement targets that exceed state requirements and have been developed in conjunction with, and approved by, MCE's governing board.

However, MCE is committed to abiding by all local and regional plan criteria, as adopted by (or on behalf of) its member communities. When applicable, or in the instance that any new policies are enacted by MCE member communities that may affect MCE's resource planning process, MCE will work collaboratively with those communities to ensure continued compliance with the community, MCE, and the State policy goals.

---

available at https://www.mcecleanenergy.org/wp-content/uploads/2020/01/MCE-Technical-Committee-Packet-May_2019.pdf.

IV.D. Lessons Learned – Assessment of RPS Portfolio Supplies and Demand

MCE's operating history confirms that diversity among renewable energy commitments is highly desirable. This diversity encompasses a broad range of considerations, including the use of various fuel sources, resource locations, contract durations, product specifications, pricing mechanisms, solicitation timing and frequency, among other differences. Early-stage discipline in renewable energy contracting allowed for MCE's solar energy commitments to gradually move down a declining cost curve, which avoided over-weighting the portfolio with an abundance of costly contracts. As California's energy landscape continued to evolve, a concentration of renewable generating assets in certain locations reinforced the benefits of geographic diversity – as certain areas of the state were overbuilt with renewable generating infrastructure, challenges related to depressed market prices and related resource curtailments began to surface and will likely continue to exist for quite some time.[28] There have also been challenges associated with transmission and deliverability of projects which can impact project viability. These observations have contributed to a more rigorous evaluation process for new generating projects, e.g., analyzing congestion patterns at specific locations, understanding the risks related to obtaining Maximum Import Capability ("MIC") for out-of-state projects and getting more involved in the CAISO regulatory processes for transmission and interconnection to understand the risks associated with transmission and deliverability for specific projects, which is expected to reduce risks associated with such issues. While historical market pricing and transmission issues are not perfect predictors

[28] It is noteworthy, however, that economic curtailment may not be feasible for certain retail sellers when considering the financial implications of long-term contract delivery shortfalls imposed under the RPS Program. Considering such significant financial charges, certain retail sellers may be forced to accept deliveries from renewable generating assets during instances of significant negative pricing to ensure that requisite long-term contracting quantities are satisfied. This could result in higher-than-anticipated renewable energy costs and related impacts to customer rates.

of future performance, attempting to understand past trends helps to mitigate potential adverse financial consequences during near-term operation of such facilities. In addition, MCE analyzes anticipated project development in a geographic area as well as planned network upgrades in the CAISO's Transmission Planning Process.

MCE has also adapted to how distinct California energy programs interact with one another. AB 1110 (stats. 2016) has devalued and, ostensibly, discouraged the use of certain renewable energy products (allowed for use under California's RPS Program) because of how associated emissions are accounted for under the PSD Program. Changes to PSD Program regulations related to AB 1110 attribute an emissions factor equivalent to system power to any PCC2 and PCC3 volumes. In addition, PCC3 certificates are not presented as renewable purchases during power source accounting. This change has led MCE and various other CCAs to forgo or minimize the use of PCC2 and PCC3 products to avoid representing an inflated emissions factor and the potential public/customer perception that reported renewable energy content is lower than required under California's RPS Program or related policy commitments of the retail seller. This adaptation to MCE's planning and procurement practice became necessary even though such products are deemed eligible for use under California's RPS Program. As such MCE will endeavor to source all renewable energy purchases from PCC1 products but may, in isolated instances, procure small quantities of PCC2 products when unanticipated renewable energy delivery shortfalls, higher than expected retail sales and/or prevailing market conditions necessitate such purchases. Exhibiting strong preferences for PCC1 products is expected to increase costs and customer rates but will promote MCE's achievement of emission-related portfolio objectives.

V. Project Development Status Update

As described in Section IV.B above, MCE's current and planned procurement is sufficient to meet both the applicable RPS procurement requirements as well as support the state's GHG reduction targets. Further, MCE's current and planned procurement supports system reliability by considering portfolio diversity, mid-term reliability requirements, and alignment with MCE customers' load curve.

As of this filing, MCE has entered into three long term contracts with utility-scale RPS-eligible resources that are not yet commercially operational, each of which is a large utility-scale project. MCE also has long term PPAs for deliveries from three smaller renewable projects, less than 5 MWs, that were selected through MCE's Feed-In-Tariff ("FIT") program or DAC-GT Program – all of which are in development. The following Table 7 shows a list of the most recent projects added to MCE's portfolio that MCE is using for RPS and/or IRP purposes to support MTR requirements, RPS, and IRP reliability and emissions goals. Each of the projects listed below are either in development or have come online in the last two years to support MCE RPS and IRP-related needs.

[redacted]

[redacted]

There are also several smaller scale projects with contract capacities below 5 MWs. [redacted]

MCE has updated the RNS template and the Cost Quantification templates to reflect projects listed in Table 7 below.[29] MCE intends to keep the Commission informed of the progress on these projects through the various monthly and quarterly reports on project status.

[29] The RNS template includes each of the resources in Table 7, with the exception of any stand-alone battery storage resources as they are not RPS eligible. However, MCE lists them in Table 7 below as they are otherwise procured as part of MCE's larger procurement strategy.

Table 7: MCE Project Development Status

Facility Name	Technology Type	MW-ac	MTR Project	Location (County in CA)	COD	Length of Contract (Years)	Network Upgrades Milestone
Daggett Solar	Solar + Storage	110 PV/60 Storage	Yes	San Bernadino	8/25/2023	15	Completed
Golden Fields Solar IV, LLC	Solar + Storage	100 PV/92 Storage	Yes	Kern	8/16/2025	15	Completed
Strauss Wind Project	Wind	93.35	Yes	Santa Barbara	12/20/2023	15	Completed
Humboldt House	Geothermal	20	Yes	Pershing, NV	2028 (anticipated)	21	In Progress
Geysers (7MW)	Geothermal	7	Yes	Sonoma	6/1/2025	20	Completed
Key30	8-Hour Battery Storage	35	Yes	Fresno	6/1/2027	15	Completed
Cormorant31	Battery Storage	188	Yes	San Mateo	6/1/2026	15	Completed
Corby32	Battery Storage	100	Yes	Solano	4/1/2027	15	Delayed
Allium Hybrid	Solar + Storage	110 PV/110 Storage		San Benito	5/1/2031	20	In progress
Conflitti	Solar	4.4	No	Fresno	3/31/2026	20	In progress
Conflitti Jr.	Solar	.24	No	Fresno	3/31/2026	20	In progress
Fallon Two Rock Rd Solar Farm	Solar	0.96	No	Marin	1/29/2024	20	Completed
Ranch Sereno	Solar	2 PV/.8 Storage	No	Fresno	12/31/2025	20	In progress

MCE's Large Scale Projects

There are a total of nine large scale new build projects with contract capacities between 7 MWs at the lower bound and a combined 110 MW Solar/188 MW Storage at the upper bound, which includes six RPS-eligible projects and three non-RPS-eligible projects. The six RPS-eligible, projects are expected to produce approximately 1,463,560 MWh annually of RPS eligible energy. Three of the projects (Daggett Solar, Strauss Wind Project and Geysers) have already achieved commercial operation, while the remaining three renewable projects are in development. MCE plans to use all nine of these projects towards its IRP-related procurement needs.

MCE's Feed-In-Tariff projects

MCE's FIT program allows developers to finance local renewable energy projects, while catalyzing local job creation associated with the construction, operation, and maintenance of these local projects.[33] By providing attractive, above market rates, this program incentivizes renewable development in MCE communities where it otherwise would not be built. To date, MCE's FIT program has supported the completion of twenty-four locally situated, small scale renewable generating projects, which are currently producing electricity that is purchased by MCE under long-term contracts. One FIT project is currently under development as of the date

[30] This is a stand-alone battery storage project that is not RPS-eligible. This resource is being provided to demonstrate additional, non-RPS MCE procurement that is in alignment with IRP needs.
[31] This is a stand-alone battery storage project that is not RPS-eligible. This resource is being provided to demonstrate additional, non-RPS MCE procurement that is in alignment with IRP needs.
[32] This is a stand-alone battery storage project that is not RPS-eligible. This resource is being provided to demonstrate additional, non-RPS MCE procurement that is in alignment with IRP needs.
[33] *See* https://www.mcecleanenergy.org/feed-in-tariff/.

of this filing.

MCE has also attached an updated version of the Project Development Status Update Report as Appendix D.

VI. Potential Compliance Delays

MCE has received favorable determinations of compliance relating to Compliance Period 1, Compliance Period 2, and Compliance Period 3, which indicate that "MCE met its RPS compliance obligations" during such periods. MCE expects similar determinations related to Compliance Period 4, which includes calendar years 2021-2024, as well as future compliance periods. This perspective is based on MCE's past success in meeting RPS compliance mandates as well as MCE's internally adopted, above-RPS renewable energy targets and procurement activities as well as actual renewable energy deliveries and projections, which seem to indicate the organization is tracking well ahead of schedule in satisfying applicable RPS mandates.

Regarding long-term contracting compliance, and as discussed above, MCE has secured long-term contract commitments sufficient to meet the noted requirements throughout the planning period, even in the event of potential delivery shortfalls equivalent to MCE's adopted MMoP.

VII. Risk Assessment

MCE closely monitors development and operational risks associated with its planned and existing renewable energy supply commitments to minimize the potential for significant variances between actual and expected renewable energy deliveries.

VII.A. Compliance Risk

An important element of MCE's RPS risk assessment process is determining potential vulnerabilities related to procurement and/or delivery shortfalls that could trigger deficits relative to MCE's anticipated compliance obligations. Considering MCE's internally adopted renewable energy procurement targets and existing contractual commitments, this risk, as internally determined by MCE, appears to be very low. As discussed throughout this plan, MCE has established a Voluntary Margin of Over-Procurement ("VMoP") and, further, a MMoP that inform RPS procurement efforts and ensure against compliance-related shortfalls. If there is any change in terms of MCE's internal assessment of RPS compliance risk, MCE will inform the CPUC accordingly in a future RPS Procurement Plan.

VII.B. Risk Modeling and Risk Factors

MCE has established a Risk Oversight Committee ("ROC"), which regularly convenes to discuss conformance of MCE's ongoing planning and procurement efforts with the organization's adopted Energy Risk Management Policy ("ERM Policy"). MCE's ERM Policy was developed for purpose of creating and maintaining controls and processes that will mitigate potential exposure to various sources of risk, including market price risk, counterparty credit and performance risk, load and generation (volumetric) risk, operational risk, liquidity risk and policy (*e.g.*, legislative and regulatory) risk.

To the extent that higher-than-expected renewable energy open positions, counterparty over-exposure, meaningful load variations or other pertinent planning observations are identified during meetings of the ROC, MCE adjusts procurement activities to address these concerns, which promotes ongoing compliance with its ERM Policy. Should any significant ERM Policy deviations be identified, MCE staff would inform its Governing Board before pursuing corrective action. MCE's risk assessment and management practices are described in greater detail below.

In general terms, MCE's process for minimizing and avoiding risk is deterministic in nature and begins with the development of bid requirements and evaluative preferences for solicitations. MCE's solicitations are intended to identify suppliers that have demonstrated a strong track record of successful project completion and ongoing project operation. Such counterparties are more likely to timely complete project development activities and successfully operate projects placed under contract, and therefore minimize project risks. This process has yielded strong results: the pool of responses to MCE-administered solicitation is generally robust; the quality of short-listed respondents is high and typically includes very experienced bidders with strong project development track records; the short-listed candidates, by virtue of their considerable project development and/or operational experience, tend to be efficient contract negotiators; and the resulting contracts have generally led to project deliveries that meet MCE's expectations.

Key risk factors are considered during evaluation of each prospective renewable energy seller, including counterparty credit rating and general financial standing; California-based project development experience; prior experience with CCA off-takers; commercial viability of the proposed generating technology; and progress towards key development milestones such as interconnection status, deliverability studies, siting, zoning, permitting, and financing requirements. With regard to transmission adequacy, MCE ensures that each project has an executed interconnection agreement with the appropriate participating transmission operator prior to contract execution so that the project's interconnection costs, deliverability and timelines are known to the extent possible. MCE also conducts a review of interconnection queues and transmission planning in the area to understand impacts of planned projects and transmission upgrades. The project review process also includes a thorough review of the permitting status from the permitting authority and must demonstrate a path to completion. A selected seller bears risk of supply chain delays impacting the seller's ability to meet its guaranteed contractual milestones on time, subject to permitted extensions and allowable Force Majeure provisions in the contract.

To the extent that a prospective renewable energy procurement opportunity comes to fruition, and a contract is executed, development milestones are rigorously monitored by MCE's contract management staff, who regularly communicate with the project sponsor throughout the development and construction processes.

MCE also seeks to minimize unnecessary financial exposure and general planning risk by assembling a diversified portfolio of renewable generating resources and products that are intended to complement the way its customers use electric power. To promote this alignment of supply and demand, MCE analyzes the impacts of proposed renewable energy deliveries to its aggregate resource portfolio relative to expected customer energy use as part of its evaluation process. To the extent that the proposed delivery profile would create undesirable net-short or net-long positions, alternative product options will continue to be evaluated. MCE may also pursue contract structures that promote volumetric stability through firm delivery quantities and/or performance guarantees that provide for financial remedies/penalties in the event of delivery shortfalls. If necessary, the financial remedies received by MCE could be used to: (1) as a first priority, procure additional renewable energy supply to address delivery shortfalls; or (2) in the event that the delivery shortfall caused MCE to be found non-compliant, offset the cost of related penalties. MCE's intent is to exceed compliance with applicable RPS mandates, and the latter option is a last resort that is not expected to apply.

Additionally, MCE believes that it is important to manage temporal risks associated with: (1) disproportionate exposure to prevailing market conditions at any particular point in time; and (2) lack of diversity related to contract start dates, end dates or term lengths within a renewable energy supply portfolio. MCE has regularly administered renewable energy solicitations throughout its operating history to ensure that its exposure to ever-changing market conditions is diversified, similar to the “dollar cost averaging” methodology that is regularly employed within the financial sector.

While attempts to “time the market” may occasionally yield short-lived benefits, such results are generally not reliable and create the potential for significant risk and financial consequences if market conditions quickly and/or significantly change. MCE’s deliberate contracting approach entails “sampling” the market at regular intervals, avoiding large contractual commitments in high-priced environments or missed opportunities in low-priced environments. MCE also ensures that its contract start/end dates and related term lengths are staggered to avoid planning “cliffs” that could occur if contracts of similar lengths and start dates were all executed at the same time. The assembly of short-, medium- and long-term contracts further diversifies risk within MCE’s renewable supply portfolio, and while increased long-term RPS contracting requirements will inevitably increase such risks, MCE will continue to pursue portfolio diversity by thoughtfully considering these temporal considerations during ongoing procurement processes.

MCE utilizes a quantitative risk assessment that evaluates the energy impacts related to supply side losses. This approach organizes prospective risks into three general categories which pose the greatest supply-side impacts to the delivery of expected RPS energy: 1) curtailment risk; 2) resource intermittency risk; 3) counterparty risk; and 4) project cancellation risk. As part of its quantitative risk assessment, MCE examines hourly forward-looking price data and historical CAISO data to quantify curtailment risk. Considering MCE’s current long-term renewable energy positions that are well in excess of requirements, a reduction in long-term RPS volumes due to curtailment is unlikely to compromise the prospect of RPS compliance. The figures presented in the column quantifying curtailment risk in Table 8 at the end of this section are calculated by quantifying the volume of energy deliveries expected to occur during the balance of each contract's respective delivery period. This volume is then multiplied by the likelihood of curtailment (expressed as a proportionate reduction in total deliveries), which varies by contract in consideration of MCE's historical observations related to generator performance and expected performance in the future. In consideration of the increased curtailment of wind and solar resources within CAISO over the past several years, MCE has assumed a minimum baseline curtailment adjustment for certain contracts within its portfolio that may be curtailed in consideration of prospective negative price risk. *Based on MCE's assessment of curtailment risk associated with its renewable energy contract portfolio, this risk category was assigned a rating of medium.* When compared to the similar categorical risk assessment presented in MCE's 2024 RPS Procurement, this risk rating remains unchanged.

Intermittency risk has become increasingly prevalent in the wake of ongoing renewable infrastructure buildout. In particular, California's substantial reliance on photovoltaic solar and wind generating facilities introduces intermittency risk for any retail seller procuring power from such projects. Such risks ought to be accounted for as part of a thoughtful quantitative risk assessment to ensure the identification of sufficient planning reserves. The following describes MCE's methodology for assessing intermittency risk. As new intermittent facilities are developed to meet the procurement burdens of increasing regulatory requirements, the risk of variances between projected and actual energy deliveries is amplified. Quantifying intermittency risk is largely dependent on available data, as each generating facility is unique (geographically, operationally, etc.). As data is gathered from facilities comprising an RPS supply portfolio, planning adjustments can be incorporated to account for variances between actual and expected historical deliveries, allowing the retail seller to incorporate adjustments in its resource planning and procurement assumptions to counteract such risk. During the early stages of any delivery period, however, data is often lacking so planning adjustments are more challenging to quantify and must be based on reasonable estimates derived by observing similar projects. Over time, as meaningful amounts of historical data are compiled, MCE should be able to make increasingly accurate adjustments to its planning assumptions to ensure that procured RPS volumes are more accurately aligned with anticipated needs.

Despite these challenges, MCE believes that intermittency risk can be reasonably quantified when available operating history reaches two years or more. Before substantive historical data becomes available, other information must be considered in assessing intermittency risk, including input from the asset owner/operator, insight derived from the operating history associated with similar generating facilities, and limited historical data (that can be applied to generate interim intermittency assessments). Once a generating facility has established steady-state operations, intermittency risk can be quantified by dividing the amount of actual energy received by the amount of expected energy for each year of a given contract, then averaging observed variances across each year of the available operating history. The resulting percentage is multiplied by the remaining expected energy deliveries under the contract to approximate potential delivery deficits related to intermittency. For facilities with limited operating history and/or facilities that have yet to achieve commercial operation, MCE imputes proxy intermittency adjustments to ensure conservatism in RPS planning assumptions. For example, if MCE's experience with smaller-scale photovoltaic solar generating facilities (e.g., facilities at or below 10 MW of nameplate capacity) suggests that actual generation typically falls within negative two percent of projections, MCE will apply a negative two percent intermittency adjustment to generating facilities falling within this category. Similarly, if MCE has observed that mid-sized wind generating facilities (e.g., wind generating facilities between 20 and 100 MW of nameplate capacity) occasionally produce ten percent less energy than projected in certain calendar years, it will apply a negative ten percent intermittency adjustments to generating facilities within this category. Again, this approach promotes a conservative RPS planning process and should avoid unexpected delivery shortfalls related to resource variability for intermittent generating sources. Employing this intermittency analysis is also helpful in identifying especially risky contracts, which in turn assists MCE in determining which facilities must be closely monitored throughout the contract delivery term. As alluded to above, as more data becomes available, intermittency risk metrics can be updated to more accurately reflect the performance of certain generating facilities over time. *Based on MCE's assessment of intermittency risk associated with its renewable energy contract portfolio, this risk category was assigned a rating of low.* MCE believes that its MMoP serves as an important mitigating strategy in addressing potential delivery shortfalls related to resource intermittency. MCE also notes that its VMoP, which significantly exceeds applicable RPS procurement mandates, serves as mitigating mechanism for any compliance risk related to resource intermittency as typical intermittency levels fall well below MCE's VMoP.

Counterparty risk is the risk posed by a counterparty being unable or unwilling to honor its total RPS delivery obligations, as reflected in related contract documents. MCE has quantified this likelihood by considering S&P Global's Global Corporate Annual Default Rates by Rating Category (%) as a measure of organizational viability and financial stability. While this rate considers industries beyond the energy sector, it provides relevant insights into the correlation and potential impacts of dealing with uncreditworthy counterparties. The likelihood of default by credit rating was averaged over the years from 2014 to 2019. These years were chosen to remove irregularities in default rates during the Covid-19 pandemic; though no material impacts to MCE's risk assessment are anticipated, MCE expects to update the time period associated with its default by credit rating assessment during completion of the 2026 planning process and may shift the aforementioned time period forward to include other/additional years. If a counterparty was found to be unrated, then the contract was reviewed to identify specified credit assurances; based on such assurances, an approximate rating was derived based on MCE's experience and risk tolerance. *Based on MCE's assessment of counterparty risk associated with its renewable energy contract portfolio, this risk category was assigned a rating of low.* The final category reflected in MCE's analysis is project/contract cancellation risk. This category is distinct from counterparty risk because the risk of project/contract cancellation may only affect a single project under a counterparty's portfolio. Projects may be cancelled for a variety of reasons, but in today's market, deals struck many months ago may no longer be economic for the seller. This risk only effects single source projects which have yet to be constructed. These projects were chosen because they have a single point of failure unlike RPS energy purchased from a pool of resources (under a portfolio-style purchase agreement in which there is generally more diversity amongst the sources of supply). Based on discussions with various counterparties, other load serving entities and its own experience, MCE has assessed that this risk affects roughly 1 in 20 deals (with such circumstances generally applying to less experienced and/or reputable suppliers). *Based on MCE's assessment of project/contract cancellation risk associated with its renewable energy contract portfolio, and the high-quality counterparties which comprise MCE's list of suppliers, this risk category was assigned a rating of low.*

Considering these categories holistically, MCE was able to derive a cumulative energy percentage at risk. In consideration of MCE's relatively conservative risk tolerances, a top-level risk of non-delivery offset at 0.25% of renewable energy procurements was added to the calculated energy at risk percentage. This adder will help to account for risks that MCE cannot foresee and will help to guarantee the sufficiency of MCE's planned RPS purchases in meeting both compliance-related and internally adopted renewable energy procurement targets. The percentage of renewable energy and error is the percentage of total renewable energy procured that was determined to be at risk, while the percentage of retail load is the energy at risk as a percentage of retail load. These "at risk" percentages reflect possible losses which, through no fault of MCE, may occur by virtue of being a market participant. These losses pose a risk for non-compliance relative to MCE's RPS goals and targets. Since this number is not a guaranteed loss, MCE will implement the previously mentioned mitigation strategies to give the greatest chance of meeting its adopted renewable energy procurement targets.

Table 8: MCE Contract Curtailment, Counterparty, and Project Cancellation Risk

			Delivery & Market Risks			
ID	**Contract**	**Energy to be Delivered to Market (MWh)**	**Curtailment Risk (MWh)**	**Counterparty Risk (MWh)**	**Intermittency Risk (MWh)**	**Project Cancellation Risk (MWh)**
7	Contract 342	906,989	36,280	9,070	90,699	-
8	Contract 343	386,291	15,452	3,863	-	-
9	Contract 491	3,463,882	138,555	34,639	346,388	-
10	Contract 492	24,219	969	242	484	-
11	Contract 494	5,857	234	59	117	-
12	Contract 496	3,144,948	125,798	31,449	314,495	-
13	Contract 497	21,275	851	213	425	-
14	Contract 498	21,275	851	213	425	-
15	Contract 499	2,318,298	92,732	23,183	46,366	-

16	Contract 500	1,317,030	263,406	13,170	26,341	-
17	Contract 501	426,286	85,257	4,263	8,526	-
18	Contract 502	722,066	144,413	7,221	14,441	-
19	Contract 503	2,039,327	407,865	20,393	40,787	-
20	Contract 505	12,980	519	130	260	-
21	Contract 507	522,652	20,906	5,227	52,265	-
22	Contract 586	123,100	-	1,231	2,462	-
23	Contract 853	41,495	1,660	415	830	-
24	Contract 855	41,495	1,660	415	830	-
25	Contract 856	38,926	1,557	389	779	-
26	Contract 886	38,926	1,557	389	779	-
27	Contract 887	38,926	1,557	389	779	-
28	Contract 1001	40,444	1,618	404	809	-
29	Contract 1002	40,444	1,618	404	809	-
30	Contract 1035	31,978	1,279	320	640	-
31	Contract 1068	460	18	5	9	-
32	Contract 1070	22,332	893	223	447	-
33	Contract 1071	460	18	5	9	-
34	Contract 1679	349,077	13,963	3,491	6,982	-
35	Contract 1680	480,134	19,205	4,801	9,603	-
36	Contract 1681	37,022	1,481	370	740	-
37	Contract 1685	228,914	9,157	2,289	4,578	-
38	Contract 1686	50,576	2,023	506	1,012	-

39	Contract 1746	427,831	17,113	4,278	42,783	-
40	Contract 1955	40,444	1,618	404	809	-
42	Contract 2131	220,372	8,815	2,204	4,407	-
43	Contract 2440	3,275,754	131,030	32,758	65,515	-
44	Contract 2475	47,820	1,913	478	4,782	-
45	Contract 2522	28,594	1,144	286	572	-
46	Contract 3548	36,159	1,446	362	723	-
47	Contract 3549	238,194	9,528	2,382	-	-
48	Contract 3550	19,431	777	194	-	-
49	Contract 3584	26,790	1,072	268	-	-
50	Contract 3585	188,631	7,545	1,886	3,773	-
51	Contract 3706	4,644,435	185,777	46,444	92,889	-
52	Contract 3710	298,982	11,959	2,990	5,980	-
53	Contract 3720	103,114	4,125	1,031	-	-
54	Contract 3735	12,781	511	128	256	-
55	Contract 3736	234,535	9,381	2,345	4,691	-
56	Contract 3749	4,335,021	173,401	6,069	-	-
58	Contract 3864	1,121,700	44,868	11,217	-	-
59	Contract 3867	3,264,963	130,599	32,650	65,299	-
61	Contract 3877	8,766,200	350,648	87,662	175,324	-
62	Contract 3878	1,227,100	49,084	12,271	24,542	-
64	Contract 3892	2,754,702	110,188	27,547	-	-
65	Contract 3926	403,557	-	4,036	8,071	-

69	Contract 3958	100,000	-	1,000	-	-
70	Contract 3959	100,000	-	1,000	-	-
75	Contract 4007	500,000	-	590	-	-
76	Contract 4015	100,000	-	1,000	-	-
77	Contract 4021	50,000	-	500	-	-
78	Contract 4022	55,000	-	65	-	-
79	Contract 4030	700,000	-	7,000	-	-
80	Contract 4052	100,000	-	1,000	-	-
81	Contract 4056	350,000	-	-	-	-
82	Contract 4057	450,000	-	531	-	-
83	Contract 4058	200,000	-	2,000	-	-
84	Contract 4059	100,000	-	1,000	-	-
85	Contract 4062	5,152,517	206,101	-	103,050	-
86	Contract 4063	477,749	19,110	4,777	9,555	-
87	Contract 4065	200,000	-	2,000	-	-
Total Energy		57,290,461	2,871,106	471,734	1,587,134	-

Total Renewable Energy	57,290,461
Total Renewable Energy at Risk	4,929,974
% of Renewable Energy at Risk	8.61%
% of Unknown Error at Risk	0.25%
% of Renewable Energy & Error at Risk	8.86%
% of Retail Load	7.91%

Based on MCE's updated risk assessment, MCE determined that approximately 8.6 percent of MCE's expected future RPS deliveries may be at risk, which equates to 7.9 percent of MCE's retail load during the current planning period – MCE notes that the 7.9 percent (relative to retail load) risk statistic falls between MCE's near-term MMoP of 6 percent, which applies through 2025, and the 8.5 percent MMoP, which applies in 2029 and beyond. This suggests that MCE's MMoP is appropriately set in consideration of its existing RPS supply portfolio. The noted percentages reflect average risk throughout the study period, which suggests that actual risk could fall somewhat above or below these percentages. Regardless, the potential risk-related impacts to MCE's RPS supply portfolio align well with MCE's MMoP trajectory, as reflected in this RPS planning process. In consideration of the results of MCE's risk analysis, the composite risk assessment, which considers all four of the previously described risk categories, results in an overall risk rating of low.

MCE's rigorous process for evaluating prospective suppliers continues to be successful in identifying highly qualified, financially viable candidates and supporting its achievement of both statutory and voluntary renewable energy procurement goals. MCE will continue to evaluate the usefulness of other risk assessment tools as it moves forward. Should MCE identify compliance-related concerns through application of its ERM Policy, recently completed risk assessment or other mechanisms, MCE will take the appropriate course of action, which may include additional or enhanced quantitative risk assessments or other planning studies, to address such issues before compliance is affected.

VII.C. Lessons Learned – Risk Assessment

In terms of lessons learned related to risk management, MCE has observed that "more is generally better" when it comes to procuring renewable energy to satisfy RPS compliance obligations. And while this approach may not be a viable or desirable option for all retail sellers, it has served MCE well. More specifically, MCE's 60% renewable energy commitment (which gradually increases to 85% in 2031) has positioned the organization with substantial RPS planning reserves and minimal compliance risk. Since the 60% renewable energy commitment became effective in 2017, the risks faced by MCE have transitioned away from compliance-related concerns in favor of broader integrated resource planning initiatives. MCE is now focused on identifying resources that are not only cost-effective, but complementary to its existing portfolio of renewable energy supply contracts and projected customer energy use. As the level of renewable energy increases within MCE's portfolio, MCE has observed that the scope of resources promoting alignment between supply and demand generally becomes narrower and more costly.

In recent years, MCE has also experienced significant impacts of the MTR compliance mandate on the market for energy storage and renewable energy. The MTR compliance mandates[34] require LSEs across California to bring 15,500 MW of incremental NQC capacity online in phases by 2028. The mandates further define the required characteristics for the new resources that, in some instances, restrict the new construction to specific technologies. Given the compliance mandates and market conditions such as labor shortages, increased equipment costs, and delayed deliveries of key components, buyers have seen significantly higher prices and been forced to take higher risk than normal on their long-term contracts in order to bring these resources online in time to meet the compliance requirements. As a result, developers are passing through unprecedented price increases to LSEs for new and existing contracts. While scenarios such as this are difficult to prepare for, one key takeaway is that timely planning and forecasting at the state level is key to building a reliable and affordable grid. Additionally, MCE is managing these risks by working on

[34] Please see section on MTR compliance mandate.

backup plans with the developers in case there are unforeseen events, while still minimizing their impact on ratepayers.

There is also concern related to the management of long-term renewable supply commitments that exist within geographic areas where negative price risk and related curtailment of energy production has become increasingly prominent. This risk is becoming more challenging to manage as California's escalating RPS procurement mandates necessitate ongoing investment in new renewable generating infrastructure, which is often sited in resource-rich areas that become oversaturated with similar generating technologies. These circumstances seem inevitable and, over the course of a long-term supply relationship, may expose the contracted parties to unexpected risks, including negative prices (and related budgetary impacts) and curtailed deliveries which may compromise the fulfillment of mandated procurement targets by the buyer. However, MCE's internally adopted, above-RPS renewable procurement targets allow flexibility if/when curtailment becomes necessary, or when contracted renewable resources underperform.

In terms of MCE's contracting process, MCE has also learned that diversified sharing of risk within a renewable contract portfolio is desirable. There are many different contract structures, all of which serve a valuable purpose, which can be employed to create the desired allocation of risk between buyers and sellers. For example, an "index-plus" pricing structure is useful in transferring nodal price risk to the seller. In such structures, the buyer pays a fixed renewable premium, while the seller assumes risk associated with market price fluctuations but also receives market revenues – even though the buyer receives the energy, renewable attribute and, in certain instances, capacity value as part of such a transaction, the buyer's financial risk is generally limited to the payment of the renewable premium. For buyers who are averse to market price risk, the index-plus pricing structure effectively eliminates this concern but may result in a higher overall contract cost, which may be acceptable as a form of insurance, to mitigate market price exposure.

In other structures, such as the "fixed-price" or "aggregate pricing" structure, the renewable energy premium and energy commodity (and oftentimes, capacity value) are reflected in a single price paid by the buyer – this structure deliberately allocates market price risk to the buyer, but the buyer may also pay a lower imputed renewable premium in instances where market revenues closely approximate, or exceed, the aggregate renewable energy price.

In considering potential contract structures, decisions are ultimately made in consideration of risk allocation preferences, and MCE has found that it is generally desirable to pursue broad diversity in renewable energy contracting, inclusive of resource location, generating technology, suppliers/developers, and contract structures, amongst other considerations. MCE acknowledges, however, that newer retail sellers that have yet to establish meaningful financial reserves or cost-conscious retail sellers, who may be working to suppress power supply costs in consideration of a cost-sensitive customer base, may choose to favor arrangements that allocate market price risk to sellers/suppliers, particularly during early-stage operations.

Finally, MCE has learned that every CCA is different and that there is no pre-determined risk management methodology or procurement approach that is without challenges. Pursuing resource diversity across a broad spectrum of planning considerations over the long-term planning horizon appears to be one of the most viable mechanisms in mitigating RPS compliance risk.

VIII. Renewable Net Short Calculations

MCE's failure rate for new-build renewable generation placed under contract is well below five percent. MCE takes several steps to guard against the risk of project failure, including:

- Pre-contracting diligence, including a rigorous proposal evaluation process. MCE requires that any new-build project be in an advanced stage of the pre-development process, including permitting, financing, and interconnection. In particular, MCE's practice is to execute a PPA only after a project's interconnection agreement is fully executed. This increases certainty with regard to the project's development timeline and costs.

- Project monitoring, MCE's PPAs for new-build projects require frequent, detailed progress reports, which helps to identify and mitigate potential problems in their early stages.
- Internal renewable portfolio targets, including a planning reserve, that meaningfully exceed statewide mandates.

MCE has increased its planned RPS procurement to account for expected delivery shortfalls and consults its periodically updated quantitative risk assessment to determine whether further adjustments are needed to its future planning assumptions. Based on its most recently updated quantitative risk assessment, MCE determined that approximately 7.9 percent of future deliveries are at risk during the current planning period, based on projected retail load within the planning period (this failure rate equates to 8.6 percent of projected future RPS deliveries; MCE has rounded this up to 10 percent within Appendix C). These adjustments were primarily made to address: 1) generalized planning conservatism to ensure the sufficiency of MCE's RPS supply relative to its relatively high, internally adopted procurement targets, 2) occasional curtailment of select in-state renewable generating facilities due to negative pricing at certain times of the year; and 3) intermittency risk associated with certain renewable generating technologies, such as those using solar and wind as fuel sources. MCE continues to use actual planning data as compared to its forecast throughout the year and can adjust to supply- or demand-side variations within a given year.

MCE has provided a quantitative assessment to support the qualitative descriptions provided in this RPS Procurement Plan, which is attached as Appendix C. As previously noted, MCE has successfully procured more than 60% of its resource needs from RPS-eligible renewable resources since 2017 and, as a result, has accrued renewable energy well in excess of applicable statewide mandates. With few exceptions, renewable suppliers have performed as expected, so the noted failure rates that are reflected in Exhibit C are well in excess of the findings reflected in MCE's previously described risk assessment, which indicate that just over two percent of such supply may be at risk. If supplier performance becomes more erratic in the future and such adjustments are deemed necessary, MCE will reflect such adjustments in a future planning document.

IX. Minimum Margin of Procurement

IX.A MMoP Level

MCE is developing an electricity supply portfolio that will further the achievement of state mandates, as well as internally adopted goals, for increasing RPS-eligible renewable energy supply over time. The following table displays MCE's intended margin of RPS over-procurement based on the differential between the SB 100 procurement targets and MCE's internally adopted RPS procurement targets. This table reflects MCE's voluntary margin of over-procurement, or VMoP.

Table 9: MCE Voluntary Margin of Over-Procurement

	SB 100 RPS Procurement Requirement (% of Retail Sales)	MCE's Internally Adopted RPS Procurement Target (% of Retail Sales)	MCE's Voluntary Margin of Over-Procurement (% of Retail Sales)
2025	46.7%	60.0%	13.3%
2026	49.3%	60.0%	10.7%
2027	52.0%	65.0%	13.0%
2028	54.7%	70.0%	15.3%

2029	57.3%	75.0%	17.7%
2030	60.0%	80.0%	20.0%
2031	60.0%	85.0%	25.0%
2032	60.0%	85.0%	25.0%
2033	60.0%	85.0%	25.0%
2034	60.0%	85.0%	25.0%
2035	60.0%	85.0%	25.0%

As reflected in Table 9, MCE's RPS-eligible renewable energy target is currently set at 60 percent through 2026, increasing to 85 percent by 2031. MCE's internally adopted renewable energy procurement targets are intended to support MCE's broader goal of providing a 95 percent carbon-free electricity to all customers, beginning in 2024, with increasing proportions of renewable energy over time. MCE's internally adopted renewable energy procurement goals ensure a significant margin of procurement above the SB 100 mandates. Further, MCE's internally adopted renewable energy procurement mandates provide a meaningful buffer above the state's RPS requirements and serves as MCE's VMoP. As shown in Table 9, MCE's VMoP will minimally exceed statewide RPS mandates by at least 10.7 percent, relative to retail sales, throughout the planning period.

To address RPS compliance risk, MCE uses its risk assessments, including its renewable net short calculations, to establish a Minimum Margin of Over-Procurement (MMoP) to guide RPS compliance planning. MCE calculated the MMoP by applying a 10 percent risk adjustment (or planning reserve) to the entirety of MCE's projected Light Green renewable energy requirements. Light Green is MCE's default retail service option, which establishes the renewable energy percentage provided to all MCE customers. On a voluntary basis, MCE customers may enroll in one of MCE's 100 percent renewable energy service offerings: Deep Green or Local Sol.[35,36] Based on the way MCE has established its MMoP, the effective MMoP percentages observed by MCE throughout the planning period range from 12.2 percent in 2026, to 14.2 percent beginning in 2031, relative to MCE's projected RPS compliance need. MCE's MMoP is intended to address potential delivery variability for intermittent resources, curtailment risk, project delays or failures and other operational peculiarities that may cause actual renewable energy deliveries to deviate from projections. The table below provides additional detail regarding the effective MMoP percentages observed by MCE.

Table 10: MCE Minimum Margin of Over-Procurement

	SB 100 RPS Procurement Requirement (% of Retail Sales)	**MCE's Internally Adopted RPS Procurement Target (% of Retail Sales)**	**MCE's RPS Planning Risk Adjustment (at 10% of Internally Adopted RPS Target)**	**MCE's Minimum Margin of Over-Procurement (% of Retail Sales)**	**MCE's Minimum Margin of Over-Procurement (% buffer relative to RPS Mandate)**
2025	46.7%	60.0%	10.0%	6.0%	12.9%
2026	49.3%	60.0%	10.0%	6.0%	12.2%
2027	52.0%	65.0%	10.0%	6.5%	12.5%
2028	54.7%	70.0%	10.0%	7.0%	12.8%
2029	57.3%	75.0%	10.0%	7.5%	13.1%
2030	60.0%	80.0%	10.0%	8.0%	13.3%
2031	60.0%	85.0%	10.0%	8.5%	14.2%

[35] *See* https://www.mcecleanenergy.org/100-renewable/.
[36] *See* https://www.mcecleanenergy.org/100-local-solar/.

2032	60.0%	85.0%	10.0%	8.5%	14.2%
2033	60.0%	85.0%	10.0%	8.5%	14.2%
2034	60.0%	85.0%	10.0%	8.5%	14.2%
2035	60.0%	85.0%	10.0%	8.5%	14.2%

IX.A.1. MMoP Methodology and Inputs

MCE's MMoP is intended to address an RPS failure similar to that which is reflected in the RNS template. In the event of substantial under-deliveries, commercial operation delays and/or project failure, the MMoP should be sufficient to ensure MCE is compliant with the RPS procurement requirements. MCE's VMoP is the annual RPS-eligible minimum portfolio content identified in MCE's internally adopted planning targets.

As discussed in Section VII, MCE has incorporated risk adjustments to certain renewable energy delivery estimates associated with existing generation. Incorporated risks include: increased fire risk throughout the state of California, the potential for related delivery reductions, delivery intermittency, and resources that are under development. Achieving MCE's MMoP requires levels of renewable energy procurement, ranging from 12.2 percent to 14.2 percent (throughout the planning period), above MCE's annual RPS compliance need. This additional renewable energy procurement accommodates potential delivery shortfalls due to a variety of circumstances while still allowing MCE to meet prescribed RPS mandates.

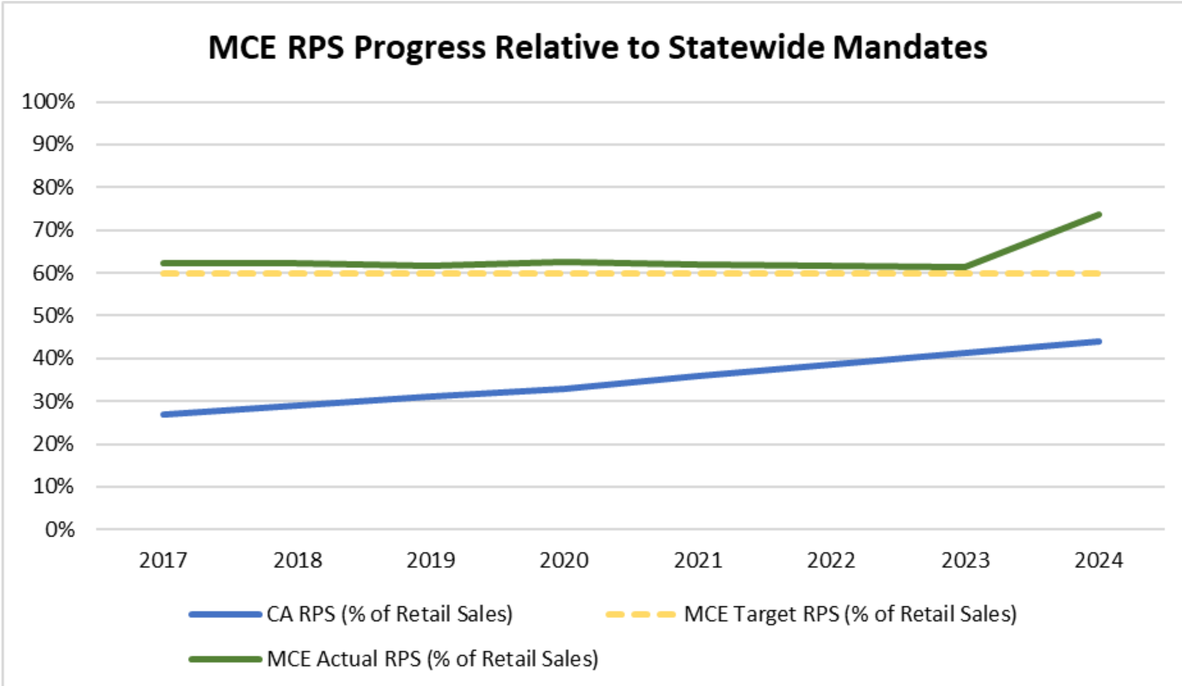
When considered in concert, MCE's VMoP and MMoP provide a substantial renewable energy planning buffer, relative to applicable compliance mandates, as reflected in the table below.

Table 11: MCE's VMoP and MMoP

	SB 100 RPS Procurement Requirement (% of Retail Sales)	MCE's Internally Adopted RPS Procurement Target (% of Retail Sales)	MCE's Voluntary Margin of Over-Procurement (% of Retail Sales)	MCE's Minimum Margin of Over-Procurement (% of Retail Sales)
2025	46.7%	60.0%	13.3%	6.0%
2026	49.3%	60.0%	10.7%	6.0%
2027	52.0%	65.0%	13.0%	6.5%
2028	54.7%	70.0%	15.3%	7.0%
2029	57.3%	75.0%	17.7%	7.5%
2030	60.0%	80.0%	20.0%	8.0%
2031	60.0%	85.0%	25.0%	8.5%
2032	60.0%	85.0%	25.0%	8.5%
2033	60.0%	85.0%	25.0%	8.5%
2034	60.0%	85.0%	25.0%	8.5%
2035	60.0%	85.0%	25.0%	8.5%

Since it began serving customers in 2010, MCE has consistently exceeded the state's RPS requirements, as reflected in the chart below. Note that MCE's reported Light Green renewable content in 2024, as reflected in its recently submitted Power Source Disclosure Report, was 70.9%. MCE will continue updating this chart in future planning documents.

Figure 3: MCE RPS Progress Relative to Statewide Mandates



IX.A.2. MMoP and VMoP Scenarios

MCE plans to meet the annual program renewable goals reflected in the table presented in Section IX (above), including the MMoPs reflected therein. As reflected in this table, MCE's anticipated MMoP percentages range from 6.0 percent in 2025 to 8.5 percent in 2035. MCE's RPS Procurement Targets, as well as the renewable net short reflected in the RNS Quantitative Template, incorporate the additional RPS-eligible renewable energy need resulting from expected participation in MCE's voluntary 100 percent renewable energy service options.

During its bid evaluation and supplier selection processes, MCE considers a variety of risks and believes that such risks are sufficiently addressed within its MMoP calculation. Based on its operating history, previous experiences related to renewable energy planning/procurement and existing contract portfolio, MCE has no reason to doubt the sufficiency of the MMoP reflected in its RPS planning targets. MCE plans to procure to the VMoP since MCE's internal RPS goals are much higher than the state mandate. This noted, MCE has incorporated an internal RPS planning reserve, as reflected in the following table, to ensure MCE can meet its internal RPS targets in the event that its previously described contract management process identifies substantial concerns related to new-build project completion, delivery shortfalls or other issues.

This reserve is additive to MCE's internally adopted RPS targets and intended to address renewable production and/or usage variability that may occur during discrete calendar years. It is intended to offset the potential impacts of noted risk adjustments and contingencies that may reduce actual renewable energy deliveries, relative to MCE's expectations. In effect, MCE's internal RPS planning reserve is a secondary VMoP, providing additional insurance against unforeseen circumstances that could impact MCE's ability to satisfy its internally adopted renewable energy commitments. As demand- and supply-side data are monitored in each year, MCE may adjust planned short-term purchases and/or pursue surplus sales arrangements if actual renewable energy deliveries are tracking above MCE's anticipated needs. By the end of each calendar year, MCE hopes to manage the level of its internal planning reserve so that actual renewable energy deliveries are closely aligned with MCE's Base RPS Procurement Target, as reflected below.

Table 12: MCE RPS Procurement Target

	SB 100 RPS Procurement Requirement (% of Retail Sales)	MCE's Internally Adopted RPS Procurement Target (% of Retail Sales)	MCE's Voluntary Margin of Over-Procurement (% of Retail Sales)	MCE's Minimum Margin of Over-Procurement (% of Retail Sales)	MCE's Aggregate Margin of Over-Procurement (% of Retail Sales)
2025	46.7%	60.0%	13.3%	6.0%	19.3%
2026	49.3%	60.0%	10.7%	6.0%	16.7%
2027	52.0%	65.0%	13.0%	6.5%	19.5%
2028	54.7%	70.0%	15.3%	7.0%	22.3%
2029	57.3%	75.0%	17.7%	7.5%	25.2%
2030	60.0%	80.0%	20.0%	8.0%	28.0%
2031	60.0%	85.0%	25.0%	8.5%	33.5%
2032	60.0%	85.0%	25.0%	8.5%	33.5%
2033	60.0%	85.0%	25.0%	8.5%	33.5%
2034	60.0%	85.0%	25.0%	8.5%	33.5%
2035	60.0%	85.0%	25.0%	8.5%	33.5%

MCE will also model demand-side sensitivities that may impact MMoP and VMoP calculations. This will be particularly important during periods of expansion of MCE's service area, when participation rates are expected to be most volatile. While MCE has no current expansion plans, MCE has completed numerous expansions during its 13-year operating history, and in each case, MCE has successfully scaled its renewable energy procurement to accommodate related increases in retail sales. In addition to load variability resulting from periodic expansions and ongoing minor fluctuations in customer participation, MCE will also monitor large load growth (for example Data Center load growth), electric vehicle penetration rates, net energy metering participation rates and other considerations that may impact overall customer energy requirements and related procurement margin calculations.

X. Bid Solicitation Protocol

X.A. Bid Selection Protocols

(i) Description of Bid Solicitation Protocols.

In its various solicitations for long-term renewable energy supply, MCE imposes numerous bid requirements on interested respondents. These requirements address a variety of considerations and are intended to identify the best qualified suppliers of MCE's long-term renewable energy needs. Such requirements include:

1. Overall quality of response, inclusive of completeness, timeliness, and conformity;
2. Price and relative value within MCE's supply portfolio;
3. Project location and local benefits, including local hiring, prevailing wage considerations and community benefits packages;
4. Project development status, including but not limited to progress toward interconnection, deliverability, siting, zoning, permitting, and financing requirements;
5. Qualifications, experience, financial stability, and structure of the prospective project team (including its ownership);
6. Environmental impacts and related mitigation requirements, including impacts to air pollution within communities that have been disproportionately impacted by the existing generating fleet;
7. Potential impacts to grid reliability;

8. Potential economic benefits created within communities with high levels of poverty and unemployment;
9. Acceptance of MCE's standard contract terms; and
10. Development milestone schedule, if applicable.

These considerations help shape the criteria against which prospective suppliers are evaluated. Based on the success of its ongoing planning and procurement efforts as well as any direction from its governing board, MCE may adapt these considerations in future renewable energy procurement efforts.

MCE considers minimum sizing requirements for certain long-term solicitations but does not solicit a specific quantity of projects, as this is based on the portfolio needs and the overall value of the project submissions. MCE considers a range of online dates based on the portfolio needs and the overall value of the project submission. MCE considers term lengths for long-term projects typically no shorter than ten years and no longer than twenty years.

Consistent with Public Utilities Code Section 399.13(a)(6)(C), MCE conducts energy product solicitations in a manner that addresses a broad range of considerations, including specific needs for eligible renewable energy resources (reflecting locational preferences, when applicable, for such resources), generating capacity, and required online dates to assist in determining what resources fit best within its desired supply portfolio. Since MCE's governing board is comprised of local elected officials, solicitation and procurement decisions are overseen by elected representatives of MCE's member communities with such decisions intended to conform with locally established targets that exceed applicable RPS requirements and promote the development of locally-situated renewable generating facilities.

(ii) Consideration of Resources Located in Disadvantaged Communities.

MCE requests information from prospective suppliers regarding whether their projects are located in disadvantaged communities and about their efforts to promote workforce development in these areas. These criteria are considered as a part of a comprehensive qualitative evaluation in addition to any benefits that enhance the value of the project through eligibility for related tax incentives for projects located in disadvantaged communities.

(iii) Alignment of Bid Selection Criteria with RPS Procurement Plan.

MCE conducts its bid selection in accordance with the goals and preferences outlined in this RPS Procurement Plan in order to meet its portfolio needs, including but not limited to meeting all of its compliance obligations, achieving the agency's equity goals, and mitigating affordability concerns.

(iv) Description of Ongoing, Planned, and Proposed Solicitations

MCE's 2025 solicitations, including applicable contract templates and general information regarding MCE's active solicitation processes, are available at the following website: https://www.mcecleanenergy.org/solicitations/. Information regarding other MCE service offerings and programs, including its FIT, can be found elsewhere on the MCE website.[37]

X.B. Solicitation Protocols for Renewables Sales

MCE does not have immediate plans to issue a solicitation for sales of renewable energy projects.

[37] For example, information on MCE's FIT program can be found at https://mcecleanenergy.org/feed-in-tariff/.

X.C. LCBF Criteria

The Least-Cost Best Fit ("LCBF") methodologies approved by the Commission pursuant to D.04-07-029, D.11-04-030, D.12-11-016, D.14-11-042, and D.16-12-044 are expressly only directly applicable to investor-owned utilities. However, consistent with Section 399.13(a)(9),[38] MCE does consider best-fit attributes that support a balanced mix of resources to help support grid reliability.

Regarding MCE's application of an LCBF methodology during selection of qualified responses, the term "costs" should appropriately include considerations beyond the basic price of renewable energy being considered for procurement. Specifically, costs should include considerations such as: (1) reputational damage resulting from failure to meet internally established renewable energy procurement targets; (2) compliance penalties resulting from failed project development efforts or delivery shortfalls; (3) administrative complexities related to dealing with inexperienced suppliers (such as prolonged contract negotiation processes and uncertainties related to project milestone timing and achievement); and (4) impacts to planning certainty resulting from higher-risk projects. MCE considers these factors, among others, as part of its cost evaluation process, which may lead to the selection of offers that are not necessarily the lowest-priced option.

The term "fit" has as much to do with organizational compatibility between buyers and sellers and alignment with key organizational objectives as it does with balancing customer usage and expected project deliveries, particularly when considering long-term contracting opportunities that will require constructive working relationships over a period of ten years or

[38] Cal. Pub. Util. Code § 399.13(a)(9) ("In soliciting and procuring eligible renewable energy resources, each retail seller shall consider the best-fit attributes of resource types that ensure a balanced resource mix to maintain the reliability of the electrical grid.").

more. In recent Open Season solicitations, MCE added a focus on matching supply to the hourly load shapes and evaluate projects based on the overall fit of the portfolio. As such, MCE's LCBF methodology takes into consideration the various planning and procurement processes described in this RPS Procurement Plan, balancing a variety of pertinent considerations at the time that each renewable purchase opportunity is being considered.

An important example supporting this perspective is MCE's FIT program, which is intended to incentivize, through above-market prices, the development of locally situated, small-scale renewable project developments. This program has achieved tremendous success, supporting numerous projects throughout MCE's service territory while utilizing local labor. By design, FIT projects are not the least expensive generating resources, but they are entirely consistent with MCE's charter objectives and a valuable component of MCE's supply portfolio.

This holistic planning approach, which may not necessarily reflect a traditional LCBF methodology, has resulted in the compilation of a diverse resource mix for MCE, deep roots in its member communities, and attention to a broad spectrum of considerations, including environmental concerns, costs and sustainability.

Finally, the requirement of Section 399.13(a)(8) to give preference to renewable projects located in certain communities is expressly only applicable to "electrical corporations" and is not mandatory for CCAs.[39] However, MCE fully recognizes the need to help mitigate the impacts of air pollution in regions of the state where communities have been disproportionately impacted by the existing generating fleet as well as the need to bring economic benefits to communities with

[39] Cal. Pub. Util. Code § 399.13(a)(8)(1) ("In soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases.").

high levels of poverty and unemployment. As noted previously, MCE submitted Advice Letters to participate in the CPUC's DAC-GT program and held a solicitation in 2021 for qualifying resources where two projects were selected and contracts were executed as part of the "Green Tariff" program. Since D.24-05-065 has made additional capacity available for the DAC-GT program, MCE plans to hold another solicitation to fill the new open program capacity. MCE continues to explore opportunities to advance this important policy goal through its procurement.

XI. Safety Considerations

MCE holds safety as a top priority. Since MCE does not own, operate, or control generation facilities, MCE's procurement of renewable resources does not present any unique safety risks. MCE's Power Purchase Agreement includes safety terms such as Prudent Operating Practice and Maintenance of Health and Safety provisions, which speak to safety precautions with respect to the operation, maintenance, repair, and replacement of a project.

This Section describes how MCE has taken actions to reduce the safety risks posed by its renewable resource portfolio and how MCE supports the state's environmental, safety, and energy policy goals.

XI.A. Wildfire Risks and Vegetation Management

At this point in time, MCE has yet to adopt any additional safety requirements for its portfolio that are specific to wildfire risks and vegetation management. MCE is aware of the mitigating impacts that biomass generators, which use forestry waste as feedstock, may have on wildfire risk, and has adopted principles on responsible biomass electricity development which state that MCE will prioritize resources that support sustainable forest management and wildlife reduction strategies to minimize the fuels for uncontrolled wildfire.[40] As mentioned in Section III, MCE has engaged with the CPUC on laying the policy foundation for CCA participation in the BioMAT program, which is inclusive of woody biomass facilities that use feedstock from fuel reduction facilities or sustainable forest management, including from such feedstocks from high hazard zones.[41]

XI.B. Decommissioning Facilities

MCE does not own any generating assets, and as such does not undertake decommissioning of assets. MCE has not yet developed any plans or requirements related to the disposition of associated generating facilities following completion of applicable delivery terms. In many cases, the project's operational life is longer than MCE's contract, so it is likely that the contract with MCE will expire before disposal of the generation assets is required.

In 2015, SB 489 authorized the California Department of Toxic Substances Control ("DTSC") to add PV panels to the list of universal wastes. The DTSC has developed regulations for PV panels but has not adopted the regulations yet.[42] Because a significant portion of MCE's solar facilities are newly constructed, and its storage facilities are yet to be constructed, MCE is confident that by the time PV solar or battery facilities under contract with MCE reach the end of their useful life, there will be statewide, comprehensive regulations addressing the safe handling and disposal/recycling of those materials.

---

[40] *See* https://www.mcecleanenergy.org/wp-content/uploads/2021/11/MCE-Technical-Committee-Packet-Thursday-November-4-2021.pdf at 106.

[41] PG&E's BioMAT Market Adjusting Tariff, Section 14.c, Sheet 22: https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/ELEC_SCHEDS_E-BioMAT.pdf

[42] *See* https://dtsc.ca.gov/photovoltaic-modules-pv-modules-universal-waste-management-regulations/.

XI.C. Climate Change Adaptation

MCE's commitment to increasing renewable energy at a more aggressive pace than California's statewide mandates itself constitutes a climate change adaptation measure. Additionally, MCE in 2019 adopted a pollinator-friendly habitat requirement for solar projects participating in both its FIT program as well as its PPAs.[43] MCE is the first California CCA to adopt this requirement, demonstrating a critical function that MCE, as a CCA, can take to help build and maintain healthy ecosystems in the local areas where MCE's solar projects are located. MCE will continue to evaluate the potential impacts of climate change on its portfolio so that adjustments to its procurement strategy can be made as needed.

XI.D. Impacts During Public Safety Power Shut-off Events

Public Safety Power Shut-off ("PSPS") events have both supply and demand side impacts. The experiences of MCE customers with wildfires and PSPS events over the last few years has led MCE to increase the focus of both its procurement as well as customer programs strategies on resiliency.

MCE assesses customer usage as a result of a PSPS event, to the extent possible with the data to which MCE has access, in real time and adjustments to supply are made accordingly. Generation resources that are located in the footprint of a PSPS event are necessarily taken offline, though MCE continues to explore ways to safely keep these resources online and serving customers. MCE is an active participant in the Commission's Enhanced Power Line Safety Settings ("EPSS") proceeding[44] to help ensure that state policy as well as IOU and CCA operating protocols are aligned and result in minimal PSPS impacts in the future.

---

[43] *See* https://mcecleanenergy.org/pollinator-friendly-ground-cover-now-required-for-new-solar-projects/.

[44] R.24-05-023 and R.19-09-009, respectively.

XI.E. Forest Biomass Procurement

In recent renewable Open Season requests for offers, MCE has not received offers from forest biomass generators. MCE's FIT program is available on a first-come, first-served basis, and is also technology-agnostic, however, MCE has not received any forest biomass applications. As MCE works toward a low emissions portfolio, MCE will be seeking non-emitting renewable technologies to contribute to its existing bioenergy resources already under contract. As mentioned in Section XI.A, MCE has been engaged in the implementation of BioMAT, which does have a dedicated category for the procurement of woody biomass facilities. Although MCE participated in laying the policy foundation for CCA participation in the BioMAT program in R.22-10-010, at the time of this filing MCE is not actively participating in the BioMAT program.

XII. Consideration of Price Adjustment Mechanisms

At the time of this filing, MCE has not currently adopted any specific price adjustment mechanisms. However, in light of the current political landscape and ongoing affordability concerns for LSEs and ratepayers throughout California, MCE may consider incorporating price adjustment mechanisms to protect ratepayers from market uncertainty.

XIII. Cost Quantification

MCE has provided the Cost Quantification Table as Appendix E. Pursuant to the direction in the ACR, MCE has completed those cells in the Cost Quantification table that correspond to Table 3, Rows 1-5 in the ACR.

XIV. Impact of Transmission and Interconnection Delays

SB 1174 (stats. 2022, ch. 229) requires electrical corporations that own transmission lines to report to the Commission on the development of transmission and interconnection facilities necessary to provide transmission deliverability for renewable energy and/or energy storage facilities that have executed interconnection agreements. MCE is not subject to the requirements of SB 1174 and does not own any transmission lines. Accordingly, MCE has not included a Transmission/Interconnection Delay Data Report as an attachment to this RPS Procurement Plan.

Dated: June 30, 2025

Respectfully submitted,

/s/Sai Powar

Sai Powar
Policy Analyst
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
(415) 464-6044
spowar@mcecleanenergy.org

Appendix A

Redlined Version of Draft 2025 RPS Plan

(Public Version)

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

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 24-01-017

**DRAFT 2025~~2024~~ RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLAN
OF
MARIN CLEAN ENERGY**

PUBLIC VERSION

Sai Powar~~Amulya Yerrapotu~~
Policy Analyst
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
(415) 464-6044~~6670~~
ayerrapotu@mcecleanenergy.org

Dated: June 30, 2025~~July 23, 2024~~

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 24-01-017

DRAFT 2025~~2024~~ RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLAN OF MARIN CLEAN ENERGY

PUBLIC VERSION

In accordance with the California Public Utilities Commission's ("Commission" or "CPUC") April~~May~~ 17, 2025~~2024~~, *Assigned Commissioner and Assigned Administrative Law Judges' Ruling Identifying Issues and Schedule of Review for 2025~~2024~~ Renewables Portfolio Standard Procurement Plans* ("ACR"), Marin Clean Energy ("MCE" or "Agency"), hereby submits this Draft 2025~~2024~~ Renewables Portfolio Standard Procurement Plan ("RPS Procurement Plan"). As directed by the ACR, this RPS Procurement Plan includes responses for the issues expressed in ACR sections 6.1-6.15~~17~~.

MCE notes that certain issues and requests in these ACR sections apply to the other retail sellers (electrical corporations and electric service providers), and do not extend to Community Choice Aggregators ("CCAs"). MCE is nevertheless voluntarily responding to these ACR sections in the interest of transparency and in order to collaborate with the Commission. However, the submission of this RPS Procurement Plan pursuant to the ACR should not be construed as a waiver of the right to assert that components of Senate Bill ("SB") 790 (2012) or that Commission decisions and rulings on RPS Procurement Plan submittals do not extend to CCAs. MCE reserves the right to challenge any such assertion of jurisdiction over these matters.

In reviewing this RPS Procurement Plan, MCE encourages the Commission to consider the differences between California's investor-owned utilities ("IOUs") and other retail sellers, including CCAs. Differing levels of detail, procedure, complexity, and coordination within the planning documents submitted by these organizations are appropriate.

I. Summary of Major Changes to RPS Plan

This Section describes the most significant changes between MCE's Draft 2024~~2023~~ RPS Procurement Plan (which was deemed ~~as~~ final by Decision 24~~23~~-12-035~~008~~) and its Draft 2025~~2024~~ RPS Procurement Plan. A redline of this Draft 2025~~2024~~ RPS Plan against MCE's Draft 2024~~2023~~ RPS Plan is included as Appendix A. The table below provides a list of key differences between MCE's ~~2023 and~~ 2024 and 2025 RPS Procurement Plans.

Table 1: Key Changes to MCE's RPS Procurement Plan

Plan Reference	Plan Section	Summary/Justification of Change
2025~~2024~~ RPS Procurement Plan: Section IV	Assessment of RPS Portfolio Supplies and Demand	Updated to provide latest information on MCE's progress towards meeting the requirements of Mid-Term Reliability Decision, D.21-06-035, D.23-02-040, and potential RPS planning implications.
2025~~2024~~ RPS Procurement Plan: Section I.V.B.2	Curtailment Frequency, Forecasting, Costs~~Project Development Status Updates~~	Updated information regarding historical curtailments in Calendar Year 2024 and Calendar Year 2025 to date.~~Updated the project development status template, Appendix D, to reflect the recent progress of renewable~~

		~~generating projects that have yet to achieve commercial operation. Updated narrative to describe projects, including status of delays and contract online dates.~~
2025~~2024~~ RPS Procurement Plan: Section V~~IV.A.1~~	~~Project Development Status Updates~~Portfolio Optimization	~~Updated the project development status template, Appendix D, to reflect the recent progress of renewable generating projects that have yet to achieve commercial operation. Updated narrative to describe projects, including status of delays and contract online dates.~~Updated to reflect how MCE is optimizing existing resources and future procurement to meet new CPUC reliability goals.
2025~~2024~~ RPS Procurement Plan: Section IV.C~~VII~~	~~Portfolio Optimization~~Risk Assessment	Updated to reflect~~include further detail on~~ how MCE is optimizing existing resources~~evaluates risk, especially in light of Mid-Term Reliability Decision, D.21-06-035~~ and ~~future procurement to meet new CPUC reliability goals~~D.23-02-040.
2025~~2024~~ RPS Procurement Plan: Section VII~~VIII~~	Risk Assessment~~Renewable Net Short Calculation~~	Updated to include further detail on how MCE evaluates risk, especially in light of Mid-Term Reliability Decisions, D.21-06-035 and D.23-02-040.~~Updated the Renewable Net Short template, Appendix C, to reflect actual data through~~

		~~2023 and updated projections through 2034.~~
2025~~2024~~ RPS Procurement Plan: Section ~~VIII~~XIII	Renewable Net Short Calculation~~Curtailment Frequency, Forecasting, Costs~~	Updated the Renewable Net Short template, Appendix C, to reflect actual data through 2024 and updated projections through 2035. ~~Updated information regarding historical curtailments in Calendar Year 2023 and Calendar Year 2024 to date.~~
2025~~2024~~ RPS Procurement Plan: Section XIV	Cost Quantification	Updated Cost Quantification template, Appendix E, to reflect updated cost projections associated with actual and planned RPS procurement through 2034.

II. Executive Summary Key Issues

In this Draft 2025~~2024~~ RPS Procurement Plan, MCE provides information and updates regarding its progress in meeting applicable renewable energy planning and procurement targets, as well as additional detail in response to the expanded requirements set forth in the ACR.

MCE, California's first CCA, is a not-for-profit public agency that began service in 2010 with a mission to confront the~~address~~ climate crisis~~change~~ by eliminating fossil free~~reducing energy-related~~ greenhouse gas emissions, producing ~~with~~ renewable energy, ~~and energy efficiency at cost-competitive rates while offering economic and workforce benefits~~ and creating ~~more~~ equitable community benefits.~~communities.~~ In 2024~~2023~~, MCE served approximately 585,000 customer accounts in 37 communities across Contra Costa, Marin, Napa, and Solano counties, with annual retail sales of approximately 5,500 gigawatt hours. ~~Beginning~~ in 2025, MCE expanded its service area to~~will serve~~ 38 communities with the inclusion of the City of Hercules.~~.~~ MCE offers its customers a 60% renewable default service ("Light Green"), as well as two 100% renewable energy service options ("Deep Green" and "Local Sol").

MCE is governed by a board of Directors ("Board") comprised of 36~~34~~ locally elected officials. The Board sets policy for the Agency and oversees its operations. Depending upon the issue, representatives from MCE's governing board and committees generally convene two to three times per month with advance public notice provided in compliance with the Brown Act.

MCE updates its biennial ~~Compliance~~ Integrated Resource Plan ("IRP") mandated by SB 350 (2015). The ~~Compliance~~ IRP submitted to the Commission biennially has been primarily oriented towards supporting California's achievement of its 2030 Greenhouse Gas ("GHG") reduction targets. MCE's internal commitment to clean energy has resulted in a default supply portfolio that reached 60% renewable in 2017, thirteen years ahead of the statewide procurement mandate. MCE is also attentive to applicable long-term renewable energy contracting requirements and has secured 65~~105~~% of its total projected 2025~~2024~~ RPS requirements (relative to California's interim annual RPS procurement mandate) via numerous long-term contracts, exceeding pertinent long-term contracting requirement established by SB 350 (2015). MCE observes that it has also procured over 100% of its voluntary, internally adopted renewable energy need, which, in aggregate, approximates 76% of projected retail load. MCE is also fully compliant with all CPUC~~Commission~~ Resource Adequacy ("RA") requirements, to support the reliability needs of the state.

MCE maintains its clean, balanced portfolio by closely monitoring ongoing market conditions, including but not limited to curtailment, customer demand, and policy changes. MCE also monitors unanticipated market events, such as inflationary and supply chain pressures and their impacts on both the supply and demand sides of the market.~~[1]~~ In optimizing its portfolio, MCE prioritizes the maintenance of a balanced, diverse, and reliable portfolio; adhering to~~keeping~~ its commitment to clean energy~~;~~ and suppressing customer costs to the greatest practical extent.

MCE's commitment to clean energy has led to the exploration of~~Agency to explore~~ opportunities to mitigate the impacts of air pollution in regions of the state where communities have been disproportionately affected by the existing generating fleet, as well as the need to bring economic benefits to communities with high levels of poverty and unemployment. To address this concern, MCE continues to evaluate the procurement of "clean resource adequacy" ("Clean RA") and the feasibility (both technological and economic) of transitioning to increased use of carbon-free capacity sources to meet statewide reserve capacity mandates.

MCE's RPS Procurement Plan details its current solicitations and its bid review and selection processes. The Plan also describes how MCE applies the Least-Cost Best Fit concept to its portfolio~~,~~ to support its priorities as an agency created to provide~~for the purpose of providing~~ clean energy, amongst~~among~~ other customer- and community-focused service offerings and programs~~things~~.

MCE continues to closely monitor its exposure to a variety of risk factors, as discussed more fully below in Section VII. MCE continues to find that its thorough analysis of both portfolio- and project- level risks, combined with its significant margin of over-procurement relative to statewide RPS goals, renders a quantitative risk assessment model unnecessary at this time. This noted, MCE continues to assess the need for such a model and may employ additional analytical tools in the future.

III. Compliance with Recent Legislation and Impact of Regulatory Changes

---

~~[1] Post COVID-19 impacts are discussed more fully in Sections IV and VI, below.~~

This RPS Procurement Plan addresses the requirements of ~~all~~ relevant legislation and the Commission's regulatory framework and ~~. This Section~~ describes ~~the relevant statutory and regulatory requirements and~~ how this RPS Procurement Plan demonstrates that MCE meets these requirements.

SB 350 was signed by the Governor on October 7, 2015. SB 350 set a new RPS procurement target of 50% by December 31, 2030. On December 20, 2016, the Commission issued Decision ("D.") ~~.~~16-12-040, which partially implemented the increased targets of SB 350 by establishing new compliance periods and procurement quantity requirements. On July 5, 2017, the Commission issued D.17-06-026, which implemented some of the key remaining elements of SB 350, including adopting new minimum procurement requirements for long-term contracts and owned resources, as well as revising the excess procurement rules. As discussed in greater detail in Section IV.A~~B~~.1, MCE projects that 96~~105~~% of its total projected 2025~~2024~~ RPS procurement target will be met with long-term contracts; MCE further expects that nearly 87~~100~~% of mandated RPS purchases related to Compliance Period 4 will be fulfilled via deliveries from long-term renewable energy contracts.

SB 100 was signed by the Governor on September 10, 2018, and became effective on January 1, 2019. SB 100 increased the RPS procurement requirements to 44% by December 31, 2024, 52% by December 31, 2027, and 60% by December 31, 2030. On June 6, 2018, the Commission issued D.18-05-026, which implemented changes made by SB 350 to the RPS waiver process and reaffirmed the existing RPS penalty scheme. In July ~~of~~ 2018, the Commission instituted Rulemaking ("R.") 18-07-003 to continue the implementation of the RPS program. On June 28, 2019, the Commission issued D.19-06-023, which continues to use a straight-line method to calculate compliance period procurement quantity requirements. The current RPS procurement targets are incorporated in MCE's Renewable Net Short ("RNS") Calculation Table as further described in Section VIII below and attached hereto as Appendix C. On a projected basis, MCE's current RPS procurement is sufficient to exceed applicable, internally adopted renewable energy procurement targets through 2025~~2024~~, including the minimum margin of over-procurement based on MCE's risk assessment, as further described in Sections VII and IX.

Additional RPS procurement efforts remain ongoing, and MCE intends to augment existing RPS contracts with additional supply to promote statutory compliance, as well as the achievement of internal RPS targets, in 2026~~2025~~ and beyond.

SB 901, signed by Governor Brown on September 21, 2018, added Public Utilities Code Section 8388, which requires any IOU, publicly owned electric utility, or CCA with a biomass contract meeting certain requirements to seek to amend the contract to extend the expiration date to be five years later than the expiration date that was operative as of 2018. MCE does not have a contract with a biomass facility that is covered by Public Utilities Code Section 8388.

In accordance with SB 255 (Bradford, 2019), D.22-04-035 revises the Commission's Supplier Diversity Program set forth in General Order ("GO") 156 to incorporate CCAs, Energy Service Providers ("ESPs"), and smaller utilities with certain revenue thresholds. MCE is committed to supporting sustained and fairly compensated local job opportunities through participation in the clean energy industry. To the extent allowed by state law, MCE seeks to create market incentives and partnerships to encourage diversity and a sustainable workforce through its support for:

- Fair compensation in direct hiring, renewable development projects, customer programs, internships, and procurement services;
- Development of locally generated renewable energy within the MCE service area;

- Direct use of union members from multiple trades;
- Quality training, apprenticeship, and pre-apprenticeship programs;
- Direct use of businesses local to the MCE service area;
- Development of California-based job opportunities;
- Business and workforce initiatives located in low-income and disadvantaged communities;
- Direct use of Disabled Veteran-owned Business Enterprises and LGBT-owned Business Enterprises;
- Direct use of green and sustainable businesses; and
- Use of direct hiring practices that promote diversity in the workplace.

These commitments, made prior to the passage of SB 255, align with SB 255's direction for CCAs to take steps to increase procurement from small, local, and diverse businesses in all procurement categories.

MCE has submitted annual supplier diversity reports to the CPUC since 2020, the first year SB 255 was in effect.[2] These reports follow the same timeline and reporting structure that~~as~~ applies to the other entities that report to the CPUC annually under GO 156, adjusted to account for MCE's status as a public agency subject to Proposition 209.[3] MCE and other CCAs have been working with the CPUC's Supplier Diversity staff since the passage of SB 255 to ensure reporting requirements for CCAs are appropriate and conform to SB 255, and will continue to do so on an

[2] *See* ~~https://mcecleanenergy.org/wp-content/uploads/2024/06/MCE_Supplier-Diversity-Report_FINAL.pdf~~ for MCE's 2024 Supplier Diversity report

[3] Proposition 209 was approved by voters in 1996 and amended the California Constitution to prohibit the state, including local government agencies, from discriminating or granting preferential treatment on the basis of race, sex, color, ethnicity, or national origin in the operation of public employment, public education, and public contracting.

ongoing basis, as set forth in D.22-04-035.

Assembly Bill ("AB") 843 (Aguiar-Curry, 2021) authorizes CCAs to submit eligible bioenergy projects for cost recovery pursuant to the Bioenergy Market Adjusting Tariff ("~~(~~BioMAT")~~)~~ program. The BioMAT program is a feed-in tariff program for small bioenergy renewable generators less than 5 megawatts ("MW") in size, offering 250 MW total to eligible projects through a fixed price standard contract to export electricity to California's IOUs and ~~now,~~ CCAs. Electricity generated through the BioMAT program counts towards RPS targets. MCE engaged~~MCE is engaging in R.22-10-010 and is working~~ with the California Community Choice Association ("CalCCA"), the CPUC, and the IOUs to establish program implementation details to facilitate CCA participation in the program; however, MCE does not participate in this program currently. ~~.~~SB 1109 (Caballero, 2022) and AB 2750 (Gallagher, 2023) require~~requires~~ entities, including CCAs, with a contract to procure electricity generated from biomass that expires or expired on or before December 31, 2028, to amend or establish a new contract that includes an expiration date five~~5~~ years later than the expiration date in the contract that was operative in 2022. MCE does not have any contracts that fit this requirement.

SB 1020 (Laird, 2022) sets interim targets for renewable and zero-carbon energy in California, requiring 90% of all retail sales of electricity be zero-carbon by December 31, 2035, and 95% of all retail sales of electricity be zero-carbon by December 31, 2040. MCE's most recent Operational Integrated Resource Plan ("~~(~~OIRP")~~)~~ adopted interim targets that are more stringent than what is~~what's~~ required for SB 1020,[4] therefore, MCE expects to meet these goals.

[4]MCE's Light Green service option is expected to be 95% GHG-free by 2023 and is expected to reach 85% renewable energy by 2029. https://www.mcecleanenergy.org/wp-content/uploads/2021/11/MCE-Operational-Integrated-Resource-Plan_2022.pdf.pdf.

Additionally, MCE is working with state partners to understand the requirements of SB 1020 for other agencies and exploring how to support those other agencies in meeting SB 1020 goals. In the interim, MCE notes that state agency accounts may enroll in ~~one of~~ MCE's 100% renewable energy service option~~options~~, Deep Green ~~or Local Sol~~, to immediately receive zero-carbon retail energy service.

AB 1373 (Garcia, 2023) authorizes the CPUC to request that the Department of Water Resources ("DWR") act as a central procurement entity ("CPE") to conduct procurement of certain eligible long lead-time resources ("LLT") on behalf of customers of all LSEs under the CPUC's IRP purview. On August 22, 2024, the CPUC issued D.24-08-064 making an initial need determination of up to 10.6 gigawatts ("GW") of nameplate capacity of the following emerging technologies: offshore wind (up to 7.6 GW), enhanced geothermal systems (up to 1 GW), multi-day long duration energy storage ("LDES") (up to 1 GW), and LDES with a discharge period of at least 12 hours (up to 1 GW). Using the most recent vintage of the demand forecast, CPUC will allocate CPE procurement benefits to LSEs and recover costs from all customers. DWR will tentatively begin development of solicitation plans and materials in 2025 and conduct pre-bid activities in early 2026 for LDES. MCE will continue to engage with the CPUC as the CPE mechanism is developed and incorporate the consideration of CPE resources, if procured, in its procurement strategy in future IRPs.

AB 1373 (Garcia, 2023) also~~AB 1373 (Garcia, 2023)~~ requires the CPUC to include cost-effective resource diversity in its integrated resource planning processes. The bill permits CCAs to satisfy their portion of the CPUC's resource diversity requirements so long as the CCA's proposal promotes the efficient achievement of state energy policy objectives and does not result in incremental costs to bundled customers. The CPUC is currently ~~implementing AB 1373 and is~~

in the process of developing a new IRP framework, the Reliable and Clean Power Procurement Program (“RCPPP”). In March 2025, the CPUC put forth its proposal on RCPPP that included reliability procurement and GHG reduction target frameworks for stakeholder consideration MCE is engaging in R.20-05-003 and working with CalCCA to facilitate effective design of the new program and establish reasonable implementation details.~~.~~ MCE will address requirements set forth in the RCPPP after the program’s adoption and tentative implementation in 2027. ~~this requirement in its next IRP in 2025.~~

AB 2368 (Petrie-Norris, 2024) requires the CPUC to ensure that the RA program can reasonably maintain a standard measure of reliability, such as a 1-in-10 loss of load expectation (“LOLE”) metric, and use it for planning purposes. The bill also adds midterm procurement, along with short term and long term, to IRP requirements. MCE will address these requirements as they are implemented by the CPUC.

IV. Assessment of RPS Portfolio Supplies and Demand

IV.A. Portfolio Supply and Demand

(i) Assessment of Portfolio Supply and Demand through 2035

MCE continues to project that it will meet or exceed applicable RPS procurement obligations over the long-term planning horizon (through 2035~~2034~~, which reflects the final year of the planning period addressed in this document). The exact characteristics of MCE’s renewable supply portfolio are expected to vary over the planning horizon~~time~~ based on a variety of considerations, including market developments and RPS product availability, policy changes, technological improvements, Agency preferences, and/or ~~myriad~~ other factors.

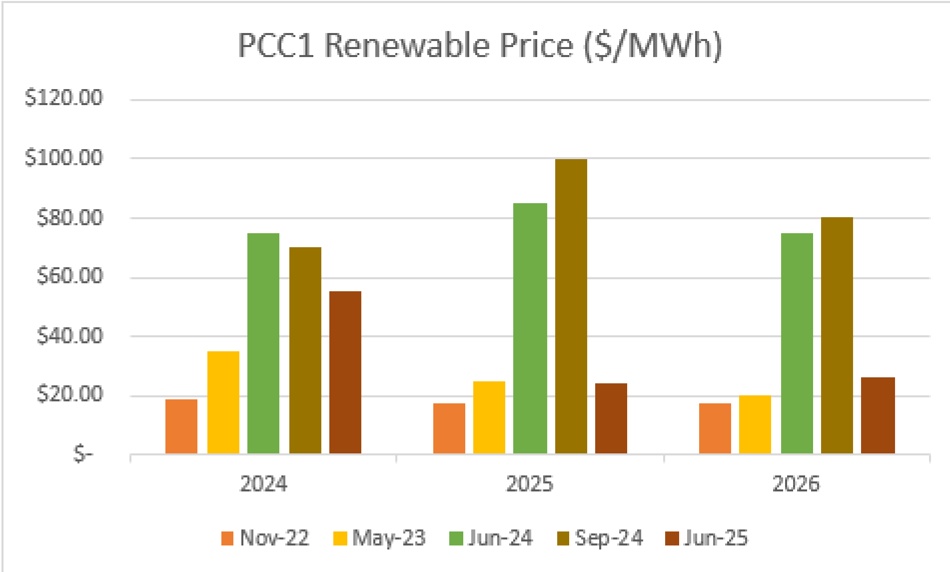
Of note, Due to apparent RPS supply constraints, which affected Portfolio Content

Category 1 (“PCC1”)[5]~~appear to be affecting~~ product availability and pricing in 2024 and 2025~~through Compliance Period 5~~, MCE observes that ~~Product Content Category 1 (~~PCC1~~)~~[6] prices ~~have~~ increased more than 400% during the 18-month period between November 2022 and June 2024. While the full scope of circumstances contributing to this pricing runup remains unclear, many retail sellers, including MCE, were subjected to substantial budgetary impacts in meeting adopted portfolio objectives. The unexpected rise in RPS prices and the associated changes in regional short-term renewable energy markets impact how MCE can balance customer affordability with achieving environmental objectives that generally exceed statewide mandates. Between June 2024 and June 2025, PCC1 prices declined for product vintages to be delivered in 2026 and beyond, and while such prices have yet to return to "historical norms," there has been budgetary relief for load serving entities (“LSE”) needing to procure incremental RPS supply thus far in Compliance Period 5. The previously described PCC1 pricing volatility is reflected~~over the past 18 to 24 months as depicted~~ in the following bar chart, which identifies average historical prices observed by MCE for index-plus PCC1 transactions over the past approximate 18-month term. MCE observes that “historically normal” PCC1 levels during the several years leading up to late 2022 were generally at/below $20/megawatt hours (“MWh”) for index-plus transactions. ~~.~~

[5] A resource which is either located within California, or directly delivers to California without substituting energy from another source.

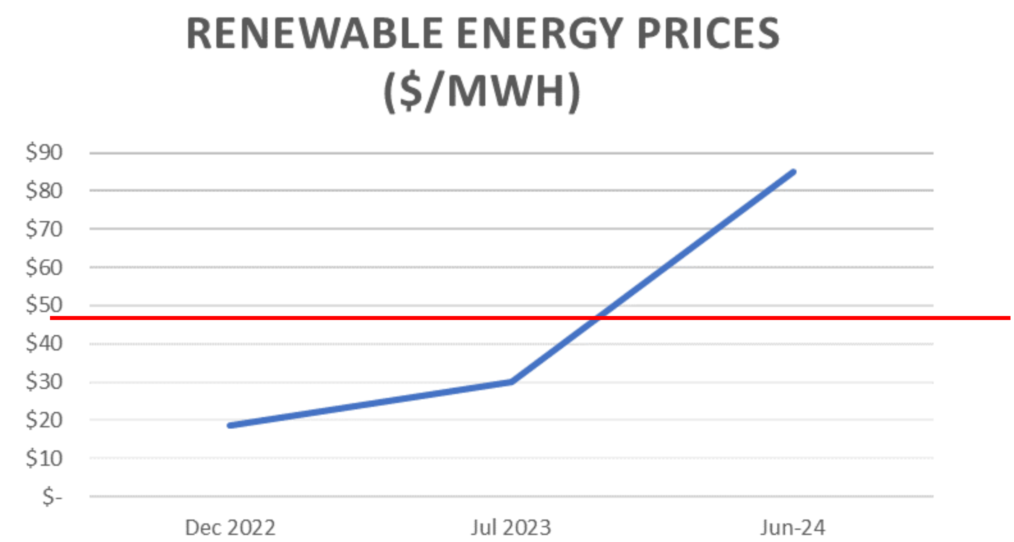
~~[6] A resource which is either located within California, or directly delivers to California without substituting energy from another source.~~

Figure 1: MCE's PCC1 Renewable Price 2024-2026



This recent price volatility highlighted a relatively new, but significant, risk facing buyers of short-term renewable energy products which, for several years, had experienced relatively low levels of pricing variability. State procurement directives, including the mid-term reliability and supplemental mid-term reliability programs, have had the effect of multiple buyers entering the market at the same time due to the universally applicable schedule of compliance deadlines assigned through such processes. Additionally, recent tariff discussions have introduced the risk of substantive cost increases for certain projects. These factors have exerted upward pressure and considerable uncertainty on certain technology/project types, which may play meaningful roles in California meeting its eventual RPS goals – particularly in a way that balances affordability for ratepayers. MCE continues to assess the best approach for dealing with these risks which may be subject to considerable iteration. For example, taking on additional long-term contracts, which can often promote increased price stability within an RPS contract portfolio (even though overall costs associated with such contracts can be higher than prices identified in short-term markets) could mitigate exposure to the occasional volatility experienced in short-term RPS markets.

However, disproportionately high levels of long-term contracting could reduce planning flexibility, including a retail seller's ability to take advantage of emerging technologies, adapt to policy changes, and react to periodic market fluctuations.



In the near term~~Accordingly~~, MCE expects budgetary and rate-related impacts associated with addressing prior (2024 and 2025) and projected (2026 and 2027) RPS ~~that the cost to address outstanding PCC1~~ open positions ~~may be especially large~~, but MCE remains committed to fulfilling its internally adopted RPS targets as planned. ~~Thankfully,~~ due to prudent planning, MCE is well resourced for the early stages of Compliance Period 5~~2024~~, so ~~its~~ short-term RPS procurement efforts will be predominantly focused on outstanding needs in 2026 and 2027, years in which prices have recently subsided. Over the long-term planning horizon, MCE believes~~Compliance Period 5. During periods of constrained RPS supply, including the situation~~ that its disciplined and diversified approach to RPS procurement ~~California is dealing with now, MCE~~ will lead to average portfolio costs that are manageable and considerate of customer rate sensitivities as well as statewide planning needs~~pay particularly close attention to its forecasted energy requirements to avoid unnecessary/excessive procurement of overly costly supply~~.

As previously noted, MCE's internally adopted renewable energy procurement targets have been set in excess of state-imposed mandates, creating a natural compliance buffer. For example, approximately 74~~68~~% of MCE's aggregate supply portfolio was comprised of RPS-eligible renewable energy in 2024~~2023~~, an amount exceeding the state's interim annual procurement mandate by nearly 68~~66~~%. Similar to previous years, this significant level of over-procurement would have accommodated massive fluctuations in annual retail sales and/or anticipated renewable energy deliveries before triggering potential compliance risks for MCE. Given the significance of MCE's internally established 60% renewable target (which persists through 2025 before increasing thereafter), past success exceeding applicable compliance mandates, existing supply commitments and ongoing planning/procurement efforts focused on RPS-eligible energy, MCE does not foresee any issues fulfilling future renewable supply commitments.

MCE continues to monitor the prospective impacts to its customer base associated with California's direct access market due to SB 237 (2018) and D.19-05-043. Should there be material changes to direct access availability for non-residential accounts, or direct access is expanded in the future, MCE will accordingly reflect such an outcome in its planning process. With this in mind, MCE's analysis shall remain ongoing and may result in future adjustments to MCE's load forecast and related renewable energy procurement obligations, which would be expected to decrease if MCE load migrates to direct access providers.

Additionally, MCE is aware that supply chain impacts continue to exist, and for renewable energy projects that have yet to achieve commercial operation, MCE will closely monitor progress in case such issues impact expected online dates. Federal policy changes regarding Tax Credits and imposition of significantly increased tariffs that could be applied to certain renewable and battery storage infrastructure is another important concern being monitored by MCE, as such risk is often being addressed by "price reopener" provisions inserted in various renewable energy contracts. These provisions not only create the potential for budgetary uncertainty but also the reality that extreme price increases may compromise the prospect of project completion (via contract termination), leaving the affected retail seller to search for project alternatives that may be necessary to backfill vacated supply. Regarding demand side impacts, these are often more challenging to isolate, as normal variations in usage caused by weather may obscure otherwise atypical variations in consumption. With current monetary policy focused on controlling inflation, MCE will be attentive to potential changes in customer usage that may result from ongoing policy adaptations, particularly those intended to control persistent inflationary pressures. Based on available data and related analyses conducted to date, impacts to MCE's overall load and sales appear to be relatively modest.

(ii) Assessment of Need for RPS Resources with Specific Deliverability Characteristics

MCE regularly analyzes and assesses its renewable portfolio mix to identify supply, fit, and compliance needs. While compliance with the RPS program has not been an issue of concern, as California increases its renewable and carbon free targets, there is a need for MCE to continue diversifying its resource mix. Resources with diverse deliverability characteristics help in mitigating risk exposure to market forces while providing grid reliability. Peaking dispatchable resources, such as storage paired with solar or wind, are critical in meeting high demand periods in the future. However, this requires having baseload resources like geothermal to allow for the flexibility to dispatch marginal resources as load shifts. Reliance on intermittent resources like solar and wind alone exposes one to congestion and potential curtailment risks. This risk continues to grow with the accelerated adoption of solar and wind on the grid. MCE is aware of these factors and continues to pursue a diverse set of renewable resources to not only meet its RPS obligations but also maintain operational flexibility while contributing to overall system reliability.

(iii) Experience Managing Exposure to Negative Market Prices

MCE closely monitors twelve separate locations that are indicative of renewable energy resources that are exposed to market prices and potential curtailment. Resources at those locations are bid into the CAISO markets and are curtailed when prices fall below individual resource's threshold prices. Weighted average prices for the generation at those locations are compared to weighted average prices at Pacific Gas and Electric's ("PG&E") Default Load Aggregation Point ("DLAP") to assess the impact of congestion on the resource's performance. In addition, the MWh of curtailment are logged.

These two metrics - weighted average price of the resources compared to that of the DLAP and MWh curtailed - are used to assess effectiveness of the resources in meeting MCE's RPS obligations at cost effective prices. If the resource's weighted average price is near the DLAP and it has been curtailed, then the reason for curtailment is system over-supply. If the resource's weighted average price diverges from the DLAP and it has been curtailed, then the reason for curtailment is local overgeneration that is contributing to congestion. This information is valuable feedback to MCE in locating potential future resources. If congestion and local oversupply is significant in certain areas, then MCE can determine by reviewing the CAISO's transmission planning documents whether transmission upgrades are planned to mitigate congestion that is observed with existing resources.

If curtailment is caused by congestion, the impact can be somewhat mitigated by obtaining CAISO Congestion Revenue Rights ("CRRs"), which MCE has done. However, CRRs are not a perfect hedge against congestion and cannot be relied upon to mitigate congestion and subsequent economic curtailment entirely. MCE will continue to monitor and plan for managing exposure to negative market prices.

(iv) Assessment of how the Renewable Net Short Quantitative Analysis Supports the Assessment of Portfolio Supply and Demand

As reflected in MCE's RNS appendix, MCE aims to procure sufficient quantities of renewable energy that: 1) meaningfully exceed statewide procurement mandates via internally adopted RPS procurement targets that range from 10.7% to 25.0% above the state's interim annual RPS procurement targets throughout the planning period (2025-2035); and 2) reflect a 10% planning reserve (in excess of projected, internally adopted RPS targets that meaningfully exceed statewide mandates) to ensure that production from intermittent resources, curtailments, potential project delays or failures, and/or other unexpected circumstances that could otherwise reduce anticipated renewable energy deliveries, do not adversely impact MCE's ability to fulfill publicly communicated renewable energy portfolio goals. These planning decisions serve as formidable protections against renewable energy delivery shortfalls.

(v) Assessment of how Procurement or Allocations are Consistent with the Evaluation of Supply and Demand

MCE has assembled a broadly diverse renewable energy contract portfolio, meaning that MCE's portfolio is attentive to technological diversity, temporal diversity, geographic diversity, and supplier diversity. These planning considerations, coupled with MCE's voluntary procurement targets that meaningfully exceed statewide mandates, minimize sources of planning vulnerability and prevent the risk of RPS compliance shortfalls. In terms of serving customer energy requirements, MCE's diverse portfolio, which includes baseload, peak, off-peak, seasonal, and dispatchable delivery profiles, is generally complementary to the manner in which MCE's customers use electric power. Dispatchable renewable resources, specifically co-located solar and battery infrastructure, allow for the shaping of certain renewable deliveries to promote improved alignment between supply and demand. Over time, MCE will continue to evaluate customer energy requirements and usage patterns relative to how its renewable resource portfolio delivers power and will pursue incremental procurement opportunities to better align supply and demand at least cost.

IV.A.1. Long-Term Procurement

(i) Assessment of How Current and Planned Procurement Meets 65 Percent Long-Term Contracting Procurement Requirement Through 2035.

MCE has been committed to supporting new, California-based renewable resource development since its inception, and has supported numerous generating assets via execution of long-term contracts. MCE has already executed long-term renewable contracts that are expected to yield approximately 96% of its total RPS/statutory renewable energy requirements (or 147% of MCE's expected RPS-related long-term renewable energy requirements) in 2025. Further, most of the renewable energy supply solicited under MCE's Open Season is intended for projects with proposed delivery terms between ten and twenty years, which bolsters MCE's proportionate use of long-term renewable energy over time.

(ii) Quantitative Assessment of MCE's Long Term RPS Positions

The table below relates projected deliveries under MCE's existing long-term RPS supply contracts to interim annual RPS procurement targets and related long-term contracting requirements.

Table 2: Projected RPS Deliveries

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Proportionate Long-Term RPS Purchases Relative to Interim Annual Statutory Procurement Mandate	96%	95%	105%	118%	114%	108%	105%	102%	90%	85%	83%
Proportionate Long-Term RPS Purchases Relative to Interim Annual Statutory Long-Term Contracting Requirement	147%	146%	162%	182%	176%	166%	161%	157%	139%	131%	127%

MCE's substantial, ongoing commitment to long-term RPS contracting has created significant projected long-term RPS surpluses. As a result of such surpluses, there is an exceptionally low risk of MCE falling short of this aspect of the RPS compliance program.

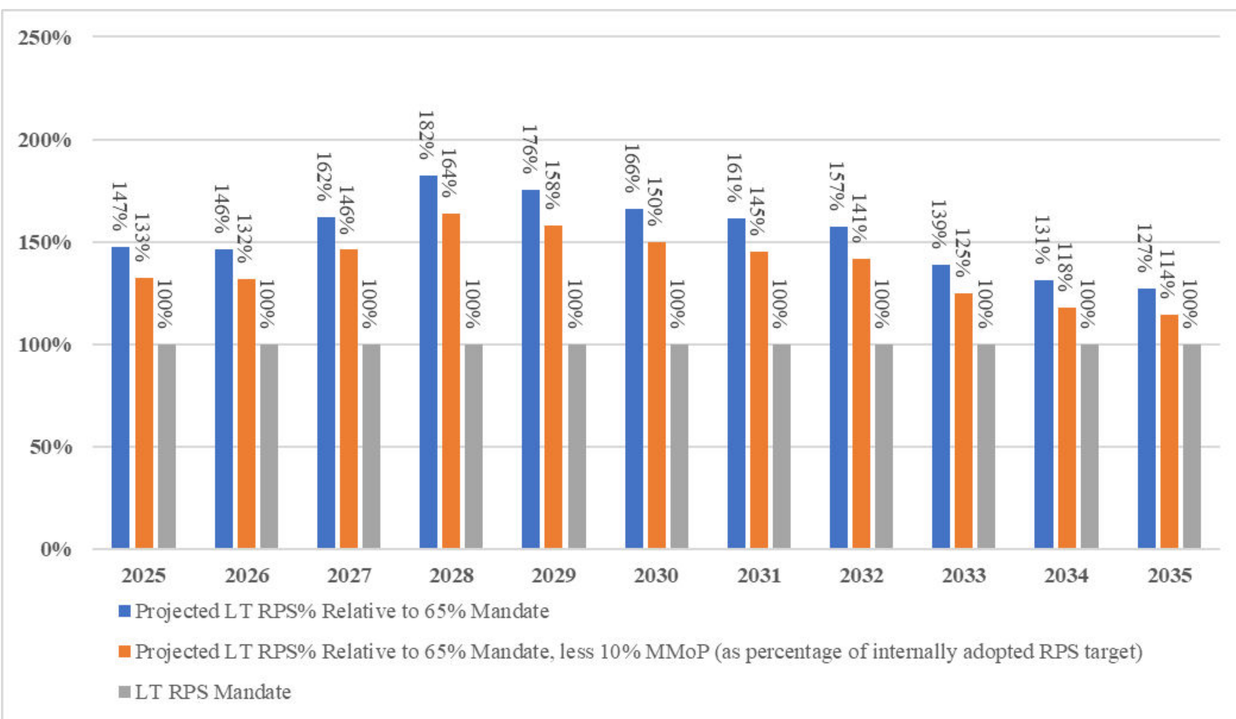
Figure 2 depicts the relationship between California's currently effective long-term RPS contracting mandates and projected deliveries related to MCE's existing long-term RPS contracts, for calendar years 2025 through 2035. The rightmost bar in each grouping reflects California's 65 percent RPS contracting mandate as 100 percent of the total long-term contracting requirement. MCE has included two additional bars in each grouping:

1) An unadjusted projection of MCE's expected annual long-term contract deliveries, relative to the 65 percent mandate. This bar represents the proportionate relationship between MCE's long-term contract deliveries and the statewide procurement mandate. For example, MCE projects that it will surpass the state's long-term contracting requirement

by 47 percent in 2025 and is not expecting to fall below 100 percent of its long-term contracting requirement during the current planning period; and

2) An adjusted projection of MCE's expected annual long-term contract deliveries relative to the 65 percent procurement mandate. This bar represents the proportionate relationship between MCE's long-term contract deliveries (including an annual reduction in such deliveries equivalent to MCE's established Minimum Margin of Over Procurement ("MMoP"), which reflects the potential impacts of delivery shortfalls related to resources intermittency, delays in commercial operation, resource curtailment, supply chain issues, and/or other operational issues) and the statewide mandate. MCE believes that this scenario represents a relatively extreme stress case. Nonetheless, MCE would expect to meet or exceed California's long-term contracting mandate throughout the planning period.

Figure 2: MCE's Projected Long-Term RPS Contracting Progress: 2025-2035



Note that the data underlying this bar chart has been compiled annually, which means that the percentages do not reflect the additional compliance flexibility related to California's multi-year compliance periods. For example, if MCE exceeds the long-term procurement mandate by 47% in 2025, it could absorb meaningful delivery shortfalls in the other years encompassing Compliance Period 5 before any compliance deficits arise. Unadjusted projections of MCE's long-term contracting progress suggest that MCE is expected to exceed applicable mandates through the current planning period. Likewise, adjusted projections also suggest that MCE will similarly exceed applicable mandates, even under a relatively extreme stress case such as the one reflected in the previous bar chart. MCE expects to engage in additional long-term contract efforts, which will further increase its long-term RPS positions as well as the compliance buffer already in place.

(iii) Summary of Current and Planned Long-Term RPS Procurement

MCE maintains a diverse set of long-term power purchase agreements to meet its long-term procurement needs. This includes multiple geothermal, solar, wind, small hydro and solar plus storage resources. These contracts are staggered in nature, spanning 10 to 30 years in length. In addition, MCE is engaged in negotiations to add more generating and storage resources to the existing fleet. MCE does not anticipate any issues meeting its long-term requirements.

(iv) Timeline Meeting 65 Percent Long Term Procurement Requirement.

MCE did not receive an SB 155 letter and does not expect any issues in meeting its long-term RPS contracting obligations, as described elsewhere in this Plan.

IV.B. Portfolio Diversity and Reliability

(i) Description of How Portfolio Diversity is Considered.

As part of MCE's forecasting and procurement processes, MCE considers the deliverability characteristics of its resources including the expected delivery profile, available capacity and dispatchability attributes, if any, associated with each of its generating resource and/or supply agreements and reviews the respective risks associated with short- and long-term purchases. These efforts lead to a more diverse resource mix, address grid integration issues, and provide value to MCE's member communities, including reduced costs and support in achieving planned procurement objectives for the period addressed in this RPS Procurement Plan. A quantitative description of MCE's forecast is attached in Appendix C.

(ii) Description of How Planned RPS Portfolio Diversity will Contribute to System Reliability.

With respect to system reliability, MCE is aware of the planning challenges faced by retail sellers with internally adopted renewable energy targets that exceed RPS mandates. In particular, such retail sellers must often bear increased costs for renewable resources with diverse and complementary delivery profiles, as well as comparatively high levels of energy storage infrastructure to allow for the reshaping of renewable energy deliveries to better align with load.

For example, renewable energy procurement efforts that may initially focus on relatively low-cost solar resources will often necessitate subsequent investments in co-located energy storage infrastructure and/or higher-cost baseload renewable generating technologies, such as those using geothermal, biomass and landfill gas fuel sources. These baseload renewable technologies are often priced at three-to-four times the level of in-state photovoltaic ("PV") solar generation but generally provide increased capacity value due to the more predictable, baseload generating profiles of such resources, and related reliability enhancements.

Despite the adverse budgetary impacts, MCE continues to pursue resource acquisitions that will promote increased alignment between supply and demand as well as the increased use of locally situated renewable generating resources. Currently, low-cost, long-term solutions are incredibly challenging to identify, as ongoing increases in California's RPS procurement mandates and technological limitations often create the need for near-term investments to balance the achievement of compliance mandates with generalized grid reliability.

Nonetheless, MCE remains committed to pursuing a conscientious planning process that balances grid reliability, compliance demonstration, and customer cost impacts. Again, there are no easy solutions in addressing this dilemma, but MCE's commitment to pursuing alignment of supply and demand as well as general resource diversity should contribute to grid reliability, reducing related risks for MCE's customers and the system at large. In consideration of MCE's diverse contractual commitments for requisite renewable energy supply and ongoing focus on the identification of RPS-eligible and complementary technologies that will mitigate reliability impacts associated with increased use of intermittent generating resources throughout the state, overall risks to system reliability associated with MCE's RPS Procurement Plan were determined to be low.

(iii) Description of How Portfolio Diversity will Maximize Ratepayer Value While Minimizing Costs and Risks.

MCE is interested in emerging and viable technologies to meet the state's reliability needs. MCE's commitment to innovation and the advancement of renewable technologies continues to drive strategic opportunities for the inclusion of emerging technologies within its supply portfolio. The extent to which such technologies will be successful in mitigating conditions of oversupply, production variability and misalignments between energy production and customer use will be monitored over time to ensure that such contractual commitments are promoting desired outcomes.

MCE will continue to procure renewable and other GHG-free and conventional energy products, as necessary, to ensure that the future energy needs of its customers are met in a clean, reliable, and cost-effective manner. MCE has established proportionate procurement targets for overall GHG-free energy content, including subcategories for renewable energy and other carbon-free products, including related planning reserves.

In 2020, MCE also implemented an "equivalent carbon-free" portfolio metric, which considers the total emissions associated with each supply source relative to a target annual emission factor for its entire supply portfolio. For example, MCE's 95% carbon-free equivalent goal in 2024 contributed to the achievement of an overall portfolio emission factor less than 1% of the California Air Resources Board's ("CARB") assigned emission factor for energy imports and system power, which is currently set at 0.428 metric tons of carbon dioxide equivalent per megawatt hour ("MT CO_2e"). Expressed differently, the 95% carbon-free equivalent goal limited, on a voluntary basis, MCE's emissions to an overall portfolio emission factor of 0.021 MT CO_2e/MWh. As reflected in its current 2024 Power Source Disclosure ("PSD") report for Light Green service,[7] MCE's actual 2024 emission factor of 0.001 MT CO_2e/MWh was below the organization's 95% carbon-free equivalent emission target (reflecting a virtual 100% carbon-free equivalency for the Light Green portfolio. The emission factors for Deep Green, Local Sol and Green Access service, as reflected in MCE's 2024 PSD report, were also zero.

As certain renewable generating technologies are known to have relatively low levels of emissions, such as certain geothermal generating technologies, MCE's equivalent carbon-free metric captures such impacts, along with any other use of carbon-emitting supply, including

[7]The 2024 Power Source disclosure Report was submitted by June 1, 2025.

system power and CARB-certified Asset Controlling Supply, to derive its proportionate use of carbon-free generation. To the extent that MCE's energy needs are not fulfilled using renewable or other GHG-free generating resources, it should be assumed that such supply will be sourced from conventional energy sources, such as natural gas generating technologies or system power purchases. MCE also plans to maintain its carbon-free equivalent metric at 95% of total supply in 2025 and beyond, meaning it will be further constrained in utilizing any carbon-emitting sources, including certain renewable generating technologies. As such, MCE will continue to creatively address the exercise of resource planning and portfolio composition to meet or exceed the aforementioned carbon-free equivalency metric.

MCE uses a portfolio risk management approach in its power purchasing program, seeking low-cost supply (based on then-current market conditions) as well as diversity among technologies, production profiles, project sizes and locations, counterparties, lengths of contract, and timing of market purchases. These factors are taken into consideration when MCE engages the market and pursues related procurement activities.

A key component of this process relates to the analysis and consideration of MCE's forward load obligations and existing supply commitments with the objectives of closely balancing supply and demand, cost/rate stability, and overall budgetary impacts, while leaving some flexibility to take advantage of market opportunities and/or technological improvements that may arise over time. MCE's long-term load forecast is a projection of the energy (reflected in MWh) that its customers will consume annually. MCE's long-term load forecast is driven primarily by the number and types of customers that MCE expects to serve, in conjunction with weather projections. Hourly class-specific load profiles are then used to break down the monthly energy forecast into more granular time-of-use and peak demand values. MCE's long-term load forecast also incorporates the load-modifying effects of electric vehicles, behind-the-meter solar and/or storage (via net energy metering), and energy efficiency.

MCE monitors its open positions separately for each renewable generating technology as well as GHG-free resources, conventional resources, and its aggregate supply portfolio. MCE maintains portfolio coverage targets of up to 100% of expected customer energy requirements in the near term (0 to 2 years) and typically leaves gradually larger open positions in the mid- to long-term, consistent with generally accepted industry practices. However, those larger open positions are continuously monitored for weather, market changes, and resource availabilities, and filled in a non-linear fashion as determined by MCE management. For example, MCE may fill residual summer positions ahead of the spring season or through procurements administered during the previous calendar year.

MCE prefers zero emission generating technologies, but within this preference MCE is largely technology-agnostic, subject to the previously discussed carbon-free equivalency metric.[8] MCE's supply preferences are intended to exhibit diversity across a broad range of renewable technologies that will deliver energy in a profile that is generally consistent with MCE's anticipated load shape. MCE is aware that significant use of intermittent renewable generating technologies has the potential to create misalignments between customer energy consumption and related power production; however, MCE regularly evaluates customer usage in light of expected renewable deliveries to reduce such risks and inform future procurement decisions. Furthermore, MCE continues to consider procurement opportunities with renewable generating facilities that will utilize storage technology, which can materially re-shape the typical delivery profile

[8] As mentioned above, MCE has a policy of not pursuing resource-specific nuclear power purchases.

associated with intermittent renewable generating assets, providing the opportunity for MCE to more accurately balance supply and changing customer demand, particularly due to the potential expansion of transportation electrification. MCE is also considering stand-alone energy storage opportunities to "recontour" purchased energy volumes in a manner that better matches changing customer usage patterns. MCE has determined that such projects are comparatively costly due to infrastructure costs and, in the case of battery storage projects, losses stemming from the common charge/discharge cycle of such projects.

Additionally, MCE offers several programs to manage its load shapes and better align MCE's supply resources with hourly demand. For example, MCE currently offers a managed EV charging app, MCE Sync, which helps customers automate EV charging and shift consumption away from peak periods.[9] Additional programs to help better align supply and demand include but are not limited to: MCE's Peak FLEXmarket;[10] Time of Use ("TOU") rates;[11] and MCE's revised Feed-In-Tariff ("FIT") Plus program,[12] that requires the addition of storage equal to 180% of the generator's nameplate capacity and enables generation to be shifted outside of normal solar production hours to better align MCE resources to match the hourly load.[13]

Recent market data continues to indicate that midday peak resources are likely to comprise a larger proportion of California's renewable supply portfolio due to the rapid decline in wholesale prices for solar PV generation and the abundance of such projects in operation and under development. Additions to MCE's portfolio during the Planning Period will likely be more heavily

[9] *See* https://www.mcecleanenergy.org/mce-sync/.
[10] *See* https://mcecleanenergy.org/peak-flex-market/.
[11] *See* https://mcecleanenergy.org/what-is-the-time-of-use-rate-plan/.
[12] *See* https://www.mcecleanenergy.org/feed-in-tariff/.
[13] *See* Agenda Item #06 from MCE's December 2, 2021, Technical Committee Meeting, available at https://www.mcecleanenergy.org/wp-content/uploads/2021/11/MCE-Technical-Committee-Packet-December_2021.pdf.

weighted toward energy resources – dispatchable, shaped during non-solar or ramping periods, or otherwise – that complement competitively priced solar already under contract or pair new solar projects with storage technologies to avoid exacerbating midday over-supply. MCE may also engage in purchases from as-available renewable generation (*e.g.*, wind) to the extent that such supply is competitively priced or otherwise provides electricity during time of day when existing supply commitments are currently lacking. Additionally, MCE is working with developers of its solar projects already under contract to add storage to those existing resources to increase the number of dispatchable resources in its portfolio. In regard to project location, MCE places the greatest value on locally-sited renewable generating and storage projects, particularly those located in its service area or within approximately 100 miles thereof. In general terms, the next highest preference related to resource selection are projects sited within the California Independent System Operator's ("CAISO") North of Path 15 Zone (generally, Northern California), followed by projects elsewhere in California, and lastly, out-of-state resources. This procurement strategy has led MCE to achieve its desired clean energy portfolio objectives as well as cost-competitive customer rates.

(iv) Description of How Energy Storage and Emerging Technologies are Addressed in Reliability and Diversity Planning.

Regarding new and emerging technologies, MCE has a particular interest in using offshore wind, long duration battery storage, and green hydrogen storage for building a carbon free portfolio for its customers and providing reliability to the grid. These technologies provide opportunities to shape MCE's hourly portfolio to match the hourly demand. MCE has provided several letters of intent with the potential to get into long term agreements once the technology is commercially viable to developers of new and emerging technologies. MCE intends to continue this approach in the future.

IV.B.1. Forecasting for Increased Transportation Electrification

A key component of the long-term load forecast includes the projections for transportation electrification load, the methodology for developing this forecast is described as follows:

MCE's load forecast is adjusted for expected increases due to electric vehicle ("EV") adoption. In order to estimate the impact of EV adoption on MCE's load forecast, MCE utilizes the California Energy Commission's ("CEC") Integrated Energy Policy Report as the basis for the estimates. MCE utilizes the state's mid-demand scenario, adjusting the forecasted EV load based upon two factors: 1) EV adoption rates within MCE's service territory and 2) Participation rates within MCE's service territory. California Department of Motor Vehicle registration data is utilized to estimate the territory's share of the state's forecasted EV load growth and internal customer data sources are utilized to adjust for MCE participation rates. MCE's EV load growth forecast does not segment by vehicle types but rather adjusts the state's total EV load based upon penetration levels.

Table 3: Transportation Electrification Load Forecast (2025-2035)

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
MCE Annual EV Load Forecast (GWh)	683	737	785	833	884	937	990	995	1,000	1,005	1,010

IV.B.2. Curtailment Frequency, Cost, and Forecasting

This Section responds to the questions presented in Section 4 of the ACR[14] and describes MCE's strategies and experience in managing the Agency's exposure to negative pricing events, overgeneration, and economic curtailment for MCE's region and portfolio of renewable resources.

[14] ACR at 19-20.

IV.B.2.(a) Factors Having the Most Impact on the Projected Increases in Incidences of Overgeneration and Negative Market Price Hours

Due in large part to the rapid increase in the amount of wind and solar generation coming online throughout the western United States, the CAISO Balancing Authority Area ("BAA") has experienced an increasing frequency and magnitude of curtailment and negative pricing events. The U.S. Energy Information Agency ("EIA") estimates that as of March 2025, California has 41,262 MW of total installed solar capacity, with 18,706 MW of that total being behind-the meter solar.[15] The CAISO reports that it has approximately 21,240 MW of utility-scale solar and 8,373 MW of utility-scale wind currently installed within its BAA.[16] This capacity results in discrete periods where the majority of load in the CAISO is served by solar and wind resources. The monthly maximum load served by wind and solar in the CAISO has averaged 87.5% over the past 5 years (April 2020 to April 2025), and the monthly maximum load served by wind and solar exceeded 142%.[17]

To address the resulting instances of over-supply, the amount of curtailment of wind and solar in the CAISO has significantly increased each year from 2015 through 2022, totaling 187,000 MWh in 2015, 308,000 MWh in 2016, 358,000 MWh in 2017, 461,000 MWh in 2018, 961,000 MWh in 2019, 1,587,497 MWh in 2020, 1,504,803 in 2021, 2,449,248 in 2022 2,659,526 MWh in 2023, and 3,423,376 in 2024. As of June 12, 2025, the total curtailment of solar and wind year to date is 2,290,000 MWh. Curtailment is typically the highest during the months of March, April,

---

[15] EIA, Electric Power Monthly, *Table 6.2.B. Net Summer Capacity Using Primarily Renewable Energy Sources and by State, March 2025 and 2024 (Megawatts)*, available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_02_b..

[16] CAISO, What are we doing to green the grid?, updated April, 2024, *at* https://www.caiso.com/about/our-business/managing-the-evolving-grid

[17] https://www.caiso.com/documents/monthly-renewables-performance-report-april-2025.html CAISO, Monthly Renewables Performance Report, April 2025, available at https://www.caiso.com/documents/monthlyrenewablesperformancereport-feb2024.html

and May when hydroelectric generation is historically at its highest and California load is at its lowest. Years in which there is an above-average snowpack results in higher-than-average hydroelectric generation which exacerbates renewable generation curtailment. The table below summarizes solar and wind curtailment from January 2025 through April 2025

Table 4: Summary of CAISO Solar and Wind Curtailment January-April 2025

2025 Data	**Wind Curtailment (MWh)**	**Solar Curtailment (MWh)**
January	15,300	114,970
February	22,890	479,630
March	61,840	857,180
April	51,480	686,710
Total Curtailment	151,510	2,138,490
Curtailment %	2.02 %	13.68%
No. of Intervals Curtailed	14,841	16,728
Pct. of Intervals Curtailed	34.14	38.48
Annual Curtailment (MWh)		
	Wind	Solar
2018	28,686	432,357
2019	43,557	921,684
2020	90,276	1,497,220
2021	78,477	1,426,326
2022	128,990	2,320,258
2023	150,604	2,508,916
2024	230,765	3,192,612

2025 (Partial Year*)	151,510	2,138,490
Annual Curtailment (% of Specific Generation)		
2018	0.17%	1.56%
2019	0.27%	3.22%
2020	0.56%	4.99%
2021	0.41%	4.19%
2022	0.70%	6.26%
2023	0.72%	6.10%
2024	1.03%	6.29%
2025 (Partial Year*)	2.02%	13.68%
Average	0.55%	4.66%
Annual Curtailment (% of Load)		
2018	0.013%	0.190%
2019	0.020%	0.420%
2020	0.041%	0.680%
2021	0.036%	0.650%
2022	0.057%	1.030%
2023	0.069%	1.148%
2024	0.103%	1.419%
2025 (Partial Year*)	0.227%	3.210%
Average	0.071%	1.093%

*Through April 2025

The CAISO notes that the majority of renewable resource curtailment is "a result of economic downward dispatch, rather than self-schedule curtailment," and that "[m]ost renewable generation dispatched down in the ISO were solar resources, rather than wind, because solar resources typically bid more economic downward capacity than wind resources".[18] That means that curtailment happened in response to congestion and was mitigated by supply that was willing to reduce its output based on price signals from the CAISO market.

CAISO system-wide 2025 curtailment percentages are higher than forecasted by MCE to date. Thus far in 2025 through May, MCE has experienced 85,404 MWh of curtailment, which is over 11.2% of MCE's RPS portfolio. This percentage will likely decrease as the summer season progresses. Curtailment to MCE's RPS portfolio is predominantly composed of the Little Bear Solar resources, which is 93.3% of MCE's curtailment volume. MCE has been in discussions with the CAISO regarding local network upgrades required and the potential for adding a battery to the project to alleviate Little Bear Solar curtailment.

IV.B.2.(b). Written Description of Quantitative Analysis of Forecast of the Number of Hours Per Year of Negative Market Pricing for the Next 10 Years

MCE's scheduling coordinator agent, ZGlobal, has the capability to perform production cost analyses based on various input assumptions through 2035 to derive hourly market prices for energy and ancillary services. PLEXOS Integrated Energy Model is a commercial optimization engine that can simulate the economic commitment and dispatch used by the CAISO's day-ahead market processes which simultaneously optimizes energy dispatch and ancillary services capacity

[18] CAISO, 2020 Annual Report on Market Issues and Performance Report, published January 20, 2022, page 41, available at http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf.

awards across the CAISO grid. In this way, the simulation will determine locational marginal prices and ancillary service marginal prices in the same manner the CAISO day-ahead market sets prices. ZGlobal has developed models using input assumptions that are based on common case inputs and planning guidelines from Western Electricity Coordinating Council, CAISO, Commission and CEC.

The key assumptions considered for the assessment included the impact of higher California renewable energy standards (60% RPS by 2030), planned gas-fired and nuclear generation retirements and adopted CEC demand forecasts which consider energy efficiency programs and increased behind-the-meter solar generation. Results are highly dependent upon input assumptions, primarily the level of new RPS generation, deployment of energy storage facilities, upgrades to CAISO-controlled transmission facilities and the ability to export energy from the CAISO to external balancing areas.

In California, electricity prices are typically set by gas-fired resources operating on the margin. However, as increasing supplies of renewable energy are added to the system, there are periods where marginal prices are being set by zero or even negatively-priced resources. Market prices have been trending downward, especially during seasons and periods of the day when loads are low and solar output is high with the influx of renewable energy resources. The modeling shows that during solar hours, prices are low during the middle of the day, driven by solar resources and their willingness to curtail and increasing in the morning and evening when gas-fired resources are needed to meet peak loads outside of the solar supply period. In short, prices as reflected by the CAISO's duck curve are expected to continue, with the amplitude of the valley and ramps dictated by the amount of energy storage available to smooth out the net supply.

IV.B.2.(c) Experience, to Date, With Managing Exposure to Negative Market Prices and/or Lessons Learned from Other Retail Sellers in California

MCE's experience and process for managing exposure to negative market prices has been addressed above in Section IV.A.(*iii*).

IV.B.2.(d) Direct Costs Incurred, to Date, for Incidences of Overgeneration and Associated Negative Market Prices

For calendar year 2025 through May, MCE's RPS portfolio has been exposed to negative market prices and experienced curtailment as summarized in the table below.

Table 5: Summary of MCE RPS Resources Curtailment January-May 2025

Location	**Day-Ahead Negative Prices**	**Real-Time Negative Prices**	**Curtailment (MWh)**	**Cost of Curtailment ($)**
South P26	-$10.79	-$16.59	1,711	$69,151
Fresno 1	-$36.83	-$43.49	79,701	$3,798,396
Fresno 2	-$18.78	-$24.52	997	$48,777
North P26	-$11.77	-$16.52	2,995	$110,174
Total	**-$22.41**		**85,404**	**$4,026,499**

The Day-Ahead and Real-Time Negative Price columns represent averages of negative prices by RPS geographic area when prices are negative for solar hours for solar resources and all hours for wind resources. The prices are averages based on resources within the area. Curtailment MWh is the amount of energy that MCE RPS resources in the areas were curtailed from January 1 through May 31, 2025. "Cost of Curtailment" is the subsequent market cost of the curtailed energy.

IV.B.2.(e) An Overall Strategy for Managing the Overall Cost Impact of Increasing Incidences of Overgeneration and Negative Market Prices

While curtailment is a viable renewable integration strategy that is generally more cost-effective than other options, there are potential negative consequences from excessive curtailment. Curtailment of solar and wind represents a lost opportunity to generate zero-GHG electricity, and excessive curtailment could impact the ability of the state to meet its environmental and energy policy goals. Additionally, these over-supply situations expose ratepayers to increased costs because their load serving entities must either economically curtail the generating resource (and often pay for the electricity that was not generated) or generate power and be exposed to negative prices.

MCE considers the impact of curtailment and negative pricing on its portfolio and factors potential curtailment into its long-term planning. Due to the difficulty in accurately forecasting curtailment, MCE will review the historical data on curtailment and negative pricing within regions where MCE may contract for generating resources. When MCE is evaluating new procurement opportunities, the potential amount of future curtailment is one factor that MCE considers. While MCE has not yet developed an individualized forecast of future curtailment, MCE will factor potential curtailment into its minimum margin of procurement (described in Section IX) and may also factor this consideration in future iterations of its Risk Assessment (Section VII). To the extent that MCE is engaged in renewable supply agreements which include curtailment provisions, it will take actions to limit the impacts of curtailment on its customers. During its current and future renewable contracting efforts, MCE will pursue contract terms that recognize and limit the potential financial impacts of negative pricing and give MCE greater flexibility to direct economic curtailment, if this becomes necessary.

IV.B.2.(f)Contract Terms Included in RPS Contracts Intended to Reduce the Likelihood of Curtailment or Protect Against Negative Prices.

MCE negotiates the right in its long-term Power Purchase Agreements (“PPA”) to economically curtail deliveries to a certain number of hours up to which there is no seller compensation. MCE also has a strong preference to be the scheduling coordinator so that it can adjust its bidding strategies to protect against negative pricing in the Day Ahead and Real Time markets.

IV.C. Portfolio Optimization

MCE plans for and secures commitments from a diverse portfolio of generating resources to reliably serve the electricity supply requirements of its customers over near-term, mid-term and long-term planning horizons. MCE’s goal is to meet organizational policies and statewide mandates in a manner that is cost effective, achieves internally adopted clean energy objectives, promotes grid reliability, and generally supports a well-balanced and diversified resource portfolio. Portfolio optimization strategies can help reduce costs and should facilitate alignment of MCE’s portfolio of resources with its forecasted needs. This noted, MCE continues to pursue its renewable energy procurement goals through the exclusive use of PCC1~~Portfolio Content Category “PCC”1~~ products but remains aware of the diminished availability of this supply during Compliance Period 5. If alternative RPS-eligible products become necessary to meet MCE’s near-term portfolio objectives, MCE will consider these alternatives as appropriate. MCE’s preference for PCC1 RPS products is expected to minimize portfolio emission impacts that would otherwise accrue using Portfolio Content Category 2 (“PCC2”) and Portfolio Content Category 3 (“PCC3”) product options, both of which are ascribed emissions under California’s current emissions calculation methodology. While this approach is more costly it promotes the achievement of MCE’s GHG-related objectives. This noted, MCE may procure small quantities of RPS supply from clean and specified PCC2 resources if unexpected delivery shortfalls are higher than expected retail sales and/or prevailing market conditions necessitate such purchases. MCE anticipates such purchases to be rare, if purchased at all. This flexibility to purchase PCC2 resources ensures that MCE can fulfill adopted portfolio commitments to its customers. MCE will advise the Commission if the Agency anticipates any deviations from the aforementioned resource preferences.

To support its RPS planning and procurement goals, MCE considers the following strategies:

- <u>Joint Solicitations:</u> Joint solicitations can expand the procurement opportunities available to a CCA, as well as provide procedural efficiencies, economies of scale, and overall cost savings for participating organizations. MCE is closely networked with other CCAs through its membership in the CalCCA, the trade organization representing California's CCA sector, and regularly coordinates with other CCAs regarding prospective procurement opportunities and portfolio balancing activities.
- <u>Purchases from Retail Sellers:</u> Purchases of RPS-eligible renewable energy from other retail sellers can provide a cost-effective way of meeting short-term resource needs or filling in gaps in procurement while long-term projects are under development. MCE will evaluate solicitations offered by other retail sellers, as necessary.
- <u>Sales Solicitations</u>: As MCE continues to manage its growing portfolio of renewable resources, it will also consider administering sales solicitations (serving as a renewable energy seller) for the benefit of other retail sellers. Such solicitations are expected to be rare and relatively small in scale. MCE may also engage in bilateral sales discussions with certain retail sellers, including CCAs, if/when divesting relatively small amounts of surplus renewable energy supply is deemed necessary to rebalance MCE's renewable portfolio

relative to internally established procurement targets. MCE has completed such processes in the past and expects to do so in the future as well. Selling excess renewable supply is an effective way for all LSEs to reduce unnecessary renewable energy expenses while providing valuable renewable energy products to other market participants.

- Optimizing Existing Procurement: As MCE considers its long-term resource needs, it may evaluate options in its future PPAs~~power purchase agreements~~ to increase the output of existing generating facilities through technological upgrades. This can be accomplished by adding new capacity to an existing generator or by adding energy storage infrastructure to an existing renewable generator. Expanding existing facilities may provide additional generation at reduced costs with a lower risk of project failure because the need for distribution system upgrades and permitting may be minimized or eliminated. Adding energy storage infrastructure to an existing renewable generator enhances grid reliability and the value of electric energy produced by the generating facility. Such enhancements allow pre-storage energy delivery profiles to be shifted to: 1) better align MCE's supply with customer demand; or 2) create more value for MCE customers by shifting electric energy deliveries to a time of day when market revenues (related to such energy deliveries) would be greater than normal. In terms of reliability impacts related to the addition of energy storage infrastructure, MCE expects that such enhancements would meaningfully increase the proportionate level of RA capacity that could be derived from an intermittent renewable generating resource. It is well documented that without such storage infrastructure, there will be reductions to the Net Qualifying Capacity ("NQC") of intermittent renewable generating resources, resulting in very little capacity benefits from solar-only generating projects. In considering these sorts of enhancements, MCE will be mindful of the need to coordinate with its resource owners/operators to evaluate potential planning constraints (*e.g.,* generator interconnection processes and limitations) before determining that the addition of energy storage infrastructure at an existing generating facility would be a viable option.

MCE launched a ~~its 2024 Open Season~~ Request for Information ("RFI") for Long-term Offers ~~("RFO")~~ on April 14, 2025.[19] The results of the RFI will inform MCE's approach to its typical Open Season solicitation process.~~March 4, 2024, and accepted offers through March 22, 2024.~~[20] Open Season provides a competitive, objectively administered opportunity for qualified suppliers of various energy products (including renewable and storage technologies) to fulfill MCE's future resource requirements and compliance obligations. Open Season is typically administered on an annual basis for purposes of soliciting offers for new-build renewable energy and storage resources and capacity that meet the procurement targets set forth in IRP.~~Integrated Resource Plan.~~ The 2025~~2024~~ Open Season will focus~~was focused~~ on soliciting resources that will provide the best value and best fit for MCE load shapes, in addition to supporting MCE's compliance with regulatory procurement requirements. ~~Under 2024 Open Season, MCE solicited offers for the following products: 1) PCC1-eligible Renewable Energy~~[21]~~, Green Attributes/RECs and capacity attributes; and 2) Renewable Energy Paired with Stand-Alone Energy Storage~~[22]

As part of the Open Season solicitation process, MCE provides a Procedural Overview and Instructions document that describes the Open Season process, schedule, and requirements for

[19] *See* https://www.mcecleanenergy.org/energy-procurement/.

[20] ~~*See* https://www.mcecleanenergy.org/energy-procurement/.~~

[21] ~~Solar PV projects submitted into MCE's 2024 Open Season were required to be paired with integrated energy storage.~~

[22] ~~MCE accepted both four-hour and long-duration (eight-hours or more) storage, as well as any other technology type.~~

submitting a conforming offer. MCE also provides an offer form and term sheets that must be submitted along with the offer.

During this year's RFI, MCE sought information from qualified suppliers of renewable energy, energy storage products and RA to inform MCE's formal long-term offer solicitation in 2025. MCE's procurement team launched an RFI as an initial step in its long-term procurement efforts in 2025. MCE believed that this new approach would streamline procurement efforts for all participants. MCE sought information for prospective full-toll agreements (all applicable products) with a minimum contract term length of ~~RFO, offerors could submit offers~~ at least five (5) years from Renewable Energy (PCC1-eligible) projects, Renewable Energy Paired with Energy Storage projects, and Standalone Energy Storage projects. Projects were to be no less than 5 MW for 24x7 load profiles or no less than 25 MW for intermittent resources. Beyond these categories, responses were not limited in any other respect. Due to numerous headwinds in the market for grid-scale projects, including interconnection delays and process reforms, permitting challenges, and federal tax credit and tariff uncertainty, MCE sought a new approach to its long-term procurement in 2025. The procurement team believed a streamlined RFI process would provide an indication of the current landscape for projects in all stages of development. The Procurement team worked closely with MCE's Public Affairs team, leveraged external stakeholders, including CalCCA, and communicated with an extensive network of developers to draw participation in the RFI. MCE will continue to evaluate the RFI results and may pursue a formal Request for Offers ("RFO") from qualified respondents.

~~time between March 4, 2024 through March 22, 2024 ("Offer Window").~~ When an offer is received, MCE first reviews an offer for completeness relative to the RFO eligibility criteria. MCE then conducts a quantitative analysis focused on the value of each conforming offer, in addition to a qualitative review evaluating non-quantitative offer details, like interconnection status, in more depth. MCE selects the strongest offers on a rolling basis, in parallel to completing evaluations of other offers as they are submitted. To ensure that favorable opportunities are not "lost" to other buyers, MCE works with the 3rd party to enter into an Exclusivity Agreement once an offer has been short-listed.

Once an Exclusivity Agreement is executed, Staff will begin contract negotiations with the shortlisted projects. The resulting PPAs~~Power Purchase Agreement(s) ("PPA")~~ and Energy Storage Agreement(s) ("ESA") are reviewed by MCE's Executive Management team before review and approval by MCE's Board.~~ of directors (Board).~~ Contract execution occurs after the agreements are approved by the Board.

MCE also considers allocations from PG&E in its portfolio optimization. Through the Power Charge Indifference Adjustment ("PCIA"),~~,~~ MCE customers (and other CCA and Direct Access customers) are required to pay their share of the above-market costs associated with PG&E's legacy resources such as its large hydroelectric fleet, PG&E's nuclear power plant, Diablo Canyon, and many PG&E PPAs including RPS PPAs. As nearly half of PG&E's customer load has departed for other LSEs, it has resulted in PG&E having excess resources in its portfolio. Accordingly, the Commission directed PG&E to offer a proportionate share allocation of output from hydroelectric and nuclear, GHG-free, resources at no additional cost on a voluntary basis to CCAs and Direct Access providers whose customers pay the PCIA for the years 2019 and 2020. ("Interim Allocation" The Interim Allocation was extended into 2021 by Resolution E-5111, in which the Commission also authorized PG&E to extend the interim approach to GHG-Free resources through December 31, 2023.). In Decision ("D.") 23-06-06 the Commission modified the PCIA methodology by allowing PG&E to elect to either offer an allocation of large hydro

GHG-Free attributes or to retain the attributes and value them at a new market price benchmark. In Advice Letter 7005-E, PG&E notified LSEs of its intent to offer large hydro allocations for 2024, and in its 2025 Energy Resource Recovery Application PG&E notified parties of its intent to offer large hydro allocations for the 2025-2027 period as well. ~~As~~ MCE's Board in late 2024, accepted the hydro allocations as well as 2025~~has previously elected not to take~~ nuclear allocations. ~~from PG&E to align with its policy of no resource-specific nuclear transactions,~~ MCE will use~~has only accepted PG&E's hydroelectric allocations since 2020 and uses~~ these allocations in meeting its internally adopted GHG-free targets. Additionally, MCE structured its Light Green portfolio to be approximately 95% GHG-free starting in 2023,[23]~~,~~ subject to market and/or regulatory changes. To structure such a clean Light Green portfolio by 2023, MCE procured three products: (1) RPS-eligible renewable energy; (2) large hydroelectric energy; and (3) Asset Controlling Supplier energy, the vast majority of which is attributable to large hydroelectric generating resources. To ensure grid reliability, MCE's contracting goals include 475 MW of stand-alone energy storage to be online by 2030~~2029~~, and to have approximately 153 MW of new energy storage paired with solar resources online by 2030.[24]

Disadvantaged Community Solar Green Tariff: In 2021, MCE launched its first solicitation for the Green Access ("Disadvantage Community – Green Tariff" or "DAC-GT") and Community Solar Connection ("DAC-CSGT") procurement process ("2021 Green Tariff"). The purpose of MCE's 2021 Green Tariff was to fulfill the requirements of ~~Assembly Bill ("~~AB~~")~~ 327, ~~CPUC Decision ("~~D.~~")~~ 18-06-027, D.18-10-007, and Resolution E-4999 (collectively the "Green Tariff

[23] MCE's Operational Integrated Resource Plan, https://www.mcecleanenergy.org/wp-content/uploads/2022/11/MCE-Operational-Integrated-Resource-Plan_2023.pdf.
[24] MCE's 2022 CPUC Integrated Resource Plan, https://www.mcecleanenergy.org/wp-content/uploads/2022/11/MCE-2022-Integrated-Resource-Plan_11012022.pdf.

policy"). The Green Tariff policy is intended to promote the installation of renewable generation among residential customers in disadvantaged communities ("DACs"). MCE executed two contracts for the DAC-GT program. To comply with the Green Tariff policy, MCE has to procure under two programs: 1) Green Access and 2) Community Solar Connection. MCE fulfilled the requirements of the Green Access program through the selected projects from the 2021 solicitation. MCE held annual solicitations for the Community Solar Connection program in 2022 and 2023 and received no offers. MCE then opened the Community Solar Connection solicitation in 2024 on an open until filled basis with no offers received. On May 30, 2024, the CPUC issued D.24-05-065, which made several modifications to the DAC-GT program, including adopting changes to the cost cap for the program, and closing~~closes~~ the Community Solar Connection program, rolling unused capacity into the DAC-GT program. MCE is currently evaluating ~~the ruling~~ and will likely release a solicitation addressing both these elements. ~~for the additional volume made available to the DAC-GT program in the Decision.~~

On June 24, 2021, the Commission adopted D.21-06-035, which directed all retail sellers to collectively procure 11,500 MW of new NQC, including LLT~~long-lead-time~~ resources ~~("LLT resources")~~ to come online between 2023 and 2026. This decision assigned each retail seller a specific procurement responsibility based on its share of peak demand. In February 2023, the Commission issued D.23-02-040, which supplemented the initial Mid-Time Reliability ("MTR") order to require LSEs to procure an additional 4,000 MW of NQC and pushing out the online date for LLT resources to 2028. MCE's total obligation, resulting from these two CPUC decisions, is 454 MW of NQC by June 1, 2028. MCE's 454 MW requirement includes 72 MW of NQC from dispatchable, zero-emitting capacity, required to be online by June 1, 2025. As part of its 454 MW requirement, MCE must also procure at least 58 MW of LLT resources, including (1) 29 NQC

MW from long duration storage resources by June 1, 2028; and (2) 29 NQC MW from firm, non-fossil fueled baseload generating resources by June 1, 2028.[25] MCE plans to meet its MTR obligations using a diverse set of resource technologies, some of which will be RPS-eligible. MCE has negotiated a number of ~~Energy Storage Agreements ("~~ESAs~~")~~ and PPAs to meet its MTR obligations~~,~~ and has~~to the extent MCE has already~~ executed agreements for RPS-eligible resources related to ~~the~~ MTR.[26] As discussed in Section V below, pursuant to the Commission's initial MTR order, MCE has eight executed contracts for projects under development that will be used to meet MTR mandates: Daggett, Golden Fields, Geysers, Humboldt House, Strauss Wind, Key, Cormorant, and Corby. MCE's RNS, Project Development Status, and Cost Quantification templates have also been updated to incorporate these eight projects.

Generally, the MTR decisions are aligned~~in alignment~~ with MCE's internally adopted contracting goals, which are highlighted above. As noted above, MCE provided~~plans to provide~~ approximately 99% GHG-free and 69% renewable energy through its Light Green base product in 2024, as shown in MCE's 2024 ~~2023. While MCE is still in the process of preparing its final 2023 Power Source Disclosure ("~~PSD~~")~~ Report.~~, which currently must be delivered to the California Energy Commission ("CEC") no later than July 29, 2024, the current draft reporting template for MCE Light Green service suggests that the organization will have achieved its lowest portfolio emission factor ever while also fulfilling its 60% renewable energy delivery target for such customers. Should the actual emission factor and/or renewable content reflected in the final reporting template differ from the previously noted statistics, MCE will accordingly advise the Commission in its Final 2024 RPS Procurement Plan.~~ All other MCE customers, including those

[25] Pursuant to D.23-02-040, the Commission changed the required online dates for LLT resources from 2026 to 2028.
[26] *See* Renewable Net Short Template Row Fb.

participating in the Deep Green, Local Sol, and Green Access service options, received supply reflecting 100% renewable and zero carbon emissions in 2024.~~2023.~~

MCE intends to use RPS-eligible resources acquired for the MTR procurement mandates to fill open positions relative to MCE's internal RPS goal.[27] MCE will continue to use procurement strategies such as joint contracting efforts, buying from other retail sellers, and optimizing existing procurement, as described earlier in this section, to meet the MTR procurement mandates and MCE's internal goals for RPS at the lowest cost to its customers.

IV.C.1 Conformance with the IRP Proceeding

The resources identified in this RPS Procurement Plan are consistent with the resources MCE expects to identify in MCE's 2025 IRP, which is currently required to be submitted to the Commission for certification by November 1, 2025.[28] MCE's RPS Procurement Plan is also consistent with the biannual MTR updates provided to the Commission addressing MCE's progress towards meeting procurement requirements under D.21-06-035 and D.23-02-040.[29] As required by the ACR,[30] specifically, Table 6below describes how MCE's 2025 RPS Procurement Plan conforms with the determinations made in the IRP Proceedings (R.16-02-007 and R.20-05-003) and highlights the interrelationships of its RPS and IRP planning processes. The following table reflects MCE's current updates, as reflected in this RPS Procurement Plan, regarding RPS alignment with the 2024-2026 IRP process.

[27] *See* Row Ga of the Renewable New Short Template.
[28] While Commission decision indicates that LSEs are to submit 2025 IRP to the Commission by November 1, 2025, Energy Division indicated via email on June 5, 2025 that the IRP timeline will be delayed.
[29] Since filing its 2022 Compliance IRP, MCE has filed six biannual MTR update filings on February 1, 2023, August 1, 2023, December 1, 2023, June 3, 2024, December 2, 2024, and June 2, 2025 respectively.
[30] ACR at 21-22.

Table 6: RPS Alignment in MCE's IRP

<table>
<tr><th>IRP Section Subsection</th><th colspan="2">RPS Alignment in IRP</th></tr>
<tr><td rowspan="2">**III. Study Results**
A. Conforming and Alternative Portfolios</td><td colspan="2">Retail sellers should explain how the RPS resources they plan to procure, outlined in their RPS Plan, will align with each of their Conforming Portfolios being developed in their IRP Plans for Commission approval and certification. This explanation should include:</td></tr>
<tr><td>*1. Existing RPS resources that the retail seller owns or contracts.*
2. Existing RPS resources that the retail seller plans to contract with in the future.
3. New RPS resources that the retail seller plans to invest in.
4. New and existing resources that will be used to meet Mid-Term Reliability obligations adopted in D.21-06-035 and the supplemental procurement ordered in D.23-02-040.</td><td>The Commission certified MCE's 2022 IRP per Ordering Paragraph 5 of D.24-02-047. Pursuant to D.24-02-047 and the *Assigned Commissioner's Amended Scoping Memo and Ruling Extending Statutory Deadline*, issued April 18, 2024, MCE's next full update to its 2022 Compliance IRP will be filed by November 1, 2025, although this filing date is subject to change due to delay in the Commission's issuance of filing materials and guidance.
MCE's portfolio mix and planned procurement met the requirements of the 2022 IRP Preferred Conforming Portfolio ("PCP") in the last IRP cycle and met MCE's compliance and internal obligations and targets. Looking forward to the upcoming 2025 IRP, MCE anticipates that its planned procurement of a diverse set of renewable resources, as represented in its 2022 PCP and as supplemented and complemented with additional near-, mid-, and long-term procurement, will meet the Commission's mandated emissions targets and reliability metrics, including the balanced and diverse set of resources identified in the most recent (2023) preferred system plan adopted by the Commission. MCE's PCP procured to the lower emissions target that was adopted in the 2023 PSP. As such, MCE expects that its portfolio will</td></tr>
</table>

		comply with the emissions metrics of the current Preferred System Plan and the emissions metrics in the upcoming IRP cycle. However, MCE notes that until official guidance and requirements for the 2025 IRP cycle are issued by the Commission, MCE cannot state with certainty what its optimal long-term procurement plan will be. To remain resilient and flexible, MCE has not set a specific ratio on the characteristics or type of resources for its planned procurement. The right balance will depend on multiple factors including but not limited to; • Specific and final IRP requirements; • Availability of eligible resource types on the market; • Project development timelines; • Deliverability of available resources for contracting; • Price and affordability; • Location and congestion analysis; and • MCE Portfolio fit. • For reference, a description MCE's PCP is as follows: • MCE's PCP achieves an overall portfolio GHG target below MCE's assigned share of the 2030 and 2035 emissions under both the 30 million metric tons ("MMT") and 25 MMT scenarios. • Using the CPUC's embedded assumptions in the 25 MMT portfolio, MCE's emissions registered at 0.493 MMT relative to MCE's assigned share of 0.640 MMT in 2030 and 0.492 MMT relative to 0.504 MMT in 2035. • MCE's PCP assumed the use of RPS resources that were reflected in

		MCE's supply portfolio at the time of the 2022 IRP filing. • The planned RPS-eligible resources reflected in MCE's PCP included: 109 MW geothermal; 356 MW wind (consisting of in-state, out-of-state, and off-shore); and 222 MW solar o Of the aforementioned PCP resources, MCE anticipated the following new RPS-eligible capacity additions: new hybrid resources totaling 212 MW solar/ 153 MW battery storage, 109 MW of geothermal, and new wind resources totaling 265 MWs. • MCE also continues to procure and develop projects (both renewable generation paired with storage and stand-alone storage) to meet its MTR requirements pursuant to D.21-06-035 and D.23-02-040 (MCE was assigned 332 MW of incremental Net Qualifying Capacity to meet its share of the state's MTR need pursuant to D.21-06-035 and was assigned an additional 122 MW of incremental NQC to be online by 2027 pursuant to D.23-02-040). MCE continues to actively procure to meet the initial MTR need, the supplemental MTR need, and RPS-related needs in compliance with the mandated timelines. All of this procurement contributes towards MCE's MTR- and IRP-related needs, and much, but not all, of the procurement will contribute towards MCE's RPS-related requirements. At the time of this filing, MCE's existing executed MTR agreements or new build RPS-eligible procurement include the following incremental capacity amounts: 27 MW

		of nameplate geothermal capacity; 100 MW nameplate solar paired with 92 MW of nameplate storage; and 110 MW of nameplate solar paired with 60 MW of nameplate storage, 93.35 MW of nameplate wind capacity, and 110 MW of nameplate solar paired with 110 MW of storage. Although not MTR-eligible, MCE has also procured and brought online 100 MW of energy-only solar capacity from a new-build solar facility. All of the referenced procurement contributes towards the diverse set of resources indicated in MCE's 2022 PCP, which portfolio will continue to be revised and supplemented to account for market conditions, regulatory requirements, and internal portfolio optimization needs. • MCE is also taking action via its annual solicitation processes to identify additional projects that contribute towards MCE's MTR, RPS, and general IRP needs through formal RFIs and RFOs as well as pursuing bilateral opportunities with project developers as described in more detail in Section IV.C, above. MCE expects that some of this procurement will be eligible to contribute towards MCE's RPS needs; all of this procurement is expected to contribute towards MCE's existing MTR needs and existing and future IRP procurement obligations to support reliability and GHG reduction efforts. Through administration of MCE's RFI procurement process, MCE is seeking to reduce outstanding resource needs required to meet portfolio specifications reflected in its PCP, MTR requirements, as well as any other internal and state-mandated RPS or reliability procurement targets.

		To the extent additional resources are needed, MCE is conducting supplemental, smaller solicitations and pursuing bilateral negotiations. • Separate from, and predating the RFI, MCE is also pursuing various new-build projects for wind capacity, additional geothermal capacity, and co-located solar and storage capacity that MCE expects to be under contact within the year or soon thereafter. • In addition to the more formal solicitation processes, MCE also solicits offers for short-term PCC1 renewable energy purchases/sales for annual portfolio balancing. Additionally, MCE participated in the PG&E Voluntary Allocation and Market Offer ("VAMO") process and received an allocation of renewable energy from the PG&E's PCIA portfolio in 2024. MCE is no longer receiving allocations from this process.
Any IV. Action Plan **A. Proposed Activities**	Retail sellers should describe how they propose to use RPS resources to implement both Conforming Portfolios. Narratives should include:	
	1. Proposed RPS procurement activities as required by Commission decision or mandated procurement. *2. Procurement plans, potential barriers, and resource viability for each new RPS resource identified.*	To ensure compliance with its IRP, GHG, reliability, and RPS targets, MCE plans to substantially rely on GHG-free and RPS-eligible resources while contributing to statewide reliability requirements and responsibly managing overall portfolio costs. As described above in the Study Results section, there is significant overlap among MCE's RPS-related procurement, IRP-related procurement, and MTR-related procurement. MCE has contracted for three co-located resources, which are expected to provide additional RPS- and

		MTR-eligible incremental capacity (one of which is online, the other two resources are expected to achieve commercial operation in August 2025 and April 2031, respectively). MCE's prior RPS procurement plan also indicated MCE had four contracts for geothermal capacity (3 of which were incremental, new build capacity; 1 is for 100 MW of existing geothermal capacity for a 10-year delivery period starting in 2027). As of this filing, and as has been previously reported to the Commission in prior RPS- or MTR-related filings, due to contract failure of one of the incremental geothermal projects, MCE now has three recently procured geothermal projects under contract (2 of which are incremental geothermal capacity eligible to count towards MTR requirements). All of the aforementioned geothermal procurement is under long-term contract. Of note, one of the aforementioned incremental projects (representing 7 MW of geothermal capacity) achieved commercial operation in June 2025 and is actively contributing towards MCE's reliability, emissions, and RPS needs. The other incremental geothermal project (representing 20 MW of nameplate capacity) has encountered a number of material delays due to interconnection and permitting. These delays will require material changes to critical contract milestones, including construction start and commercial operation, both of which MCE expects to be achieved before 2030. For more detailed descriptions of MCE's MTR procurement, please refer to MCE's biannual MTR update filings, the latest of which was filed on June 2, 2025. MCE is also actively pursuing various new-build projects for wind capacity, additional geothermal capacity, and co-

		located solar and storage capacity, as mentioned in the Study Results Section above and throughout this RPS Plan. MCE expects these resources to be under contact within the year or soon thereafter.
IV. Action Plan **B. Procurement Activities**	The retail seller should describe the solicitation strategies for the RPS resources that will be included in both Conforming Portfolios. This description should include:	
	1. The type of solicitation. *2. The timeline for each solicitation.* *3. Desired online dates.* *4. Other relevant procurement planning information, such as solicitation goals and objectives.*	MCE will issue future solicitations, as described above in Section X, on a timeline that is appropriate for the resource development plan that is: responsive to the anticipated needs for the upcoming 2025 IRP cycle; consistent with MTR procurement timelines and attributes; conducive to MCE meeting its internal and state-mandated RPS targets. As part of such processes, MCE may pursue additional resources that will be needed to fulfill resource specifications reflected in its own portfolio needs, to meet MTR requirements or future potential mandates or CPUC procurement program, upcoming IRP requirements. Responsive to current portfolio needs, and in anticipation of future needs, MCE's current RFI process is specifically targeting PCC 1-eligible renewable energy generating facilities that may be paired with energy storage and/or renewable baseload capacity. MCE is currently evaluating responses to this RFI and expects to launch a subsequent RFO and/or commence discussions with potential project developers bilaterally to try to secure projects that can meet MCE's current and anticipated RPS, IRP, and MTR needs. In addition to the more formal solicitation processes, MCE also solicits offers for short term PCC1

		renewable energy purchases/sales for annual portfolio balancing.
IV. Action Plan **C. Potential Barriers**	Retail sellers should provide a summary of the potential barriers to implementing both Conforming Portfolios as they relate to RPS resources. The section should include:	
	1. Key market, regulatory, financial, or other resource viability barriers or risks associated with the RPS resources coming online in both retail sellers' Preferred Portfolios. *2. Key risks associated with the potential retirement of existing RPS resources on which the retail seller intends to rely in the future.*	MCE notes that even though a balanced, diverse RPS portfolio is desirable, the limited resource availability and lead time required for some technology types will necessitate planning flexibility. While MCE has a highly successful track record of contracting with new-build renewable resources, there is always a risk of project failure due to market and regulatory conditions beyond MCE's control. Of increasing concern to MCE is the backlogged interconnection queue and delays in processing the numbers of applications for interconnection studies and deliverability. Restrictions and uncertainty on this front increase risk and uncertainty for LSEs and can ultimately present a material barrier to LSEs bringing on new RPS resources that have sufficient deliverability to meet RPS program and reliability needs. Importantly, transmission and interconnection issues not only affect the viability of projects at the outset, but impact the on-going economics of projects once the generation is online – this is particularly relevant for non-dispatchable renewable projects that are subject to curtailment due to insufficient transmission. Adding to this constraint are lingering supply chain issues and permitting delays that impact timely development and interconnection of new resources. MCE also notes that potential changes to federal tax policy threaten to materially impact renewable energy development in

		California – the full impacts of which are yet to be determined.

IV.C.2. Response~~B. Responsive~~ to Local and Regional Policies

(i) Responsiveness to Policies of MCE Governing Board

MCE is a local governmental agency that is subject to the control of its governing board and is directly accountable to the community that it serves. MCE strongly supports and is committed to meeting the state's GHG reduction and renewable procurement goals. As a member of CalCCA, MCE actively supported the passage of SB 100 (2018) and has fully incorporated the procurement requirements of the state's RPS program into its overall procurement strategy.

As previously noted, MCE's internally adopted renewable energy procurement target has been set at 60% (through 2025, increasing thereafter). All related renewable energy purchases will be sourced from CEC-certified generating facilities, which will be eligible for use under California's RPS Program. All of MCE's renewable energy purchases are expected to be sourced from products meeting the delivery requirements established for PCC1.

Furthermore, MCE's existing contractual commitments have secured the significant majority of its renewable energy requirements. Existing contracts continue to address the majority of MCE's renewable energy needs throughout the planning period addressed in this RPS Procurement Plan and are expected to account for 97~~129~~% of statutorily mandated long-term renewable energy procurement requirements in 2035.~~2034 and 94% of total RPS procurement requirements in that year.~~ MCE's planning and procurement process remains ongoing, which is expected to result in additional renewable energy acquisition, the substantial majority of which will be secured via long-term contracts.

Additionally, MCE policy, established by MCE's founding documents and directed on an ongoing basis by MCE's governing board, guides development of the resource plan and related procurement activities. MCE's key resource planning policies are as follows:

- Reduce GHG emissions and other pollutants within the electric power sector through increased use of renewable, GHG-free, and low-GHG energy resources;
- Maintain competitive~~affordable~~ electric rates and increase control over energy costs through management of a diversified resource portfolio;
- Benefit the local~~area's~~ economy by offering competitive electricity rates and customer programs, and investing~~though investments~~ in local infrastructure, energy, and workforce-development programs within MCE's service area;
- Help customers reduce energy consumption and electric bills by supporting and administering enhanced customer energy efficiency, cost effective distributed generation, and~~,~~ other demand-side programs;
- ~~Pursue load and generation shaping to help reduce grid reliance on fossil power, manage costs, and promote reliability.~~
- Enhance system reliability through investments in supply- and demand-side resources;
- Actively monitor and manage operating risks to promote MCE's continued financial strength and stability; and
- Support supplier and workforce diversity as permitted by law.

MCE translates these broad policy objectives into more specific plans for the use of various types of electric resources, taking into consideration MCE's projected customer needs and MCE's existing resource commitments.

To enable MCE to meet its resource planning objectives, MCE's governing board has formally adopted the following policies related to resource planning and procurement:

(1) MCE's Sustainable Workforce and Diversity Policy:[31] MCE is committed to supporting sustained and fairly compensated local job opportunities through participation in the energy industry. To the extent allowed by state law, MCE seeks to create market incentives and partnerships to encourage diversity and a sustainable workforce through its support for:

- Fair compensation in direct hiring, renewable development projects, customer programs, internships, and procurement services;
- Development of locally generated renewable energy within MCE's~~the MCE~~ service area;
- Direct use of union members from multiple trades;
- Quality training, apprenticeship, and pre-apprenticeship programs;
- Direct use of businesses local to MCE's~~the MCE~~ service area;
- Development of California-based job opportunities;
- Business and workforce initiatives located in low-income and disadvantaged communities;
- Direct use of Disabled Veteran-owned Business Enterprises and LGBT-owned Business Enterprises;
- Direct use of green and sustainable businesses; and
- Use of direct hiring practices that promote diversity in the workplace.

(2) MCE's Energy Risk Management Policy:[32] MCE manages its energy resources and

---

[31] *See* Attachment A to Agenda Item #7 from MCE's November 16, 2017 Board Meeting, available at https://www.mcecleanenergy.org/wp-content/uploads/2020/05/MCE-Board-Meeting-Packet-November_2017.pdf.
[32] *See* Attachment to Agenda Item #7 from MCE's May 2, 2019, Technical Committee Meeting, available at https://www.mcecleanenergy.org/wp-content/uploads/2020/01/MCE-Technical-Committee-Packet-May_2019.pdf.

transactions for the purpose of providing its customers with low-cost renewable, carbon free and other energy, while at the same time minimizing risks. MCE procures energy and RA consistent with its Energy Risk Management Policy, which has been developed to ensure that MCE achieves its mission and adheres to policies established by the MCE Board of Directors, power supply and related contract commitments, good utility practice, and all applicable laws and regulations.

(ii) Responsiveness to Regional Policies

MCE is governed by a 36~~34~~-member Board of Directors comprised of elected Councilmembers or Supervisors from its 38 member communities and is committed to benefiting its service area's economy through investments in local infrastructure and energy programs. Though several of MCE's member communities have adopted their own climate, transportation, and/or land use goals or policies, MCE is not aware of any specific policies that require MCE to alter its resource planning or procurement practices at this time, nor is MCE aware of local or regional policies that would affect MCE's risk of RPS compliance at this time. In part, this may be due to MCE's voluntary renewable procurement targets that exceed state requirements and have been developed in conjunction with, and approved by, MCE's governing board.

However, MCE is committed to abiding by all local and regional plan criteria, as adopted by (or on behalf of) its member communities. When applicable, or in the instance that any new policies are enacted by MCE member communities that may affect MCE's resource planning process, MCE will work collaboratively with those communities to ensure continued compliance with the community, MCE, and the State policy goals.

~~**IV.B.1. Long-term Procurement**~~

~~MCE has been committed to supporting new, California-based renewable resource~~

~~development since its inception, and has supported numerous generating assets via execution of long-term contracts. MCE has already executed long-term renewable contracts that are expected to yield approximately 105% of its total RPS/statutory renewable energy requirements (or 162% of MCE's expected RPS-related long-term renewable energy requirements) in 2024. Further, most of the renewable energy supply solicited under MCE's Open Season is intended for projects with proposed delivery terms between ten and twenty years, which bolsters MCE's proportionate use of long-term renewable energy over time. The table below relates projected deliveries under MCE's existing long-term RPS supply contracts to interim annual RPS procurement targets and related long-term contracting requirements.~~

~~Table 2: Projected RPS Deliveries~~

	~~2024~~	~~2025~~	~~2026~~	~~2027~~	~~2028~~	~~2029~~	~~2030~~	~~2031~~	~~2032~~	~~2033~~	~~2034~~
~~Proportionate Long-Term RPS Purchases Relative to Interim Annual Statutory Procurement Mandate~~	~~105%~~	~~113%~~	~~111%~~	~~120%~~	~~126%~~	~~121%~~	~~115%~~	~~109%~~	~~107%~~	~~96%~~	~~94%~~
~~Proportionate Long-Term RPS Purchases Relative to Interim Annual Statutory Long-Term Contracting Requirement~~	~~162%~~	~~174%~~	~~171%~~	~~184%~~	~~194%~~	~~187%~~	~~176%~~	~~163%~~	~~156%~~	~~137%~~	~~129%~~

~~It is clear that MCE's substantial, ongoing commitment to long-term RPS contracting has created significant projected long-term RPS surpluses. As a result of such surpluses, there is virtually no risk of MCE falling short of this aspect of the RPS compliance program.~~

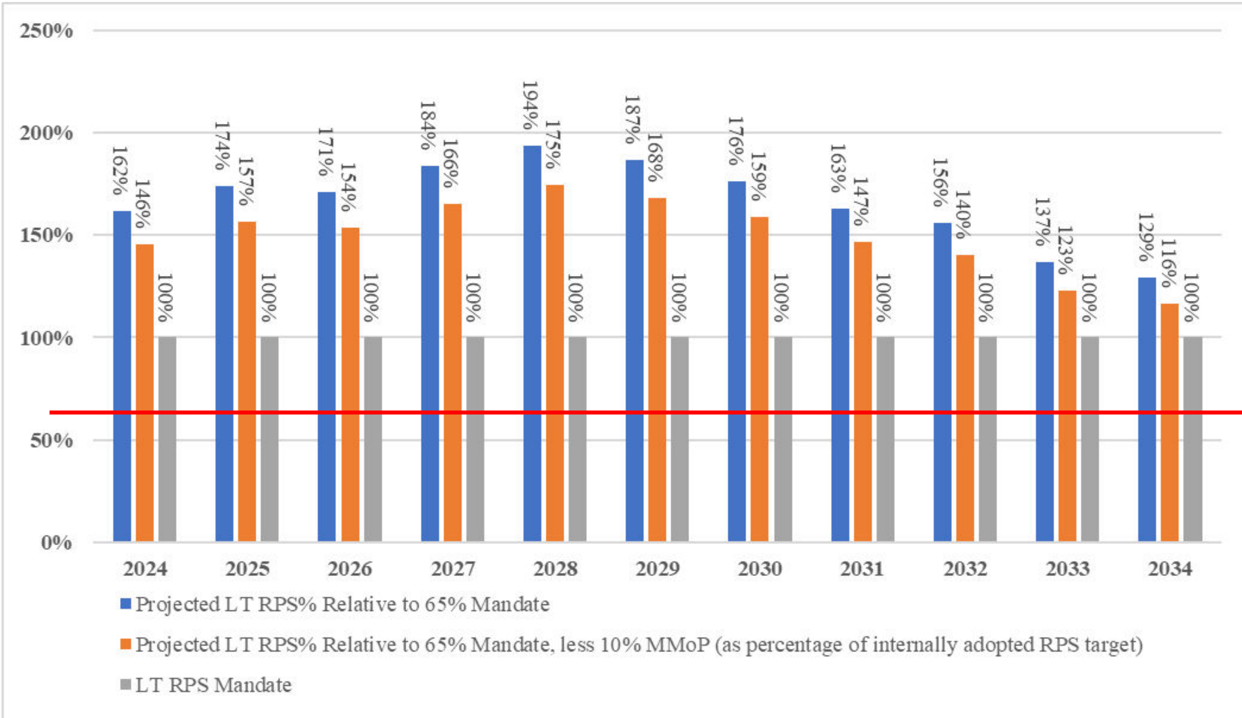
~~Figure 1 also depicts the relationship between California's currently effective long-term RPS contracting mandates and projected deliveries related to MCE's existing long-term RPS contracts, for calendar years 2024 through 2034. The rightmost bar in each grouping reflects~~

~~California's 65 percent RPS contracting mandate as 100 percent of the total long-term contracting requirement. MCE has included two additional bars in each grouping:~~

~~1) An unadjusted projection of MCE's expected annual long-term contract deliveries, relative to the 65 percent mandate. This bar represents the proportionate relationship between MCE's long-term contract deliveries and the statewide procurement mandate. For example, MCE projects that it will surpass the state's long-term contracting requirement by 62 percent in 2024 and is not expecting to fall below 100 percent of its long-term contracting requirement through 2034; and~~

~~2) An adjusted projection of MCE's expected annual long-term contract deliveries relative to the 65 percent procurement mandate. This bar represents the proportionate relationship between MCE's long-term contract deliveries (including an annual reduction in such deliveries equivalent to MCE's established Minimum Margin of Over Procurement (MMoP), which reflects the potential impacts of delivery shortfalls related to resources intermittency, delays in commercial operation, resource curtailment, supply chain issues, and/or other operational issues) and the statewide mandate. MCE believes that this scenario represents a relatively extreme stress case. Nonetheless, MCE would expect to meet or exceed California's long-term contracting mandate through 2034.~~

~~**Figure 1: MCE's Projected Long-Term RPS Contracting Progress: 2024-2034**~~



~~Note that the data underlying this bar chart has been compiled annually, which means that the noted percentages do not reflect the additional compliance flexibility related to California's multi-year compliance periods. For example, if MCE exceeds the long-term procurement mandate by 62% in 2024, it could absorb meaningful delivery shortfalls in the other years encompassing Compliance Period 4 before any compliance deficits arise. Unadjusted projections of MCE's long-term contracting progress suggest that MCE is expected to exceed applicable mandates through the current planning period (2034). Likewise, adjusted projections also suggest that MCE will similarly exceed applicable mandates, even under a relatively extreme stress case such as the one reflected in the previous bar chart. MCE expects to engage in additional long-term contract efforts, which will further increase its long-term RPS positions as well as the compliance buffer already in place.~~

~~**IV.C. Portfolio Diversity and Reliability**~~

~~As part of MCE's forecasting and procurement processes, MCE also considers the deliverability characteristics of its resources including the expected delivery profile, available capacity and dispatchability attributes, if any, associated with each of its generating resource and/or supply agreements and reviews the respective risks associated with short- and long-term purchases. These efforts lead to a more diverse resource mix, address grid integration issues, and provide value to MCE's member communities, including reduced costs and support in achieving planned procurement objectives for the period addressed in this RPS Procurement Plan. A quantitative description of MCE's forecast is attached in Appendix C.~~

~~MCE is interested in emerging and viable technologies to meet the state's reliability needs. MCE's commitment to innovation and the advancement of renewable technologies continues to drive strategic opportunities for the inclusion of emerging technologies within its supply portfolio. The extent to which such technologies will be successful in mitigating conditions of over-supply, production variability and misalignments between energy production and customer use will be monitored over time to ensure that such contractual commitments are promoting desired outcomes.~~

~~MCE will continue to procure renewable and other GHG-free and conventional energy products, as necessary, to ensure that the future energy needs of its customers are met in a clean, reliable, and cost-effective manner. MCE has established proportionate procurement targets for overall GHG-free energy content, including subcategories for renewable energy and other carbon-free products, including related planning reserves.~~

~~In 2020, MCE also implemented an "equivalent carbon-free" portfolio metric, which considers the total emissions associated with each supply source relative to a target annual~~

~~emission factor for its entire supply portfolio. For example, MCE's 95% carbon-free equivalent metric in 2023 allowed an overall portfolio emission factor equal to 5% of the California Air Resources Board's ("CARB") assigned emission factor for energy imports and system power, which is currently set at 0.428 metric tons of carbon dioxide equivalent per megawatt hour ("MT CO_2e"). Expressed differently, the 95% carbon-free equivalent metric limited, on a voluntary basis, MCE's emissions to an overall portfolio emission factor of 0.021 MT CO_2e. As reflected in its current draft 2023 PSD report for Light Green service[33], MCE's 2023 emission factor of 0.002 MT CO_2e was below the organization's 95% carbon-free equivalent emission target (reflecting an approximate 99% carbon-free equivalency for the Light Green portfolio. The emission factor for Deep Green, Local Sol and Green Access service, as reflected in the respective 2023 PSD reports for each retail service offering, was zero.~~

~~As certain renewable generating technologies are known to have relatively low levels of emissions, such as certain geothermal generating technologies, MCE's equivalent carbon-free metric captures such impacts, along with any other use of carbon-emitting supply, including system power and CARB-certified Asset Controlling Supply, to derive its proportionate use of carbon-free generation. To the extent that MCE's energy needs are not fulfilled using renewable or other GHG-free generating resources, it should be assumed that such supply will be sourced from conventional energy sources, such as natural gas generating technologies or system power purchases. MCE also plans to maintain its carbon-free equivalent metric at 95% of total supply in 2024 and beyond, meaning it will be further constrained in utilizing any carbon-emitting sources,~~

~~[33] The due date for California's 2023 Power Source Disclosure Report is July 29, 2024. MCE is still finalizing the report for Light Green service and will update the Commission (within its Final 2024 RPS Procurement Plan) if there are any material deviations from the information presented herein.~~

~~including certain renewable generating technologies. As such, MCE will continue to creatively address the exercise of resource planning and portfolio composition to meet or exceed the aforementioned carbon-free equivalency metric.~~

~~MCE uses a portfolio risk management approach in its power purchasing program, seeking low-cost supply (based on then-current market conditions) as well as diversity among technologies, production profiles, project sizes and locations, counterparties, lengths of contract, and timing of market purchases. These factors are taken into consideration when MCE engages the market and pursues related procurement activities.~~

~~A key component of this process relates to the analysis and consideration of MCE's forward load obligations and existing supply commitments with the objectives of closely balancing supply and demand, cost/rate stability and overall budgetary impacts, while leaving some flexibility to take advantage of market opportunities and/or technological improvements that may arise over time. MCE's long-term load forecast is a projection of the energy (reflected in MWh) that its customers will consume annually. MCE's long-term load forecast is driven primarily by the number and types of customers that MCE expects to serve, in conjunction with weather projections. Hourly class-specific load profiles are then used to break down the monthly energy forecast into more granular time-of-use and peak demand values. MCE's long-term load forecast also incorporates the load-modifying effects of electric vehicles, behind-the-meter solar and/or storage (via net energy metering), and energy efficiency.~~

~~A key component of the long-term load forecast includes the projections for transportation electrification load, the methodology for developing this forecast is described as follows:~~

~~MCE's load forecast is adjusted for expected increases due to electric vehicle ("EV") adoption. In order to estimate the impact of EV adoption on MCE's load forecast, MCE utilizes~~

~~the CEC's Integrated Energy Policy Report as the basis for the estimates. MCE utilizes the state's mid-demand scenario, adjusting the forecasted EV load based upon two factors: 1) EV adoption rates within MCE's service territory and 2) Participation rates within MCE's service territory. CA Department of Motor Vehicle registration data is utilized to estimate the territory's share of the state's forecasted EV load growth, and internal customer data sources are utilized to adjust for MCE participation rates. MCE's EV load growth forecast does not segment by vehicle types, but rather adjusts the state's total EV load based upon penetration levels.~~

~~MCE monitors its open positions separately for each renewable generating technology as well as GHG-free resources, conventional resources, and its aggregate supply portfolio. MCE maintains portfolio coverage targets of up to 100% of expected customer energy requirements in the near-term (0 to 2 years), and typically leaves gradually larger open positions in the mid- to long-term, consistent with generally accepted industry practices. However, those larger open positions are continuously monitored for weather, market changes and resource availabilities, and filled in a non-linear fashion as determined by MCE management. For example, MCE may fill residual summer positions ahead of the spring season or through procurements administered during the previous calendar year.~~

~~MCE prefers zero emission generating technologies, but within this preference MCE is largely technology-agnostic, subject to the previously discussed carbon-free equivalency metric.~~[34] ~~MCE's supply preferences are intended to exhibit diversity across a broad range of renewable technologies that will deliver energy in a profile that is generally consistent with MCE's anticipated load shape. MCE is aware that significant use of intermittent renewable generating~~

[34] ~~As mentioned above, MCE has a policy of not pursuing resource-specific nuclear power purchases.~~

~~technologies has the potential to create misalignments between customer energy consumption and related power production; however, MCE regularly evaluates customer usage in light of expected renewable deliveries to reduce such risks and inform future procurement decisions. Furthermore, MCE continues to consider procurement opportunities with renewable generating facilities that will utilize storage technology, which can materially re-shape the typical delivery profile associated with intermittent renewable generating assets, providing the opportunity for MCE to more accurately balance supply and changing customer demand, particularly due to the potential expansion of transportation electrification. MCE is also considering stand-alone energy storage opportunities to "recontour" purchased energy volumes in a manner that better matches changing customer usage patterns. MCE has determined that such projects are comparatively costly (due to infrastructure costs and, in the case of battery storage projects, losses stemming from the common charge/discharge cycle of such projects). In 2024, approximately 10.8 percent of MCE's total retail sales were expected to come from transportation electrification load in MCE's service territory, and this number is projected to increase to 17.4 percent of MCE's total retail sales in 2034. MCE currently offers a managed EV charging app, MCE Sync, which helps customers automate EV charging and shift consumption away from peak periods.[35] Additionally, MCE offers several programs to manage its load shapes and better align MCE's supply resources with hourly demand. These programs include, but are not limited to: MCE's Peak FLEXmarket,[36] Time of Use ("~~TOU~~") rates,[37] and MCE's revised Feed-In-Tariff ("~~FIT~~") Plus program,[38] that requires the addition of storage equal to 180% of the generator's nameplate capacity, and enables generation to be shifted~~

~~[35] *See* https://www.mcecleanenergy.org/mce-sync/.~~
~~[36] *See* https://mcecleanenergy.org/peak-flex-market/.~~
~~[37] *See* https://mcecleanenergy.org/what-is-the-time-of-use-rate-plan/.~~
~~[38] *See* https://www.mcecleanenergy.org/feed-in-tariff/.~~

~~outside of normal solar production hours to better align MCE resources to match the hourly load.~~[39]

~~Recent market data continues to indicate that midday peak resources are likely to comprise a larger proportion of California's renewable supply portfolio due to the rapid decline in wholesale prices for solar PV generation and the abundance of such projects in operation and under development. Additions to MCE's portfolio during the Planning Period will likely be more heavily weighted toward energy resources – dispatchable, shaped during non-solar or ramping periods, or otherwise – that complement competitively priced solar already under contract or pair new solar projects with storage technologies to avoid exacerbating midday over-supply. MCE may also engage in purchases from as-available renewable generation (*e.g.*, wind) to the extent that such supply is competitively priced or otherwise provides electricity during time of day when existing supply commitments are currently lacking. Additionally, MCE is working with developers of its solar projects already under contract to add storage to those existing resources to increase the number of dispatchable resources in its portfolio. In regard to project location, MCE places the greatest value on locally-sited renewable generating and storage projects, particularly those located in its service area or within approximately 100 miles thereof. In general terms, the next highest preference related to resource selection are projects sited within the California Independent System Operator's ("CAISO") North of Path 15 Zone (generally, Northern California), followed by projects elsewhere in California, and lastly, out-of-state resources. This procurement strategy has led MCE to achieve its desired clean energy portfolio objectives as well as cost-competitive customer rates.~~

[39] ~~*See* Agenda Item #06 from MCE's December 2, 2021, Technical Committee Meeting, available at https://www.mcecleanenergy.org/wp-content/uploads/2021/11/MCE-Technical-Committee-Packet-December_2021.pdf.~~

~~Regarding new and emerging technologies, MCE has a special interest in using offshore wind, long duration battery storage and green hydrogen storage for building a carbon free portfolio for its customers and providing reliability to the grid. These technologies provide opportunities to shape MCE's hourly portfolio to match the hourly demand. MCE has provided several letters of intent with the potential to get into long term agreements once the technology is commercially viable to developers of new and emerging technologies. MCE intends to continue this approach in the future~~

IV.D. Lessons Learned – Assessment of RPS Portfolio Supplies and Demand

MCE's operating history confirms that diversity among renewable energy commitments is highly desirable. This diversity encompasses a broad range of considerations, including the use of various fuel sources, resource locations, contract durations, product specifications, pricing mechanisms, solicitation timing and frequency, among other differences. Early-stage discipline in renewable energy contracting allowed for MCE's solar energy commitments to gradually move down a declining cost curve, which avoided over-weighting the portfolio with an abundance of costly contracts. As California's energy landscape continued to evolve, a concentration of renewable generating assets in certain locations reinforced the benefits of geographic diversity – as certain areas of the state were overbuilt with renewable generating infrastructure, challenges related to depressed market prices and related resource curtailments began to surface and will likely continue to exist for quite some time.[40] There have also been challenges associated with

[40] It is noteworthy, however, that economic curtailment may not be feasible for certain retail sellers when considering the financial implications of long-term contract delivery shortfalls imposed under the RPS Program. Considering such significant financial charges, certain retail sellers may be forced to accept deliveries from renewable generating assets during instances of significant negative pricing to ensure that requisite long-term contracting quantities are satisfied. This could result in higher-than-anticipated renewable energy costs and related impacts to customer rates.

transmission and deliverability of projects which can impact project viability. These observations have contributed to a more rigorous evaluation process for new generating projects, e.g., analyzing congestion patterns at specific locations, understanding the risks related to obtaining Maximum Import Capability ("MIC") for out-of-state projects and getting more involved in the CAISO regulatory processes for transmission and interconnection to understand the risks associated with transmission and deliverability for specific projects, which is expected to reduce risks associated with such issues. While historical market pricing and transmission issues are not perfect predictors of future performance, attempting to understand past trends helps to mitigate potential adverse financial consequences during near-term operation of such facilities. In addition, MCE analyzes anticipated project development in a geographic area as well as planned network upgrades in the CAISO's Transmission Planning Process.

MCE has also adapted to how distinct California energy programs interact with one another. ~~Assembly Bill ("~~AB~~")~~ 1110 (stats. 2016) has devalued and, ostensibly, discouraged the use of certain renewable energy products (allowed for use under California's RPS Program) because of how associated emissions are accounted for under the PSD Program. Changes to PSD Program regulations related to AB 1110 attribute an emissions factor equivalent to system power to any PCC2 and PCC3 volumes. In addition, PCC3 certificates are not presented as renewable purchases during power source accounting. This change has led MCE and various other CCAs to forgo or minimize the use of PCC2 and PCC3 products to avoid representing an inflated emissions factor and the potential public/customer perception that reported renewable energy content is lower than required under California's RPS Program or related policy commitments of the retail seller. This adaptation to MCE's planning and procurement practice became necessary even though such products are deemed eligible for use under California's RPS Program. As such MCE will endeavor to source all renewable energy purchases from PCC1 products but may, in isolated instances, procure small quantities of PCC2 products when unanticipated renewable energy delivery shortfalls, higher than expected retail sales and/or prevailing market conditions necessitate such purchases. Exhibiting strong preferences for PCC1 products is expected to increase costs and customer rates but will promote MCE's achievement of emission-related portfolio objectives.

V. Project Development Status Update

As described in Section IV.B above, MCE's current and planned procurement is sufficient to meet both the applicable RPS procurement requirements as well as support the state's GHG reduction targets. Further, MCE's current and planned procurement supports system reliability by considering ~~both~~ portfolio diversity, mid-term reliability requirements, and alignment with MCE customers' load curve.

As of this filing, MCE has entered into three long term ~~twelve utility-scale~~ contracts with utility-scale RPS-eligible ~~renewable energy~~ resources that are not yet commercially operational, each~~. Eight~~ of which is a ~~these twelve contracts are~~ large utility-scale project. MCE also has long term PPAs for deliveries from three smaller renewable ~~projects, while the remaining four are smaller~~ projects, less than 5 MWs, that were selected through MCE's Feed-In-Tariff ("FIT") program or DAC-GT Program – all of which are in development.~~.~~ The following table 7 shows a list of the most recent projects added to MCE's portfolio that MCE is using for RPS and/or IRP purposes to support MTR requirements, RPS, and IRP reliability and emissions goals. Each of the projects listed below~~that~~ are either in development or have come online in the last two years to support MCE RPS and IRP-related needs~~year~~.

[redacted]

[redacted]

There are also several smaller scale projects with contract capacities below 5 MWs. [redacted]

MCE has updated the RNS template and the Cost Quantification templates to reflect projects listed in Table 7 below.[41] MCE intends to keep the Commission informed of the progress on these projects through the various monthly and quarterly reports on project status.

[41] The RNS template includes each of the resources in Table 7, with the exception of any stand-alone battery storage resources as they are not RPS eligible. However, MCE lists them in Table 7 below as they are otherwise procured as part of MCE's larger procurement strategy.

Table 7: MCE Project Development Status~~**Table 3: MCE Project Development Status**~~

Facility Name	**Technology Type**	**MW-ac**	**MTR Project**	**Location (County in CA)**	**COD**	**Length of Contract (Years)**	**Network Upgrades Milestone**
Daggett Solar	Solar + Storage	110 PV/60 Storage	Yes	San Bernadino	8/25/2023	15	Completed
Golden Fields Solar IV, LLC	Solar + Storage	100 PV/92 Storage	Yes	Kern	8/16~~6/1~~/2025	15	Completed ~~In progress~~
Strauss Wind Project	Wind	93.35~~[42]~~	Yes	Santa Barbara	12/20/2023	15	Completed
Humboldt House	Geothermal	20	Yes	Pershing, NV	2028 (anticipated)~~6/30/2025~~	21	In Progress
Geysers (7MW)	Geothermal	7	Yes	Sonoma	6/1/2025	20	Completed
Key~~43~~	8-Hour Battery Storage	35	Yes	Fresno	6/1/2027	15	Completed ~~In Progress~~
Cormorant~~44~~	Battery Storage	188	Yes	San Mateo	6/1/2026	15	Completed~~In Progress~~
Corby~~45~~	Battery Storage	100	Yes	Solano	4/1/2027	15	Delayed
Allium Hybrid	Solar + Storage	110 PV/110 Storage		San Benito	5/1/2031	20	In progress
Conflitti	Solar	4.4	No	Fresno	3/31/2026	20	In progress
Conflitti Jr.	Solar	.24	No	Fresno	3/31/2026	20	In progress
Fallon Two Rock Rd Solar Farm	Solar	0.96	No	Marin	1/29/2024~~12/31/2023~~	20	Completed
Ranch Sereno	Solar	2 PV/.8 Storage	No	Fresno	12/31/2025 ~~Delayed~~	20	In progress

MCE's Large Scale ~~Renewable~~ Projects

There are a total of nine~~eight~~ large scale new build projects with contract capacities between 7 MWs at the lower bound and a combined 110~~100~~ MW Solar/188~~92~~ MW Storage at the upper bound, which includes six RPS-eligible projects and three non-RPS-eligible projects. The six RPS-eligible,~~. These projects are listed in the first eight rows in Table 3 above. In total, the eight~~ projects are expected to produce approximately 1,463,560~~131,000~~ MWh annually~~. Two~~ of RPS eligible energy. Three of the projects (~~,~~ Daggett Solar,~~and~~ Strauss Wind Project and Geysers)~~,~~ have already achieved commercial operation, while the remaining three renewable ~~six~~ projects are in development. MCE plans to use all nine~~eight~~ of these projects ~~to count~~ towards its IRP-related ~~obligation for the MTR~~ procurement needs. ~~mandates.~~ [redacted]

~~There are also several smaller scale projects with contract capacities below 5 MWs.~~ [redacted]

~~[42] MCE hasn't yet executed a formal amendment that reduces the overall capacity of the project.~~

~~[43] This is a stand-alone battery storage project that is not RPS-eligible. This resource is being provided to demonstrate additional, non-RPS MCE procurement that is in alignment with IRP needs.~~

~~[44] This is a stand-alone battery storage project that is not RPS-eligible. This resource is being provided to demonstrate additional, non-RPS MCE procurement that is in alignment with IRP needs.~~

~~[45] This is a stand-alone battery storage project that is not RPS-eligible. This resource is being provided to demonstrate additional, non-RPS MCE procurement that is in alignment with IRP needs.~~

[redacted]

~~MCE has updated the RNS template related to these projects and the Cost Quantification templates. Furthermore, MCE intends to keep the Commission informed of the progress on these projects through the various monthly and quarterly reports on project status.~~

MCE's Feed-In-Tariff projects

MCE's FIT program allows developers to finance local renewable energy projects, while catalyzing local job creation associated with the construction, operation, and maintenance of these local projects.[46] By providing attractive, above market rates, this program incentivizes renewable development in MCE communities where it otherwise would not be built. To date, MCE's FIT program has supported the completion of twenty-four locally situated, small scale renewable generating projects, which are currently producing electricity that is purchased by MCE under long-term contracts. One FIT project is currently under development as of the date of this filing.

MCE has also attached an updated version of the Project Development Status Update Report as Appendix D.

VI. Potential Compliance Delays

MCE has received favorable determinations of compliance relating to Compliance Period 1, Compliance Period 2, and Compliance Period 3, which indicate that "MCE met its RPS

[46] *See* https://www.mcecleanenergy.org/feed-in-tariff/.

compliance obligations" during such periods. MCE expects similar determinations related to Compliance Period 4, which includes calendar years 2021-2024, as well as future compliance periods. This perspective is based on MCE's past success in meeting RPS compliance mandates as well as MCE's internally adopted, above-RPS renewable energy targets and procurement activities as well as actual renewable energy deliveries and projections,~~received to date (within Compliance Period 4),~~ which seem to indicate~~show (on a projected basis) that~~ the organization is tracking well ahead of schedule in satisfying applicable RPS mandates.

Regarding long-term contracting compliance, and as discussed above, MCE has secured long-term contract commitments sufficient to meet the noted requirements throughout the planning period~~through 2034~~, even in the event of potential delivery shortfalls equivalent to MCE's adopted MMoP.

VII. Risk Assessment

MCE closely monitors development and operational risks associated with its planned and existing renewable energy supply commitments to minimize the potential for significant variances between actual and expected renewable energy deliveries.

VII.A. Compliance Risk

An important element of MCE's RPS risk assessment process is determining potential vulnerabilities related to procurement and/or delivery shortfalls that could trigger deficits relative to MCE's anticipated compliance obligations. Considering MCE's internally adopted renewable energy procurement targets and existing contractual commitments, this risk, as internally determined by MCE, appears to be very low. As discussed throughout~~elsewhere in~~ this plan~~planning document~~, MCE has established a Voluntary Margin of Over-Procurement ("VMoP") and, further, a MMoP that inform RPS procurement efforts and ensure against compliance-related shortfalls. If there is any change in terms of MCE's internal assessment of RPS compliance risk, MCE will inform the CPUC accordingly in a future RPS Procurement Plan.

VII.B. Risk Modeling and Risk Factors

MCE has established a Risk Oversight Committee ("ROC"), which regularly convenes to discuss conformance of MCE's ongoing planning and procurement efforts with the organization's adopted Energy Risk Management Policy ("ERM Policy"). MCE's ERM Policy was developed for purpose of creating and maintaining controls and processes that will mitigate potential exposure to various sources of risk, including market price risk, counterparty credit and performance risk, load and generation (volumetric) risk, operational risk, liquidity risk and policy (*e.g.*, legislative and regulatory) risk.

To the extent that higher-than-expected renewable energy open positions, counterparty over-exposure, meaningful load variations or other pertinent planning observations are identified during meetings of the ROC, MCE adjusts procurement activities to address these concerns, which promotes ongoing compliance with its ERM Policy. Should any significant ERM Policy deviations be identified, MCE staff would inform its Governing Board before pursuing corrective action. MCE's risk assessment and management practices are described in greater detail ~~in Section VII,~~ below.

In general terms, MCE's process for minimizing and avoiding risk is deterministic in nature and begins with the development of bid requirements and evaluative preferences for solicitations. MCE's solicitations are intended to identify suppliers that have demonstrated a strong track record of successful project completion and ongoing project operation. Such counterparties are more likely to timely complete project development activities and successfully operate projects placed under contract, and therefore minimize project risks. This process has yielded strong results: the pool of responses to MCE-administered solicitation is generally robust; the quality of short-listed respondents is high and typically includes very experienced bidders with strong project development track records; the short-listed candidates, by virtue of their considerable project development and/or operational experience, tend to be efficient contract negotiators; and the resulting contracts have generally led to project deliveries that meet MCE's expectations.

Key risk factors are considered during evaluation of each prospective renewable energy seller, including counterparty credit rating and general financial standing; California-based project development experience; prior experience with CCA off-takers; commercial viability of the proposed generating technology; and progress towards key development milestones such as interconnection status, deliverability studies, siting, zoning, permitting, and financing requirements. With regard to transmission adequacy, MCE ensures that each project has an executed interconnection agreement with the appropriate participating transmission operator prior to contract execution so that the project's interconnection costs, deliverability and timelines are known to the extent possible. MCE also conducts a review of interconnection queues and transmission planning in the area to understand impacts of planned projects and transmission upgrades. The project review process also includes a thorough review of the permitting status from the permitting authority and must demonstrate a path to completion. A selected seller bears risk of supply chain delays impacting the seller's ability to meet its guaranteed contractual milestones on time, subject to permitted extensions and allowable Force Majeure provisions in the contract.

To the extent that a prospective renewable energy procurement opportunity comes to fruition, and a contract is executed, development milestones are rigorously monitored by MCE's contract management staff, who regularly communicate with the project sponsor throughout the development and construction processes.

MCE also seeks to minimize unnecessary financial exposure and general planning risk by assembling a diversified portfolio of renewable generating resources and products that are intended to complement the way its customers use electric power. To promote this alignment of supply and demand, MCE analyzes the impacts of proposed renewable energy deliveries to its aggregate resource portfolio relative to expected customer energy use as part of its evaluation process. To the extent that the proposed delivery profile would create undesirable net-short or net-long positions, alternative product options will continue to be evaluated. MCE may also pursue contract structures that promote volumetric stability through firm delivery quantities and/or performance guarantees that provide for financial remedies/penalties in the event of delivery shortfalls. If necessary, the financial remedies received by MCE could be used to: (1) as a first priority, procure additional renewable energy supply to address delivery shortfalls; or (2) in the event that the delivery shortfall caused MCE to be found non-compliant, offset the cost of related penalties. MCE's intent is to exceed compliance with applicable RPS mandates, and the latter option is a last resort that is not expected to apply.

Additionally, MCE believes that it is important to manage temporal risks associated with: (1) disproportionate exposure to prevailing market conditions at any particular point in time; and (2) lack of diversity related to contract start dates, end dates or term lengths within a renewable energy supply portfolio. MCE has regularly administered renewable energy solicitations throughout its operating history to ensure that its exposure to ever-changing market conditions is diversified, similar to the "dollar cost averaging" methodology that is regularly employed within the financial sector.

While attempts to "time the market" may occasionally yield short-lived benefits, such results are generally not reliable and create the potential for significant risk and financial consequences if market conditions quickly and/or significantly change. MCE's deliberate contracting approach entails "sampling" the market at regular intervals, avoiding large contractual commitments in high-priced environments or missed opportunities in low-priced environments. MCE also ensures that its contract start/end dates and related term lengths are staggered to avoid planning "cliffs" that could occur if contracts of similar lengths and start dates were all executed at the same time. The assembly of short-, medium- and long-term contracts further diversifies risk within MCE's renewable supply portfolio, and while increased long-term RPS contracting requirements will inevitably increase such risks, MCE will continue to pursue portfolio diversity by thoughtfully considering these temporal considerations during ongoing procurement processes.

MCE utilizes a quantitative risk assessment that evaluates the energy impacts related to supply side losses. This approach organizes prospective risks into three general categories which pose the greatest supply-side impacts to the delivery of expected RPS energy: 1) curtailment risk; 2) resource intermittency risk; 3) counterparty risk; and 4) project cancellation risk. As part of its quantitative risk assessment, MCE examines hourly forward-looking price data and historical CAISO data to quantify curtailment risk. Considering MCE's current long-term renewable energy positions that are well in excess of requirements, a reduction in long-term RPS volumes due to curtailment is unlikely to compromise the prospect of RPS compliance. The figures presented in the column quantifying curtailment risk in Table 8~~4~~ at the end of this section are calculated by quantifying the volume of ~~expected~~ energy deliveries expected to occur during the balance of each contract's respective delivery period. This~~and multiplying such~~ volume is then multiplied by the likelihood of curtailment (expressed as a proportionate reduction in total deliveries),~~,~~ which varies by contract in consideration of~~resource based on~~ MCE's historical observations related to~~regarding~~ generator performance and expected performance in the future. In consideration of the increased curtailment of wind and solar resources within CAISO over the past several years~~36 months~~, MCE has assumed a minimum baseline curtailment adjustment for certain contracts within its portfolio that may be curtailed in consideration of prospective negative price risk. *Based on MCE's assessment of curtailment risk associated with its renewable energy contract portfolio, this risk category was assigned a rating of medium.* When compared to the similar categorical risk assessment presented in MCE's 2024*~~MCE has increased the current risk rating related to curtailment, relative to its Final 2023~~ RPS Procurement*, this risk rating remains unchanged. *~~Plan, in consideration of the aforementioned increases in wind and solar curtailments in CAISO.~~*

Intermittency risk has become increasingly prevalent in the wake of ongoing renewable infrastructure buildout. In particular, California's substantial reliance on photovoltaic solar and wind generating facilities introduces intermittency risk for any retail seller procuring power from such projects. Such risks ought to be accounted for as part of a thoughtful quantitative risk assessment to ensure the identification of sufficient planning reserves. The following describes MCE's methodology for assessing intermittency risk. As new intermittent facilities are developed to meet the procurement burdens of increasing regulatory requirements, the risk of variances between projected and actual energy deliveries is amplified. Quantifying intermittency risk is largely dependent on available data, as each generating facility is unique (geographically, operationally, etc.). As data is gathered from facilities comprising an RPS supply portfolio, planning adjustments can be incorporated to account for variances between actual and expected historical deliveries, allowing the retail seller to incorporate adjustments in its resource planning and procurement assumptions to counteract such risk. During the early stages of any delivery period, however, data is often lacking so planning adjustments are more challenging to quantify and must be based on reasonable estimates derived by observing similar projects. Over time, as meaningful amounts of historical data are compiled, MCE should be able to make increasingly accurate adjustments to its planning assumptions to ensure that procured RPS volumes are more accurately aligned with anticipated needs.

Despite these challenges, MCE believes that intermittency risk can be reasonably quantified when available operating history reaches two years or more. Before substantive historical data becomes available, other information must be considered in assessing intermittency risk, including input from the asset owner/operator, insight derived from the operating history associated with similar generating facilities, and limited historical data (that can be applied to generate interim intermittency assessments). Once a generating facility has established steady-state operations, intermittency risk can be quantified by dividing the amount of actual energy received by the amount of expected energy for each year of a given contract, then averaging observed variances across each year of the available operating history. The resulting percentage is multiplied by the remaining expected energy deliveries under the contract to approximate potential delivery deficits related to intermittency. For facilities with limited operating history and/or facilities that have yet to achieve commercial operation, MCE imputes proxy intermittency adjustments to ensure conservatism in RPS planning assumptions. For example, if MCE's experience with smaller-scale photovoltaic solar generating facilities (e.g., facilities at or below 10 MW of nameplate capacity) suggests that actual generation typically falls within negative two percent of projections, MCE will apply a negative two percent intermittency adjustment to generating facilities falling within this category. Similarly, if MCE has observed that mid-sized wind generating facilities (e.g., wind generating facilities between 20 and 100 MW of nameplate capacity) occasionally produce ten percent less energy than projected in certain calendar years, it will apply a negative ten percent intermittency adjustments to generating facilities within this category. Again, this approach promotes a conservative RPS planning process and should avoid unexpected delivery shortfalls related to resource variability for intermittent generating sources. Employing this intermittency analysis is also helpful in identifying especially risky contracts, which in turn assists MCE in determining which facilities must be closely monitored throughout the contract delivery term. As alluded to above, as more data becomes available, intermittency risk metrics can be updated to more accurately reflect the performance of certain generating facilities over time. *Based on MCE's assessment of intermittency risk associated with its renewable energy contract portfolio, this risk category was assigned a rating of low.* MCE believes that its MMoP serves as an important mitigating strategy in addressing potential delivery shortfalls related to resource intermittency. MCE also notes that its VMoP, which significantly exceeds applicable RPS procurement mandates, serves as mitigating mechanism for any compliance risk related to resource intermittency as typical intermittency levels fall well below MCE's VMoP.

Counterparty risk is the risk posed by a counterparty being unable or unwilling to honor its total RPS delivery obligations, as reflected in related contract documents. MCE has quantified this likelihood by considering S&P Global's~~,~~ Global Corporate Annual Default Rates by Rating Category (%) as a measure of organizational viability and financial stability. While this rate considers industries beyond the energy sector, it provides relevant insights into the correlation and potential impacts of dealing with uncreditworthy counterparties. The likelihood of default by credit rating was averaged over the years from 2014 to 2019. These years were chosen to remove irregularities in default rates during the Covid-19 pandemic; though no material impacts to MCE's risk assessment are anticipated, MCE expects to update the time period associated with its default by credit rating assessment during completion of the 2026 planning process and may shift the aforementioned time period forward to include other/additional years.~~.~~ If a counterparty was found to be unrated, then the contract was reviewed to identify specified credit assurances; based on such assurances, an approximate rating was derived based on MCE's experience and risk tolerance. *Based on MCE's assessment of counterparty risk associated with its renewable energy contract portfolio, this risk category was assigned a rating of low.* The final category reflected in MCE's analysis is project/contract cancellation risk. This category is distinct from counterparty risk because the risk of project/contract cancellation may only affect a single project under a counterparty's portfolio. Projects may be cancelled for a variety of reasons, but in today's market, deals struck many months ago may no longer be economic for the seller. This risk only effects single source projects which have yet to be constructed. These projects were chosen because they have a single point of failure unlike RPS energy purchased from a pool of resources (under a portfolio-style purchase agreement in which there is generally more diversity amongst the sources of supply). Based on discussions with various counterparties, other load serving entities and its own experience, MCE has assessed that this risk affects~~effects~~ roughly 1 in 20 deals (with such circumstances generally applying to less experienced and/or reputable suppliers).~~.~~ *Based on MCE's assessment of project/contract cancellation risk associated with its renewable energy contract portfolio, and the high-quality counterparties which comprise MCE's list of suppliers, this risk category was assigned a rating of low.*

Considering these categories holistically, MCE was able to derive a cumulative energy percentage at risk. In consideration of MCE's relatively conservative risk tolerances, a top-level risk of non-delivery offset at 0.25% of renewable energy procurements was added to the calculated energy at risk percentage. This adder will help to account for risks that MCE cannot foresee and will help to guarantee the sufficiency of MCE's planned RPS purchases in meeting both compliance-related and internally adopted renewable energy procurement targets. The percentage of renewable energy and error is the percentage of total renewable energy procured that was determined to be at risk, while the percentage of retail load is the energy at risk as a percentage of retail load. These "at risk" percentages reflect possible losses which, through no fault of MCE, may occur by virtue of being a market participant. These losses pose a risk for non-compliance relative to MCE's RPS goals and targets. Since this number is not a guaranteed loss, MCE will implement the previously mentioned mitigation strategies to give the greatest chance of meeting its adopted renewable energy procurement targets.

Table 8~~4~~: MCE Contract Curtailment, Counterparty, and Project Cancellation Risk

			Delivery & Market Risks			
ID	**Contract**	**Energy to be Delivered to Market (MWh)**	**Curtailment Risk (MWh)**	**Counterparty Risk (MWh)**	**Intermittency Risk (MWh)**	**Project Cancellation Risk (MWh)**
~~1~~	~~Contract 333~~	~~183,851~~	~~7,354~~	~~1,839~~	~~-~~	~~-~~
~~2~~	~~Contract 334~~	~~104,557~~	~~4,182~~	~~1,046~~	~~-~~	~~-~~
~~4~~	~~Contract 336~~	~~263,040~~	~~10,522~~	~~2,630~~	~~-~~	~~-~~
~~6~~	~~Contract 337~~	~~246,434~~	~~9,857~~	~~2,464~~	~~-~~	~~-~~
7	Contract 342	906,989~~965,261~~	36,280 ~~38,610~~	9,070~~653~~	90,699 ~~96,526~~	- ~~-~~
8	Contract 343	386,291~~334,581~~	15,452 ~~13,383~~	3,863~~346~~	- ~~-~~	- ~~-~~
9	Contract 491	3,463,882~~160,196~~	138,555 ~~126,408~~	34,639 ~~31,602~~	346,388 ~~316,020~~	- ~~-~~

10	Contract 492	24,219~~22,000~~	969 ~~880~~	242 ~~220~~	484 ~~440~~	-~~-~~
11	Contract 494	5,857~~500~~	234 ~~220~~	59 ~~55~~	117 ~~110~~	-~~-~~
12	Contract 496	3,144,948~~2,762,023~~	125,798 ~~110,481~~	31,449 ~~27,620~~	314,495 ~~276,202~~	-~~-~~
13	Contract 497	21,275~~19,800~~	851 ~~792~~	213 ~~198~~	425 ~~396~~	-~~-~~
14	Contract 498	21,275~~19,800~~	851 ~~792~~	213 ~~198~~	425 ~~396~~	-~~-~~
15	Contract 499	2,318,298~~603,291~~	92,732 ~~104,132~~	23,183 ~~26,033~~	46,366 ~~52,066~~	-~~-~~
16	Contract 500	1,317,030~~156,153~~	263,406 ~~231,231~~	13,170 ~~11,562~~	26,341 ~~23,123~~	-~~-~~
17	Contract 501	426,286~~578,077~~	85,257 ~~115,615~~	4,263 ~~5,781~~	8,526 ~~11,562~~	-~~-~~
18	Contract 502	722,066~~1,445,193~~	144,413 ~~289,039~~	7,221 ~~14,452~~	14,441 ~~28,904~~	-~~-~~
19	Contract 503	2,039,327~~1,445,193~~	407,865 ~~289,039~~	20,393 ~~14,452~~	40,787 ~~28,904~~	-~~-~~
20	Contract 505	12,980~~14,630~~	519 ~~585~~	130 ~~146~~	260 ~~293~~	-~~-~~
21	Contract 507	522,652~~722,558~~	20,906 ~~28,902~~	5,227 ~~7,226~~	52,265 ~~72,256~~	-~~-~~

22	Contract 586	123~~290~~,100	-~~-~~	1,231 ~~2,901~~	2,462 ~~5,802~~	-~~-~~
23	Contract 853	41,495~~28,581~~	1,660~~143~~	415 ~~286~~	830 ~~572~~	-~~-~~
24	Contract 855	41,495~~28,581~~	1,660~~143~~	415 ~~286~~	830 ~~572~~	-~~-~~
25	Contract 856	38,926~~29,099~~	1,557~~164~~	389 ~~291~~	779 ~~582~~	-~~-~~
26	Contract 886	38,926~~29,099~~	1,557~~164~~	389 ~~291~~	779 ~~582~~	-~~-~~
27	Contract 887	38,926~~29,099~~	1,557~~164~~	389 ~~291~~	779 ~~582~~	-~~-~~
28	Contract 1001	40,444~~27,887~~	1,618~~115~~	404 ~~279~~	809 ~~558~~	-~~-~~
29	Contract 1002	40,444~~27,887~~	1,618~~115~~	404 ~~279~~	809 ~~558~~	-~~-~~
30	Contract 1035	31,978~~22,407~~	1,279 ~~896~~	320 ~~224~~	640 ~~448~~	-~~-~~
31	Contract 1068	460~~552~~	18 ~~22~~	5 ~~6~~	9 ~~11~~	-~~-~~
32	Contract 1070	22,332~~18,220~~	893 ~~729~~	223 ~~182~~	447 ~~364~~	-~~-~~
33	Contract 1071	460~~552~~	18 ~~22~~	5 ~~6~~	9 ~~11~~	-~~-~~

34	Contract 1679	349,077~~299,026~~	13,963 ~~11,961~~	3,491 ~~2,990~~	6,982 ~~5,981~~	- ~~-~~
35	Contract 1680	480,134~~326,210~~	19,205 ~~13,048~~	4,801 ~~3,262~~	9,603 ~~6,524~~	- ~~-~~
36	Contract 1681	37,022~~27,184~~	1,481~~087~~	370 ~~272~~	740 ~~544~~	- ~~-~~
37	Contract 1685	228,914~~187,139~~	9,157 ~~7,486~~	2,289 ~~1,871~~	4,578 ~~3,743~~	- ~~-~~
38	Contract 1686	50,576~~42,761~~	2,023 ~~1,710~~	506 ~~428~~	1,012 ~~855~~	- ~~-~~
39	Contract 1746	427,831~~407,930~~	17,113 ~~16,317~~	4,278~~079~~	42,783 ~~40,793~~	- ~~-~~
40	Contract 1955	40,444~~27,887~~	1,618~~115~~	404 ~~279~~	809 ~~558~~	- ~~-~~
42	Contract 2131	220,372~~146,996~~	8,815 ~~5,880~~	2,204 ~~1,470~~	4,407 ~~2,940~~	- ~~-~~
43	Contract 2440	3,275,754~~2,848,583~~	131,030 ~~113,943~~	32,758 ~~28,486~~	65,515 ~~56,972~~	- ~~-~~
44	Contract 2475	47,820~~29,094~~	1,913~~164~~	478 ~~291~~	4,782 ~~2,909~~	- ~~-~~
45	Contract 2522	28,594~~17,846~~	1,144 ~~714~~	286 ~~178~~	572 ~~357~~	- ~~-~~

46	Contract 3548	36,159~~20,799~~	1,446 ~~832~~	362 ~~208~~	723 ~~416~~	- ~~-~~
47	Contract 3549	238,194~~149,349~~	9,528 ~~5,974~~	2,382 ~~1,493~~	- ~~-~~	- ~~-~~
48	Contract 3550	19,431~~11,573~~	777 ~~463~~	194 ~~116~~	- ~~-~~	- ~~-~~
49	Contract 3584	26,790~~30,260~~	1,072~~210~~	268 ~~303~~	- ~~-~~	- ~~-~~
50	Contract 3585	188,631~~151,828~~	7,545 ~~6,073~~	1,886~~518~~	3,773~~037~~	- ~~-~~
51	Contract 3706	4,644,435~~3,016,624~~	185,777 ~~120,665~~	46,444 ~~30,166~~	92,889 ~~60,332~~	- ~~-~~
52	Contract 3710	298,982~~184,191~~	11,959 ~~7,368~~	2,990 ~~1,842~~	5,980 ~~3,684~~	- ~~-~~
53	Contract 3720	103,114~~58,124~~	4,125 ~~2,325~~	1,031 ~~81~~	- ~~-~~	- ~~-~~
54	Contract 3735	12,781~~5,774~~	511 ~~231~~	128 ~~58~~	256 ~~115~~	- ~~-~~
55	Contract 3736	234,535~~105,925~~	9,381 ~~4,237~~	2,345 ~~1,059~~	4,691 ~~2,119~~	- ~~-~~
56	Contract 3749	4,335,021~~3,669,174~~	173,401 ~~146,767~~	6,069 ~~36,692~~	- ~~-~~	- ~~-~~

~~57~~	~~Contract 3785~~	~~848,093~~	~~33,924~~	~~8,481~~	~~16,962~~	~~-~~
58	Contract 3864	1,121,700~~607,078~~	44,868~~24,283~~	11,217~~6,071~~	-~~-~~	-~~-~~
59	Contract 3867	3,264,963~~1,488,521~~	130,599~~59,541~~	32,650~~14,885~~	65,299~~29,770~~	-~~-~~
~~60~~	~~Contract 3875~~	~~45,000~~	~~-~~	~~450~~	~~900~~	~~-~~
61	Contract 3877	8,766,200~~6,649,800~~	350,648~~265,992~~	87,662~~66,498~~	175,324~~132,996~~	-~~-~~
62	Contract 3878	1,227,100~~588,112~~	49,084~~23,524~~	12,271~~5,881~~	24,542~~11,762~~	-~~-~~
64	Contract 3892	2,754,702	110,188	27,547	-	-
65	Contract 3926	403,557	-	4,036	8,071	-
69~~63~~	Contract 3958~~3891~~	100~~300~~,000	-~~-~~	1,000~~354~~	-~~6,000~~	-~~-~~
70~~64~~	Contract 3959~~3892~~	100,000~~1,836,507~~	-~~73,460~~	1,000~~18,365~~	-~~-~~	-~~-~~
75~~65~~	Contract 4007~~3926~~	500,000~~681,924~~	-~~-~~	590~~6,819~~	-~~13,638~~	-~~-~~

76~~66~~	Contract 4015~~3942~~	100,000	-~~-~~	1,000 ~~118~~	-~~-~~	-~~-~~
77~~67~~	Contract 4021~~3952~~	50,000~~185,964~~	-~~-~~	500 ~~1,860~~	-~~-~~	-~~-~~
78~~68~~	Contract 4022~~3953~~	55,000~~127,796~~	-~~-~~	65 ~~1,278~~	-~~-~~	-~~-~~
79~~69~~	Contract 4030~~3958~~	700~~300~~,000	-~~-~~	7,000 ~~-~~	-~~-~~	-~~-~~
80~~70~~	Contract 4052~~3959~~	100,000	-~~-~~	1,000 ~~118~~	-~~-~~	-~~-~~
81~~71~~	Contract 4056~~3973~~	350~~140~~,000	-~~-~~	- ~~1,400~~	-~~-~~	-~~-~~
82~~72~~	Contract 4057~~3979~~	450,000~~25,001~~	-~~-~~	531 ~~250~~	-~~-~~	-~~-~~
83~~73~~	Contract 4058~~3980~~	200~~125~~,000	-~~-~~	2,000 ~~-~~	-~~-~~	-~~-~~
84	Contract 4059	100,000	-	1,000	-	-
85	Contract 4062	5,152,517	206,101	-	103,050	-
86~~74~~	Contract 4063~~4003~~	477,749~~115,645~~	19,110 ~~4,626~~	4,777 ~~1,156~~	9,555 ~~2,313~~	-~~-~~
87~~75~~	Contract 4065~~4007~~	200~~500~~,000	-~~-~~	2 ~~5~~,000	-~~-~~	-~~-~~

Total **Energy**	57,290,461	~~43,112,919~~	2,871,106~~3~~ ~~47,624~~	471,734 ~~421,969~~	1,587,134~~3~~ ~~24,058~~	-~~-~~

Total Renewable Energy	57,290,461
Total Renewable Energy at Risk	4,929,974
% of Renewable Energy at Risk	8.61%
% of Unknown Error at Risk	0.25%
% of Renewable Energy & Error at Risk	8.86%
% of Retail Load	7.91%

~~**Energy**~~	
~~**Total Renewable Energy**~~	~~**43,112,919**~~
~~**Total Renewable Energy at Risk**~~	~~**4,093,651**~~
~~**% of Renewable Energy at Risk**~~	~~**9.50%**~~
~~**% of Unknown Error at Risk**~~	~~**0.25%**~~
~~**% of Renewable Energy & Error at Risk**~~	~~**9.75%**~~
~~**% of Retail Load**~~	~~**6.57%**~~

Based on MCE's updated risk assessment, MCE determined that approximately 8.6~~9.5~~ percent of MCE's expected future RPS deliveries may be at risk, which equates to 7.9~~6.57~~ percent of MCE's retail load during the current planning period ~~(2024 through 2034) –~~ MCE notes that the 7.9~~6.57~~ percent (relative to retail load) risk statistic falls between~~is similar to~~ MCE's near-term MMoP of 6 percent, which applies through 2025, and the~~well below its~~ 8.5 percent MMoP, which applies in 2029 and beyond. This suggests that MCE's MMoP is appropriately ~~(but conservatively)~~ set in consideration of its existing RPS supply portfolio. The noted percentages reflect average risk throughout the study period, which suggests that actual risk could fall somewhat above or below these percentages. Regardless, the potential risk-related impacts to MCE's RPS supply portfolio align well with MCE's MMoP trajectory, as reflected in this RPS planning process. In consideration of the results of MCE's risk analysis, the composite risk assessment, which considers all four of the previously described risk categories, results in an overall risk rating of low.

MCE's rigorous process for evaluating prospective suppliers continues to be successful in identifying highly qualified, financially viable candidates and supporting its achievement of both statutory and voluntary renewable energy procurement goals. MCE will continue to evaluate the usefulness of other risk assessment tools as it moves forward. Should MCE identify compliance-related concerns through application of its ERM Policy, recently completed risk assessment or other mechanisms, MCE will take the appropriate course of action, which may include additional or enhanced quantitative risk assessments or other planning studies, to address such issues before compliance is affected.

VII.C. ~~System Reliability~~

~~With respect to system reliability, MCE is aware of the planning challenges faced by retail sellers with internally adopted renewable energy targets that exceed RPS mandates. In particular, such retail sellers must often bear increased costs for renewable resources with diverse and complementary delivery profiles, as well as comparatively high levels of energy storage infrastructure to allow for the reshaping of renewable energy deliveries to better align with load.~~

~~For example, renewable energy procurement efforts that may initially focus on relatively low-cost solar resources will often necessitate subsequent investments in co-located energy storage infrastructure and/or higher-cost baseload renewable generating technologies, such as those using geothermal, biomass and landfill gas fuel sources. These baseload renewable technologies are often priced at three-to-four times the level of in-state photovoltaic solar generation but generally provide increased capacity value due to the more predictable, baseload generating profiles of such resources, and related reliability enhancements.~~

~~Despite the adverse budgetary impacts, MCE continues to pursue resource acquisitions that will promote increased alignment between supply and demand as well as the increased use of locally situated renewable generating resources. Currently, low-cost, long-term solutions are incredibly challenging to identify, as ongoing increases in California's RPS procurement mandates and technological limitations often create the need for near-term investments to balance the achievement of compliance mandates with generalized grid reliability.~~

~~Nonetheless, MCE remains committed to pursuing a conscientious planning process that balances grid reliability, compliance demonstration and customer cost impacts. Again, there are no easy solutions in addressing this dilemma, but MCE's commitment to pursuing alignment of supply and demand as well as general resource diversity should contribute to grid reliability, reducing related risks for MCE's customers and the system at large. In consideration of MCE's diverse contractual commitments for requisite renewable energy supply and ongoing focus on the identification of RPS-eligible and complementary technologies that will mitigate reliability impacts associated with increased use of intermittent generating resources throughout the state, overall risks to system reliability associated with MCE's RPS Procurement Plan were determined to be low.~~

~~VII.D.~~ Lessons Learned – Risk Assessment

In terms of lessons learned related to risk management, MCE has observed that "more is generally better" when it comes to procuring renewable energy to satisfy RPS compliance obligations. And while this approach may not be a viable or desirable option for all retail sellers, it has served MCE well. More specifically, MCE's 60% renewable energy commitment (which gradually increases to 85% in 2031~~2029~~) has positioned the organization with substantial RPS planning reserves and minimal compliance risk. Since the 60% renewable energy commitment became effective in 2017, the risks faced by MCE have transitioned away from compliance-related concerns in favor of broader integrated resource planning initiatives. MCE is now focused on identifying resources that are not only cost-effective, but complementary to its existing portfolio of renewable energy supply contracts and projected customer energy use. As the level of renewable energy increases within MCE's portfolio, MCE has observed that the scope of resources promoting alignment between supply and demand generally becomes narrower and more costly.

In recent~~the last two~~ years, MCE has also experienced significant impacts of the MTR compliance mandate on the market for energy storage and renewable energy. The MTR compliance mandates[47] require LSEs across California to bring 15,500 MW of incremental NQC capacity online in phases by 2028. The mandates further define the required characteristics for the new resources that, in some instances, restrict the new construction to specific technologies. Given the compliance mandates and market conditions such as labor shortages, increased equipment costs, and delayed deliveries of key components, buyers have seen~~are seeing~~ significantly higher prices and been~~being~~ forced to take higher risk than normal on their long-term contracts in order to bring these resources online in time to meet the compliance requirements. As a result, developers are passing through unprecedented price increases to LSEs for new and existing contracts. While scenarios such as this~~the past two years~~ are difficult to prepare for, one key takeaway is that timely planning and forecasting at the state level is key to building a reliable and affordable grid. Additionally, MCE is managing these risks by working on backup plans with the developers in case there are unforeseen events, ~~all~~ while still ~~being cost effective and~~ minimizing their impact on ratepayers.

[47] Please see section on MTR compliance mandate.

There is also concern related to the management of long-term renewable supply commitments that exist within geographic areas where negative price risk and related curtailment of energy production has become increasingly prominent. This risk is becoming more challenging to manage as California's escalating RPS procurement mandates necessitate ongoing investment in new renewable generating infrastructure, which is often sited in resource-rich areas that become oversaturated with similar generating technologies. These circumstances seem inevitable and, over the course of a long-term supply relationship, may expose the contracted parties to unexpected risks, including negative prices (and related budgetary impacts) and curtailed deliveries which may compromise the fulfillment of mandated procurement targets by the buyer. However, MCE's internally adopted, above-RPS renewable procurement targets allow flexibility if/when curtailment becomes necessary, or when contracted renewable resources underperform.

In terms of MCE's contracting process, MCE has also learned that diversified sharing of risk within a renewable contract portfolio is desirable. There are many different contract structures, all of which serve a valuable purpose, which can be employed to create the desired allocation of risk between buyers and sellers. For example, an "index-plus" pricing structure is useful in transferring nodal price risk to the seller. In such structures, the buyer pays a fixed renewable premium, while the seller assumes risk associated with market price fluctuations but also receives market revenues – even though the buyer receives the energy, renewable attribute and, in certain instances, capacity value as part of such a transaction, the buyer's financial risk is generally limited to the payment of the renewable premium. For buyers who are averse to market price risk, the index-plus pricing structure effectively eliminates this concern but may result in a higher overall contract cost, which may be acceptable as a form of insurance, to mitigate market price exposure.

In other structures, such as the "fixed-price" or "aggregate pricing" structure, the renewable energy premium and energy commodity (and oftentimes, capacity value) are reflected in a single price paid by the buyer – this structure deliberately allocates market price risk to the buyer, but the buyer may also pay a lower imputed renewable premium in instances where market revenues closely approximate, or exceed, the aggregate renewable energy price.

In considering potential contract structures, decisions are ultimately made in consideration of risk allocation preferences, and MCE has found that it is generally desirable to pursue broad diversity in renewable energy contracting, inclusive of resource location, generating technology, suppliers/developers, and contract structures, amongst other considerations. MCE acknowledges, however, that newer retail sellers that have yet to establish meaningful financial reserves or cost-conscious retail sellers, who may be working to suppress power supply costs in consideration of a cost-sensitive customer base, may choose to favor arrangements that allocate market price risk to sellers/suppliers, particularly during early-stage operations.

Finally, MCE has learned that every CCA is different and that there is no pre-determined risk management methodology or procurement approach that is without challenges. Pursuing resource diversity across a broad spectrum of planning considerations over the long-term planning horizon appears to be one of the most viable mechanisms in mitigating RPS compliance risk.

VIII. Renewable Net Short Calculations

MCE's failure rate for new-build renewable generation placed under contract is well below five percent. MCE takes several steps to guard against the risk of project failure, including:

- Pre-contracting diligence, including a rigorous proposal evaluation process. MCE requires that any new-build project be in an advanced stage of the pre-development process, including permitting, financing, and interconnection. In particular, MCE's practice is to execute a PPA only after a project's interconnection agreement is fully executed. This increases certainty with regard to the project's development timeline and costs.

- Project monitoring, MCE's PPAs for new-build projects require frequent, detailed progress reports, which helps to identify and mitigate potential problems in their early stages.
- Internal renewable portfolio targets, including a planning reserve, that meaningfully exceed statewide mandates.

MCE has increased its planned RPS procurement to account for expected delivery shortfalls and consults~~quantified through~~ its periodically updated quantitative risk assessment to determine whether further adjustments are needed to its future planning assumptions. Based on its most recently updated quantitative risk assessment, MCE determined that approximately 7.9~~which reflected an average 6.57~~ percent of future deliveries are at risk during the current planning period, ~~shortfall/failure rate (~~based on projected retail load within the planning period~~)~~ ~~during the current planning period~~ (this failure rate equates to 8.6~~9.75~~ percent of projected future RPS deliveries; MCE has rounded this up to 10 percent within Appendix C). These adjustments were primarily made to address: 1) generalized planning conservatism to ensure the sufficiency of MCE's RPS supply relative to its relatively high, internally adopted procurement targets, 2) occasional curtailment of select in-state renewable generating facilities due to negative pricing at certain times of the year; and 3) intermittency risk associated with certain renewable generating technologies, such as those using solar and wind as fuel sources. MCE continues to use actual planning data as compared to its forecast throughout the year and can adjust to supply- or demand-side variations within a given year.

MCE has provided a quantitative assessment to support the qualitative descriptions provided in this RPS Procurement Plan, which is attached as Appendix C. As previously noted, MCE has successfully procured more than 60% of its resource needs from RPS-eligible renewable resources since 2017 and, as a result, has accrued renewable energy well in excess of applicable statewide mandates. With few exceptions, renewable suppliers have performed as expected, so the noted failure rates that are reflected in Exhibit C are well in excess of the findings reflected in MCE's previously described risk assessment, which indicate that just over two percent of such supply may be at risk. If supplier performance becomes more erratic in the future and such adjustments are deemed necessary, MCE will reflect such adjustments in a future planning document.

IX. Minimum Margin of Procurement ~~(MMoP)~~

IX.A MMoP Level

MCE is developing an electricity supply portfolio that will further the achievement of state mandates, as well as internally adopted goals, for increasing RPS-eligible renewable energy supply over time. The following table displays MCE's intended margin of RPS over-procurement based on the differential between the SB 100 procurement targets and MCE's internally adopted RPS procurement targets. This table reflects MCE's voluntary margin of over-procurement, or VMoP.

Table 9~~5~~: MCE Voluntary Margin of Over-Procurement

	SB 100 RPS Procurement Requirement (% of Retail Sales)	MCE's Internally Adopted RPS Procurement Target (% of Retail Sales)	MCE's Voluntary Margin of Over-Procurement (% of Retail Sales)
~~**2024**~~	~~44.0%~~	~~60.0%~~	~~16.0%~~
2025	46.7%	60.0%	13~~1~~.3%
2026	49.3%	60~~70~~.0%	10~~20~~.7%
2027	52.0%	65~~75~~.0%	13~~23~~.0%

2028	54.7%	70~~80~~.0%	15~~25~~.3%
2029	57.3%	75~~85~~.0%	17~~27~~.7%
2030	60.0%	80~~85~~.0%	20~~25~~.0%
2031	60.0%	85.0%	25.0%
2032	60.0%	85.0%	25.0%
2033	60.0%	85.0%	25.0%
2034	60.0%	85.0%	25.0%
2035	60.0%	85.0%	25.0%

As reflected in Table 9~~5~~, MCE's RPS-eligible renewable energy target is currently set at 60 percent through 2026~~2025~~, increasing to 85 percent by 2031~~2029~~. MCE's internally adopted renewable energy procurement targets are intended to support MCE's broader goal of providing a 95 percent carbon-free electricity to all customers, beginning in 2024~~ and beyond~~, with increasing proportions of renewable energy over time. MCE's internally adopted renewable energy procurement goals ensure a significant margin of procurement above the SB 100 mandates. Further, MCE's internally adopted renewable energy procurement mandates provide a meaningful buffer above the state's RPS requirements and serves as MCE's VMoP. As shown in Table 9~~5~~, MCE's VMoP will minimally exceed statewide RPS mandates by at least 10.7~~13.3~~ percent, relative to retail sales, throughout the planning period~~through 2034~~.

To address RPS compliance risk, MCE uses its risk assessments, including its renewable net short calculations, to establish a Minimum Margin of Over-Procurement (MMoP) to guide RPS compliance planning. MCE calculated the MMoP by applying a 10 percent risk adjustment (or planning reserve) to the entirety of MCE's projected Light Green renewable energy requirements. Light Green is MCE's default retail service option, which establishes the renewable energy percentage provided to all MCE customers. On a voluntary basis, MCE customers may enroll in one of MCE's 100 percent renewable energy service offerings: Deep Green or Local Sol.[48,49] Based on the way MCE has established its MMoP, the effective MMoP percentages observed by MCE throughout the planning period~~through 2034~~ range from 12.2~~9~~ percent in 2026~~2025~~, to 14.2~~8~~ percent beginning in 2031~~2029~~, relative to MCE's projected RPS compliance need. MCE's MMoP is intended to address potential delivery variability for intermittent resources, curtailment risk, project delays or failures and other operational peculiarities that may cause actual renewable energy deliveries to deviate from projections. The table below provides additional detail regarding the effective MMoP percentages observed by MCE.

Table 10~~6~~: MCE Minimum Margin of Over-Procurement

	SB 100 RPS Procurement Requirement (% of Retail Sales)	MCE's Internally Adopted RPS Procurement Target (% of Retail Sales)	MCE's RPS Planning Risk Adjustment (at 10% of Internally Adopted RPS Target)	MCE's Minimum Margin of Over-Procurement (% of Retail Sales)	MCE's Minimum Margin of Over-Procurement (% buffer relative to RPS Mandate)
~~**2024**~~	~~44.0%~~	~~60.0%~~	~~10.0%~~	~~6.0%~~	~~13.6%~~
2025	46.7%	60.0%	10.0%	6.0%	12.9%
2026	49.3%	60~~70~~.0%	10.0%	6~~7~~.0%	12~~14~~.2%
2027	52.0%	65~~75~~.0%	10.0%	6~~7~~.5%	12.5~~14.4~~%
2028	54.7%	70~~80~~.0%	10.0%	7~~8~~.0%	12.8~~14.6~~%
2029	57.3%	75~~85~~.0%	10.0%	7~~8~~.5%	13.1~~14.8~~%

48 *See* https://www.mcecleanenergy.org/100-renewable/.
49 *See* https://www.mcecleanenergy.org/100-local-solar/.

2030	60.0%	80~~85~~.0%	10.0%	8.0~~5~~%	13.3~~14.2~~%
2031	60.0%	85.0%	10.0%	8.5%	14.2%
2032	60.0%	85.0%	10.0%	8.5%	14.2%
2033	60.0%	85.0%	10.0%	8.5%	14.2%
2034	60.0%	85.0%	10.0%	8.5%	14.2%
2035	60.0%	85.0%	10.0%	8.5%	14.2%

IX.A.1. MMoP Methodology and Inputs

MCE's MMoP is intended to address an RPS failure similar to that which is reflected in the RNS template. In the event of substantial under-deliveries, commercial operation delays and/or project failure, the MMoP should be sufficient to ensure MCE is compliant with the RPS procurement requirements. MCE's VMoP is the annual RPS-eligible minimum portfolio content identified in MCE's internally adopted planning targets.

As discussed in Section VII~~VIII~~, MCE has incorporated risk adjustments to certain renewable energy delivery estimates associated with existing generation. Incorporated risks include: increased fire risk throughout the state of California, the potential for related delivery reductions, delivery intermittency, and resources that are under development. Achieving MCE's MMoP requires levels of renewable energy procurement, ranging from 12.2~~9~~ percent to 14.2~~8~~ percent (throughout the planning period),~~through 2034,~~ above MCE's annual RPS compliance need. This additional renewable energy procurement accommodates potential delivery shortfalls due to a variety of circumstances while still allowing MCE to meet prescribed RPS mandates.

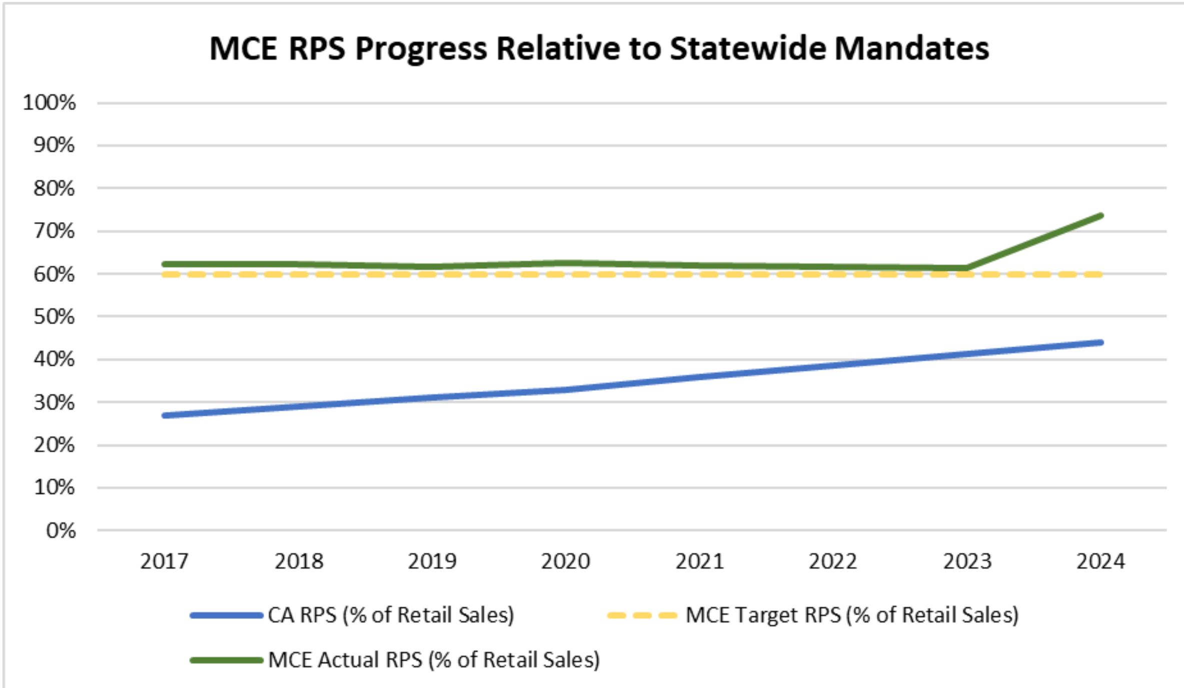
When considered in concert, MCE's VMoP and MMoP provide a substantial renewable energy planning buffer, relative to applicable compliance mandates, as reflected in the table below.

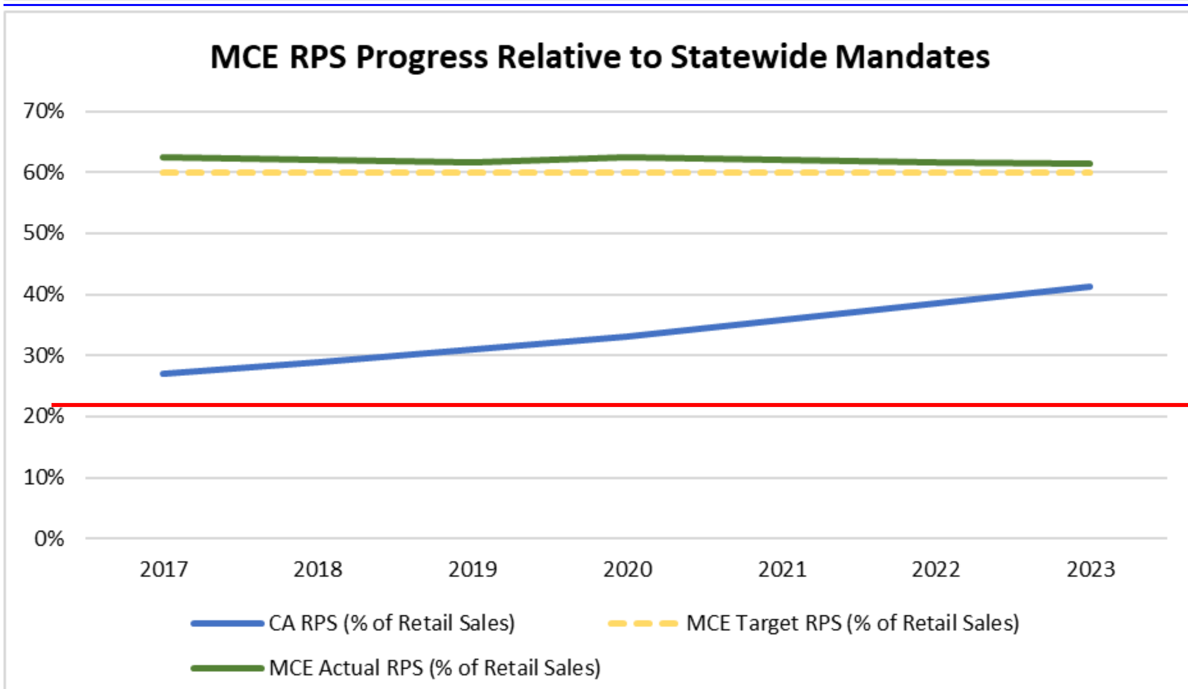
Table 11~~7~~: MCE's VMoP and MMoP

	SB 100 RPS Procurement Requirement (% of Retail Sales)	MCE's Internally Adopted RPS Procurement Target (% of Retail Sales)	MCE's Voluntary Margin of Over-Procurement (% of Retail Sales)	MCE's Minimum Margin of Over-Procurement (% of Retail Sales)
~~**2024**~~	~~44.0%~~	~~60.0%~~	~~16.0%~~	~~6.0%~~
2025	46.7%	60.0%	13.3%	6.0%
2026	49.3%	60~~70~~.0%	10~~20~~.7%	6~~7~~.0%
2027	52.0%	65~~75~~.0%	13~~23~~.0%	6~~7~~.5%
2028	54.7%	70~~80~~.0%	15~~25~~.3%	7~~8~~.0%
2029	57.3%	75~~85~~.0%	17~~27~~.7%	7~~8~~.5%
2030	60.0%	80~~85~~.0%	20~~25~~.0%	8.0~~5~~%
2031	60.0%	85.0%	25.0%	8.5%
2032	60.0%	85.0%	25.0%	8.5%
2033	60.0%	85.0%	25.0%	8.5%
2034	60.0%	85.0%	25.0%	8.5%
2035	60.0%	85.0%	25.0%	8.5%

Since it began serving customers in 2010, MCE has consistently exceeded the state's RPS requirements, as reflected in the chart below. Note that MCE's reported Light Green renewable content in 2024, as reflected~~2023 is not yet finalized – MCE is completing its Light Green PSD report for 2023~~ in its recently submitted Power Source Disclosure Report, was 70.9%.~~consideration of the upcoming July 29, 2024 deadline and will advise the Commission in its Final 2024 RPS Procurement Plan if the 2023 renewable percentage noted below requires revision.~~ MCE will continue updating this chart in future planning documents.

Figure 3~~2~~: MCE RPS Progress Relative to Statewide Mandates





IX.A.2~~B~~. MMoP and VMoP Scenarios

MCE plans to meet the annual program renewable goals reflected in the table presented in Section IX (above), including the MMoPs reflected therein. As reflected in this table, MCE's anticipated MMoP percentages range from 6.0 percent in 2025~~2024~~ to 8.5 percent in 2035.~~20334~~ MCE's RPS Procurement Targets, as well as the renewable net short reflected in the RNS Quantitative Template, incorporate the additional RPS-eligible renewable energy need resulting from expected participation in MCE's voluntary 100 percent renewable energy service options.

During its bid evaluation and supplier selection processes, MCE considers a variety of risks and believes that such risks are sufficiently addressed within its MMoP calculation. Based on its operating history, previous experiences related to renewable energy planning/procurement and existing contract portfolio, MCE has no reason to doubt the sufficiency of the MMoP reflected in its RPS planning targets. MCE plans to procure to the VMoP since MCE's internal RPS goals are much higher than the state mandate. This noted, MCE has incorporated an internal RPS planning reserve, as reflected in the following table, to ensure MCE can meet its internal RPS targets in the event that its previously described contract management process identifies substantial concerns related to new-build project completion, delivery shortfalls or other issues.

This reserve is additive to MCE's internally adopted RPS targets and ~~is~~ intended to address renewable production and/or usage variability that may occur during discrete calendar years. It is intended to offset the potential impacts of noted risk adjustments and ~~/~~contingencies that may reduce actual renewable energy deliveries, relative to MCE's expectations. In effect, MCE's internal RPS planning reserve is a secondary VMoP, providing additional insurance against unforeseen circumstances that could impact MCE's ability to satisfy its internally adopted renewable energy commitments. As demand- and supply-side data are monitored in each year, MCE may adjust planned short-term purchases and/or pursue surplus sales arrangements if actual renewable energy deliveries are tracking above MCE's anticipated needs. By the end of each calendar year, MCE hopes to manage the level of its internal planning reserve so that actual renewable energy deliveries are closely aligned with MCE's Base RPS Procurement Target, as reflected below.

Table 12~~8~~: MCE RPS Procurement Target

	SB 100 RPS Procurement Requirement (% of Retail Sales)	MCE's Internally Adopted RPS Procurement Target (% of Retail Sales)	MCE's Voluntary Margin of Over-Procurement (% of Retail Sales)	MCE's Minimum Margin of Over-Procurement (% of Retail Sales)	MCE's Aggregate Margin of Over-Procurement (% of Retail Sales)
~~**2024**~~	~~44.0%~~	~~60.0%~~	~~16.0%~~	~~6.0%~~	~~22.0%~~
2025	46.7%	60~~6~~.0%	13.3%	6.0%	19.3%
2026	49.3%	60~~70~~.0%	10~~20~~.7%	6~~7~~.0%	16~~27~~.7%
2027	52.0%	65~~75~~.0%	13~~23~~.0%	6~~7~~.5%	19~~30~~.5%
2028	54.7%	70~~80~~.0%	15~~25~~.3%	7~~8~~.0%	22~~33~~.3%
2029	57.3%	75~~85~~.0%	17~~27~~.7%	7~~8~~.5%	25~~36~~.2%
2030	60.0%	80~~85~~.0%	20~~25~~.0%	8.0~~5~~%	28.0~~33.5~~%
2031	60.0%	85.0%	25.0%	8.5%	33.5%
2032	60.0%	85.0%	25.0%	8.5%	33.5%
2033	60.0%	85.0%	25.0%	8.5%	33.5%
2034	60.0%	85.0%	25.0%	8.5%	33.5%
2035	60.0%	85.0%	25.0%	8.5%	33.5%

MCE will also model demand-side sensitivities that may impact MMoP and VMoP calculations. This will be particularly important during periods of expansion of MCE's service area, when participation rates are expected to be most volatile. While MCE has no current expansion plans, MCE has completed numerous expansions during its 13-year operating history, and in each case, MCE has successfully scaled its renewable energy procurement to accommodate related increases in retail sales. In addition to load variability resulting from periodic expansions and ongoing minor fluctuations in customer participation, MCE will also monitor large load growth (for example Data Center load growth), electric vehicle penetration rates, net energy metering participation rates and other considerations that may impact overall customer energy requirements and related procurement margin calculations.

X. Bid Solicitation Protocol

X.A. ~~Solicitation Protocols for Renewables Sales~~

~~MCE does not have immediate plans to issue a solicitation for sales of renewable energy projects.~~

~~X.B.~~ Bid Selection Protocols

(i) Description of Bid Solicitation Protocols.

In its various solicitations for long-term renewable energy supply, MCE imposes numerous bid requirements on interested respondents. These requirements address a variety of considerations and are intended to identify the best qualified suppliers of MCE's long-term renewable energy needs. Such requirements include:

1. Overall quality of response, inclusive of completeness, timeliness, and conformity;
2. Price and relative value within MCE's supply portfolio;
3. Project location and local benefits, including local hiring, ~~and~~ prevailing wage considerations and community benefits packages;
4. Project development status, including but not limited to progress toward interconnection, deliverability, siting, zoning, permitting, and financing requirements;

5. Qualifications, experience, financial stability, and structure of the prospective project team (including its ownership);
6. Environmental impacts and related mitigation requirements, including impacts to air pollution within communities that have been disproportionately impacted by the existing generating fleet;
7. Potential impacts to grid reliability;
8. Potential economic benefits created within communities with high levels of poverty and unemployment;
9. Acceptance of MCE's standard contract terms; and
10. Development milestone schedule, if applicable.

These considerations help shape the criteria against which prospective suppliers are evaluated. Based on the success of its ongoing planning and procurement efforts as well as any direction from its governing board, MCE may adapt these considerations in future renewable energy procurement efforts.

MCE considers minimum sizing requirements for certain long-term solicitations but does not solicit a specific quantity of projects, as this is based on the portfolio needs and the overall value of the project submissions. MCE considers a range of online dates based on the portfolio needs and the overall value of the project submission. MCE considers term lengths for long-term projects typically no shorter than ten years and no longer than twenty years.

Consistent with Public Utilities Code Section 399.13(a)(6)(C), MCE conducts energy product solicitations in a manner that addresses a broad range of considerations, including specific needs for eligible renewable energy resources (reflecting locational preferences, when applicable, for such resources), generating capacity, and required online dates to assist in determining what resources fit best within its desired supply portfolio. Since MCE's governing board is comprised of local elected officials, solicitation and procurement decisions are overseen by elected representatives of MCE's member communities with such decisions intended to conform with locally established targets that exceed applicable RPS requirements and promote the development of locally-situated renewable generating facilities.

(ii) Consideration of Resources Located in Disadvantaged Communities.

MCE requests information from prospective suppliers regarding whether their projects are located in disadvantaged communities and about their efforts to promote workforce development in these areas. These criteria are considered as a part of a comprehensive qualitative evaluation in addition to any benefits that enhance the value of the project through eligibility for related tax incentives for projects located in disadvantaged communities.

(iii) Alignment of Bid Selection Criteria with RPS Procurement Plan.

MCE conducts its bid selection in accordance with the goals and preferences outlined in this RPS Procurement Plan in order to meet its portfolio needs, including but not limited to meeting all of its compliance obligations, achieving the agency's equity goals, and mitigating affordability concerns.

(iv) Description of Ongoing, Planned, and Proposed Solicitations

MCE's 2025~~2024~~ solicitations ~~are cited in Section IV.A and materials~~, including applicable contract templates and general information regarding MCE's active solicitation processes, are available at the following website: https://www.mcecleanenergy.org/energy-procurement/. Information regarding other MCE service offerings and programs, including its FIT, can be found elsewhere on the MCE website.[50]

X.B. Solicitation Protocols for Renewables Sales

MCE does not have immediate plans to issue a solicitation for sales of renewable energy projects.

X.C. LCBF Criteria

The Least-Cost Best Fit ("LCBF") methodologies approved by the Commission pursuant to D.04-07-029, D.11-04-030, D.12-11-016, D.14-11-042, and D.16-12-044 are expressly only directly applicable to investor-owned utilities. However, consistent with Section 399.13(a)(9),[51] MCE does consider best-fit attributes that support a balanced mix of resources to help support grid reliability.

Regarding MCE's application of an LCBF methodology during selection of qualified responses, the term "costs" should appropriately include considerations beyond the basic price of renewable energy being considered for procurement. Specifically, costs should include considerations such as: (1) reputational damage resulting from failure to meet internally established renewable energy procurement targets; (2) compliance penalties resulting from failed project development efforts or delivery shortfalls; (3) administrative complexities related to dealing with inexperienced suppliers (such as prolonged contract negotiation processes and uncertainties related to project milestone timing and achievement); and (4) impacts to planning certainty resulting from higher-risk projects. MCE considers these factors, among others, as part of its cost evaluation process, which may lead to the selection of offers that are not~~aren't~~

[50] For example, information on MCE's FIT program can be found at https://mcecleanenergy.org/feed-in-tariff/.

[51] Cal. Pub. Util. Code § 399.13(a)(9) ("In soliciting and procuring eligible renewable energy resources, each retail seller shall consider the best-fit attributes of resource types that ensure a balanced resource mix to maintain the reliability of the electrical grid.").

necessarily the lowest-priced option.

The term "fit"~~"Fit" also~~ has as much to do with organizational compatibility between buyers and sellers and alignment with key organizational objectives as it does with balancing customer usage and expected project deliveries, particularly when considering long-term contracting opportunities that will require constructive working relationships over a period of ten years or more. In ~~the most~~ recent Open Season solicitations, MCE ~~also~~ added a focus on matching ~~the~~ supply to the hourly load shapes and evaluate~~will be evaluating~~ projects based on the overall fit of the portfolio. As such, MCE's LCBF methodology takes into consideration the various planning and procurement processes described in this RPS Procurement Plan, balancing a variety of pertinent considerations at the time that each renewable purchase opportunity is being considered.

An important example supporting this perspective is MCE's FIT program, which is intended to incentivize, through above-market prices, the development of locally situated, small-scale renewable project developments. This program has achieved tremendous success, supporting numerous projects throughout MCE's service territory while utilizing local labor. By design, FIT projects are not the least expensive generating resources, but they are entirely consistent with MCE's charter objectives and a valuable component of MCE's supply portfolio.

This holistic planning approach, which may not necessarily reflect a traditional LCBF methodology, has resulted in the compilation of a diverse resource mix for MCE, deep roots in its member communities, and attention to a broad spectrum of considerations, including environmental concerns, costs and sustainability.

Finally, the requirement of Section 399.13(a)(8) to give preference to renewable projects located in certain communities is expressly only applicable to "electrical corporations" and is not mandatory for CCAs.[52] However, MCE fully recognizes the need to help mitigate the impacts of air pollution in regions of the state where communities have been disproportionately impacted by the existing generating fleet as well as the need to bring economic benefits to communities with high levels of poverty and unemployment. As noted previously, MCE submitted Advice Letters to participate in the CPUC's DAC-GT program and held a solicitation in 2021 for qualifying resources where two projects were selected and contracts were executed as part of the "Green Tariff" program. Since D.24-05-065 has made additional capacity available for the DAC-GT program, MCE plans to hold another solicitation to fill the new open program capacity. MCE continues to explore opportunities to advance this important policy goal through its procurement.

XI. Safety Considerations

MCE holds safety as a top priority. Since MCE does not own, operate, or control generation facilities, MCE's procurement of renewable resources does not present any unique safety risks. MCE's Power Purchase Agreement includes~~include~~ safety terms such as Prudent Operating Practice and Maintenance of Health and Safety provisions, which speak to safety precautions with respect to the operation, maintenance, repair, and replacement of a project.

This Section describes how MCE has taken actions to reduce the safety risks posed by its renewable resource portfolio and how MCE supports the state's environmental, safety, and energy policy goals.

[52] Cal. Pub. Util. Code § 399.13(a)(8)(1) ("In soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases.").

XI.A. Wildfire Risks and Vegetation Management

At this point in time, MCE has yet to adopt any additional safety requirements for its portfolio that are specific to wildfire risks and vegetation management. MCE is aware of the mitigating impacts that biomass generators, which use forestry waste as feedstock, may have on wildfire risk, and has adopted principles on responsible ~~but does not have any specific procurement policies or preferences for forest~~ biomass electricity development which state that MCE will prioritize resources that support sustainable forest management and wildlife reduction strategies to minimize the fuels for uncontrolled wildfire.[53] ~~at this time.~~ As mentioned in Section III, MCE has engaged with the CPUC on laying the policy foundation for CCA participation in the BioMAT program, which is inclusive of woody biomass facilities that use feedstock from fuel reduction facilities or sustainable forest management, including from such feedstocks from high hazard zones.[54]

XI.B. Decommissioning Facilities

MCE does not own any generating assets, and as such does not undertake decommissioning of assets. MCE has not yet developed any plans or requirements related to the disposition of associated generating facilities following completion of applicable delivery terms. In many cases, the project's operational life is longer than MCE's contract, so it is likely that the contract with MCE will expire before disposal of the generation assets is required.

---

[53] *See* https://www.mcecleanenergy.org/wp-content/uploads/2021/11/MCE-Technical-Committee-Packet-Thursday-November-4-2021.pdf at 106.

[54] PG&E's BioMAT Market Adjusting Tariff, Section 14.c, Sheet 22: https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/ELEC_SCHEDS_E-BioMAT.pdfhttps://www.pge.com/assets/pge/docs/about/doing-business-with-pge/ELEC_SCHEDS_E-BioMAT.pdf

In 2015, SB 489 authorized the California Department of Toxic Substances Control ("DTSC") to add PV panels to the list of universal wastes. The DTSC has developed regulations for PV panels~~,~~ but has not adopted the regulations yet.[55] Because a significant portion of MCE's solar facilities are newly constructed, and its storage facilities are yet to be constructed, MCE is confident that by the time PV solar or battery facilities under contract with MCE reach the end of their useful life, there will be statewide, comprehensive regulations addressing the safe handling and disposal/recycling of those materials.

XI.C. Climate Change Adaptation

MCE's commitment to increasing renewable energy at a more aggressive pace than California's statewide mandates itself constitutes a climate change adaptation measure. Additionally, MCE in 2019 adopted a pollinator-friendly habitat requirement for solar projects participating in both its FIT program as well as its PPAs.[56] MCE is the first California CCA to adopt this requirement, demonstrating~~which is~~ a critical function that~~way~~ MCE, as a CCA, can take to help build and maintain healthy ecosystems in the local areas where MCE's solar projects are located. MCE will continue to evaluate the potential impacts of climate change on its portfolio so that adjustments to its procurement strategy can be made as~~if~~ needed.

XI.D. Impacts During Public Safety Power Shut-off Events

Public Safety Power Shut-off ("PSPS") events have both supply and demand side impacts. The experiences of MCE customers with wildfires and PSPS events over the last few years has led MCE to increase the focus of both its procurement as well as customer programs strategies on

[55] *See* https://dtsc.ca.gov/photovoltaic-modules-pv-modules-universal-waste-management-regulations/.
[56] *See* https://mcecleanenergy.org/pollinator-friendly-ground-cover-now-required-for-new-solar-projects/.

resiliency.

MCE assesses customer usage as a result of a PSPS event, to the extent possible with the data to which MCE has access, in real time and adjustments to supply are made accordingly. Generation resources that are located in the footprint of a PSPS event are necessarily taken offline, though MCE continues to explore ways to safely keep these resources online and serving customers. MCE is an active participant in the Commission's Enhanced Power Line Safety Settings ("EPSS") proceeding~~PSPS and microgrid proceedings~~[57] to help ensure that state policy as well as IOU and CCA operating protocols are aligned and result in minimal PSPS impacts in the future.

XI.E. Forest Biomass Procurement

In recent renewable Open Season requests for offers, MCE has not received offers from forest biomass generators. MCE's FIT program is available on a first-come, first-served basis, and is also technology-agnostic, however, MCE has not received any forest biomass applications. As MCE works toward a low emissions portfolio, MCE will be seeking non-emitting renewable technologies to contribute to its existing bioenergy resources already under contract. As mentioned in Section XI.A, MCE has been engaged in the implementation of BioMAT, which does have a dedicated category for the procurement of woody biomass facilities. Although MCE participated in laying the policy foundation for CCA participation in the BioMAT program in R.22-10-010, at the time of this filing MCE is not actively participating in the BioMAT program.

XII. Consideration of Price Adjustment Mechanisms

At~~In~~ the time of this filing~~future, and consistent with SB 350 and SB 100~~, MCE ~~will review the possibility of incorporating price adjustments in contracts with online dates more than~~

[57] R.24-05-023~~18-12-005~~ and R.19-09-009, respectively.

~~24 months after the date of contract execution. As noted in the ACR, such price adjustments could include price indexing to key components or to the Consumer Price Index.~~

~~XIII. Curtailment Frequency, Cost, and Forecasting~~

~~This Section responds to the questions presented in Section 6.13 of the ACR~~[58] ~~and describes MCE's strategies and experience so far in managing the Agency's exposure to negative pricing events, overgeneration, and economic curtailment for MCE's region and portfolio of renewable resources.~~

~~XIII.A. Factors Having the Most Impact on the Projected Increases in Incidences of Overgeneration and Negative Market Price Hours~~

~~Due in large part to the rapid increase in the amount of wind and solar generation that~~ has not ~~been coming online throughout the western United States, the California Independent System Operator's ("CAISO") Balancing Authority Area (BAA) has experienced an increasing frequency and magnitude of curtailment and negative pricing events. The U.S. Energy Information Agency ("EIA") estimates that as of March 2024, California has 37,507.1 MW of total installed solar capacity, with 17,191.5 MW of that total being behind-the meter solar.~~[59] ~~The CAISO reports that it has approximately 19,479 MW of utility-scale solar and 8,120 MW of utility-scale wind~~ currently ~~installed within its BAA.~~[60] ~~This capacity results in discrete periods where the majority of load in the CAISO is served by solar and wind resources. The monthly maximum load served by wind and solar in the CAISO has averaged 71.5% over the past 5 years (April 2019 to April~~

---

[58] ~~ACR at 31-32.~~

[59] ~~EIA, Electric Power Monthly, *Table 6.2.B. Net Summer Capacity Using Primarily Renewable Energy Sources and by State, April 2024 and 2023 (Megawatts)*, available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_02_b.~~

[60] ~~CAISO, What are we doing to green the grid?, updated April, 2024, *at* https://www.caiso.com/about/our-business/managing-the-evolving-grid~~

~~2024), and the monthly maximum load served by wind and solar exceeded 109%.~~[61]

~~To address the resulting instances of over-supply, the amount of curtailment of wind and solar in the CAISO has significantly increased each year from 2015 through 2022, totaling 187,000 MWh in 2015, 308,000 MWh in 2016, 358,000 MWh in 2017, 461,000 MWh in 2018, 961,000 MWh in 2019, 1,587,497 MWh in 2020, 1,504,803 in 2021, and 2,449,248 in 2022 and 2,659,526 MWh in 2023. As of May 31, 2024, the total curtailment of solar and wind year to date is 1,899,759 MWh. Curtailment is typically the highest during the months of March, April, and May when hydroelectric generation is historically at its highest and California load is at its lowest. Years in which there is an above-average snowpack results in higher-than-average hydroelectric generation which exacerbates renewable generation curtailment. The table below summarizes solar and wind curtailment from January 2024 through April 2024.~~

[61] ~~CAISO, Monthly Renewables Performance Report, February 2024, available at https://www.caiso.com/documents/monthlyrenewablesperformancereport-feb2024.html~~

~~Table 9: Summary of CAISO Solar and Wind Curtailment January-April 2024~~

~~2024 Data~~	~~Wind Curtailment (MWh)~~	~~Solar Curtailment (MWh)~~
~~January~~	~~5,515~~	~~95,505~~
~~February~~	~~15,263~~	~~213,625~~
~~March~~	~~54,677~~	~~675,569~~
~~April~~	~~41,781~~	~~797,804~~
~~Total Curtailment~~	~~117,236~~	~~1,782,523~~
~~Curtailment %~~	~~1.65 %~~	~~13.75%~~
~~No. of Intervals Curtailed~~	~~9218~~	~~13351~~
~~Pct. of Intervals Curtailed~~	~~26.45~~	~~38.31~~

~~The CAISO notes that the majority of renewable resource curtailment is "a result of economic downward dispatch, rather than self-schedule curtailment," and that "Most renewable generation dispatched down in the ISO were solar resources, rather than wind, because solar resources typically bid more economic downward capacity than wind resources.[62] That means that curtailment happened in response to congestion and was mitigated by supply that was willing to reduce its output based on price signals from the CAISO market.~~

~~CAISO system-wide 2024 curtailment percentages are higher than forecasted by MCE to date. Thus far in 2024 through May, MCE has experienced 82,501 MWh of curtailment, which is over 8% of MCE's RPS portfolio. Curtailment to MCE's RPS portfolio is predominantly composed of the Little Bear Solar resources, which is 90% of MCE's curtailment volume. MCE has been in discussions with the CAISO regarding local network upgrades required and potential~~

[62] ~~CAISO, 2020 Annual Report on Market Issues and Performance Report, published January 20, 2022, page 41, available at http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf.~~

~~for adding a battery to the project to alleviate Little Bear Solar curtailment.~~

~~XIII.B. Written Description of Quantitative Analysis of Forecast of the Number of Hours Per Year of Negative Market Pricing for the Next 10 Years~~

~~MCE's scheduling coordinator agent, ZGlobal, has the capability to perform production cost analyses based on various input assumptions through 2035 to derive hourly market prices for energy and ancillary services. PLEXOS Integrated Energy Model is a commercial optimization engine that can simulate the economic commitment and dispatch used by the CAISO's day-ahead market processes which simultaneously optimizes energy dispatch and ancillary services capacity awards across the CAISO grid. In this way, the simulation will determine locational marginal prices and ancillary service marginal prices in the same manner the CAISO day-ahead market sets prices. ZGlobal has developed models using input assumptions that are based on common case inputs and planning guidelines from WECC, CAISO, Commission and CEC.~~

~~The key assumptions considered for the assessment included the impact of higher California renewable energy standards (60% RPS by 2030), planned gas-fired and nuclear generation retirements and~~ adopted any specific price adjustment mechanisms.~~California Energy Commission ("CEC") demand forecasts which consider energy efficiency programs and increased behind-the-meter solar generation. Results are highly dependent upon input assumptions, primarily the level of new RPS generation, deployment of energy storage facilities, upgrades to CAISO-controlled transmission facilities and the ability to export energy from the CAISO to external balancing areas.~~[63]

~~[63] More recently, load has become an important input variable with the onset of the COVID-19 pandemic and its effect on load. However, ZGlobal has not performed long-term studies to determine the impact of load on long-term market prices as there is not enough data to determine a suitable load trajectory.~~

~~In California, electricity prices are typically set by gas-fired resources operating on the margin.~~ However, in light of the current political landscape and ongoing affordability concerns for LSEs and ~~as increasing supplies of renewable energy are added to the system, there are periods where marginal prices are being set by zero or even negatively-priced resources. Market prices have been trending downward, especially during seasons and periods of the day when loads are low and solar output is high with the influx of renewable energy resources. The modeling shows that during solar hours, prices are low during the middle of the day, driven by solar resources and their willingness to curtail and increasing in the morning and evening when gas-fired resources are needed to meet peak loads outside of the solar supply period. In short, prices as reflected by the CAISO's duck curve are expected to continue, with the amplitude of the valley and ramps dictated by the amount of energy storage available to smooth out the net supply.~~

~~XIII.C. Experience, to Date, With Managing Exposure to Negative Market Prices and/or Lessons Learned from Other Retail Sellers in California~~

~~MCE closely monitors six separate locations that are indicative of renewable energy resources that are exposed to market prices and potential curtailment. Resources at those locations are bid into the CAISO markets and are curtailed when prices fall below individual resource's threshold prices. Weighted average prices for the generation at those locations are compared to weighted average prices at PG&E's Distributed Load Aggregation Point ("DLAP") to assess the impact of congestion on the resource's performance. In addition, the MWh of curtailment are logged.~~

~~These two metrics - weighted average price of the resources compared to that of the DLAP and MWh curtailed – are used to assess effectiveness of the resources in meeting MCE's RPS obligations at cost effective prices. If the resource's weighted average price is near the DLAP and~~

~~it has been curtailed, then the reason for curtailment is system over-supply. If the resource's weighted average price diverges from the DLAP and it has been curtailed, then the reason for curtailment is local overgeneration that is contributing to congestion. This information is valuable feedback to MCE in locating potential future resources. If congestion and local oversupply is significant in certain areas, then MCE can determine by reviewing the CAISO's transmission planning documents whether transmission upgrades are planned to mitigate congestion that is observed with existing resources.~~

~~If curtailment is caused by congestion, the impact can be somewhat mitigated by obtaining CAISO Congestion Revenue Rights ("CRRs"), which MCE has done. However, CRRs are not a perfect hedge against congestion and cannot be relied upon to mitigate congestion and subsequent economic curtailment entirely.~~

~~XIII.D. Direct Costs Incurred, to Date, for Incidences of Overgeneration and Associated Negative Market Prices~~

~~For calendar year 2024 through May, MCE's RPS portfolio has been exposed to negative market prices and experienced curtailment as summarized in the table below.~~

~~Table 10: Summary of MCE RPS Resources Curtailment January-May 2024~~

~~Location~~	~~Day-Ahead Negative Prices~~	~~Real-Time Negative Prices~~	~~Curtailment (MWh)~~	~~Cost of Curtailment ($)~~
~~South P26~~	~~-$20.68~~	~~-$28.51~~	~~4,312~~	~~$254,071~~
~~Fresno 1~~	~~-$66.40~~	~~-$82.34~~	~~74,089~~	~~$7,356,470~~
~~Fresno 2~~	~~-$25.06~~	~~-$32.20~~	~~1,843~~	~~$90,300~~
~~North P26~~	~~-$33.32~~	~~-$41.35~~	~~2,257~~	~~$149,982~~
~~Total~~	**~~-$95.16~~**		**~~82,501~~**	**~~$7,850,823~~**

~~The Day-Ahead and Real-Time Negative Price columns represent averages of negative~~

~~prices by RPS geographic area when prices are negative for solar hours for solar resources and all hours for wind resources. The prices are averages based on resources within the area. Curtailment megawatt hour ("MWh") is the amount of energy that MCE RPS resources in the areas were curtailed from January 1 through May 31, 2024. "Cost of Curtailment" is the subsequent market cost of the curtailed energy.~~

~~XIII.E. An Overall Strategy for Managing the Overall Cost Impact of Increasing Incidences of Overgeneration and Negative Market Prices~~

~~While curtailment is a viable renewable integration strategy that is generally more cost-effective than other options, there are potential negative consequences from excessive curtailment. Curtailment of solar and wind represents a lost opportunity to generate zero-GHG electricity, and excessive curtailment could impact the ability of the state to meet its environmental and energy policy goals. Additionally, these over-supply situations expose~~ ratepayers throughout California,~~to increased costs because their load serving entities must either economically curtail the generating resource (and often pay for the electricity that was not generated) or generate power and be exposed to negative prices.~~

~~MCE will consider the impact of curtailment and negative pricing on its portfolio and will factor potential curtailment into its long-term planning. Due to the difficulty in accurately forecasting curtailment, MCE will review the historical data on curtailment and negative pricing within regions where~~ MCE may consider incorporating price adjustment mechanisms to protect ratepayers from market uncertainty~~contract for generating resources. When MCE is evaluating new procurement opportunities, the potential amount of future curtailment will be one factor that MCE will consider. While MCE has not yet developed an individualized forecast of future curtailment, MCE will factor potential curtailment into its minimum margin of procurement~~

~~(described in Section IX) and may also factor this consideration in future iterations of its Risk Assessment (Section VII). To the extent that MCE is engaged in renewable supply agreements which include curtailment provisions, it will take actions to limit the impacts of curtailment on its customers. During its current and future renewable contracting efforts, MCE will pursue contract terms that recognize and limit the potential financial impacts of negative pricing and give MCE greater flexibility to direct economic curtailment, if this becomes necessary.~~

~~XIII.F. Contract Terms Included in RPS Contracts Intended to Reduce the Likelihood of Curtailment or Protect Against Negative Prices.~~

~~MCE has negotiated pre-paid curtailment hours into some of its new contracts and has a strong preference to be the scheduling coordinator so that it can modify the bidding strategies to mitigate impacts of curtailment~~.

XIII~~XIV~~. Cost Quantification

MCE has provided the Cost Quantification Table as Appendix E. Pursuant to the direction in the ACR, MCE has completed those cells in the Cost Quantification table that correspond to Table 3~~2~~, Rows 1-5 in the ACR.

~~XV. Conformance with the IRP Proceeding~~

~~The resources identified in this RPS Procurement Plan are consistent with the resources identified in MCE's 2022 IRP, which was submitted to the Commission for certification on November 1, 2022, and with biannual MTR updates provided to the Commission regarding MCE's progress towards meeting procurement requirements under D.21-06-035 and D.23-02-040.[64] As required by the ACR,[65] MCE includes the Table 11 below, which describes how MCE's 2024 RPS~~

~~[64] Since filing its 2022 Compliance IRP, MCE has filed four biannual MTR update filings on February 1, 2023, August 1, 2023, December 1, 2023, and June 3, 2024, respectively.~~
~~[65] ACR at 32-35.~~

~~Procurement Plan conforms with the determinations made in the IRP Proceedings (R.16-02-007 and R.20-05-003). As required, MCE highlights the interrelationships of its RPS and IRP planning processes in this RPS Procurement Plan. The following table reflects MCE's current updates, as reflected in this RPS Procurement Plan, regarding RPS alignment with the 2022 IRP process.~~

~~Table 11: RPS Alignment in MCE's IRP~~

~~IRP Section Subsection~~	**~~RPS Alignment in IRP~~**	
~~III. Study Results~~ **~~A. Conforming and Alternative Portfolios~~**	~~Retail sellers should explain how the RPS resources they plan to procure, outlined in their RPS Plan, will align with each of their Conforming Portfolios being developed in their IRP Plans for Commission approval and certification. This explanation should include:~~	
	~~1. Existing RPS resources that the retail seller owns or contracts.~~ *~~2. Existing RPS resources that the retail seller plans to contract with in the future.~~* *~~3. New RPS resources that the retail seller plans to invest in.~~* *~~4. New and existing resources that will be used to meet Mid-Term Reliability obligations adopted in D.21-06-035 and the supplemental procurement ordered in D.23-02-040.~~*	~~The Commission certified MCE's 2022 Compliance IRP per Ordering Paragraph 5 of D.24-02-047. Pursuant to D.24-02-047 and the~~ *~~Assigned Commissioner's Amended Scoping Memo and Ruling Extending Statutory Deadline~~*~~, issued April 18, 2024, MCE's next full update to its 2022 Compliance IRP will not be filed until November 1, 2025. As part of this last biennial IRP filing MCE submitted a single Preferred Conforming Portfolio (PCP) that meets MCE's internal and mandated RPS targets and achieves MCE's proportional share of both the 30 MMT GHG targets (~~*~~i.e.~~*~~ 38 MMT by 2030 and 30 MMT by 2035) and the 25 MMT GHG targets (~~*~~i.e.~~*~~ 30 MMT by 2030 and 25 MMT by 2035). MCE provided the same PCP for consideration under both aforementioned GHG target scenarios. For its PCP, new resources were added to MCE's currently contracted RPS resources to achieve the respective GHG targets as well as RPS procurement~~

		~~requirements, including the 65% long-term contracting requirement.~~ ~~Description of MCE's PCP:~~ • ~~MCE's PCP achieves an overall portfolio GHG target below MCE's assigned share of the 2030 and 2035 emissions under both the 30 MMT and 25 MMT scenarios.~~ • ~~Using the CPUC's embedded assumptions in the 30 MMT portfolio, MCE's emissions registered at 0.500 MMT relative to MCE's assigned share of 0.848 MMT in 2030 and 0.514 MMT relative to MCE's assigned share of 0.630 MMT in 2035.~~ • ~~Using the CPUC's embedded assumptions in the 25 MMT portfolio, MCE's emissions registered at 0.493 MMT relative to MCE's assigned share of 0.640 MMT in 2030 and 0.492 MMT relative to 0.504 MMT in 2035.~~ • ~~MCE's PCP assumed the use of RPS resources that were reflected in MCE's supply portfolio at the time of the 2022 Compliance IRP filing.~~ • ~~The planned RPS-eligible resources reflected in MCE's PCP included: 109 MW geothermal; 356 MW wind (consisting of in-state, out-of-state, and off-shore); and 222 MW solar~~ ○ ~~Of the aforementioned PCP resources, MCE anticipated the following new RPS-eligible capacity additions: new hybrid resources totaling 212 MW solar/ 153 MW battery storage, 109 MW of geothermal, and new wind resources totaling 265 MW~~ • ~~Pursuant to D.21-06-035, MCE was assigned 332 MW of incremental Net Qualifying Capacity to meet its share~~

		~~of state's MTR need. MCE was also assigned an additional 122 MW of incremental Net Qualifying Capacity to be online by 2027 pursuant to D.23-02-040. As reflected in MCE's 2022 PCP, MCE is actively procuring to meet the initial MTR need and the supplemental need on the mandated timelines. To date, MCE has executed a number of contracts for RPS-eligible resources that contribute towards MCE's RPS needs and MTR requirements. Due to circumstances outside of MCE's control, however, some contracted RPS and mid-term reliability resources have fallen out of MCE's portfolio or are delayed, or expected to be delayed, beyond the initial milestone and commercial operation dates. Moreover, regulatory and market conditions coupled with insufficient transmission capacity and deliverability allocations has limited MCE's ability to procure resources that meet both the attributes and timelines mandated by the Commission. At the time of this filing, MCE's existing executed MTR agreements include the following incremental capacity amounts: 27 MW of nameplate geothermal capacity ; 100 MW nameplate solar paired with 92 MW of nameplate storage; and 110 MW of nameplate solar paired with 60 MW of nameplate storage, and 93.35 MW of nameplate wind capacity.~~ • ~~Although not RPS-eligible, MCE has also executed several agreements for stand-alone storage that will be applied towards MCE's generic MTR needs. These non-RPS-eligible contracts amount to 323 MW of nameplate storage capacity.~~ • ~~MCE is pursuing additional procurement to satisfy MTR open~~

		~~positions, including the supplemental procurement under D.23-02-040, via its 2024 Open Season, some of which procurement will also be eligible to contribute towards MCE's RPS needs.~~
~~**IV. Action Plan**~~ ~~**A. Proposed Activities**~~	~~Retail sellers should describe how they propose to use RPS resources to implement both Conforming Portfolios. Narratives should include:~~	
	~~*1. Proposed RPS procurement activities as required by Commission decision or mandated procurement.*~~ ~~*2. Procurement plans, potential barriers, and resource viability for each new RPS resource identified.*~~	~~To ensure compliance with its IRP, GHG, reliability, and RPS targets, MCE plans to substantially rely on GHG-free and RPS-eligible resources while contributing to statewide reliability requirements and responsibly managing overall portfolio costs.~~ ~~MCE's compliance with the IRP incremental procurement obligation required by D.19-11-016 has been met through a mix of resources currently under contract and online, some of which are RPS-eligible. Such incremental capacity is comprised of the following resource types: natural gas (Sutter Energy Center), solar, landfill-gas-to-energy generation, and demand response. These resources are further described in MCE's 2022 IRP and MCE's biannual MTR update filings filed in February 2023 and August 2023. .~~ ~~As part of its Open Season procurement process and additional efforts to secure resources to meet MTR procurement requirements under D.21-06-035 and D.23-02-040, as described above, MCE also contracted for two hybrid resources, which are expected to provide additional RPS-eligible incremental capacity. MCE's prior RPS procurement plan indicated MCE had four geothermal projects under contract (three of which were new, incremental geothermal capacity). As of this filing, due to contract failure of one of those geothermal projects, MCE has three geothermal projects under contract (2 of~~

		~~which are incremental geothermal capacity) All of the aforementioned projects are under long-term contract.~~ ~~For detailed descriptions of MCE's MTR procurement, please refer to MCE's MTR update filings that were filed with the Commission in February 2023, August 2023, December 2023, and June 2024.~~ ~~MCE is currently administering 2024 Open Season procurement processes to fill outstanding resource needs required to meet portfolio specifications reflected in its PCP, MTR requirements, as well as any other internal and state-mandated RPS or reliability procurement targets. To the extent additional resources are needed, MCE is conducting supplemental, smaller solicitations and pursuing bilateral negotiations.~~
~~IV. Action Plan~~ **~~B. Procurement Activities~~**	~~The retail seller should describe the solicitation strategies for the RPS resources that will be included in both Conforming Portfolios. This description should include:~~	
	~~1. The type of solicitation.~~ *~~2. The timeline for each solicitation.~~* *~~3. Desired online dates.~~* *~~4. Other relevant procurement planning information, such as solicitation goals and objectives.~~*	~~MCE will issue future solicitations, as described above in Section X, on a timeline that is appropriate for the resource development plan reflected in its PCP, consistent with MTR procurement timelines and attributes, and that will allow MCE to meet its internal as well as state-mandated RPS targets. MCE typically administers its annual Open Season procurement processes each Spring and, as part of such processes, may pursue additional resources that will be needed to fulfill resource specifications reflected in its PCP or to meet MTR requirements. MCE's 2024 Open Season specifically targeted PCC 1-eligible renewable energy generating facilities that may be paired with energy storage. MCE expects this Open Season process to conclude Q3/early Q4 2024.~~

		~~In addition to the Open Season solicitations, MCE also solicits offers for short term PCC1 renewable energy purchases/sales for annual portfolio balancing. Additionally, MCE also participates in the PG&E VAMO process and receives an allocation of renewable energy from the PG&E's PCIA portfolio.~~
~~IV. Action Plan~~ **~~C. Potential Barriers~~**	~~Retail sellers should provide a summary of the potential barriers to implementing both Conforming Portfolios as they relate to RPS resources. The section should include:~~	
	~~1. Key market, regulatory, financial, or other resource viability barriers or risks associated with the RPS resources coming online in both retail sellers' Preferred Portfolios.~~ *~~2. Key risks associated with the potential retirement of existing RPS resources on which the retail seller intends to rely in the future.~~*	~~MCE notes that even though a balanced, diverse RPS portfolio is desirable, the limited resource availability and lead time required for some technology types may necessitate planning flexibility. While MCE has a highly successful track record of contracting with new-build renewable resources, there is always a risk of project failure due to market and regulatory conditions beyond MCE's control. Of increasing concern to MCE is the growing interconnection queue and delays in processing the unprecedented numbers of applications for interconnection studies and deliverability. Restrictions and uncertainty on this front increase risk and uncertainty for LSEs and can ultimately present a material barrier to LSEs bringing on new RPS resources that have sufficient deliverability to meet RPS program and reliability needs. Adding to this constraint are lingering supply chain issues and permitting delays that impact timely development and interconnection of new resources.~~

~~XVI~~XIV. Impact of Transmission and Interconnection Delays

SB 1174 (stats. 2022, ch. 229) requires electrical corporations that own transmission lines to report to the Commission on the development of transmission and interconnection facilities necessary to provide transmission deliverability for renewable energy and/or energy storage facilities that have executed interconnection agreements. MCE is not subject to the requirements of SB 1174 and does not own any transmission lines. Accordingly, MCE has not included a Transmission/Interconnection Delay Data Report as an attachment to this RPS Procurement Plan.

Dated: June 30, 2025~~July 23, 2024~~

Respectfully submitted,

/s/Sai Powar~~Amulya Yerrapotu~~

Sai Powar~~Amulya Yerrapotu~~
Policy Analyst
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
(415) 464-6044~~6670~~
ayerrapotu@mcecleanenergy.org

Appendix B

Draft 2025 RPS Procurement Plan Checklist and Verification

Draft 2025 RPS Procurement Plan Checklist- Task Completed

Retail seller name: Marin Clean Energy	**YES/NO**	**NOTES**
I. Summary of Major Changes to RPS Plan	YES	
II. Executive Summary Key Issues	YES	
III. Compliance with Recent Legislation and Impact of Regulatory	YES	
IV. Assessment of RPS Portfolio Supplies and Demand	YES	
IV.A. Portfolio Supply and Demand	YES	
IV.A.1. Long-term Procurement	YES	
IV.B. Portfolio Diversity and Reliability	YES	
IV.B.1 Forecasting for Increased Transportation Electrification	YES	
IV.B.2 Curtailment Frequency, Cost, and Forecasting	YES	
IV.C. Portfolio Optimization	YES	
IV.C.1 Conformance with the IRP Proceeding	YES	
IV.C.2 Response to Local and Regional Policies	YES	
IV.D. Lessons Learned	YES	
V. Project Development Status Update	YES	
VI. Potential Compliance Delays	YES	
VII. Risk Assessment	YES	
VII.A Compliance Risk	YES	
VII.B Risk Modeling and Risk Factors	YES	
VII.C Lessons Learned	YES	
VIII. Renewable Net Short Calculation	YES	
IX. Minimum Margin of Procurement (MMoP)	YES	
IX.A MMoP Level	YES	
IX.A.1 MMoP Methodology and Inputs	YES	
IX.A.2 MMoP Scenarios	YES	
X. Bid Solicitation Protocol	YES	
X.A. Bid Selection Protocols	YES	
X.B. Solicitation Protocols for Renewables Sales	YES	
X.C. Least-Cost Best-Fit (LCBF) Criteria	YES	
XI. Safety Considerations	YES	
XII. Consideration of Price Adjustments Mechanisms	YES	
XIII. Cost Quantification	YES	
XIV. Impact of Transmission and Interconnection Delays	N/A	
Appendix A: Redlined Version of the Draft 2025 RPS Plan	YES	

Officer Verification

I am an officer of the reporting organization herein and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters, I believe them to be true. The spreadsheet templates used within this filing have not been altered from the version issued or approved by Energy Division.

Executed on June 30, 2025 at San Rafael, California.

/s/ Vicken Kasarjian
Vicken Kasarjian
Chief Operating Officer
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
(415) 464-6659
vkasarjian@mcecleanenergy.org

Appendix C

Renewable Net Short Calculation

LSE Name:	Marin Clean Energy (MCE)		Input required	No input required
Date Filed:	6/30/25			

Variable	Calculation	Item	2021 Actual	2022 Actual	2023 Actual	2024 Actual	**2021-2024**
		Forecast Year					**CP 4**
		Annual RPS Requirement					
A		**Total Retail Sales (MWh)**	5,333,206	5,535,963	5,500,637	5,545,653	**21915459.59**
B		RPS Procurement Quantity Requirement (%)	0.3575	0.385	0.4125	0.44	0.399127711
C	A*B	**Gross RPS Procurement Quantity Requirement (**	**1906621.257**	**2131345.698**	**2269012.816**	**2440087.451**	**8747067.222**
D		Voluntary Margin of Over-procurement (MWh)	1,385,084	1,285,215	1,497,340	1,509,405	5677044.502
E	C+D	**Net RPS Procurement Need (MWh)**	**3,291,705**	**3,416,561**	**3,766,353**	**3,949,493**	**14424111.72**
		RPS-Eligible Procurement					
Fa		**Risk-Adjusted RECs from Online Generation (M**	**3,424,705**	**3,439,018**	**3,997,424**	**4,319,508**	**15180655**
Faa		Forecast Failure Rate for Online Generation (%)					#DIV/0!
Fb		**Risk-Adjusted RECs from RPS Facilities in Development (MWh)**					**0**
Fbb		Forecast Failure Rate for RPS Facilities in Development (%)					#DIV/0!
Fc		**Pre-Approved Generic RECs (MWh)**					**0**
Fd		**Executed REC Sales (MWh)**	**133,000**	**22,457**	**231,412**	**231,412**	**618281**
F	Fa+Fb+Fc-Fd	**Total RPS Eligible Procurement (MWh)**	**3,291,705**	**3,416,561**	**3,766,012**	**4,088,096**	**14562374**
F0		Category 0 RECs			585,554	525,681	1111235
F1		Category 1 RECs	3,084,578	3,350,361	3,180,799	3,793,827	13409565
F2		Category 2 RECs	207,127	39,000			246127
F3		Category 3 RECs	-	27,200			27200
		Gross RPS Position (Physical Net Short)					
Ga	F-E	**Annual Gross RPS Position (MWh)**	**0**	**-**	**(341)**	**138,603**	**138262.2758**
Gb	F/A	Annual Gross RPS Position (%)	0.617209387	0.617157501	0.684650143	0.737171219	0.664479517
		Application of Bank					
Ha	J-Hc (from previous CP)	**Existing Banked RECs above the PQR**					**0**
Hb		RECs above the PQR added to Bank					**0**
Hc		Non-bankable RECs above the PQR					**0**
H	Ha+Hb	**Gross Balance of RECs above the PQR**	**0**	**0**	**0**	**0**	**0**
Ia		Planned Application of RECs above the PQR towards RPS Compliance					**0**
Ib		Planned Sales of RECs above the PQR					**0**
J	H-Ia-Ib	**Net Balance of RECs above the PQR**	**0**	**0**	**0**	**0**	**0**
J0		Category 0 RECs					0
J1		Category 1 RECs					0
J3		Category 3 Bundled RECs (Non-CBA Utilities Only)*					0
		Expiring Contracts					
K		RECs from Expiring RPS Contracts (MWh)	815,227	1,294,994	1,048,666	1,671,826	4830712.51
		Net RPS Position (Optimized Net Short)					
La	Ga+Ia-Ib-Hc	**Annual Net RPS Position after Bank Optimizatio**	**0**	**0**	**-341**	**138603.2758**	**138262.2758**
Lb	(F+Ia-Ib-Hc)/A	Annual Net RPS Position after Bank Optimization (	0.617209387	0.617157501	0.684650143	0.737171219	0.664479517

Note: All values are to be input in MWhs

*D.17-11-037 provides for utilities serving load in areas outside California Independent System Operator Balancing Authority (Non-CBA Utilities) to bank excess bundled PCC3 RECs

LSE Name:	Marin Clean Energy (MCE)				Hard-coded			
Date Filed:	6/30/25							

Variable	Calculation	Item	2025 Forecast	2026 Forecast	2027 Forecast	2025-2027	2028 Forecast	2029 Forecast
		Forecast Year	1	2	3	CP 5	4	5
		Annual RPS Requirement						
A		**Total Retail Sales (MWh)**	5,608,766	5,591,289	5,533,994	16734049.74	5,474,800	5,406,236
B		RPS Procurement Quantity Requirement (%)	0.4667	0.4933	0.52	0.493214214	0.5467	0.5733
C	A*B	**Gross RPS Procurement Quantity Requirement (**	2617611.273	2758182.938	2877676.983	8253471.194	2993073	3099395.072
D		Voluntary Margin of Over-procurement (MWh)	1,633,655	1,486,497	1,629,709	4749860.942	1,770,858	1,902,933
E	C+D	**Net RPS Procurement Need (MWh)**	4,251,267	4,244,680	4,507,386	13003332.14	4,763,931	5,002,328
		RPS-Eligible Procurement						
Fa		**Risk-Adjusted RECs from Online Generation (M**	4,004,716	2,889,168	3,461,443	10355326.88	2,929,534	2,923,263
Faa		Forecast Failure Rate for Online Generation (%)	10%	10%	10%	0.1	10%	10%
Fb		**Risk-Adjusted RECs from RPS Facilities in Dev**	305,115	562,751	563,105	1430970.31	720,171	717,374
Fbb		Forecast Failure Rate for RPS Facilities in Developme	10%	10%	10%	0.1	10%	10%
Fc		**Pre-Approved Generic RECs (MWh)**				0		
Fd		**Executed REC Sales (MWh)**				0		
F	Fa+Fb+Fc-Fd	**Total RPS Eligible Procurement (MWh)**	4,309,831	3,451,919	4,024,547	11786297.19	3,649,706	3,640,637
F0		Category 0 RECs				0		
F1		Category 1 RECs	4,309,831	3,451,919	4,024,547	11786297.19	3,649,706	3,640,637
F2		Category 2 RECs				0		
F3		Category 3 RECs				0		
		Gross RPS Position (Physical Net Short)						
Ga	F-E	**Annual Gross RPS Position (MWh)**	58564.01105	-792760.3727	-482838.5837	-1217034.945	-1114225.631	-1361691.3
Gb	F/A	Annual Gross RPS Position (%)	0.768409734	0.617374462	0.727240981	0.704330235	0.666637319	0.673414407
		Application of Bank						
Ha	J-Hc (from previous CP)	**Existing Banked RECs above the PQR**	0			0	0	
Hb		RECs above the PQR added to Bank				0		
Hc		Non-bankable RECs above the PQR				0		
H	Ha+Hb	**Gross Balance of RECs above the PQR**	0	0	0	0	0	0
Ia		Planned Application of RECs above the PQR towar				0		
Ib		Planned Sales of RECs above the PQR				0		
J	H-Ia-Ib	**Net Balance of RECs above the PQR**	0	0	0	0	0	0
J0		Category 0 RECs				0		
J1		Category 1 RECs				0		
J3		Category 3 Bundled RECs (Non-CBA Utilities Only)				0		
		Expiring Contracts						
K		RECs from Expiring RPS Contracts (MWh)	1,273,100	591,232	900,000	2764332	-	184
		Net RPS Position (Optimized Net Short)						
La	Ga+Ia-Ib-Hc	**Annual Net RPS Position after Bank Optimizatio**	58564.01105	-792760.3727	-482838.5837	-1217034.945	-1114225.631	-1361691.3
Lb	(F+Ia-Ib-Hc) / A	Annual Net RPS Position after Bank Optimization (	0.768409734	0.617374462	0.727240981	0.704330235	0.666637319	0.673414407

Note: All values are to be input in MWhs

*D.17-11-037 provides for utilities serving load in areas outside California Indepen

LSE Name:	Marin Clean Energy (MCE)
Date Filed:	6/30/25

Variable	Calculation	Item	2030 Forecast	2028-2030	2031 Forecast	2032 Forecast	2033 Forecast	2031-2033
		Forecast Year	6	CP 6	7	8	9	CP 7
		Annual RPS Requirement						
A		**Total Retail Sales (MWh)**	5,450,346	16331381.78	5,494,873	5,570,366	5,593,623	16658862.05
B		RPS Procurement Quantity Requirement (%)	0.6	0.573293544	0.6	0.6	0.6	0.6
C	A*B	**Gross RPS Procurement Quantity Requirement (**	3270207.674	9362675.745	3296923.755	3342219.628	3356173.845	9995317.228
D		Voluntary Margin of Over-procurement (MWh)	2,066,802	5740594.015	2,377,358	2,406,310	2,417,628	7201296.017
E	C+D	**Net RPS Procurement Need (MWh)**	5,337,010	15103269.76	5,674,282	5,748,529	5,773,802	17196613.24
		RPS-Eligible Procurement						
Fa		**Risk-Adjusted RECs from Online Generation (M**	2,922,115	8774912.69	2,761,848	2,747,655	2,418,151	7927653.43
Faa		Forecast Failure Rate for Online Generation (%)	10%	0.1	10%	10%	10%	0.1
Fb		**Risk-Adjusted RECs from RPS Facilities in Dev**	715,449	2152995.12	895,223	965,321	959,998	2820541.55
Fbb		Forecast Failure Rate for RPS Facilities in Developme	10%	0.1	10%	10%	10%	0.1
Fc		**Pre-Approved Generic RECs (MWh)**		0				0
Fd		**Executed REC Sales (MWh)**		0				0
F	Fa+Fb+Fc-Fd	**Total RPS Eligible Procurement (MWh)**	3,637,565	10927907.81	3,657,070	3,712,976	3,378,149	10748194.98
F0		Category 0 RECs		0				0
F1		Category 1 RECs	3,637,565	10927907.81	3,657,070	3,712,976	3,378,149	10748194.98
F2		Category 2 RECs		0				0
F3		Category 3 RECs		0				0
		Gross RPS Position (Physical Net Short)						
Ga	F-E	**Annual Gross RPS Position (MWh)**	-1699445.019	-4175361.95	-2017212.078	-2035553.037	-2395653.15	-6448418.265
Gb	F/A	Annual Gross RPS Position (%)	0.667400702	0.66913553	0.665542259	0.66655873	0.603928558	0.645193828
		Application of Bank						
Ha	J-Hc (from previous CP)	**Existing Banked RECs above the PQR**		0	0			0
Hb		RECs above the PQR added to Bank		0				0
Hc		Non-bankable RECs above the PQR		0				0
H	Ha+Hb	**Gross Balance of RECs above the PQR**	0	0	0	0	0	0
Ia		Planned Application of RECs above the PQR towar		0				0
Ib		Planned Sales of RECs above the PQR		0				0
J	H-Ia-Ib	**Net Balance of RECs above the PQR**	0	0	0	0	0	0
J0		Category 0 RECs		0				0
J1		Category 1 RECs		0				0
J3		Category 3 Bundled RECs (Non-CBA Utilities Only)		0				0
		Expiring Contracts						
K		RECs from Expiring RPS Contracts (MWh)	150,564	150747.83	18,643	69,392	69,263	157297.5
		Net RPS Position (Optimized Net Short)						
La	Ga+Ia-Ib-Hc	**Annual Net RPS Position after Bank Optimizatio**	-1699445.019	-4175361.95	-2017212.078	-2035553.037	-2395653.15	-6448418.265
Lb	(F+Ia-Ib-Hc)/A	Annual Net RPS Position after Bank Optimization (	0.667400702	0.66913553	0.665542259	0.66655873	0.603928558	0.645193828

Note: All values are to be input in MWhs

*D.17-11-037 provides for utilities serving load in areas outside California Indepen

LSE Name:	Marin Clean Energy (MCE)
Date Filed:	6/30/25

Variable	Calculation	Item	2034 Forecast	2035 Forecast
		Forecast Year	10	11
		Annual RPS Requirement		
A		**Total Retail Sales (MWh)**	5,630,580	5,668,684
B		RPS Procurement Quantity Requirement (%)	0.6	0.6
C	A*B	**Gross RPS Procurement Quantity Requirement (**	3378348.074	3401210.202
D		Voluntary Margin of Over-procurement (MWh)	2,433,765	2,450,396
E	C+D	**Net RPS Procurement Need (MWh)**	5,812,113	5,851,607
		RPS-Eligible Procurement		
Fa		**Risk-Adjusted RECs from Online Generation (M**	2,348,510	2,348,338
Faa		Forecast Failure Rate for Online Generation (%)	10%	10%
Fb		**Risk-Adjusted RECs from RPS Facilities in Dev**	955,816	952,486
Fbb		Forecast Failure Rate for RPS Facilities in Developme	10%	10%
Fc		**Pre-Approved Generic RECs (MWh)**		
Fd		**Executed REC Sales (MWh)**		
F	Fa+Fb+Fc-Fd	**Total RPS Eligible Procurement (MWh)**	3,304,326	3,300,824
F0		Category 0 RECs		
F1		Category 1 RECs	3,304,326	3,300,824
F2		Category 2 RECs		
F3		Category 3 RECs		
		Gross RPS Position (Physical Net Short)		
Ga	F-E	**Annual Gross RPS Position (MWh)**	-2507786.926	-2550783.098
Gb	F/A	Annual Gross RPS Position (%)	0.586853635	0.582291021
		Application of Bank		
Ha	J-Hc (from previous CP)	**Existing Banked RECs above the PQR**	0	
Hb		RECs above the PQR added to Bank		
Hc		Non-bankable RECs above the PQR		
H	Ha+Hb	**Gross Balance of RECs above the PQR**	0	0
Ia		Planned Application of RECs above the PQR towar		
Ib		Planned Sales of RECs above the PQR		
J	H-Ia-Ib	**Net Balance of RECs above the PQR**	0	0
J0		Category 0 RECs		
J1		Category 1 RECs		
J3		Category 3 Bundled RECs (Non-CBA Utilities Only)		
		Expiring Contracts		
K		RECs from Expiring RPS Contracts (MWh)	-	-
		Net RPS Position (Optimized Net Short)		
La	Ga+Ia-Ib-Hc	**Annual Net RPS Position after Bank Optimizatio**	-2507786.926	-2550783.098
Lb	(F+Ia-Ib-Hc)/A	Annual Net RPS Position after Bank Optimization (	0.586853635	0.582291021

Note: All values are to be input in MWhs

*D.17-11-037 provides for utilities serving load in areas outside California Indepen

Appendix D

Project Development Status Update

(Public Version)

Reporting LSE Name	RPS Contract ID	Project Name	Technology Type	Project Development Phase	City	County	State	Zip Code	Latitude
Marin Clean Energy (MCE)	MCE50001	Daggett Solar	Hybrid	Post-Construction	Daggett	San Bernardino	CA	92327	34.8686
Marin Clean Energy (MCE)	MCE50007	Golden Fields Solar IV, LLC	Hybrid	Post-Construction	Rosamond	Kern	CA	93560	34.8344
Marin Clean Energy (MCE)	MCE60001	Strauss Wind Project	Wind	Post-Construction	Lompoc	Santa Barbara	CA	93436	34.34.53
Marin Clean Energy (MCE)	MCE30003	Humboldt House	Geothermal	Pre-Construction	Pershing	Pershing	NV	89418	118.55
Marin Clean Energy (MCE)	MCE30001	Geysers (7MW)	Geothermal	Construction	NA	Sonoma / Lake	CA	95425	38.7749
Marin Clean Energy (MCE)		Key		Pre-Construction		Fresno	CA		
Marin Clean Energy (MCE)		Cormorant		Pre-Construction	Daly City	San Mateo	CA		
Marin Clean Energy (MCE)		Corby		Pre-Construction	Vacaville	Solano	CA		
Marin Clean Energy (MCE)	MCE50177	Allium	Hybrid	Pre-Construction	Hollister	San Benito	CA	95023	36.9178
Marin Clean Energy (MCE)	MCE 50008	Conflitti	Solar PV - Ground mount	Construction	Firebaugh	Fresno	CA	93622	36.628
Marin Clean Energy (MCE)	MCE50009	Conflitti jr.	Solar PV - Ground Mount	Construction	Firebaugh	Fresno	CA	93622	36.628
Marin Clean Energy (MCE)	MCE50113	Fallon Two Rock Rd Solar	Solar PV - Ground Mount	Post-Construction	Tomales	Marin	CA	94952	38.2795
Marin Clean Energy (MCE)	MCE50010	Ranch Sereno	Solar PV - Ground mount	Pre-Construction	Byron	Contra Costa	CA	94514	37.8731

Reporting LSE Name	RPS Contract ID	Project Name	Longitude	Contract Length (Years)	Contract Execution Date (mm/dd/yyyy)	Contract Start Date (mm/dd/yyyy)	Contract End Date (mm/dd/yyyy)
Marin Clean Energy (MCE)	MCE50001	Daggett Solar	-116.8029	15	9/25/20	[redacted]	[redacted]
Marin Clean Energy (MCE)	MCE50007	Golden Fields Solar IV, LLC	-118.3003	15	2/4/22	[redacted]	[redacted]
Marin Clean Energy (MCE)	MCE60001	Strauss Wind Project	130.21.25	15	10/19/18	[redacted]	[redacted]
Marin Clean Energy (MCE)	MCE30003	Humboldt House	41.59	20	11/22/22	[redacted]	[redacted]
Marin Clean Energy (MCE)	MCE30001	Geysers (7MW)	122.7553	20	2/28/23	[redacted]	[redacted]
Marin Clean Energy (MCE)		Key		15	10/20/23	[redacted]	[redacted]
Marin Clean Energy (MCE)		Cormorant		15	3/8/24	[redacted]	[redacted]
Marin Clean Energy (MCE)		Corby		15	10/20/23	[redacted]	[redacted]
Marin Clean Energy (MCE)	MCE50177	Allium	-121.4301	20	2/14/25	[redacted]	[redacted]
Marin Clean Energy (MCE)	MCE 50008	Conflitti	-120.568	20	3/20/22	[redacted]	[redacted]
Marin Clean Energy (MCE)	MCE50009	Conflitti jr.	-120.568	20	3/20/22	[redacted]	[redacted]
Marin Clean Energy (MCE)	MCE50113	Fallon Two Rock Rd Solar	-122.8663	20	4/5/21	[redacted]	[redacted]
Marin Clean Energy (MCE)	MCE50010	Ranch Sereno	-121.6258	20	2/23/22	[redacted]	[redacted]

Reporting LSE Name	RPS Contract ID	Project Name	Contract Capacity	Expected Annual Generation	Total Contract Volume	Commercial Operation Date (COD)
Marin Clean Energy (MCE)	MCE50001	Daggett Solar	110	342,577	4,962,640	8/25/23
Marin Clean Energy (MCE)	MCE50007	Golden Fields Solar IV, LLC	100	322,635		3/1/25
Marin Clean Energy (MCE)	MCE60001	Strauss Wind Project	93.35	290,400	4,356,000	12/22/23
Marin Clean Energy (MCE)	MCE30003	Humboldt House	20	158,000	3,318,000	2/1/28
Marin Clean Energy (MCE)	MCE30001	Geysers (7MW)	7	61,320	1226400	6/1/25
Marin Clean Energy (MCE)		Key	35			6/1/27
Marin Clean Energy (MCE)		Cormorant	188			6/1/26
Marin Clean Energy (MCE)		Corby	100			4/1/27
Marin Clean Energy (MCE)	MCE50177	Allium	110	276,374	5,223,472	5/1/31
Marin Clean Energy (MCE)	MCE 50008	Conflitti	4.4	12,254	232,612	3/31/26
Marin Clean Energy (MCE)	MCE50009	Conflitti jr.	0.26	668	12,680	3/31/26
Marin Clean Energy (MCE)	MCE50113	Fallon Two Rock Rd Solar	0.96	1,899	37,980	1/29/24
Marin Clean Energy (MCE)	MCE50010	Ranch Sereno	2	5,649	107,774	2/22/24

Reporting LSE Name	RPS Contract ID	Project Name	Transmission Status	Storage: Rated Power (MW)	Storage: Capacity (MWh)
Marin Clean Energy (MCE)	MCE50001	Daggett Solar	complete	60	240
Marin Clean Energy (MCE)	MCE50007	Golden Fields Solar IV, LLC	complete	92	368
Marin Clean Energy (MCE)	MCE60001	Strauss Wind Project	complete		
Marin Clean Energy (MCE)	MCE30003	Humboldt House	in development		
Marin Clean Energy (MCE)	MCE30001	Geysers (7MW)	complete		
Marin Clean Energy (MCE)		Key	in development	35	280
Marin Clean Energy (MCE)		Cormorant	in development	188	752
Marin Clean Energy (MCE)		Corby	in development	100	400
Marin Clean Energy (MCE)	MCE50177	Allium	in development	110	440
Marin Clean Energy (MCE)	MCE 50008	Conflitti	distribution		
Marin Clean Energy (MCE)	MCE50009	Conflitti jr.	distribution		
Marin Clean Energy (MCE)	MCE50113	Fallon Two Rock Rd Solar	distribution		
Marin Clean Energy (MCE)	MCE50010	Ranch Sereno	distribution	0.8	3.2

Reporting LSE Name	RPS Contract ID	Project Name	Project Notes
Marin Clean Energy (MCE)	MCE50001	Daggett Solar	[redacted]
Marin Clean Energy (MCE)	MCE50007	Golden Fields Solar IV, LLC	
Marin Clean Energy (MCE)	MCE60001	Strauss Wind Project	
Marin Clean Energy (MCE)	MCE30003	Humboldt House	
Marin Clean Energy (MCE)	MCE30001	Geysers (7MW)	
Marin Clean Energy (MCE)		Key	
Marin Clean Energy (MCE)		Cormorant	
Marin Clean Energy (MCE)		Corby	
Marin Clean Energy (MCE)	MCE50177	Allium	
Marin Clean Energy (MCE)	MCE 50008	Conflitti	
Marin Clean Energy (MCE)	MCE50009	Conflitti jr.	
Marin Clean Energy (MCE)	MCE50113	Fallon Two Rock Rd Solar	
Marin Clean Energy (MCE)	MCE50010	Ranch Sereno	

Appendix E

Cost Quantification

(Public Version)

LSE Name:	Marin Clean Energy (MCE)
Date Filed:	6/30/25

Input Required

No Input Required

Table 1: Cost Quantification (Actual Net Costs, $)		Actual RPS-Eligible Procurement and Generation Net Costs ($)		
1	**Executed RPS-Eligible Contracts by Technology Type* (Purchases and Sales)**	**T1_2022**	**T1_2023**	**T1_2024**
2	Biogas: Digester Gas	$41,389		
3	Biogas: Landfill Gas	$7,961,327	$8,197,853	$11,133,658
4	Biodiesel			
5	Biomass	$19,794,125	$8,758,574	$5,176,013
6	Muni Solid Waste			
7	Geothermal	$24,698,751	$13,894,201	$7,877,750
8	Small Hydro (Non-UOG)	$12,788,238	$24,382,556	$15,936,503
9	Conduit Hydro			
10	Water Supply / Conveyance			
11	Ocean Wave			
12	Ocean Thermal			
13	Tidal Current			
14	Solar PV (Non-UOG)	$67,758,249	$171,242,881	$180,442,243
15	Solar Thermal	$3,681,646		
16	Wind	$87,597,850	$76,919,773	$96,029,278
17	Unbundled RECs (REC Only)	$149,600		
18	Various (Index Plus REC)***			
19	Fuel Cell			
20	Linear Generator			
21	UOG: Small Hydro	$5,728,906		
22	UOG: Solar PV	$23,407,696		
23	UOG: Other	$978,023		
24	Executed REC Sales (Revenue)	$3,063,500		
25	**Total RPS-Eligible Procurement and Generation Net Cost**	**251522300.6**	**303395837**	**316595444.8**
26	Total Retail Sales (MWh)	5,535,963	5,500,637	5,545,653
27	**Incremental Rate Impact**	**4.543424647**	**5.515649003**	**5.708893575**

LSE Name:	Marin Clean Energy (MCE)
Date Filed:	6/30/25

Input Required

No Input Required

Table 2: Cost Quantification (Forecast Costs and Revenues, $)		Forecast RPS-Eligible Procurement Costs and Revenues ($)										
1	Executed But Not Approved RPS-Eligible Contracts (Purchases and Sales)**	T2_2025_EBNA	T2_2026_EBNA	T2_2027_EBNA	T2_2028_EBNA	T2_2029_EBNA	T2_2030_EBNA	T2_2031_EBNA	T2_2032_EBNA	T2_2033_EBNA	T2_2034_EBNA	T2_2035_EBNA
2	Biogas: Digester Gas											
3	Biogas: Landfill Gas											
4	Biodiesel											
5	Biomass											
6	Muni Solid Waste											
7	Geothermal											
8	Small Hydro (Non-UOG)											
9	Conduit Hydro											
10	Water Supply / Conveyance											
11	Ocean Wave											
12	Ocean Thermal											
13	Tidal Current											
14	Solar PV (Non-UOG)											
15	Solar Thermal											
16	Wind											
17	Unbundled RECs (REC Only)											
18	Various (Index Plus REC)***											
20	Fuel Cell											
21	Linear Generator											
22	UOG: Small Hydro											
23	UOG: Solar PV											
24	UOG: Other											
25	Executed REC Sales (Revenue)											
26	Total Executed But Not Approved RPS-Eligible Procurement and Generation Cost	0	0	0	0	0	0	0	0	0	0	0
27	Total Retail Sales (MWh)	5,608,766	5,591,289	5,533,994	5,474,800	5,406,236	5,450,346	5,494,873	5,570,366	5,593,623	5,630,580	5,668,684
28	Incremental Rate Impact	0	0	0	0	0	0	0	0	0	0	0
29	Executed RPS-Eligible Contracts (Purchases and Sales)****	T2_2025_EAA	T2_2026_EAA	T2_2027_EAA	T2_2028_EAA	T2_2029_EAA	T2_2030_EAA	T2_2031_EAA	T2_2032_EAA	T2_2033_EAA	T2_2034_EAA	T2_2035_EAA
30	Biogas: Digester Gas	[redacted]										
31	Biogas: Landfill Gas				9,863,658	9,887,048	9,936,058	9,028,305	7,113,050	3,689,886	2,583,467	2,583,467
32	Biodiesel											
33	Biomass											
34	Muni Solid Waste											
35	Geothermal				82,657,815	82,464,536	82,464,536	82,464,536	82,689,728	82,465,550	82,434,651	82,465,550
36	Small Hydro (Non-UOG)				1,744,637	1,742,347	1,742,347	1,742,347	1,744,637	1,742,347	1,742,347	1,742,347
37	Conduit Hydro											
38	Water Supply / Conveyance											
39	Ocean Wave											
40	Ocean Thermal											
41	Tidal Current											
42	Solar PV (Non-UOG)				85,279,767	85,191,479	85,197,082	93,961,713	97,486,718	82,758,712	79,946,435	79,906,928
43	Solar Thermal											
44	Wind				30,243,448	30,165,212	30,135,734	23,528,618	23,599,481	23,529,442	23,533,128	23,533,381
45	Unbundled RECs (REC Only)											
47	Various (Index Plus REC)***											
48	Fuel Cell											
49	Linear Generator											
50	UOG: Small Hydro											
51	UOG: Solar PV											
52	UOG: Other											
53	Executed REC Sales (Revenue)											
54	Total Executed and Approved RPS-Eligible Procurement and Generation Cost				209789326.2	209450622.4	209475757.8	210725520.3	212633613.7	194185936.7	190240028.2	190231672.6
55	Total Retail Sales (MWh)	5,608,766	5,591,289	5,533,994	5,474,800	5,406,236	5,450,346	5,494,873	5,570,366	5,593,623	5,630,580	5,668,684
56	Incremental Rate Impact	[redacted]			3.831908699	3.874241232	3.843347801	3.834948017	3.817228741	3.471559203	3.378693209	3.355835035
57	Total RPS-Eligible Procurement and Generation Cost				209789326.2	209450622.4	209475757.8	210725520.3	212633613.7	194185936.7	190240028.2	190231672.6
58	Total Incremental Rate Impact				3.831908699	3.874241232	3.843347801	3.834948017	3.817228741	3.471559203	3.378693209	3.355835035

*Note: Technology definitions are given in the PCC Classification Handbook located in the RPS Compliance Reporting section of: https://www.cpuc.ca.gov/RPSComplianceReporting/

**Note: For contracts that have been executed but still require formal approval (CPUC or other formal approval process) for purchases and sales.

***Note: The "Various" technology type is to be used in the case of contracts encompassing multiple facilities where the generation type is not yet known

****Note: For IOUs and SMJUs: Include all executed contracts that required CPUC approval. For CCAs and ESPs: Include all executed contracts that have been approved through relevant formal approval processes.

LSE Name:	Marin Clean Energy (MCE)
Date Filed:	6/30/25

Input Required

No Input Required

Table 3: Cost Quantification (Actual Procurement / Generation and Sales, MWh)		Actual RPS-Eligible Procurement / Generation and Sales (MWh)		
1	Technology Type* (Procurement / Generation and Sales)	T3_2022	T3_2023	T3_2024
2	Biogas: Digester Gas	410		
3	Biogas: Landfill Gas	80,148	91,513	113,004
4	Biodiesel			
5	Biomass	199,046	130,185	50,940
6	Muni Solid Waste			
7	Geothermal	271,560	154,515	95,839
8	Small Hydro (Non-UOG)	142,322	418,173	256,614
9	Conduit Hydro			
10	Water Supply / Conveyance			
11	Ocean Wave			
12	Ocean Thermal			
13	Tidal Current			
14	Solar PV (Non-UOG)	1,330,970	2068961	2,613,960
15	Solar Thermal	83,960		
16	Wind	1,003,289	1,134,077	1,189,151
17	Unbundled RECs (REC Only)	27,200		
18	Various (Index Plus REC)***			
19	Fuel Cell			
20	Linear Generator			
21	UOG: Small Hydro	57,071		
22	UOG: Solar PV	233,242		
23	UOG: Other	9,800		
24	Executed REC Sales (MWh)	22,457	231,412	231,412
25	**Total RPS Eligible Procurement (MWh)**	**3416561**	**3766012**	**4088096**

LSE Name:	Marin Clean Energy (MCE)
Date Filed:	6/30/25

Input Required

No Input Required

Table 4: Cost Quantification (Forecast Procurement / Generation and Sales, MWh)		Forecast RPS-Eligible Procurement / Generation and Sales (MWh)										
1	Executed But Not Approved RPS-Eligible Contracts (Purchases and Sales) **	T4_2025_EBNA	T4_2026_EBNA	T4_2027_EBNA	T4_2028_EBNA	T4_2029_EBNA	T4_2030_EBNA	T4_2031_EBNA	T4_2032_EBNA	T4_2033_EBNA	T4_2034_EBNA	T4_2035_EBNA
2	Biogas: Digester Gas											
3	Biogas: Landfill Gas											
4	Biodiesel											
5	Biomass											
6	Muni Solid Waste											
7	Geothermal											
8	Small Hydro (Non-UOG)											
9	Conduit Hydro											
10	Water Supply / Conveyance											
11	Ocean Wave											
12	Ocean Thermal											
13	Tidal Current											
14	Solar PV (Non-UOG)											
15	Solar Thermal											
16	Wind											
17	Unbundled RECs (REC Only)											
18	Various (Index Plus REC)***											
20	Fuel Cell											
21	Linear Generator											
22	UOG: Small Hydro											
23	UOG: Solar PV											
24	UOG: Other											
25	Executed REC Sales (MWh)											
26	**Total Executed But Not Approved RPS-Eligible Procurement**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
27	**Executed and Approved RPS-Eligible Contracts (Purchases and Sales) ******	**T4_2025_EAA**	**T4_2026_EAA**	**T4_2027_EAA**	**T4_2028_EAA**	**T4_2029_EAA**	**T4_2030_EAA**	**T4_2031_EAA**	**T4_2032_EAA**	**T4_2033_EAA**	**T4_2034_EAA**	**T4_2035_EAA**
28	Biogas: Digester Gas											
29	Biogas: Landfill Gas	103,437	103,437	103,437	103,695	103,437	103,437	93,926	74,553	39,748	30,394	30,394
30	Biodiesel											
31	Biomass											
32	Muni Solid Waste											
33	Geothermal	123,559	148,913	575,013	1,097,738	1,095,170	1,095,170	1,095,170	1,098,161	1,095,184	1,094,774	1,095,184
34	Small Hydro (Non-UOG)	160,171	237,071	37,071	37,120	37,071	37,071	37,071	37,120	37,071	37,071	37,071
35	Conduit Hydro											
36	Water Supply / Conveyance											
37	Ocean Wave											
38	Ocean Thermal											
39	Tidal Current											
40	Solar PV (Non-UOG)	2,053,637	1,993,444	2,589,957	1,840,620	1,835,850	1,833,451	2,013,115	2,084,114	1,788,345	1,724,222	1,720,306
41	Solar Thermal											
42	Wind	869,026	769,053	719,069	570,533	569,108	568,435	417,787	419,028	417,801	417,865	417,869
43	Unbundled RECs (REC Only)											
45	Various (Index Plus REC)***	1,000,000	200,000									
46	Fuel Cell											
47	Linear Generator											
48	UOG: Small Hydro											
49	UOG: Solar PV											
50	UOG: Other											
51	Executed REC Sales (MWh)											
52	**Total Executed and Approved RPS-Eligible Procurement**	**4309830.69**	**3451919.13**	**4024547.37**	**3649705.8**	**3640637.18**	**3637564.83**	**3657070.14**	**3712976.12**	**3378148.72**	**3304326.41**	**3300823.6**
53	**Total RPS Eligible Procurement (MWh)**	**4309830.69**	**3451919.13**	**4024547.37**	**3649705.8**	**3640637.18**	**3637564.83**	**3657070.14**	**3712976.12**	**3378148.72**	**3304326.41**	**3300823.6**

*Note: Technology definitions are given in the PCC Classification Handbook located in the RPS Compliance Reporting section of: https://www.cpuc.ca.gov/RPSComplianceReporting/

**Note: For contracts that have been executed but still require formal approval (CPUC or other formal approval process) for purchases and sales.

***Note: The "Various" technology type is to be used in the case of contracts encompassing multiple facilities where the generation type is not yet known

****Note: For IOUs and SMJUs: Include all executed contracts that required CPUC approval. For CCAs and ESPs: Include all executed contracts that have been approved through relevant formal approval processes.

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE

June 30, 2025

Advice Letter 20-E/20-G et. al.

Lujuana Medina
Division Manager, Environmental Initiatives
County of Los Angeles
On behalf of Southern California Regional Energy Network

SUBJECT: Tier 2 Advice Letter Filed by Southern California Regional Energy Network on Behalf of the Energy Efficiency Portfolio Administrators for Program Overlap Analysis

Dear Ms. Medina,

Advice Letter 20-E/20-G et al. is approved effective June 11, 2025.

Southern California Regional Energy Network (SoCalREN) submitted Advice Letter 20-E/20-G et al. requesting approval of compliance with Ordering Paragraph 32 of D.23-06-055. The Public Advocates Office of the California Public Utilities Commission (Cal Advocates) protested the advice letter on the grounds that the advice letter does not comply with OP 32 because the analysis of substantially similar programs is insufficient, the advice letter does not define program precedence, and it does not describe mitigation effectiveness. Pacific Gas and Electric (PG&E) filed comments, agreeing with the need for further assessment to determine program precedence, but arguing that the Commission should approve the advice letter. Bay Area Regional Energy Network, Inland Regional Energy Network, Marin Clean Energy, SoCalREN, Tri-County Regional Energy Network, Pacific Gas & Electric, Southern California Edison, Southern California Gas, and San Diego Gas and Electric submitted replies to the protest arguing that the advice letter complies with applicable Commission policy and guidance.

Attachment 1 provides more detail on the advice letter background, protest, comments, and Energy Division disposition.

Sincerely,

Candace J. Morey (for)
Leuwam Tesfai
Deputy Executive Director for Energy and Climate Policy/
Director, Energy Division
California Public Utilities Commission

cc:
Service List R.13-11-005
Service List R.25-04-010
ED Tariff Unit, CPUC
Jacob Coby Rudolph, Energy Division, CPUC

Lujuana Medina, LMedina@isd.lacounty.gov
Shelly Lyser. Shelly.Lyser@cpuc.ca.gov
Alejandra Tellez, Alejandra.Tellez@ventura.org
Jane Elias, jelias@bayareametro.gov
Casey Dailey, cdailey@wrcog.us
Wade Stano, wstano@mcecleanenergy.org,
Karyn Gansecki, Karyn.Gansecki@sce.com,
Greg Anderson, GAnderson@sdge.com
Gary Lenart, GLenart@socalgas.com
Sidney Dietz, c/o Megan Lawson, PG&E
Connor Flanigan, connor.flanigan@sce.com
PG&E Tariff Unit, PGETariffs@pge.com, PG&E
SCE Tariff Unit, AdviceTariffManager@sce.com, SCE
SoCalGas Tariff Unit, Tariffs@socalgas.com
SDG&E Tariff Unit, SDGETariffs@SDGE.com, SDG&E

ATTACHMENT 1

Background

Ordering Paragraph (OP) 32 of D.23-06-055 directs the Portfolio Administrators (PAs) to provide information on substantively similar programs and steps that they have taken and will take to mitigate or minimize ratepayer risk of program overlap and duplication in a Tier 2 advice letter no later than September 1, 2024. On August 16, 2024, SoCalREN, on behalf of the PAs, requested and was granted a one-month extension for the advice letter. On October 1, 2024, SoCalREN filed Advice Letter 20-E/20-G et al. requesting approval of compliance with OP 32 of D.23-06-055. The advice letter, hereafter called the Joint AL, was filed as SoCalREN AL 20-E/20-G, BayREN AL 27-E, I-Ren AL 6 E/6-G, MCE AL 83-E, PCG AL 4980-E/7390-G, SDGE AL 4523-E/3351-G, SCE AL 5383-E, SoCalGas AL 6375-G, and TC REN AL 12-E/11-G. The Joint AL includes as an attachment a report authored by the PAs, herein called the OP 32 Report, in adherence with the six requirements of the OP. PG&E, SCE, and SDG&E included a statement in the Joint AL that they plan to further analyze measure-level overlap and the concept of program precedence.

Section 9.1 of D.23-06-055 highlights a call by the Public Advocates Office at the California Public Utilities Commission (Cal Advocate) for an assessment of duplication among statewide, PA-implemented and third party-implemented programs and recommends that the Commission provide guidance for the prioritization of programs. In rebuttals to D.23-06-055, BayREN, MCE, PG&E, SCE, SDG&E, SoCalREN, and 3C-REN disagreed with Cal Advocates' request. BayREN, 3C-REN, MCE, CEDMC and SoCalREN recommended that the Joint Cooperation Memo process and other established PA coordination efforts are sufficient to resolve these issues. SCE countered Cal Advocates' identification of some of their programs as duplicative. However, SCE argued that the Commission needs to provide guidance regarding program prioritization. The Commission concluded in D.23-06-055 that an assessment using specific examples and scenarios could be informative and stated that they "are not wedded to establishing formal guidance if the PAs demonstrate they have a process or protocol to, among themselves, effectively mitigate or minimize ratepayer risks associated with duplicative or overlapping program".[1] Accordingly, OP 32 of D.23-06-055 orders the PAs to file an advice letter that provides:

a. A comprehensive list of any substantively similar ratepayer-funded energy efficiency programs among the PAs.
b. A clear statement of the issues or problems that result from program offerings identified in Item (a).
c. Definitions or clarifications of any jargon that PAs suggest specifying, in order to have a shared understanding of the issues or problems associated with substantively similar ratepayer-funded energy efficiency programs among different PAs. For example, the joint advice letter should propose definitions for "overlap," "duplication," and "precedence."
d. Description of the risk to ratepayers of ratepayer-funded energy efficiency programs that "overlap" or are otherwise "duplicative" (as defined in response to Item (c), above) in some substantive way. What is the estimated dollar value of the risk? Describe how the value was calculated or assessed.
e. Description of the actions, measures, etc. that PAs have taken thus far to identify and mitigate or minimize risks to ratepayers of substantively similar ratepayer-funded energy efficiency

[1] D.23-06-055 at 87

programs among different PAs, and any other issues identified in response to Item (b). Include, for instance, any agreed-upon criteria for determining program "overlap," "duplication," and/or "precedence," and what steps have been taken by each PA in cases where "overlap" or "duplication" was identified. Explain the effectiveness of each of these measures, actions, etc. in mitigating ratepayer risks, and identify and describe what issues remain unresolved.

f. Description of how the PAs will effectively mitigate or minimize ratepayer risks associated with similar ratepayer-funded energy efficiency programs among different PAs through the JCM or any other agreed-upon process or protocol.[2]

The PAs request Commission approval that the information in their OP 32 Report, attached to the Joint AL, complies with the six requirements (above) in OP 32 of D.23-06-055. The report outlines information on 27 programs that are substantively similar, as well as the measures PAs implement to mitigate or minimize the risk of program overlap or duplication for ratepayers.

The PAs believe that the Joint AL complies with OP 32(a) by providing a list (Table 12 of the report), and in an excel spreadsheet in an Appendix to the report. The PAs identified 27 programs that met their agreed-upon criteria of substantially similar or duplicative programs. OP 32(b) orders that the PAs provide a clear statement of the issues or problems that result from these programs. The PAs state, "Generally, the potential risks of program duplication include inefficiencies in resource allocation, confusion among customers, and increased costs due to duplication of efforts. Duplicative programs may also struggle with clear delineation of responsibilities, leading to gaps in service delivery or redundant work. Additionally, program overlap can result in competition for the same funding sources and beneficiaries, which might undermine the effectiveness of the programs involved."[3] For compliance with OP 32(c), the PAs provide agreed-upon definitions to address substantially similar energy efficiency programs among different PAs. They agreed to define four terms: "similar", "program overlap", "substantially similar", and "program duplication".[4] They met multiple times in 2024 and developed definitions for each term.[5]

OP 32(d) orders the PAs to describe the risk to ratepayers of rate-payer-funded energy efficiency programs that overlap or are otherwise duplicative, using their definitions of these terms. The OP instructs the PAs to include a dollar amount for the risk and explain their method for the valuation. The PAs explain that "potential ratepayer risk can be thought of as the expenditure of ratepayer funds without maximum value provided or created."[6] Using their authorized budgets, the PAs identified approximately $4,900,000 in potential annual ratepayer risk. However, if mitigation strategies are taken into account, the risk is lowered by 69% to approximately $1,500,000 in potential annual risk, according to the PAs.

OP 32(e) orders the PAs to describe the actions they have taken to mitigate risks to ratepayers of substantively similar ratepayer-funded energy efficiency programs among different PAs. The PAs agreed upon four types of Mitigation Actions that address ratepayer risk and identified which

[2] Ibid at 129-130
[3] OP 32 Report at 43
[4] Ibid at 19-21
[5] See OP 32 Table 7 at 20
[6] OP 32 Report at 37

Mitigation Actions apply to each of the 27 programs identified as Substantively Similar or Duplicative. In their advice letter, the PAs describe the four types of mitigation strategies as:

1. Cross PA & Program Coordination: e.g., JCM, PA Sector Coordination, including sharing data between programs for marketing & implementation transparency.
2. Program engages in Community-Based Initiatives: e.g., Collaborate with local organizations to conduct community assessments and align program efforts with local needs, avoiding unnecessary overlap in service delivery.
3. Customer Education & Coordination and/or Joint Program Initiatives (JPI): e.g., Educate stakeholders & participants to help make informed decisions as to which programs to participate in; JPI - Coordinate training sessions, workshops, events, etc.
4. Programmatic Actions including Implementation Plan updates; have developed program protocols and decision trees; assessment of core program offerings relative to other similar programs; etc.[7]

The PAs state that the Joint AL complies with OP 32(f) by stating that the PAs will continue to use the processes and strategies discussed in their respective Joint Cooperation Memos to continue ensuring effective mitigation of potential ratepayer risk associated energy efficiency programs, particularly those that potentially are Substantively Similar or Duplicative. The Southern California PAs, SoCalREN, SCE, SoCalGas, I-REN, and 3C-REN, have recurring sector-specific Portfolio Administrator Sector Coordination meetings (PASC), where they coordinate to ensure that their programs do not overlap or duplicate each other.[8]

Protest

Cal Advocates requested an extension of time to protest, which the Commission granted, so that they could issue a data request to SoCalREN and conduct a more detailed analysis of program overlap. Cal Advocates filed a timely protest on November 4, 2024. In the protest, Cal Advocates asserts that the definition of substantially similar is too narrow in the Joint AL, leading to an incomplete list of potentially overlapping or duplicative programs and a risk lower than if it included more programs. Cal Advocates also argues that the Joint AL fails to comply with the Commission's order in OP 32 because it does not include a definition of precedence.

Cal Advocates asserts that the four types of mitigation strategies in the Joint AL do not explain how the PAs have effectively mitigated and will continue to mitigate the risk to ratepayers from duplicative programs. Cal Advocates issued a data request to the PAs for workpapers for more information. Cal Advocates says in the protest that the workpapers show the mitigation by program, but they do not analyze the effectiveness and fail to explain how PAs will mitigate overlap and/or duplication in the future.

Cal Advocates claims that the Joint AL does not analyze the potential overlap of several PG&E programs with programs administered by BayREN and MCE, which are in the same territory. Cal Advocates asserts that PG&E submitted implementation plans for these programs 10 days after the Joint AL was filed; therefore, Cal Advocates believes that the Joint PAs should have corrected the Joint AL through a supplemental AL for PG&E's EmPower My Home program, and that all other programs should also be re-analyzed with the most up-to-date data to address overlap and

[7] Ibid at 29
[8] Ibid at 46

duplication. Additionally, Cal Advocates claims that the Joint AL understates the financial impact on ratepayers. They believe that the calculations should include marketing, education, and outreach costs, direct implementation non-incentives and incentive costs, and program administration.

Cal Advocates proposes that the Commission should direct the PAs to submit a supplemental advice letter to correct the errors and omissions in the Joint AL as detailed in their protest, and there should be an opportunity for the parties to protest or respond to the supplemental advice letter. They request that the supplemental advice letter demonstrate a process or protocol that will effectively mitigate or minimize ratepayer risks associated with duplicative or overlapping programs.

Responses

PG&E filed a timely response to the Joint AL on November 4, 2024. PG&E reiterates that the Joint AL complies with OP 32. They clarify that the intention of the electric IOUs, i.e., PG&E, SCE, and SDG&E, in their joint statement is to request that the Commission wait to determine if guidance is needed until after the PAs have completed another program overlap assessment that more completely captures the potential overlap between statewide midstream and statewide/local downstream programs. They anticipate that the complexity of program implementation for overlapping programs will very likely warrant Commission guidance on program precedence. In their response, they provide the scenario that if two different programs provide the same piece of equipment, but one is midstream distribution and the other is downstream resident, does one have more right to the savings claims than the other?[9]

PG&E, SCE, SoCalGas, and SDG&E separately filed replies to the Cal Advocates protest on November 12, 2024.

PG&E agrees that the definition of substantially similar is too narrow to capture overlap between some programs, such as deemed or not deemed programs. They point out that this excludes statewide deemed programs from being analyzed alongside downstream Normalized Metered Energy Consumption (NMEC) programs. However, rather than requiring a revision of the existing assessment and a supplemental advice letter as Cal Advocates suggest, PG&E argues that a new assessment is needed that focuses more narrowly on statewide midstream and statewide/local downstream before the Commission decides on program precedence. PG&E agrees with Cal Advocates that up-to-date data should be used, and, again, PG&E suggests that the PAs should conduct a new overlap assessment. However, they disagree with Cal Advocates that the Joint AL erred in analysis of some programs due to lack of data. For instance, PG&E supports the claim in the Joint AL that the PAs can use their Implementation Plans to determine mitigation actions for programs that do not have claims data available.

SCE acknowledges that there are different definitions of the key terms, but believes that the OP 32 Report meets the requirements of the OP and the Commission should not require a supplemental AL. SCE re-iterates that the electric IOUs plan to continue to analyze program overlap. SCE asserts that managing ratepayer risk is an ongoing process, and the PAs plan to continue further analysis. SCE urges that the Commission approve the Joint AL and would like the Commission to wait to provide guidance on program precedence until after the electric IOU PAs' next assessment is complete.

---

[9] PG&E Response at 6-7

SoCalGas asserts in response to Cal Advocates' protest that some SoCalGas programs were not on the list because there are "fully operational monthly verification protocols to address such topics as duplicative program offerings, customer eligibility and double-dipping."[10] SoCalGas further clarifies that Joint Cooperation Memos, recurring PA coordination meetings, and individual meetings with PAs in the same geographic area are where mitigation of risks happens.

SDG&E comments that "ultimately no duplication was identified through the analysis, however there were coordination gaps identified regarding Statewide programs" and reiterates that the electric IOUs plan to continue to analyze program overlap.[11] SDG&E clarifies that San Diego REN programs were not available at the time of the OP 32 Report analysis, so they were not included, and coordination is currently taking place between SDG&E and San Diego REN.

SoCalREN requested and the Commission granted an extension of time to reply to the Cal Advocates' protest. BayREN, I-REN, MCE, SoCalREN, and 3C-REN filed jointly on November 18, 2024. In their reply, they reiterate that the Joint AL complies with OP 32 by defining agreed-upon terms and criteria for four terms: "similar," "program overlap," "substantially similar," and "program duplication". They state that the PAs agreed upon the method for determining substantial overlap and duplication, which they say complies with the OP. Contrary to the Cal Advocates protest, they argue that the OP does not specifically order that the PAs include the term "precedence." The Joint AL places emphasis on the OP's requirement that the AL should define "agreed-upon criteria for determining 'overlap,' 'duplication, and/or 'precedence."[12] The RENs and MCE assert that "additional analysis to address potential midstream and downstream double dipping of incentives and double counting of savings claims should occur separately and not be required as a revision to the Joint AL."[13] They note that existing frameworks of JCMs and coordination meetings allow the PAs to address overlap without Commission guidance. They provide examples of items discussed in monthly PA coordination meetings: customer targeting, verifying customer eligibility, and incentive double dip checks.

Additionally, the RENs and MCE state that the workpapers in response to Cal Advocates' data request provide details on which and how the PAs applied mitigation actions to the 27 programs. They offer that, in the future, the PAs can share the Joint Cooperation Memos and PASC meeting discussion notes regarding customer-targeting and measure-level offerings, if requested. Regarding Cal Advocates' claim that the Joint AL should re-analyze PG&E's EmPower My Home and other programs using more up-to-date data, the RENs and MCE state that those programs had not met the threshold of change in a program, so updating the analysis was not necessary for those programs. They reiterate that Joint Cooperation Memos and PA coordination, including monthly calls, provide ways to check for overlap and double dipping.

Energy Division Disposition

Energy Division reviewed the Joint AL, the protest from Cal Advocates, the PG&E response, and all replies to the protest and/or response. Energy Division summarizes the relevant issues into the categories below.

---

[10] SoCalGas at 2

[11] SDG&E at 2

[12] RENs and MCE Reply at ii

[13] Ibid at iii

Substantially similar programs
Cal Advocates argue that the Joint AL does not comply with OP 32 because the definition of substantially similar is too narrow. They correctly note that the PA's method identified programs that are in the same sector, have the same delivery type and program segment, are in the same IOU territory, and engage with the same audience. However, Energy Division staff determined that the method in the Joint AL to identify substantially similar programs complies with OP 32 because the OP did not specify the definition.

Program precedence
Cal Advocates claims that the Joint AL does not comply with OP 32 because the AL does not define the term "precedence". Energy Division staff agree with the PAs who point out that the OP states, "*For example* [emphasis added], the joint advice letter *should* [emphasis added] propose definitions for "overlap," "duplication," and "precedence." The PAs took the direction as a list of suggested terms, not mandatory ones.[14] PG&E suggests that the specific concerns raised by Cal Advocates should be addressed through a new assessment "that more completely addresses the extent of Statewide midstream and Statewide/local downstream program overlap."[15] Energy Division staff agree that further assessment of program precedence could be warranted, but is not required for compliance with OP 32.

Mitigation to minimize or avoid overlap and duplication
Cal Advocates assert that the Joint AL does not include an explanation of how mitigation was conducted. The OP 32 Report lists four categories of mitigation and states which mitigation types were applied to each program. Energy Division staff agree with Cal Advocates that an explanation could be useful to better understand the effectiveness of the various mitigation measures; however, staff finds that OP 32 did not direct the PAs to produce an analysis of methods for choosing mitigation activities and measuring their effectiveness. Staff finds that the four categories of mitigation activities are a good first step for understanding how PAs can avoid or minimize overlap or duplication of programs.

Ratepayer risk calculations
Cal Advocates protest that additional elements should have been included in the valuation of ratepayer risk. PG&E disagrees that additional elements should be included because they could be misleading. Energy Division staff finds that the Joint AL includes sufficient elements into the valuation of risk for the purpose of compliance with OP 32. This is an issue that could be further studied in a future assessment, if needed.

In Reply to Cal Advocates' request for a supplemental AL, the RENs and MCE state, "This OP 32 effort has not only highlighted the effective mitigation strategies currently in place but also the gaps that still need to be addressed. The cross-PA coordination efforts to effectively mitigate ratepayer risk have only begun and PAs are expected to improve and increase their coordination efforts to share best practices while integrating additional strategies into their processes to more effectively minimize ratepayer risk."[16] Consistent with the PAs, Energy Division staff agrees that the process for Joint Cooperation Memos, existing coordination meetings, and implementation plans are places

[14] D.23-06-055 at 87
[15] PG&E Response at 4
[16] RENs and MCE Reply at v

where PAs will continue to discuss substantially similar programs and ways to avoid risk to ratepayers from program overlap or duplication.

Conclusion

AL 20-E/20-G et al. is approved as described in this letter.

Docket No.: A.24-10-014

Exhibit No.: ______________________

Date: June 30, 2025

Witness: Kyra J. Coyle

**PREPARED DIRECT TESTIMONY OF KYRA J. COYLE
ON BEHALF OF
THE JOINT COMMUNITY CHOICE AGGREGATORS
IN PG&E'S BILLING MODERNIZATION INITIATIVE**

June 30, 2025

EXECUTIVE SUMMARY OF RECOMMENDATIONS

This testimony presents the recommendations of the Joint CCAs[1] concerning certain issues in the *Application of Pacific Gas and Electric Company for Approval of Its Billing Modernization Initiative*, submitted on October 23, 2024.

The Joint CCAs recommend the Commission order PG&E to adopt the following modifications to its proposed BMI:

- Order PG&E to implement the following changes to facilitate CCAs' communications with their customers via customer bill messaging:
  - Shorten the timeline to process changes to CCA-specific bill messaging to be in line with SCE's timeline of two business days.
  - Design the final end-state billing system to have increased flexibility and text space for messaging (in both the "swim lane" and "on-bill message" portions of the bill).
  - Limit the ability of PG&E to modify requested CCA-specific messaging.
  - Design the end-state billing system to allow placement changes of the CCA messaging (*i.e.*, allow the "about" information to be moved from the bottom right corner).
  - Design the end-state billing system to allow CCAs to incorporate customer-specific messaging on customer bills (*e.g.*, messaging specific to particular customer classes, to customers who are enrolled in specific programs like CARE or FERA, or to EV customers).
  - Design the end-state billing system to allow clickable URLs in online bills, CCA logos in color, and messaging in color.
- Order PG&E to conduct joint PG&E-CCA stakeholder workshops prior to the design portion of Phase 3 of the BMI, covering: comprehensive bill redesign, dynamic rate bill presentation, and any remaining implementation issues arising out of the CCA bill presentation changes discussed above;

---

[1] Acronyms and defined terms used in this Summary of Recommendations are defined within the body of this testimony.

- Reflect all discounts that are calculated based on the total bill (*i.e.*, CARE and FERA) in a completely consistent manner and as a reduction to an eligible customer's total electric charges;
- Separate the PCIA as a separate line item on customers' bills, so that it can be presented in a consistent manner that reflects the kWh usage and applicable kWh rate used to calculate the PCIA;
- Order PG&E to functionalize all BMI costs it proposes to functionalize to the generation function to the distribution function instead;
- Reject PG&E's proposal to recover the costs associated with the CC&B 25.1 upgrade as BMI costs;
- Order PG&E to ensure its BMI addresses certain shortcomings and persistent billing problems associated with its legacy billing system, including by:
    - Sharing certain critical billing data with CCAs.
    - Addressing various issues with the quality of the billing data currently shared with the CCAs.
    - Dedicating more resources toward resolving CCA customer billing issues and delays in a timely manner, including via a designated PG&E point of contact for such issues and a semi-annual PG&E-CCA stakeholder workshop on resolving outstanding technical billing issues.
    - Clarifying, via an advice letter filing, PG&E's plan regarding how and when it will communicate with various customer groups on major upcoming changes arising out of the BMI, with the constraint that PG&E must provide at least three months' notice in advance of implementation of such billing changes.
    - Remediating various issues with billing mechanics and delays related to rate switch requests, inaccurate applications of bill credits, and backlogged billing projects.
- Order PG&E to regularly track and publicly report on its billing system efficiency metrics, and ensure that its BMI allows it to achieve consistent quarterly improvements on these efficiency metrics;

- With respect to the rollout of the BMI, order PG&E to: (1) commit to specific dates certain for achieving implementation of its backlogged rate projects, and (2) commit to a specific timeline of seven business days for resolving any CCA billing and revenue delays arising out of the BMI deployment; and
- Order PG&E to clearly outline the BMI's likely impact on CCA service fees and commit to service fee updates post BMI implementation.

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Its Billing Modernization Initiative.	Application 24-10-014 (Filed October 23, 2024)

Prepared Direct Testimony of Kyra J. Coyle
on behalf of the Joint Community Choice Aggregators

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q: Please state your name, position, and business address.

A: My name is Kyra Coyle. I am a Principal at NewGen Strategies and Solutions, LLC. My business address is 225 Union Boulevard, Suite 450, Lakewood, Colorado 80228.

Q: Please describe your experience and qualifications.

A: I have over 15 years of experience in the utility, mining, and public accounting sectors. My expertise includes utility revenue requirement analyses, strategic planning, project management, contract negotiations, financial modeling, regulatory affairs, budgeting, forecasting, and regulatory accounting. My rate-related projects have included studies to develop retail electric, natural gas, transmission, ancillary service, standby, and special contract rates. I have provided expert witness testimony before several public utility commissions, including Texas, Utah, Oregon, Indiana, and Wyoming, as well as the Federal Energy Regulatory Commission (FERC). A summary of my qualifications is provided within **Attachment KJC-1** to this testimony.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Ava Community Energy (Ava), Central Coast Community Energy (3CE), CleanPowerSF, Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), San Jose Clean Energy (SJCE), Silicon Valley Clean Energy (SVCE), and Sonoma Clean Power Authority (SCP) (collectively, the Joint CCAs).[1] Each of these community choice aggregators (CCAs) operate and provide power supply services within Pacific Gas and Electric Company's (PG&E) service territory.

Q: Why do the CCAs have an interest in the BMI?

A: Over the next five years, PG&E's Billing Modernization Initiative (BMI) will replace the utility's aging billing system currently used to serve its electric and gas customers in the areas of billing, customer service, and customer data management. By law, PG&E is required to serve as the billing agent for the CCAs in its service territory, and to provide

---

[1] PCE submitted a Protest to PG&E's Application on November 25, 2024, and therefore has party status in this proceeding. The remainder of the Joint CCAs filed a motion for party status on June 25, 2025, which was granted on June 30, 2025.

"metering, billing, collection, and customer service" to CCA customers.[2] Under this setup, PG&E bills CCA customers on behalf of CCAs and handles the collection and transfer of payments made by CCA customers to CCAs. Currently, more than half of PG&E's customers are unbundled and receive service from CCAs, and additional CCA expansion is expected in the next few years.[3] Therefore, CCAs have an interest in ensuring the BMI upgrades will result in billing systems and processes that are sufficient to meet CCA customer needs, and are designed to equitably serve both PG&E's bundled and unbundled customers.

In addition, PG&E proposes to recover the costs of the various billing system upgrades implemented through the BMI from all electric and gas customers within its service territory, including from the unbundled electric customers of CCAs.[4] CCAs have an interest in ensuring the BMI costs are appropriately and fairly functionalized and allocated to customers because CCA customers will be responsible for part of the costs of the BMI.

Finally, the billing agent relationship between PG&E and CCAs—coupled with the fact that PG&E competes with CCAs in its service territory for electric customers—compels the Joint CCAs to ensure that PG&E's billing system and cost allocation proposals do not confer an unfair competitive advantage to PG&E.

Q: What is the purpose of your testimony?

A: This testimony primarily focuses on the following issues in the March 27, 2025, *Assigned Commissioner's Scoping Memo and Ruling* (Scoping Ruling):[5]

3. Whether the timing of the BMI is reasonable, including its phases and implementation plan;

---

2 Cal. Pub. Util. Code § 366.2(c)(9).

3 *See* Community Choice Aggregation and Energy Service Provider Formation Status Report (Feb. 28, 2024), *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2024-status-report-on-community-choice-aggregation-formation.pdf?utm_source=chatgpt.com.

4 A.24-10-014, PG&E's Prepared Testimony, Chapter 8, Table 8-1 and Table 8-2 (PG&E Testimony).

5 *See* A.24-10-014, *Assigned Commissioner's Scoping Memo and Ruling*, p. 4 (March 27, 2025) (Scoping Ruling).

4. Whether the BMI cost is reasonable and provides benefits and savings to ratepayers. This includes consideration of stranded investments in the current billing system, comparison to the alternative billing upgrade approaches, and difference in costs from the costs proposed in the 2023 GRC;
5. Whether PG&E's proposed cost recovery treatment for its BMI is reasonable and appropriate, including whether PG&E should modify its proposed cost allocation and rate mechanism for recovery of the Billing Modernization Initiative costs;
6. Whether the BMI will include any anti-competitive design elements or have any anti-competitive impacts, as well as whether the upgrades will support corrections to the current bill presentation that facilitate greater transparency and foster fair competition.

Specifically, this testimony focuses on (1) the proper presentment of rates and other critical information on bundled and unbundled customer bills generated by PG&E's billing system, as upgraded through the BMI, (2) the need for greater collaboration with the CCAs and other stakeholders in the design and bill presentment process going forward, (3) the appropriate functionalization of certain BMI costs to electric distribution rather than to the electric generation function, (4) the rejection of cost recovery for the Customer Care and Billing (CC&B) 25.1 upgrade as BMI costs in light of PG&E's extensive delay that necessitated this interim step in the upgrade process, (5) the need for firm commitments from PG&E on addressing certain persistent billing issues, improving certain billing system efficiency metrics in its post-BMI end-state billing system, and meeting reasonable timelines on various aspects of BMI implementation, and (6) PG&E's insufficient showing regarding likely changes to its CCA service fees as a result of the BMI.

Q: Can you summarize the Joint CCAs' specific recommendations on these issues?

A: The Joint CCAs recommend the Commission order PG&E to adopt the following modifications to its proposed BMI:

- Order PG&E to implement the following changes to facilitate CCAs' communications with their customers via customer bill messaging:

    - Shorten the timeline to process changes to CCA-specific bill messaging to be in line with Southern California Edison Company's (SCE) timeline of two business days.
    - Design the final end-state billing system to have increased flexibility and text space for messaging (in both the "swim lane" and "on-bill message" portions of the bill).
    - Limit the ability of PG&E to modify requested CCA-specific messaging.
    - Design the end-state billing system to allow placement changes of the CCA messaging (*i.e.*, allow the "about" information to be moved from the bottom right corner).
    - Design the end-state billing system to allow CCAs to incorporate customer-specific messaging on customer bills (*e.g.*, messaging specific to particular customer classes, to customers who are enrolled in specific programs like California Alternate Rates for Energy (CARE) or Family Electric Rate Assistance (FERA), or to electric vehicle (EV) customers).
    - Design the end-state billing system to allow clickable URLs in online bills, CCA logos in color, and messaging in color.
- Order PG&E to conduct joint PG&E-CCA stakeholder workshops prior to the design portion of Phase 3 of the BMI, covering: comprehensive bill redesign, dynamic rate bill presentation, and any remaining implementation issues arising out of the CCA bill presentation changes discussed above;
- Reflect all discounts that are calculated based on the total bill (*i.e.*, CARE and FERA) in a completely consistent manner and as a reduction to an eligible customer's total electric charges;
- Separate the Power Charge Indifference Adjustment (PCIA) as a separate line item on customers' bills, so that it can be presented in a consistent manner that reflects the kilowatt-hour (kWh) usage and applicable kWh rate used to calculate the PCIA;
- Order PG&E to functionalize all BMI costs it proposes to functionalize to the generation function to the distribution function instead;

- Reject PG&E's proposal to recover the costs associated with the CC&B 25.1 upgrade as BMI costs;
- Order PG&E to ensure its BMI addresses certain shortcomings and persistent billing problems associated with its legacy billing system, including by:
    - Sharing certain critical billing data with CCAs.
    - Addressing various issues with the quality of the billing data currently shared with the CCAs.
    - Dedicating more resources toward resolving CCA customer billing issues and delays in a timely manner, including via a designated PG&E point of contact for such issues and a semi-annual PG&E-CCA stakeholder workshop on resolving outstanding technical billing issues.
    - Clarifying, via an advice letter filing, PG&E's plan regarding how and when it will communicate with various customer groups on major upcoming changes arising out of the BMI, with the constraint that PG&E must provide at least three months' notice in advance of implementation of such billing changes.
    - Remediating various issues with billing mechanics and delays related to rate switch requests, inaccurate applications of bill credits, and backlogged billing projects.
- Order PG&E to regularly track and publicly report on its billing system efficiency metrics, and ensure that its BMI allows it to achieve consistent quarterly improvements on these efficiency metrics;
- With respect to the rollout of the BMI, order PG&E to: (1) commit to specific dates certain for achieving implementation of its backlogged rate projects, and (2) commit to a specific timeline of seven business days for resolving any CCA billing and revenue delays arising out of the BMI deployment; and
- Order PG&E to clearly outline the BMI's likely impact on CCA service fees and commit to service fee updates post BMI implementation.

II. THE COMMISSION SHOULD ORDER PG&E TO IMPLEMENT SPECIFIC CHANGES RELATED TO THE PRESENTATION OF ITS CUSTOMER BILLS DURING THE BMI PROCESS.

Q: Why do PG&E's choices regarding bill presentation matter to the Joint CCAs?

A: PG&E is the statutorily designated billing agent for the CCAs in its service territory.[6] As the designated billing agent, PG&E generates and issues bills for both its bundled and unbundled electric customers, including customers of CCAs. PG&E also collects customer bill payments on behalf of CCAs and transfers those payments to the CCAs. Because PG&E controls the issuance of bills sent to CCA customers, CCAs cannot make changes to much of the CCA-specific content on bills directly without first going through PG&E.

CCAs must ensure that the bills PG&E issues CCA customers contain accurate and fair representations of their rates and other key customer-facing information. Additionally, CCAs have an interest in ensuring clarity and transparency in both unbundled and bundled customer bills, and specifically, in ensuring PG&E's bundled customer bills do not obfuscate or misrepresent the rate differences between bundled and unbundled service. CCAs have been working on these issues since the inception of community choice aggregation in California. Lastly, CCAs compete with PG&E for electric customers, so any misrepresentation of rates or information on customer bills can impact a customer's understanding of their bill and potentially their decision to switch electric service providers.

Q: Does the Commission impose any standards on PG&E that apply to PG&E's approach to bill presentation?

A: Yes. The Commission's Code of Conduct governing the conduct of investor-owned utilities (IOUs) in their interactions with and treatment of CCAs applies to issues of bill presentation. The Code of Conduct was adopted to ensure CCAs are able to "compete on a fair and equal basis with other [load serving entities], and to prevent utilities from using their position or market power to gain unfair advantages."[7] The Code of Conduct provides,

---

6 Cal. Pub. Util. Code § 366.2(c)(9).

7 D.12-12-036, Finding of Fact (FOF) 4 (definition added).

among other things, that PG&E may not, "through a tariff provision or otherwise, discriminate between its own customers and those of a CCA."[8]

Q: Why are the Joint CCAs concerned with bill presentment in this proceeding in particular?

A: The upgrades to PG&E's billing system through the BMI will have an impact on customer bill format and presentation. However, at this phase in the BMI process, PG&E is unable to confirm what specific changes in bill presentment will look like for bundled versus CCA customers. Possible changes to bill presentment will not be known for several years until Stage 3 of the BMI process, according to PG&E.[9]

Scoping Issue 6 from the Scoping Ruling specifically addresses whether the BMI upgrades will support corrections to the current bill presentation to facilitate greater transparency and foster fair competition. Leaving modifications to bill presentation to PG&E's discretion at a later phase of the upgrade process is not reasonable. This approach would give PG&E the green light to continue certain anticompetitive billing practices related to how it presents bundled and unbundled customer rates and charges differently,[10] and would give PG&E the option to disregard specific CCA concerns regarding their ability to present clear messaging on their customers' bills and update that content in a timely manner. I believe it is important to approach the BMI bill redesign process with the goal of addressing the needs of both unbundled and bundled customers simultaneously—this approach ensures that the needs of CCA customers are not considered an afterthought and protects against anticompetitive outcomes.

Q: What bill presentment issues do you discuss in this section of your testimony?

A: I discuss the following bill presentment recommendations in this section of my testimony:

- The Commission should order PG&E to (1) adopt certain bill presentation changes to facilitate CCA communication with their customers, and (2) conduct joint PG&E-CCA

---

8 D.12-12-036, Attachment 1: Code of Conduct and Expedited Complaint Procedure, Rules 14 and 18.

9 Attachment KJC-2 (PG&E Response to PCE DR 1.10).

10 Specifically, I am referring here to the presentation of CARE and FERA discounts as well as the PCIA charge on customer bills, discussed further in Section II herein.

stakeholder workshops on comprehensive bill redesign and the implementation of CCA bill presentation changes prior to the design portion of Phase 3.

- The Commission should order PG&E to develop its dynamic rate presentation approach collaboratively with CCAs through the joint PG&E-CCA stakeholder workshops prior to the design portion of Phase 3 or the implementation of dynamic rates.
- The CARE and FERA discounts should be reflected on both unbundled and bundled customers' bills by Q3 of 2026.
- The PCIA should be reflected on both unbundled and bundled customers' bills by Q3 of 2026.

A. PG&E Should Adopt Bill Presentation Changes to Facilitate Communications Between CCAs and Their Customers.

Q: Please explain the relationship between customer bills and communication between customers and their CCA.

A: Monthly bills are one of the primary means by which customers access information about their electric rates. As such, CCAs often use monthly bills to communicate important information to customers, including key contact information, rate updates, and general information about CCA service.

Q: Why are the CCAs concerned with customer messaging issues on unbundled customer bills?

A: The Joint CCAs are concerned with both PG&E's lengthy turnaround times for implementing messaging changes and particular areas of inflexibility. The billing agent relationship between PG&E and CCAs is mandated by law,[11] and pursuant to that relationship, PG&E manages the process for implementing most customer messaging on CCA customer bills. The ability to provide accurate and detailed information to customers in conjunction with rates and charges is critical for ensuring transparency, especially because a monthly bill typically represents a customer's most frequent interaction with its electric service provider. Constraints to a CCA's ability to communicate with its customers

[11] Cal. Pub. Util. Code § 366.2(c)(9).

through bills unnecessarily harms the CCA's relationship with its customers. Certain issues surrounding messaging constraints also create a competitive disadvantage for CCA providers, as discussed in more depth below.

Q: How does PG&E currently reflect CCA customer messaging on customer bills?

A: An unbundled customer bill issued by PG&E contains areas where messaging can be included to allow a CCA to communicate information to its customers. Typically, there are two areas where a CCA can include messaging on a customer bill: the "swim lane" and the "on-bill message." The on-bill message area is more limited in size compared to the swim lane and appears under the CCA's generation charges section of an unbundled customer's bill.

Q: Can you provide an example of what this looks like on a typical CCA customer bill?

A: Yes. Figure 1 below is an example of an unbundled customer bill showing where CCA-specific customer messaging can occur. The red box on the left is the on-bill message, while the red box on the right is the swim lane.

Figure 1: CCA Customer Messaging Options on PG&E Bills[12]

ENERGY STATEMENT
www.pge.com/MyEnergy

Account No: [redacted]
Statement Date: 04/18/2025
Due Date: 05/09/2025

Details of Peninsula Clean Energy Electric Generation Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: [redacted]
Service Agreement ID: [redacted] ESP Customer Number: [redacted]

03/14/2025 – 04/13/2025

Rate Schedule: E-1

Generation - Total	428.940000 kWh	@ $0.12797		$54.89
		Net Charges	54.89	
Local Utility Users Tax				2.74
Energy Commission Surcharge				0.13

Peninsula Clean Energy is your community's official electricity provider. You are receiving clean electricity at low rates!

Total Peninsula Clean Energy Electric Generation Charges $57.76

Service Information
Total Usage 428.940000 kWh

For questions regarding charges on this page, please contact:
PENINSULA CLEAN ENERGY
2075 WOODSIDE RD
REDWOOD CITY CA 94061
1-866-966-0110
PenCleanEnergy.com
info@PeninsulaCleanEnergy.com

Additional Messages

Your city has chosen to receive electricity sourced by Peninsula Clean Energy. Peninsula Clean Energy is a not-for-profit, public agency that sources energy that is least 50% renewable and 100% clean. Its energy generation charge replaces that of PG&E's, but at a lower rate.

Energy **generation** is one component of your overall electric bill. PG&E continues to own and operate the infrastructure and charge for the **delivery** of the electricity. PG&E is responsible for all gas services and gas charges.

Please do not hesitate to contact us at **info@PeninsulaCleanEnergy.com** or **866-966-0110** or visit our web site at **PenCleanEnergy.com** if you have any questions.

Peninsula Clean Energy is committed to protecting customer privacy. Learn more at **PenCleanEnergy.com/privacy**.

Q: What is PG&E's current process for facilitating updates to this customer messaging on CCA customer bills?

A: PG&E handles CCAs' requests for updates to the swim lane portion of the bill, and it does not utilize a standard or formalized form or timeline for implementing these changes. For on-bill messaging, a CCA currently can update or change this messaging as needed through their back-office billing provider. CCAs want to maintain this level of control over on-bill messaging even after the BMI upgrades are complete.

PG&E's current timeline to implement a CCA request to update "swim lane" language is typically two to three months, depending on internal review, legal compliance

12 Attachment KJC-2 (PG&E Response to PCE DR 2.15).

changes, and scheduling of IT development work.[13] As PG&E has stated, this is the *typical* timeline for processing changes, but the processing timeline can vary.[14]

Q: What issues do the Joint CCAs have with the current process of updating customer messaging on CCA customer bills?

A: PG&E's timeline to implement a request to change CCA-specific messaging on the swim lane portion of the bill is too lengthy. A typical timeline of two to three months for a change in messaging[15] could easily render a requested message change invalid by the time it is included on the customer's bill, especially if it is time-sensitive messaging. PG&E recognizes that other IOUs may have different timelines, and that SCE processes on-bill messaging requests from CCAs within only two business days.[16] However, PG&E claims that differences in system architecture, configurations and integrations, and processes account for these timeline differences.[17] PG&E maintains that it cannot comment on system capabilities that may support improved message configuration and scheduling until Stage 3 of the BMI and it does not expect immediate changes to the processing timeline until those future-stage functionalities are incorporated.[18]

Q: Do the Joint CCAs have other concerns surrounding PG&E's process for updating CCA customer messaging?

A: Under the current process, PG&E must approve of the language to be included in the swim lane before the update goes live on a CCA customer's bill. However, CCAs are not allowed to review or approve PG&E's final messaging in the swim lane prior to its implementation. This dynamic is anti-competitive, allowing PG&E final discretion as to the ultimate message conveyed to CCA customers.

---

13 Attachment KJC-2 (PG&E Response to PCE DR 2.14).

14 *Id.*

15 *Id.*

16 Attachment KJC-2 (PG&E Response to PCE DR 2.14); *see also* Attachment KJC-3 (SCE Bill Message Request Template).

17 Attachment KJC-2 (PG&E Response to PCE DR 2.14).

18 *Id.*

Q: What other concerns do the Joint CCAs have with PG&E's current on-bill messaging capabilities?

A: Based on my conversations with CCA representatives, PG&E unreasonably constrains CCAs' ability to efficiently and effectively communicate with their customers via messaging on customer bills. First, I understand that PG&E provides CCAs with little flexibility and text space for messaging in both the "swim lane" portion of the bill and the "on-bill message" portion of the bill. For example, PG&E will not reorder the swim lane or allow placement of the requested messaging in a manner that moves the "about" information from the bottom right corner. Further, PG&E will not incorporate clickable URLs in online bills, CCA logos in color, or messaging in color.[19] Finally, CCAs are unable to incorporate customer-specific messaging on customer bills, *e.g.*, messaging specific to CARE, FERA, or EV customers. CCAs similarly are unable to differentiate messaging by customer class, *e.g.*, residential or commercial.

Q: What are your specific recommendations for improving PG&E's approach to CCA customer messaging on bills?

A: As part of the BMI, the Commission should require PG&E to make the following changes to its CCA customer messaging capabilities and approach:

- Shorten the timeline it takes to process CCAs' requested changes to the swim lane portion of the bill to be in line with SCE's timeline of two business days.[20]
- Design the BMI system to have increased flexibility and text space for messaging (in both the swim lane and on-bill message).
- Limit the ability of PG&E to modify requested CCA specific messaging and require PG&E to provide the final version of the modified language to CCAs for final signoff.
- Design the end-state billing system to allow placement changes of the CCA messaging (*i.e.*, allow the "about" information to be moved from the bottom right corner).
- Design the end-state billing system to allow CCAs to incorporate customer-specific messaging on customer bills (*e.g.*, messaging specific to particular customer classes, to

[19] Attachment KJC-2 (PG&E Response to PCE DR 2.16).
[20] *See* Attachment KJC-3 (SCE Bill Message Request Template).

customers who are enrolled in specific programs like CARE or FERA, and to EV customers).

- Design the end-state billing system to allow clickable URLs in online bills, CCA logos in color, and messaging in color.

Q: Do you have any other recommendations regarding CCA customer bill presentation?

A: Yes. PG&E has indicated that it is not yet in the phase of the BMI where it can work on bill presentment and is unable to answer questions regarding proposed changes to bill presentment.[21] In light of PG&E's inability to work on comprehensive bill redesign at this time, the Commission should order PG&E to conduct joint PG&E-CCA stakeholder workshops on comprehensive redesign of customer bills prior to the design portion of BMI Phase 3.

This workshop series should cover a holistic review of PG&E's bill design, with the goal of redesigning bills to be clear and easily understandable to both unbundled and bundled customers. Bills must be designed with the understanding that unbundled customers represent the majority of PG&E's customers, and that therefore bills should be designed with CCA customer needs in mind and in conjunction with CCA representatives. Finally, if needed, this workshop series could also cover any lingering issues with the implementation of the specific CCA bill presentation changes recommended herein.

B. PG&E Should Develop Dynamic Rate Presentation Collaboratively with CCAs Through a Workshop Process.

Q: What are dynamic rates?

A: Dynamic rates are rates that vary by time and that are structured to provide incentives to customers to conserve electricity when demand is low through differences in rates. Whereas time-of-use rates are set by time of day and remain in place throughout the season, dynamic rates change from day to day and hour to hour. This means that dynamic rates provide a more granular and variable price signal about when to shift load compared to time-varying rates.[22]

---

[21] Attachment KJC-2 (PG&E Response to PCE DR 1.10).

[22] D.21-12-015, p. 85.

In D.21-12-015, several dynamic rate program pilots were approved by the Commission for PG&E and SCE.[23] In particular, PG&E was instructed to work with Valley Clean Energy, a CCA in PG&E's service territory, on funding, administration, tariff design, and evaluation for a pilot program where dynamic rates would be used to provide incentives for large agricultural customers to pump water when it is least costly to do so.[24] This pilot program, as well as SCE's program approved in D.21-12-015, were both expanded in D.24-01-032, issued on January 25, 2024.[25] These two programs were authorized to run from 2024 to 2027.[26]

Additionally, in October 2022, the California Energy Commission adopted updated state load management standards, effective April 1, 2023, that required PG&E, SCE, the Sacramento Municipal Utility District (SMUD), San Diego Gas and Electric Company (SDG&E), Los Angeles Department of Water and Power (LADWP), and large CCAs to develop retail electricity rates that change at least hourly.[27] In particular, large CCAs were required, if approved by their rate approving bodies, to either adopt the dynamic price rate design required of IOUs, develop their own dynamic rates, or provide load shifting programs to customers by 2027.[28] The advent of dynamic rates has clearly impacted both the California IOUs and CCAs and therefore the implementation of dynamic rates through the BMI is of particular interest to CCAs.

Q: How will dynamic rates on customer bills be handled under PG&E's BMI?

A: PG&E explains that final bill presentment features, which include the display of dynamic rate components, have not yet been finalized and are not expected to be incorporated until Stage 3 of the BMI. At this time, PG&E states it is unable to confirm the final format or level of detail for dynamic rates that will be presented on customer bills. PG&E expects

---

23 *Id.*, p. 89 and p. 96.
24 *Id.*, p. 87 and p. 89.
25 D.24-01-032, pp. 2-3.
26 *Id.*, p. 2.
27 CEC 2022 Load Management Standards Rulemaking Fact Sheet, *available at* https://www.energy.ca.gov/sites/default/files/2022-10/Load_Management_Fact_Sheet_ADA.pdf.
28 *See* LMS § 1623.1(b).

that decisions impacting the presentation of dynamic rates will be determined later in the program based on system capabilities, customer needs, and regulatory guidance.[29]

Q: How should PG&E determine how to present dynamic rates on customer bills in PG&E's upgraded billing system?

A: As dynamic rates are not currently in place for all customers and it is unclear at this time how these may be reflected on customer bills, the Commission should order PG&E to address this issue in the joint PG&E-CCA workshop series recommended above, prior to the design portion of BMI Phase 3. CCAs must be equal partners in determining dynamic rate bill presentation because this will help ensure that both bundled and unbundled customers are treated consistently when it comes to the presentation of dynamic rates on bills. Overall, this will maintain consistency and improve transparency for customers when reviewing their bills.

C. CARE And FERA Discounts Should Be Clearly Reflected on Both Bundled and Unbundled Customer Bills by Q3 of 2026.

Q: What are the CARE and FERA discounts?

A: The CARE program offers a 30-35% or more discount on electric bills for customers with a household income under 200% of Federal Poverty Guidelines, or customers enrolled in certain other public assistance programs.[30] The FERA program offers an 18% discount on electric bills if a customer's household income slightly exceeds CARE allowances.[31] Both bundled and unbundled customers may be eligible to receive CARE and FERA discounts, and these discounts apply to the customer's entire bill.

Q: Are CARE and FERA discounts currently reflected clearly on PG&E customer bills?

A: Partially. On the first page of customer bills for bundled and unbundled customers, PG&E identifies the CARE or FERA discounts clearly and consistently. Figure 2 below reflects the "Account Summary" section of both types of customer bills, which identifies the

---

[29] Attachment KJC-2 (PG&E Response to PCE DR 2.17).

[30] "California Alternative Rates for Energy (CARE)," *available at* https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/california-alternate-rates-for-energy.

[31] "Family Electric Rate Assistance Program (FERA)," *available at* https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/family-electric-rate-assistance-program.

program the customer is enrolled in as well as the total amount of credit included on the customer's bill.

Figure 2: Account Summary Section of PG&E Electric Bill for Bundled and Unbundled Customers[32]

Bundled Customer Bill Example:

Service For:

REDACTED - Customer Info
[redacted]

Questions about your bill?

Mon-Fri 7 a.m.-7 p.m.
Saturday 8 a.m.-5 p.m.
Phone: 1-800-743-5000
www.pge.com/MyEnergy

Ways To Pay

www.pge.com/waystopay

Your Enrolled Programs

CARE Discount

Your Account Summary

Amount Due on Previous Statement	$16.06
Payment(s) Received Since Last Statement	-16.06
Previous Unpaid Balance	$0.00
Current Electric Charges	$161.13
Current Gas Charges	0.00
Total Amount Due by 06/09/2025	**$161.13**

Current charges include a discount of $100.96 for CARE.

Unbundled Customer Bill Example:

Service For:

REDACTED - Customer Info
[redacted]

Questions about your bill?

Mon-Fri 7 a.m.-7 p.m.
Saturday 8 a.m.-5 p.m.
Phone: 1-800-743-5000
www.pge.com/MyEnergy

Ways To Pay

www.pge.com/waystopay

Your Enrolled Programs

CARE Discount

Your Account Summary

Amount Due on Previous Statement	$232.14
Payment(s) Received Since Last Statement	-232.14
Previous Unpaid Balance	$0.00
Current PG&E Electric Delivery Charges	$61.50
Electric Adjustments	-58.23
Peninsula Clean Energy Electric Generation Charges	57.76
Current Gas Charges	98.99
Gas Adjustments	-67.03
Total Amount Due by 05/09/2025	**$92.99**

Current charges include discounts of $222.74 for CARE and CA Climate Credit.

32 Attachment KJC-2 (PG&E Response to PCE DR 2.18).

Q: Beyond the "Account Summary" section, are the CARE and FERA discounts presented consistently on the remainder of bundled and unbundled customer bills?

A: No. Contrary to PG&E's assertion otherwise, it does not present CARE and FERA discounts in a consistent manner between bundled and unbundled customers.[33]

Q: Can you provide an example of how CARE and FERA discounts are presented on a typical unbundled customer bill?

A: Yes. For unbundled customers, the CARE or FERA credit shows up as a discount line-item in the "Details of PG&E Electric Delivery Charges" section of a customer's bill, as shown in Figure 3 below. This section of an unbundled customer's bill details the PG&E electric delivery charges, but not always the customer's electric generation charges.

Figure 3: CARE and FERA Discounts on PG&E Unbundled Customer Bill[34]

Unbundled Customer Bill Example:

CARE Discount

Details of PG&E Electric Delivery Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: E1 TB Residential Service
Enrolled Programs: CARE (Renew by 04/04/2025)

03/14/2025 – 04/13/2025	Your Tier Usage	1	2		
Tier 1 Allowance	232.50	kWh		(31 days x 7.5 kWh/day)	
Tier 1 Usage	232.500000	kWh	@	$0.40730	$94.70
Tier 2 Usage	196.440000	kWh	@	$0.51031	100.25
CARE Discount					-74.79
Generation Credit					-66.78
Power Charge Indifference Adjustment					4.76
Franchise Fee Surcharge					0.45
Daly City Utility Users' Tax (5.000%)					2.91
Total PG&E Electric Delivery Charges					**$61.50**

2016 Vintaged Power Charge Indifference Adjustment

Adjustments

California Climate Credit	-$58.23
Total Adjustments	**-$58.23**

FERA Discount

Details of PG&E Electric Delivery Charges

04/04/2025 - 05/04/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: Time-of-Use (Peak Pricing 4 - 9 p.m. Every Day)
Enrolled Programs: FERA

04/04/2025 – 05/04/2025					
Baseline Allowance	452.60	kWh		(31 days x 14.6 kWh/day)	
Energy Charges					
Peak	52.454000	kWh	@	$0.50086	$26.27
Off Peak	180.198000	kWh	@	$0.47086	84.85
Baseline Credit	232.652000	kWh	@	-$0.10301	-23.97
FERA Discount					-15.69
Generation Credit					-33.34
Power Charge Indifference Adjustment					1.56
Franchise Fee Surcharge					0.25
San Jose Utility Users' Tax (5.000%)					1.98
San Jose Franchise Surcharge					0.12
Total PG&E Electric Delivery Charges					**$42.03**

2018 Vintaged Power Charge Indifference Adjustment

---

[33] Attachment KJC-2 (PG&E Response to PCE DR 2.18c).

[34] Attachment KJC-2 (PG&E Response to PCE DR 2.18).

Q: Can you provide an example of how CARE and FERA discounts are presented on a typical bundled customer bill?

A: For bundled customers, the CARE and FERA discount shows up as a discount to the "Total Electric Charges" section of a bundled customer's bill. This section of a bundled customer's bill reflects charges for both electric delivery and generation. This is reflected in Figure 4, below.

Figure 4: CARE and FERA Discount on PG&E Bundled Customer Bill[35]

Bundled Customer Bill Example:

CARE Discount

Details of Electric Charges

04/17/2025 - 05/15/2025 (29 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: Time-of-Use (Peak Pricing 4 - 9 p.m. Every Day)
Enrolled Programs: CARE (Renew by 02/16/2029)

04/17/2025 – 05/15/2025

Baseline Allowance	301.60	kWh	(29 days x 10.4 kWh/day)		
Energy Charges					
Peak	213.030800	kWh	@	$0.50086	$106.70
Off Peak	395.622400	kWh	@	$0.47086	186.28
Baseline Credit	301.600000	kWh	@	-$0.10301	-31.07
CARE Discount					-100.96
Energy Commission Tax					0.18
Total Electric Charges					**$161.13**

FERA Discount

Details of Electric Charges

04/18/2025 - 05/18/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: Time-of-Use (Peak Pricing 4 - 9 p.m. Every Day)
Enrolled Programs: FERA

04/18/2025 – 05/18/2025

Baseline Allowance	303.80	kWh	(31 days x 9.8 kWh/day)		
Energy Charges					
Peak	62.934300	kWh	@	$0.50086	$31.52
Off Peak	245.126600	kWh	@	$0.47086	115.42
Baseline Credit	303.800000	kWh	@	-$0.10301	-31.29
FERA Discount					-20.82
Energy Commission Tax					0.09
Bakersfield Franchise Surcharge					0.95
Total Electric Charges					**$95.87**

Q: On first glance, these discounts appear to be displayed similarly. Can you please explain the discrepancies between the CARE and FERA bill presentation on bundled and unbundled bills?

A: CARE and FERA discounts apply to both delivery and generation services. PG&E clearly communicates this fact through bundled customer bills by including the CARE or FERA discount within the "Total Electric Charges." Conversely, for unbundled customers, PG&E reflects the CARE or FERA discount as a reduction solely to PG&E's delivery service.

The current presentation of CARE and FERA discounts on unbundled customer bills is confusing in that it appears these discounts are not applicable to CCA generation charges. In other words, it appears that unbundled customers receive only a portion of the CARE or FERA discount, as opposed to bundled customers whose entire bill is discounted.

35 *Id.*

Q: What are your concerns with this confusing bill presentation?

A: Clear bill presentation is key in ensuring that customers fully understand the rates they pay. While PG&E does include a clear mention of the applicable CARE or FERA discount in the "Account Summary" section, this description alone is not sufficient. It is also necessary that these discounts be presented clearly where all other electric charges and discounts are laid out, which is likely the first place customers will look to understand their monthly bill.

Beyond customer confusion, current CARE and FERA bill presentation could also create anticompetitive effects. For example, unbundled customers may opt to return to bundled PG&E service under the mistaken belief that they will once again receive the full CARE or FERA discount after returning to bundled service.

Q: What changes are you recommending regarding how CARE and FERA discounts are presented on bundled and unbundled customer bills?

A: I recommend that the Commission require PG&E to reflect all discounts that are calculated based on the total bill, such as the CARE and FERA discounts, in a completely consistent manner and as a reduction to an eligible customer's total electric charges, with no differences between a bill for bundled customers versus unbundled customers. For unbundled customers, these discounts should not be shown as a reduction to only the delivery charges portion of unbundled customers' bills. The specific changes for how this should be reflected on bundled and unbundled customer bills can be determined through my recommended workshops between PG&E and the CCAs.

Q: By what deadline should the Commission order PG&E to implement these changes?

A: PG&E explained that it is too early to confirm what changes, if any, will be made to the presentation of CARE and FERA discounts or how these changes may differ between bundled and unbundled customers. PG&E states it will not have any clarity on these potential changes until Stage 3 of the BMI.[36] It is unreasonable to allow PG&E to continue with its massive BMI investment without any guarantee as to whether or at what time the upgrades will facilitate improved CARE and FERA bill presentation. Accordingly, the Commission should order PG&E to conduct joint PG&E-CCA stakeholder workshops and

[36] Attachment KJC-2 (PG&E Response to PCE DR 1.11).

to implement the recommendations regarding total bill discounts by no later than Q3 of 2026, when PG&E implements the second stage of the BMI process, CC&B 25.1. According to PG&E, the implementation of the update to CC&B 25.1 is scheduled to go live in Q3 of 2026.[37]

D. The PCIA Should Be Broken Out as a Line Item on Bundled Customer Bills by Q3 of 2026.

Q: What is the PCIA?

A: Bundled and unbundled customers alike are responsible for paying the above-market costs of PG&E's generation resources procured on their behalf. These costs are reflected in the PCIA. PG&E develops PCIA rates in its annual Energy Resource Recovery Account (ERRA) Forecast proceedings to determine all customers' responsibility for these above-market costs. Unbundled customers are subject to a separate, non-bypassable PCIA charge to cover their share of the above-market generation costs. PG&E currently recovers bundled customers' share of PCIA costs through its Bundled PCIA tariff rates.

Q: Before discussing the challenges surrounding the current PCIA bill presentation, has the Commission provided any specific direction to PG&E on this topic?

A: Yes. Per Resolution E-5131, adopted by the Commission in 2021, PG&E was required to add the PCIA to bundled customer bills by December 31, 2021. However, compliance with this order has been delayed due to PG&E's billing infrastructure upgrades.

Q: How does PG&E currently present the PCIA charge on *unbundled* customer bills?

A: Unbundled customer bills currently show a customer's PCIA charge as a single line item on their bill located on the "Details of PG&E Electric Delivery Charges" page of the bill. While the PCIA is broken out from other electric generation charges, it does not include the sum of the kWh quantity used nor the applicable $/kWh PCIA rate, only the vintage of the PCIA.[38]

---

[37] Application, p. 8.

[38] Attachment KJC-2 (PG&E Response to PCE DR 2.13).

Q: How does PG&E currently present the PCIA charge on *bundled* customer bills?

A: In contrast to unbundled customer bills, PG&E does not display the PCIA rate as a separate line item on bundled customers' bills. Instead, it is only found in the specific rate tariff under a section entitled "UNBUNDLING OF TOTAL RATES."[39]

Q: Can you give an example of how a typical unbundled customer bill versus a typical bundled customer bill looks in this regard?

A: Yes. PG&E provided samples of current bundled and unbundled customer bills in response to a data request from PCE. Those samples are reflected in Figure 5 below.

---

39 *Id.*

Figure 5: Comparison of PG&E Electric Generation Charges Section from Current Unbundled and Bundled Customer Bills[40]

Bundled Customer Bill Example:

Details of Electric Charges

04/18/2025 - 05/18/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED -
Rate Schedule: Time-of-Use (Peak Pricing 4 - 9 p.m. Every Day)
Enrolled Programs: FERA

04/18/2025 – 05/18/2025

Baseline Allowance	303.80	kWh	(31 days x 9.8 kWh/day)		
Energy Charges					
Peak	62.934300	kWh	@	$0.50086	$31.52
Off Peak	245.126600	kWh	@	$0.47086	115.42
Baseline Credit	303.800000	kWh	@	-$0.10301	-31.29
FERA Discount					-20.82
Energy Commission Tax					0.09
Bakersfield Franchise Surcharge					0.95
Total Electric Charges					**$95.87**

Rate Identification Number

USCA-PGPG-0100-0000
www.pge.com/rin
To program your smart device, scan the QR code or enter the RIN code above and follow the on-screen instructions.

Service Information

Meter #	REDACTED - Customer Info
Total Usage	308.060900 kWh
Baseline Territory	W
Heat Source	B - Not Electric
Serial	Y
Rotating Outage Block	6I

Additional Messages

As a customer who receives electricity directly from PG&E, a portion of your electric charges currently includes the Power Charge Indifference Adjustment (PCIA). To learn more, review page 2 of this Energy Statement or visit **www.pge.com/cca**.

Unbundled Customer Bill Example:

Details of PG&E Electric Delivery Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: E1 TB Residential Service
Enrolled Programs: CARE (Renew by 04/04/2025)

03/14/2025 – 04/13/2025 **Your Tier Usage** 1 **2**

Tier 1 Allowance	232.50	kWh	(31 days x 7.5 kWh/day)		
Tier 1 Usage	232.500000	kWh	@	$0.40730	$94.70
Tier 2 Usage	196.440000	kWh	@	$0.51031	100.25
CARE Discount					-74.79
Generation Credit					-66.78
Power Charge Indifference Adjustment					4.76
Franchise Fee Surcharge					0.45
Daly City Utility Users' Tax (5.000%)					2.91
Total PG&E Electric Delivery Charges					**$61.50**

2016 Vintaged Power Charge Indifference Adjustment

Adjustments

California Climate Credit	-$58.23
Total Adjustments	**-$58.23**

Service Information

Meter #	REDACTED - Customer Info
Total Usage	428.940000 kWh
Baseline Territory	T
Heat Source	B - Not Electric
Serial	T
Rotating Outage Block	9P

Your CARE usage is charged at these rates ($/kWh). Differences may occur due to rounding.

03/14/2025 - 04/13/2025	
Tier 1	0.24947
Tier 2	0.31643
Tier 2 Usage continued	0.31643

Additional Messages

You received a **California Climate Credit** on your electric bill. Learn how you can use these savings to further reduce your energy costs and help fight climate change at **cpuc.ca.gov/climatecredit.**

40 *Id.*

Q: What are some of the issues with current PCIA bill presentation on unbundled customer bills?

A: As shown in Figure **5: Comparison of PG&E Electric Generation Charges Section from Current Unbundled and Bundled Customer Bills**5, the PCIA for unbundled customers is displayed as a single charge on the unbundled customer's bill in the "Details of PG&E Electric Delivery Charges" section. The PCIA line item does not display the relevant kWh usage or $/kWh rate applied. Without this information presented clearly on monthly bills, unbundled customers have no readily available way to understand that the PCIA is a volumetric charge, or how it is calculated.

The only other information regarding the PCIA within this section of the bill is similarly confusing. Under the total delivery charges in Figure 5 for unbundled customers, there is a line item that reads "2016 Vintage Power Charge Indifference Adjustment" with no clear indication what this applies to. Without additional context, most customers likely do not understand what their PCIA vintage is, how it was assigned, and most importantly, how it impacts their rates.

Q: What are some of the issues with current PCIA presentation on bundled customer bills?

A: Although bundled customers pay the latest vintage of the PCIA every year, the PCIA charge is not specifically identified as a charge on bundled customers' bills. As demonstrated in Figure 5, bundled customers' PCIA charges are not included as a specific line-item charge as on unbundled customer bills. Rather, PG&E simply includes a sidenote that "a portion of your (bundled) electric charges currently includes the Power Charge Indifference Adjustment (PCIA)."[41]

Q: What are the consequences of both the general opacity and discrepancies in PCIA bill presentation between bundled and unbundled customers?

A: Presenting the PCIA charge as a line item solely for unbundled customers creates a visual misrepresentation that only unbundled customers are subject to this charge. This is compounded by the fact that the PCIA charge for unbundled customers is not displayed as

[41] *Id*.

volumetric—instead, it appears to simply be a monthly charge associated with CCA service.

In a similar vein, embedding PCIA charges in bundled customer commodity rates masks bundled customers' responsibility for these costs, thereby reducing customers' understanding of their rates. While PG&E explains that bundled customers pay the PCIA in separate sections of the bill, the absence of the actual PCIA charge within bundled customers' electric generation charges could easily be misconstrued by any customer that bundled customers do not pay a PCIA charge as part of their electric charges.

Opaque billing practices such as these can make it impossible for both bundled and unbundled customers to accurately compare the costs and benefits of selecting a load-serving entity (LSE) between PG&E, CCAs, or Direct Access (DA) providers. This dynamic creates a distinct competitive disadvantage for alternative LSEs, such as CCAs, by implying that the PCIA rate is an "additional" charge specific to unbundled service instead of a rate paid by both bundled and unbundled customers.

Q: Have the CCAs worked to address this disparity between bundled and unbundled customer bills in other proceedings?

A: Yes. The CCAs have been actively involved in several proceedings in front of the Commission to address this disparity, and this topic remains of top interest to the CCAs.

With regard to PG&E's PCIA bill presentation specifically, several of the Joint CCAs participated in PG&E's 2020 Phase 2 General Rate Case (GRC),[42] where the Commission approved several rate design settlements that resulted in the separation of PG&E's PCIA rates from bundled customer generation rates in the context of designing generation rates and publishing tariff schedules.[43] Separating the PCIA in bundled tariff rates was intended as a necessary first step to allow PG&E to move forward with more transparent PCIA bill presentment.

[42] A.19-11-019.

[43] D.21-11-016, pp. 84, 140, and 149-152 (PCE, MCE, Ava (formerly East Bay Community Energy), SJCE, SVCE and SCP participated in PG&E's GRC Phase II).

Q: Has the Commission issued any other guidance relevant to this issue?

A: Yes. The Commission has repeatedly stressed the importance of transparency in bill presentation and ensuring competitive neutrality between CCAs and IOUs, both within the billing context generally and specifically with regard to PCIA bill presentation. For example:

- D.22-05-015: "It is important to have transparency of costs in bill presentation, as much as possible, so customers can more effectively compare costs related to generation and distribution services, and to promote fair competition among retail providers."[44]
- D.18-10-019: "We agree that bundled customers should be made aware of the fact that all customers are paying their share of the utility's uneconomic costs. Clearly, changes to bills are necessary."[45]
- Resolution E-4734: "Breaking out the PCIA as a separate change on a customer's bill is not precluded by the Decision either. We are persuaded by MCE and CCSF that ensuring that bill comparisons are equivalent between CCA and GTSR customers are reasonable and in accord with general state policy to maintain competitive neutrality between CCAs and IOUs…we order SCE and PG&E in their supplements to the CSIALs, and in their implementation of the GTSR program, to break out, for PG&E, the PCIA…as a separate charge on a GTSR customer's bill and to ensure that the bill describes the PCIA…in a way that is easily understandable."[46]

Q: To ensure transparency and competitive neutrality, how should the PCIA charge be presented on all customer bills?

A: To increase rate transparency, ensure consistency, and allow customers to make fair comparisons between the unbundled and bundled rates they are charged, the PCIA charge on all customer bills should also be displayed as separate line item, depicting the kWh quantity and kWh rate, which mathematically results in the total PCIA charge included in a customer's bill.

---

44 D.22-05-015, FOF 17.

45 D.18-10-019, p. 119.

46 Resolution E-4734, pp. 11-12 (Oct. 2, 2015).

Q: Has PG&E provided any information as to the timing of Commission-ordered updates, or whether the BMI will facilitate greater PCIA transparency on customer bills?

A: PG&E originally planned to implement a breakout of the PCIA charge (kWh quantity and kWh rate) on bundled customers' billing statements, but this implementation was delayed until the end of 2027 due to the BMI process.[47] At this time, PG&E will not confirm if and how the presentation of the PCIA will change under the new billing system. Additionally, PG&E states it is unable to confirm whether customer bills for either bundled or unbundled customers will display both the kWh usages and applicable kWh rate used to calculate the monthly PCIA charge. PG&E explained that it will not know the details of bill presentment for the PCIA charge until Stage 3 of the BMI.[48]

Q: Is it reasonable for the Commission to allow PG&E an unbounded extension to break out the PCIA and discretion as to whether it should implement updates for transparency?

A: No. Given the Commission's outstanding order that PG&E implement changes to PCIA bill presentation, as well as the history of clear Commission guidance regarding the importance of bill transparency, the Commission should set a definitive timeline by which PG&E should implement the recommendations described herein. Specifically, the Commission should require PG&E to implement these PCIA billing presentment updates no later than Q3 of 2026, when PG&E implements the second stage of the BMI process, CC&B 25.1. According to PG&E, the implementation of the update to CC&B 25.1 is scheduled to go live in Q3 of 2026,[49] which is more than 10 years later than the Commission order which required PG&E to separate the PCIA charge for bundled customers and ensure the bill describes the PCIA in a way that is easily understandable.[50]

---

47 Attachment KJC-2 (PG&E Response to PCE DR 1.13).

48 Attachment KJC-2 (PG&E Response to PCE DR 1.10).

49 Application, p. 8.

50 Resolution E-4734, pp. 11-12 (Oct. 2, 2015).

III. THE COMMISSION SHOULD NOT ALLOW PG&E TO FUNCTIONALIZE ANY BMI COSTS TO THE ELECTRIC GENERATION FUNCTION.

Q: Please summarize this section of your testimony.

A: In this section of my testimony, I will address the issues with PG&E's proposal to allocate BMI costs using a modified version of the common cost allocation methodology as defined by D.23-11-069 and D.24-12-038. Under PG&E's application of this methodology, a portion of BMI costs would be functionalized as electric generation, which I believe is incorrect. Since the BMI takes end meter data and builds from these data sets, there are no aspects of the BMI that can be directly tied to electric generation. Therefore, any BMI costs PG&E currently plans to functionalize to electric generation should instead be added to the BMI costs functionalized as distribution costs.

Q: Please explain the origins of the common cost allocation methodology.

A: In D.23-11-069, the Commission adopted a methodology for allocating particular costs included in PG&E's GRC that were classified as Common, General, and Intangible (CGI) to different functional areas within PG&E. According to D.23-11-069, a portion of the GRC CGI costs is allocated to PG&E's generation function. These generation-related GRC costs are then recovered from bundled and unbundled customers through PG&E's generation and PCIA rates. In PG&E's annual ERRA Forecast proceedings, the generation-related GRC costs, including common costs, are apportioned among PG&E's Portfolio Allocation Balancing Account (PABA), ERRA, and New System Generation Balancing Account (NSGBA) cost recovery mechanisms.

At the conclusion of PG&E's 2025 ERRA Forecast proceeding, D.24-12-038 adopted a refined process for allocating the generation-related common costs approved in the GRC. This updated approach allows PG&E to recover, among other things, Energy

Supply Administration (ESA) costs associated with PG&E generation procurement that are deemed common to both bundled and unbundled customers.[51]

Q: Please explain how PG&E proposes to apply the common cost allocation methodology to BMI costs.

A: Using the GRC common cost allocation methodology, PG&E proposes to allocate BMI costs totaling $393.1 million (2023-2030) to electric generation, electric distribution, gas distribution, gas transmission and storage, and gas local transmission functional areas.[52] PG&E proposes that the BMI costs allocated to electric generation be allocated between the ERRA, PABA, and NSGBA, with CCA customers sharing the costs allocated to PABA and NSGBA.[53] More specifically, the BMI costs allocated to the PABA will be allocated with other generation-related GRC costs to PCIA vintages UOG Legacy, 2009, 2010, 2011, and 2012.[54]

PG&E proposes to allocate a total of $40.5 million of BMI costs between 2023-2030 to electric generation. Table 1 below shows the BMI costs PG&E proposes to allocate to each functional area across the timeframe of the BMI.

Table 1: BMI Revenue Requirement Summary By Functional Area[55]

RRQ by Functional Area	2023	2024	2025	2026	2027	2028	2029	2030	2023-2030
Electric Distribution (ED)	$344,930	$2,424,356	$7,886,196	$24,761,634	$33,598,519	$31,388,777	$26,905,630	$70,810,737	$198,120,780
Electric Generation (EG)	$190,365	$1,337,992	$2,933,454	$4,755,492	$6,452,623	$6,028,240	$5,167,248	$13,599,260	$40,464,675
Gas Distribution (GD)	$182,239	$1,280,877	$4,166,569	$13,082,488	$17,751,342	$16,583,853	$14,215,241	$37,411,934	$104,674,544
Gas Transmission & Storage (GT&S)	$86,858	$610,482	$1,985,839	$6,235,278	$8,460,513	$7,904,073	$6,775,162	$17,830,998	$49,889,203
Total RRQ (without RF&U)	**$804,392**	**$5,653,707**	**$16,972,058**	**$48,834,893**	**$66,262,997**	**$61,904,944**	**$53,063,282**	**$139,652,929**	**$393,149,203**

Q: Do you agree with the application of the common cost allocation methodology to BMI costs?

A: I do not, because I do not agree with the allocation of any BMI costs to the electric generation functional area. The goal of the BMI is to replace PG&E's aging billing system

[51] D.24-12-038, p. 30.

[52] Attachment KJC-2 (PG&E Response to PCE DR 1.17).

[53] *Id.* Note the electric generation functional area is the only revenue adjustment category under the common cost allocation methodology that distinguishes between bundled and CCA customers, and other types of departing load.

[54] *Id.*

[55] *Id.*

and move customers to "a single unified customer care, service order, metering, and billing system" that could deal with the complexities of the California energy market.[56] None of the BMI upgrades are related to, or caused by, anything concerning PG&E's generation business.

As the BMI costs are not at all related to the generation function, they should not be functionalized as generation costs. It is inappropriate to recover non-generation costs through an allocation methodology that includes generation. The purpose of functionalization is to assign utility costs to the function they provide in the electricity supply chain.[57] As the BMI costs relate to PG&E's delivery services only, they should be functionalized accordingly.

Q: Are BMI costs similar to the ESA costs to which PG&E applies the generation-related common cost allocation methodology adopted by D.24-12-038 in PG&E's ERRA proceeding?

A: No. To my knowledge, the common costs at issue in D.24-12-038 are only related to administering various aspects of PG&E's generation business, not other functional areas within PG&E. For example, in PG&E's direct testimony in the 2025 ERRA forecast it states, "The authorized ESA cost and the Forecast Collateral Costs … is the 'Common Cost' which PG&E is allocating."[58] ESA costs include the costs of business functions performed by PG&E's Energy Policy and Procurement organization, for example to oversee and implement procurement-related activities such as bidding and scheduling generation into the CAISO market or administering new resource solicitations.[59] Collateral costs include carrying costs of posting collateral to counterparties to cover market movements associated with power supply related transactions.[60] The costs included in the BMI are to replace the utility's aging billing system currently used to serve its electric and

---

56 PG&E Testimony, Chapter 1, p. 1-2.

57 National Association of Regulatory Utility Commissioners, *Primer on Rate Design for Cost-Reflective Tariffs*, p. 15 (Jan. 2021), *available at* https://pubs.naruc.org/pub.cfm?id=7BFEF211-155D-0A36-31AA-F629ECB940DC.

58 A.24-05-009, PG&E Prepared Testimony, p. 10-9.

59 A.24-05-009, PG&E Response to CalCCA Data Request 1.27.

60 A.24-05-009, PG&E Prepared Testimony, p. 6-6.

gas customers in the areas of billing, customer service, and customer data management and do not have a direct connection to PG&E's generation business.

Q: Did PG&E directly apply the common cost allocation methodology from D.23-11-069 to the costs in this case?

A: No, PG&E did not – it used a modified version of the methodology from D.23-11-069. As stated previously, the Commission adopted a methodology for allocating particular costs included in PG&E's GRC that were classified as CGI to different functional areas using the authorized Operations and Maintenance labor allocation factors adopted in D.23-11-069.[61] PG&E has recommended that all costs for the BMI project be allocated 100% to the cost categories subject to the Commission's jurisdiction, with no portion of the costs being recovered from the cost categories under FERC jurisdiction even though PG&E references the use of the CGI allocation factors as adopted in D.23-11-069.[62] The CGI allocation methodology from D.23-11-069 includes an allocation to the FERC transmission function and this is shown in PG&E's WP 7-1 CGI RRQ Allocation.[63] Table 2 below shows PG&E's CGI estimated allocation factors by year and by function.

---

61 PG&E Testimony, Chapter 7, p. 7-7.

62 *Id.* at 7-7.

63 Attachment KJC-2 (PG&E Response to PCE DR 1.1, WP 7-1).

Table 2: CGI Allocation Factors by Functional Area by Year[64]

Functional Area Allocation %	2023	2024	2025	2026	2027	2028	2029	2030
Electric Distribution (ED)	38.772%	38.772%	41.679%	45.058%	45.058%	45.058%	45.058%	45.058%
Electric Generation (EG)	21.398%	21.398%	15.504%	8.653%	8.653%	8.653%	8.653%	8.653%
Gas Distribution (GD)	20.484%	20.484%	22.021%	23.806%	23.806%	23.806%	23.806%	23.806%
Gas Transmission and Storage (GT&S)	9.763%	9.763%	10.495%	11.346%	11.346%	11.346%	11.346%	11.346%
Electric Transmission (ET)	9.583%	9.583%	10.302%	11.137%	11.137%	11.137%	11.137%	11.137%
Total	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%

In PG&E's requested cost recovery, PG&E has taken the allocated percentage of the CGI allocation factors for electric transmission and reallocated it to the electric distribution, electric generation, gas distribution, and gas transmission and storage functions. PG&E's choice to modify the CGI allocation no longer aligns with the Commission-approved allocation methodology PG&E claims that it used. Table 3 summarizes PG&E's new CGI allocation factors, which have not been approved by this Commission.

64 *Id.*

Table 3: PG&E's Modified CGI Allocation Factors by Functional Area[65]

Functional Area Allocation %	2023	2024	2025	2026	2027	2028	2029	2030
Electric Distribution (ED)	42.881%	42.881%	46.466%	50.705%	50.705%	50.705%	50.705%	50.705%
Electric Generation (EG)	23.666%	23.666%	17.284%	9.738%	9.738%	9.738%	9.738%	9.738%
Gas Distribution (GD)	22.656%	22.656%	24.550%	26.789%	26.789%	26.789%	26.789%	26.789%
Gas Transmission and Storage (GT&S)	10.798%	10.798%	11.701%	12.768%	12.768%	12.768%	12.768%	12.768%
Electric Transmission (ET)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Total	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%

Q: Can you give examples of other, more appropriate approaches to allocating the costs associated with upgrading or replacing a customer billing system used by an IOU?

A: Yes. One example is SCE's functionalization of its recent billing systems upgrade entirely to the electric distribution function. SCE submitted an application on July 22, 2021 (A.21-07-009) for authorization to recover in rates the costs tracked in its Customer Service Re-Platform Memorandum Account (CSRPMA). The CSRPMA tracks costs associated with SCE's Customer Service Re-Platform (CSRP) project, which replaced SCE's legacy Customer Service System (CSS) in April of 2021 with a new enterprise customer relationship and billing system to perform core customer service-related functions, such as generating customer bills, processing payments, enabling customer account management, and providing customer access to SCE rates and programs.[66] SCE's requested cost recovery

---

65 *Id.* (percentage calculation of RRQ by Functional Area table).

66 D.23-03-019, p. 2.

mechanism—which was approved by the Commission in D.23-03-019—functionalized all CSRP costs to electric distribution.[67]

Another example is Duke Energy Ohio, Inc. (Duke). Duke submitted an application to the Public Utilities Commission of Ohio in 2019 (Case No. 19-1750-EL-UNC) for approval to include Duke's Rider PF in its initial infrastructure modernization plan consisting of customer information system upgrades and other infrastructure investment programs (Infrastructure Modernization Plan) and for deferral authority for Operations and Maintenance (O&M) costs, incremental to amounts in base electric and natural gas rates that have been or will be incurred in relation to the Infrastructure Modernization Plan.[68] The Ohio Commission's Finding and Order in that case determined "the revenue requirement shall be allocated based on the percentage of base distribution revenues approved in the Company's most recent electric rate case. In Duke's next electric rate case, the Company's application will include a proposal to roll plant-in-service assets, depreciation, and property taxes from Rider PF filings into base rates."[69] In other words, the costs tied to system upgrades and investments associated with Duke's Infrastructure Modernization Plan were allocated solely to the utility's distribution function, *not* its electric generation function—unlike PG&E's proposed approach to allocating BMI costs here.

Q: How should PG&E treat the BMI costs it proposes to allocate to electric generation?

A: In this Application, PG&E is proposing a new CGI allocation methodology that is inconsistent with the methodology that the Commission previously endorsed; this proposed methodology should be rejected in this case. For all the reasons discussed herein, there should be no costs allocated to the electric generation function, as the BMI costs are not related to PG&E's generation business. I recommend that PG&E instead follow SCE's and Duke's example and re-allocate the BMI costs it currently proposes to functionalize as

---

67 *Id.*, Ordering Paragraph (OP) 2.

68 Case No. 19-1750-EL-UNC, *In the Matter of the Application of Duke Energy Ohio, Inc. for Authority to Adjust its Rider PF*, Finding and Order, p. 1.

69 *Id.*, p. 4.

electric generation costs to the electric distribution function to ensure all electric customers are treated consistently in the recovery of the BMI costs.

Q: Can you summarize the impact of your proposal regarding cost functionalization on PG&E's revenue requirement request?

A: This proposal has no impact on the magnitude of PG&E's revenue requirement request; it only impacts how this revenue requirement would be functionalized. I have summarized my proposed changes in Table 4 below.

Table 4: Joint CCAs' Proposed BMI Revenue Requirement Summary by Functional Area

RRQ by Functional Area	2023	2024	2025	2026	2027	2028	2029	2030	2023-2030
Electric Distribution (ED)	$535,295	$3,762,348	$10,819,650	$29,517,126	$40,051,142	$37,417,017	$32,072,878	$84,409,997	$238,585,455
Gas Distribution (GD)	$182,239	$1,280,877	$4,166,569	$13,082,488	$17,751,342	$16,583,853	$14,215,241	$37,411,934	$104,674,544
Gas Transmission & Storage (GT&S)	$86,858	$610,482	$1,985,839	$6,235,278	$8,460,513	$7,904,073	$6,775,162	$17,830,998	$49,889,203
Total RRQ (without RF&U)	**$804,392**	**$5,653,707**	**$16,972,058**	**$48,834,893**	**$66,262,997**	**$61,904,944**	**$53,063,282**	**$139,652,929**	**$393,149,203**

Q: Why is it important that none of the BMI costs be allocated to the generation function?

A: This is important for a few reasons. First, as noted above, the purpose of functionalization is to assign utility costs to the function those costs serve in the electricity supply chain. PG&E's cost functionalization proposal does not accurately do this, and it should be modified so that it aligns with this generally accepted best practice in ratemaking—especially since the methodology PG&E proposes is not consistent with the CGI allocation methodology previously approved by this Commission.

Second, this issue matters to CCA customers in particular because recovery of BMI costs through the PABA will raise PCIA rates—a line item on unbundled customer bills that makes unbundled service appear more expensive. The Commission should not allow

PG&E to funnel costs through the PCIA that improperly inflate this charge, to the detriment of CCAs' competitive position.

Finally, PG&E's proposal to recover these "generation" costs via the UOG Legacy, 2009, 2010, 2011, and 2012 PCIA vintages[70] will impact different CCA customers differently, depending on their departure date from bundled service (*i.e.*, their assigned vintage year). This is both unfair and illogical, as even PG&E has admitted that all customers will benefit similarly from the BMI project.[71]

IV. THE COMMISSION SHOULD NOT ALLOW PG&E TO RECOVER THE COSTS ASSOCIATED WITH THE CC&B 25.1 UPGRADE AS BMI COSTS.

Q: Please summarize this portion of your testimony.

A: In this section of my testimony, I discuss PG&E's unnecessary and unreasonable delay in proceeding with its BMI process. This delay necessitated an interim step in the upgrade process—implementation of the CC&B 25.1 upgrade—that will result in approximately $25 million of stranded costs.[72] I do not evaluate in this testimony whether the CC&B 25.1 upgrade is necessary; instead, I focus here on the extent to which ratepayers should be responsible for the costs associated with PG&E's delays.

I recommend that the Commission either deny PG&E's request to recover the costs of the CC&B 25.1 upgrade as BMI costs, or disallow a return on rate base for the portion of the BMI costs associated with the CC&B 25.1 upgrade and credit customers for the associated stranded costs.

Q: Please explain PG&E's planned CC&B 25.1 upgrade within the context of the BMI process.

A: Stage 2 of PG&E's BMI process includes updating the outdated version of Oracle Utilities CC&B currently used by PG&E, version 2.4, to the up-to-date version 25.1. PG&E states that "[r]ather than upgrade directly to C2M, PG&E evaluated (and ultimately selected) an

---

70 Attachment KJC-2 (PG&E Response to PCE DR 1.17).

71 Attachment KJC-2 (PG&E Response to PCE DR 2.28).

72 Attachment KJC-2 (PG&E Response to PCE DR 1.05).

option to perform an intermediate upgrade to stabilize PG&E's CC&B system by upgrading to the most up-to-date version of Oracle's CC&B program, CC&B 25.1."[73]

PG&E has identified the upgrade to version 25.1 as a stabilization exercise that provides a solution to several of the issues with the legacy billing system. PG&E states that upgrading to this version will address the following issues: (1) allow PG&E to remedy the cybersecurity vulnerabilities that are currently open and Oracle's lack of support for the current version of the system, (2) remedy the incompatibility with current versions of PG&E's software that are integral to its stable functioning, which has led to difficulties performing disaster recovery exercises, (3) transition from COBOL to Java, which is the language that C2M uses as well, and (4) bring the associated applications into support along with the CC&B system.[74] PG&E believes that upgrading to CC&B 25.1 would address issues with maintaining CC&B 2.4 for two or more years while waiting for C2M to go live.[75]

However, the CC&B 25.1 upgrade is not the target-state solution because it does not enable multiple critical business outcomes that PG&E has identified. For example, the CC&B 25.1 upgrade will not move from linear rates to modular rates, reduce the number of customizations, integrate with an MDMA solution, or move PG&E to a single modular rate engine.[76] Thus, PG&E proposes that the CC&B 25.1 system be replaced by the upgrade to C2M during Stage 3 of the BMI.[77]

Q: When will this CC&B 25.1 upgrade occur and what are the costs associated with it?

A: The CC&B upgrade to version 25.1 began in Q4 2024 and is currently forecasted for completion by the end of 2026**,** as shown in Figure 6 below. The CC&B 25.1 upgrade is projected to cost $127.5 million between 2024 and 2026, including $91.2 million in capital costs, $8.5 million in expense costs, and $27.8 million in contingency.[78]

---

73 PG&E Testimony, Chapter 4, pp. 4-28 to 4-29.

74 *Id.* at 4-29 to 4-30.

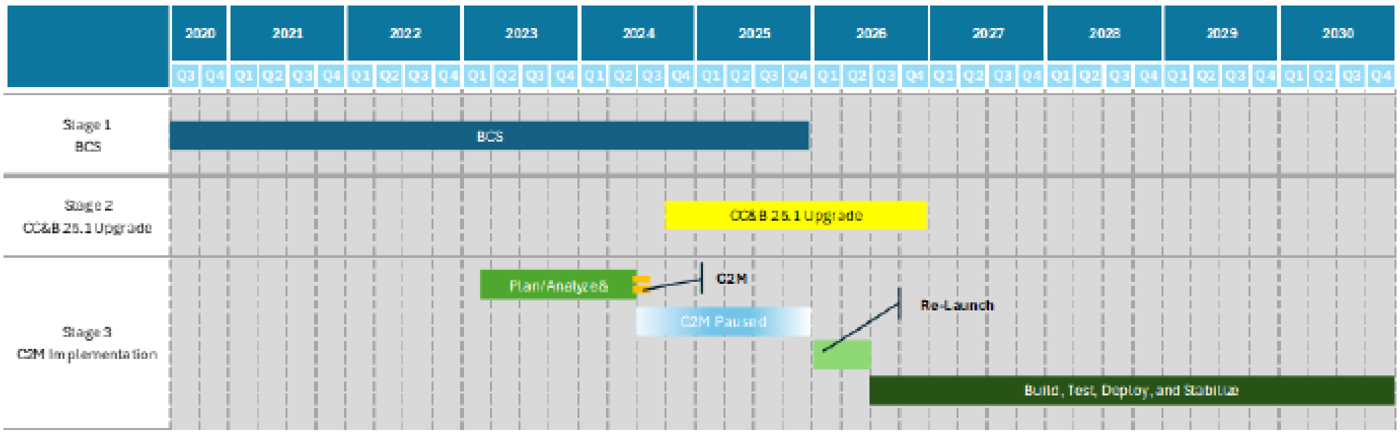
75 *Id.* at4-29.

76 *Id.* at4-30.

77 Attachment KJC-2 (PG&E Response to PCE DR 1.03).

78 PG&E Testimony, Chapter 6, p. 6-21.

Figure 6: Timeline for Billing Modernization Initiative[79]



Q: Please explain the role of the CC&B 25.1 upgrade in relation to the C2M upgrade during Stage 3 of the BMI.

A: As mentioned above, the CC&B 25.1 system will be entirely replaced by the C2M system. Essentially, PG&E describes the CC&B 25.1 upgrade as a temporary solution that is necessary to provide a secure and reliable billing platform for customers until the implementation of the C2M system in 2029/2030.[80] The C2M system will replace all billing components and consolidate the electric Biling Cloud System (BCS) and Advance Billing System (ABS) into one system.

Q: Will the CC&B 25.1 upgrade result in stranded costs since it will be fully replaced by C2M?

A: Yes. PG&E admits that if it transitions directly from legacy systems to C2M—*i.e.*, without implementation of the BCS or CC&B 25.1 projects—there would be no stranded costs associated with the BMI.[81] However, because the CC&B 25.1 system will be replaced by C2M, PG&E states that 25 percent of the system component upgrade cost for CC&B 25.1, or $24.7 million, is associated with investments that will no longer be utilized once C2M is implemented.[82]

---

79 PG&E Testimony, Chapter 1, p. 1-6, Figure 1-2.
80 *Id.* at 1-6.
81 Attachment KJC-2 (PG&E Response to PCE DR 1.26).
82 Attachment KJC-2 (PG&E Response to PCE DR 1.05).

Q: How did PG&E end up in this situation in which it will be investing significantly in an interim upgrade (CC&B 25.1) that it will be fully replacing with its end-state billing system (C2M) within a few years?

A: The CC&B 25.1 upgrade is an interim step that is necessary only because PG&E substantially delayed implementation of C2M. PG&E originally planned to upgrade the outdated CC&B 2.4 directly to C2M, with the C2M system's implementation planned to go live in 2024, as proposed in PG&E's 2023 GRC.[83] However, since the Commission's rejection of PG&E's proposal in the 2023 GRC—due to PG&E's insufficient showing in that case[84]—PG&E has continuously stalled its upgrade processes and forgone many opportunities to keep its billing systems in adequate condition.

Q: What is PG&E's explanation for its significant delays?

A: PG&E seems to suggest that the Commission's rejection of its original billing upgrade proposal in its 2023 GRC is the primary reason for this delay. PG&E explains that it moved the current timeline for the potential implementation of the C2M system to 2026 after the rejection of PG&E's billing upgrade proposal in the 2023 GRC.[85] PG&E notes that this delay led to further deterioration of the CC&B 2.4 system as the system became increasingly out-of-date, unsupported, and vulnerable to cyber threats.[86] Additionally, PG&E claims the recent completion of PG&E's Plan, Analyze, and Design phase of C2M revealed additional complexities in the direct upgrade from CC&B 2.4 to C2M pertaining to requirements of a peak day pricing user interface, bill print extract functionality, and payment plans.[87] Because of the continued deterioration of the CC&B 2.4 system and the additional complexities associated with a direct upgrade from CC&B 2.4 to C2M, PG&E asserts that the intermediate upgrade to CC&B 25.1 is needed to stabilize the billing system.

Q: Was it reasonable for PG&E to continue to allow its CC&B 2.4 system to deteriorate in this manner?

---

83 PG&E Testimony, Chapter 4, p. 4-26 and p. 4-27.
84 D.23-11-069, pp. 546-550.
85 PG&E Testimony, Chapter 4, p. 4-26 and p. 4-27.
86 *Id.* at 4-28.
87 *Id.* at 4-27 to 4-28.

A: No. PG&E upgraded from CC&B version 2.3 to the current CC&B version 2.4 in 2017.[88] There have been at least five updated CC&B versions released by Oracle since version 2.4, as shown in Table .

Table 5: Oracle Releases of CC&B Versions[89]

CC&B Version	Release Date
CC&B 2.4	October 2013
CC&B 2.5	October 2015
CC&B 2.6	May 2017
CC&B 2.7	August 2018
CC&B 2.8	April 2021
CC&B 2.9	April 2022
CC&B 25.1[90]	April 2025

PG&E could have updated its CC&B system numerous times in the past but instead chose to delay such an update until the BMI. This decision resulted in PG&E's current situation in which its CC&B system does not have standard vendor support and remediation options to address cyber vulnerabilities.[91]

Q: Are there other third-party sources that indicate this course of action was not reasonable?

A: Yes. This delay was also contrary to the advice PG&E received as a result of multiple outside consultant reviews. For instance, in a 2018 evaluation, Accenture recommended that PG&E re-platform to a next generation CIS within the 2024 timeframe, and in a 2022 evaluation, Accenture reiterated the need to re-platform in the near-term.[92]

PG&E's delay was also inconsistent with PG&E's own articulation of its best practices in these kinds of situations. PG&E notes in discovery that its optimal timeline for analyzing IT asset replacement options is through routine check-ins performed as a regular part of system maintenance as soon as the asset has been deployed and is operating without

---

88 Attachment KJC-2 (PG&E Response to PCE DR 2.03).

89 *Id.*

90 The table included in PG&E Response to PCE DR 2.03 incorrectly noted this version as being CC&B 25.4; it has been corrected in this table to reflect the proposed upgrade of CC&B 25.1.

91 PG&E Testimony, Chapter 1, p. 1-3.

92 Attachment KJC-2 (PG&E Response to PCE DR 1.22).

significant defects,[93] and that its optimal timeline for undertaking asset replacement is "*within* the operational lifespan of the asset[,]" which "[f]or most software and hardware . . . is typically between 3 to 10 years."[94] The aging billing systems at issue are fully depreciated and "have more than fulfilled their asset lives[,]" with the original system implementation in 2001 and the most recent update occurring in 2017.[95] Thus by waiting until the end of 2024 to even file this Application, PG&E has strayed far beyond the timelines for review and replacement it calls out as prudent.

Q: Could PG&E have approached the planning of the C2M upgrade differently to avoid the need for the CC&B 25.1 upgrade?

A: Yes. I believe PG&E could have taken a few different reasonable courses of action to prevent the situation in which it now finds itself.

First, PG&E could have prepared a more robust showing in its 2023 GRC that provided the Commission with sufficient information to review and approve the billing upgrade request at that time.[96]

Second, even in the scenario in which PG&E provided that deficient showing in the 2023 GRC, following that 2023 GRC decision, it was fully within PG&E's discretion to determine when to file a new application for cost recovery approval of its billing system upgrade. PG&E could have filed this Application earlier in 2024, and prior to Commission approval of the Application, it could have requested authorization to track the costs associated with necessary billing upgrade work in a memorandum account, to be later reviewed by the Commission for reasonableness and cost recovery. With a memorandum account in place, PG&E could have proceeded with its C2M implementation without delay, deployed C2M by the end of 2026 as planned,[97] and avoided the need for the interim CC&B 25.1 upgrade.

---

93 Attachment KJC-2 (PG&E Response to PCE DR 1.20).

94 *Id.* (emphasis added).

95 PG&E Testimony, Chapter 2, p. 2-15.

96 *See* PG&E Testimony, Chapter 1, p. 1-11, Table 1-3 (listing all the directives from the 2023 GRC decision that describe the items that were missing from PG&E's initial proposal in that case).

97 Attachment KJC-2 (PG&E Response to PCE DR 1.19).

Alternatively, even if PG&E was for some reason unable to file its Application earlier, it could have filed a standalone request for authorization to track the costs associated with necessary billing upgrade work in a memorandum account. With a memorandum account in place, PG&E could have proceeded with the C2M upgrade, achieving implementation by the end of 2026 as discussed above,[98] and it would not now need to invest in the CC&B 25.1 upgrade and further delay C2M implementation.

Q: Why do you think requesting cost tracking via a memorandum account would have been appropriate for these costs?

A: The Commission has a procedural mechanism available to IOUs so that they may proceed with necessary and time-sensitive investments in the absence of upfront approval for full cost recovery: memorandum accounts. While the Commission's general practice "is not to authorize increased utility rates to account for previously incurred expenses," the Commission commonly makes an exception when, "before the utility incurs those expenses, the Commission has authorized the utility to book those expenses into a memorandum or balancing account for possible future recovery in rates."[99] Memorandum accounts are routinely used to track these kinds of time-sensitive investments so that a utility can proceed with what it deems to be necessary or prudent work, and later seek cost recovery for the associated costs.[100]

Q: Given all this context, do you think PG&E's approach to its C2M implementation was reasonable?

A: No. It appears that PG&E has delayed C2M implementation and delayed CC&B upgrades several times because it was not yet guaranteed through a Commission decision that it

---

98 *Id.*

99 *In the Matter of the Application of Southern California Water Company for authority pursuant to Public Utilities Code Section 851 to sell, and, if necessary, lease back its headquarters property in Los Angeles, California (U 133 M)*, D.92-03-094, 1992 Cal. PUC LEXIS 236, *7-9. *See also* D.23-05-003, p. 5 ("The courts have accepted that when the Commission approves of the scope of a program in advance, and when there is a subsequent review of the reasonableness of the utility's decision-making and management of the program, then forecast costs can subsequently be 'trued up' to actual and any revenue shortfall or overcollection is recoverable by the utility or refundable to ratepayers. The preapproval of the scope of the balancing account averts a finding of retroactive ratemaking, *i.e.*, it becomes an exception to the test year forecast requirement.").

100 *See, e.g.*, D.21-08-024; D.19-01-019; D.09-07-038; D.03-05-076.

would get full cost recovery for these investments. This is not a reasonable course of action. It is not prudent for a utility to put itself in a situation in which it is vulnerable to cyber security threats and is operating unsupported software—especially when the associated software is key to the management of customer billing and data. It is also not reasonable for a utility, in an effort to secure cost recovery approval prior to taking action, to delay billing upgrades to the point that its customers must then bear significant incremental costs—$25 million of which will ultimately be stranded costs.

Q: In light of PG&E's inappropriate approach to the C2M upgrade, how should the costs associated with the CC&B 25.1 upgrade be treated?

A: Given PG&E's unreasonable delay in moving forward with its billing system upgrades, I recommend that the Commission deny PG&E's request to recover the costs of the CC&B 25.1 upgrade as BMI costs, which is estimated to be $119 million of capital costs and $8.5 million of O&M expense.[101]

In the alternative, if the Commission allows PG&E to include the CC&B 25.1 upgrade costs as part of the BMI, then PG&E should not be allowed a return on rate base for this portion of the BMI costs, which is estimated to be $119 million.[102] Additionally, the Commission should order PG&E to reimburse customers for the $24.7 million in associated investments that will not be used in the final C2M system. This recommendation is in line with the example set by SCE in its ERP reimbursement proposal in A.25-03-009. In that case, SCE plans to reimburse customers for ERP benefits associated with O&M and capital expenditures no longer needed for the ERP program but anticipated to be authorized in SCE's 2025 GRC. Furthermore, savings associated with O&M or capital expenditures no longer required due to the ERP program upgrades in 2029 and beyond and not anticipated to be requested in SCE's future GRCs will be returned to customers in SCE's future GRCs through lower recorded costs, specific line-item reduction to capital or O&M forecasts, and/or SCE excluding incremental forecast costs.[103]

---

[101] PG&E Testimony, Chapter 1, Table 1-1.

[102] *Id.*

[103] A.25-03-009, *Application of Southern California Edison Company (U 338-E) for Authorization to Recover Costs Related to NextGen Enterprise Resource Planning Program*, Testimony-Volume 2, pp. 77-78.

V. THE COMMISSION SHOULD HOLD PG&E ACCOUNTABLE FOR ENSURING THE BMI FIXES CERTAIN PERSISTENT BILLING PROBLEMS, IMPROVES PG&E'S PERFORMANCE ON DESIGNATED BILLING SYSTEM EFFICIENCY METRICS, AND ACHIEVES TARGET TIMELINES FOR CRITICAL GOALS.

Q: Please summarize this portion of your testimony.

A: In this section of my testimony, I recommend that the Commission order PG&E to ensure its substantial BMI investment addresses certain persistent billing issues experienced by CCAs and CCA customers and measurably improves PG&E's performance on key billing system efficiency metrics. I also recommend that the Commission hold PG&E accountable for achieving set timelines for the implementation of its many backlogged rate projects and for resolving any CCA billing and revenue delays arising out of the BMI deployment. The Commission should not approve this level of investment in PG&E's billing system without concrete commitments from PG&E that its new system will effectively address the significant problems plaguing its legacy billing systems and approach, with minimal disruption to customers.

E. The Commission Should Order PG&E to Ensure its BMI Investment Addresses Certain Persistent Billing System Problems.

Q: What kinds of billing system issues are CCAs and CCA customers experiencing on a regular basis?

A: Based on my discussions with representatives from the CCAs' data management providers, my understanding is that the most pervasive billing issues experienced by the CCAs under PG&E's current billing system fit into the following general categories: (1) data access; (2) data quality; (3) communication and coordination; and (4) billing mechanics challenges and delays.

Q: Can you explain the issues CCAs have been experiencing with data access?

A: In PG&E's current billing system, there is certain critical billing data to which CCAs and their data management providers do not have access. In the table below, I provide a list of additional data needed and explain why in each case it is vital for CCAs to have access to the data.

Table 6: Additional Data Needed by CCAs in End-State PG&E Billing System

Data File	Description	Why CCAs Need Access
Hourly and Sub-Hourly Billing Interval Data	PG&E Electronic Data Interchange (EDI) billing transactions still only provide scalar usage aggregated by time-of-use (TOU) period, unlike SCE and SDG&E which have included interval data for approximately 10 years.	Scalar data is inadequate for dynamic pricing, energy efficiency programs, and many other key functions to CCA business. The absence of interval data effectively prevents CCAs from creating their own rate schedules, dynamic pricing programs, or even different TOU hours. PG&E's workaround of using the ShareMyData (SMD) platform for the last decade is not an adequate solution. CCAs need to bill on the EDI transactions supplied by PG&E. Furthermore, SMD data is not utilized by PG&E for billing; therefore the data is not fully processed or reliable. This level of data should already be required to be provided to the CCAs today. The Commission should order PG&E to provide this level of detail by the end of 2025 and ensure that this level of detail will still be able to be provided upon conclusion of the BMI project.

810 Files for "Rate Ready"[104] Accounts	An 810 file is an EDI file type that consists of a detailed customer invoice (*e.g.*, it includes all the separate transactions that comprise the total bill). Currently, for "Rate Ready" accounts, CCAs do not receive detailed invoice files from PG&E.	Having 810 files for these accounts will allow CCAs to (1) provide better service to customers and help customers understand their charges, and (2) validate individual transactions and confirm the accuracy of these customers' bills.
Expected Versus Sent Usage/Account Reporting	An 814 file is an EDI file type that provides account attributes; an 867 file is an EDI file type that provides usage data. Currently, the CCAs receive these 814 and 867 files every day from PG&E, but they do not have sufficient insight into situations in which these files are unexpectedly missing for particular accounts.	Daily reports on the expected versus actually sent EDI 814 and EDI 867 counts would allow CCAs to track delays or items of concern in PG&E-CCA data exchange.

[104] There are two types of billing available to PG&E CCAs: "Rate Ready" and "Bill Ready." "Rate Ready" accounts operate as follows: the CCA gives PG&E its rates, and PG&E then uses its billing system to calculate the invoice for CCA services. In contrast, "Bill Ready" accounts operate as follows: PG&E sends the CCA/CCA Data Manager its usage data, and then the CCA/CCA Data Manager calculates the invoice amount and sends PG&E an invoice to be placed on the consolidated bill.

Adding the “Billed To” Date in 4013 Files	A 4013 file is an Excel/CSV file type that consists of a weekly snapshot of all active accounts in a given CCA territory (also referred to as a “Customer List”). Currently, this file type does not include a “billed to” date (*i.e.*, the last date PG&E billed the account).	CCAs have a list of PG&E accounts with usage transactions missing. This can be due to issues with PG&E’s billing system. In other cases CCAs have identified inactive accounts incorrectly left open. Adding a “billed to” date field in this file would give CCAs more insight into which accounts have missing customer usage information—a common issue that leads to delayed billing and back billing.
Daily API Pushes Sharing 4013 Data	The manual method by which PG&E shares 4013 file data with the CCAs via weekly postings is onerous for both PG&E and the CCAs.	Creating an Application Program Interface (API) connection where daily changes to 4013 data could be pushed to the CCAs would reduce storage and manual processes on both the PG&E and CCA sides.
Including “White Bill” Data on “Blue Bills” for Solar/Storage Customers	PG&E currently does not include the detailed information from its “white bills” in its regular “blue bills” for solar/storage customers.	Including the information currently included on “white bills” within PG&E’s “blue bills” would enhance bill clarity and facilitate customer understanding. Once this is accomplished, “white bills” should be discontinued.

Q: What do you recommend with respect to data access?

A: The Commission should order PG&E to provide the data files included in Table 6 above to CCAs as a regular course of business once it has transitioned to its final end-state billing system via the BMI. However, with respect to hourly and sub-hourly interval data, PG&E should be required to provide this data sooner. Specifically, PG&E should be required to provide the hourly and sub-hourly data to CCAs by no later than the end of 2025. The hourly and sub-hourly data has been provided by SCE and SDG&E for nearly 10 years.

Q: Can you explain the issues CCAs have been experiencing with data quality?

A: It is my understanding from conversations with representatives from the CCAs' data management providers that many of the data files PG&E shares with CCAs in the normal course of providing billing services are often incomplete or error ridden. In the table below, I provide a list of the data quality issues experienced by the CCAs and how PG&E's post-BMI end-state billing system should address them.

Table 7: Data Quality Fixes Needed in End-State PG&E Billing System

Data Quality Issue	Description of Data Quality Problem	Data Quality Solution
No Clear Process for Resolving Unbilled Invoices (810 Files)	An 810 file is an EDI file type that consists of a detailed customer invoice. It is currently used for "Bill Ready" accounts; per the Joint CCAs' suggestion in Table 6 above, 810s should be provided for "Rate Ready" accounts as well. Currently, PG&E does not adhere to any clear process for resolving unbilled 810 files. These are accounts that are billed by the CCA, but there is no acknowledgement from PG&E if CCA charges have been presented to the customer.	There should be an established, enforceable service level expectation that PG&E must provide full resolution within three business days once it receives notice from a CCA of unbilled invoices. This will ensure CCAs can get the revenues they are due in a timely manner.

Inconsistency in Classification of Rate Changes (814 Files)	An 814 file is an EDI file type that provides account attributes. PG&E has a practice of inconsistently classifying account rate changes—sometimes it classifies them as an "814 Rate Change"; sometimes it classifies them as an "814 Enrollment"; and sometimes it classifies them as an "814 Other" transaction. This affects how these files are processed in automation and where they appear in reports.	Any rate change should be sent via an 814 file and classified as "814 Rate Change" to avoid confusion.
Unclear Drop/Enrollment Transaction Data	PG&E has a practice of communicating about all customer drops and enrollments via 814 transactions (the EDI file type that provides account attributes). When there are multiple drop/enrollment transactions on the same day for an account, PG&E does not clearly differentiate between the transactions with precise date/time stamps or indicate the final state (*i.e.*, "Active" or "Closed") of the account.	PG&E should clearly differentiate between all drop/enrollment transactions with precise date/time stamps and indicate the final state (*i.e.*, "Active" or "Closed") of the account.
Inconsistent Communication of Usage Data	PG&E is inconsistent in how it sends customer usage data to the CCAs. Sometimes PG&E sends usage data via EDI, but other times it states it cannot do so, and must instead provide the data via spreadsheet or via its green button AMI platform.	PG&E should send all usage data via EDI. This will streamline data transfer and minimize significant additional work on the CCA side.

Usage Data Sent Without Enrollment Data	PG&E often sends CCAs customer usage data without any corresponding enrollment data for the customer account. When the CCA receives usage without an enrollment, CCAs are unable to load that usage data into their billing systems without manual follow-up.	PG&E should be required to consistently send 814 files whenever a new customer enrolls.
Unauthorized Invoice Cancellation	In instances in which there is duplicate usage in a bill period in error, PG&E at times will cancel CCA charges without CCA authorization.	PG&E should never cancel CCA charges unless it receives authorization to do so from a CCA.
Errors in PG&E Files Sent to CCA Banks	Currently, PG&E's process for sending credit and debit transactions to CCAs' banks is problematic. PG&E limits the number of transactions it sends in one file, and it sends all credit transactions first, followed by all debit transactions. This causes issues with file receipt and processing.	PG&E should be required to streamline its process for sending files to CCAs' banks, including by sending all transactions at once (without dividing credit and debit transactions).
Process For Switching From Rate Ready to Bill Ready	PG&E has no good way of indicating when customers switch from Rate Ready to Bill Ready accounts. Currently, PG&E sends a drop notice and then a change request, which is cumbersome and causes unnecessary manual work.	PG&E should approach this in a simpler way: when a customer is switching from Rate Ready to Bill Ready, this should always be indicated via an 814 Change Form.
Inability to Audit Rate Ready Accounts	CCAs are unable to audit Rate Ready customer bills because CCAs do not receive detailed invoice files from PG&E for these accounts.	PG&E should ensure CCAs can audit bills for Rate Ready customers. This could be achieved (1) if PG&E provides 810 files for these accounts, as proposed in Table 6 above, or (2) if PG&E provides more information via its 248 files (billing confirmation files) associated with the Rate Ready accounts.

Incorrectly Sending Both Interval and Scalar Usage	There are two types of usage data PG&E can provide: interval read (15 minute or hourly data for entire billing period) or scalar read (total kWh per billing period, sometimes broken up between TOU buckets). PG&E at times sends scalar data and then follows up later with interval data for the same accounts. This is unnecessary and causes manual work on the CCA side.	PG&E should only send one type of usage data per account per billing period. Per the recommendation regarding interval data in Table 6 above, PG&E should always be sending *just* interval data.

Q: What do you recommend with respect to these data quality issues?

A: The Commission should order PG&E to ensure that its post-BMI end-state billing system will address the data quality issues summarized in Table 7 in accordance with the recommendations therein.

Q: Can you explain the issues CCAs have been experiencing with communication and coordination between the billing teams at PG&E and those at the CCAs?

A: Based on my conversations with CCA representatives as well as the CCAs' data management providers, in general it seems that PG&E is directing insufficient resources toward resolving CCA customer billing issues and delays in a timely manner. PG&E does not have designated points of contact for resolving technical billing issues or ongoing, collaborative working groups dedicated to resolving CCA billing issues and delays.

Given this context, the CCAs are concerned that the various stages of BMI rollout will not be communicated with sufficient detail or notice to CCAs and their customers. This concern is reinforced by the lack of detail provided in PG&E's Application and Testimony on this point. PG&E has not clearly explained how the various BMI changes will be communicated, acknowledging that "most PG&E customers do not have account representatives, so the C2M project will need to differentiate its approach to communicate the changes to customers"[105] but failing to specify how it will "differentiate its approach."

Q: What are your recommendations with respect to ensuring effective communication and coordination between the PG&E and CCA billing teams?

- The Commission should order PG&E to provide a designated point of contact for resolving technical billing issues impacting CCAs, in line with common practices at other California IOUs.
- The Commission should order PG&E to hold a semi-annual PG&E-CCA stakeholder workshop on resolving outstanding technical billing issues.
- The Commission should order PG&E to clarify, via an advice letter filing, its plan regarding how and when it will communicate with various customer groups on major upcoming changes arising out of the BMI. The Commission should also set a minimum timeframe for such communications, and specifically, order that PG&E must notify and educate customers and CCAs about all major upcoming billing changes arising out of the BMI at least three months in advance of implementation.[106]

Q: Can you explain the issues and concerns CCAs have with billing mechanics and delays?

A: Yes. Based on my conversations with CCA representatives, there are several key items of concern:

- **Delays in switching rates**. CCAs experience excessive delays in getting some customers switched from one rate to another. For example, SVCE highlighted a situation in which it took nearly eight months to move an account from a TOU-C rate to an E-ELEC rate. When this change was finally implemented, it resulted in a large balloon payment due from the customer. These types of delays cause customer experience issues, and in the aggregate, they could have anticompetitive impacts.
- **Inaccurate application of bill credits**. When a CCA issues a credit on a customer's bill that is greater than the generation charges on the bill, the credit

---

105 PG&E Testimony, Chapter 5, p. 5-46.

106 *Id*.

flows to the PG&E charges on the bill. Meaning, PG&E takes the CCA credit and applies it to the electric transmission, electric distribution, or gas portion of the bill instead of holding the credit to be applied to future generation charges. This effectively is causing the CCA to pay for those services on behalf of customers.

- **Backlogged billing projects**. In general, PG&E has been unable to develop new billing functionalities in a timely manner due to its backlog of projects. As one example, PG&E maintains that it cannot commit to enabling tariff on-bill (TOB) program billing functionality,[107] even though it acknowledges that current billing functionality enabling on-bill financing (OBF) cannot support TOB.[108] PG&E has stated in the TOB proceeding (Rulemaking 20-08-022) that it will not be able to implement a new TOB line item in the billing system before 2030 without requiring trade-offs with other projects. However, in Testimony in this case, PG&E acknowledges that the BMI end-state system must be able to manage the anticipated continued addition of new and more complex rates.[109] TOB would be such an addition, and it is unclear why PG&E's BMI proposal does not contemplate a specific plan and timeline for enabling TOB program billing functionality.

Q: What are your recommendations with respect to these issues around billing mechanics and delays?

- The Commission should order PG&E to design its final end-state billing system to efficiently switch customers between rate schedules when requested. This process should not take longer than one month.
- The Commission should order PG&E to design its final end-state billing system to allow for the escrow of CCA bill credits so that these credits are maintained on the

---

107 TOB financing is classified as a utility investment in behind-the-meter resources. TOB requires a new utility tariff with a cost recovery charge on the utility portion of the bill. The charge is tied to the meter and is applied to the account associated with the meter; when the account holder changes, the TOB charge is automatically applied to the next account holder.

108 R. 20-08-022, *Pacific Gas and Electric Company's (U39 M) Reply Comments on Administrative Law Judge's Ruling Directing Parties to File Comments on Tariff On-Bill Proposals*, pp. 1-4 (May 30, 2025).

109 PG&E Testimony, Chapter 4, p. 4-5.

generation side of the bill (thus avoiding a situation in which the CCAs are paying for the PG&E side of the bill).

- The Commission should order PG&E to commit to preparing its billing system to enable TOB functionality by the time Phase 3 of the BMI is completed.

F. The Commission Should Order PG&E to Ensure its BMI Investment Results in Improvements on Key Billing System Efficiency Metrics.

Q: Has PG&E provided any insight into how the BMI will increase efficiencies in the CCA billing process?

A: PG&E explains that the "BMI is expected to enhance the efficiency and automation of several processes related to CCA services," likely resulting in reduced manual intervention as certain activities "become more streamlined and system driven."[110] PG&E notes these services "are expected to benefit from automation, improved data handling, and reduced administrative effort under the upgraded system." [111] In terms of the specific changes or upgrades in the BMI that PG&E expects will improve efficiency in CCA billing, PG&E explains that at this point it has identified only "potential areas of improvement," and does not have "a comprehensive or final list, as PG&E is still in the early stages of the BMI program" and "[m]any specific features have not yet been finalized, confirmed, or prioritized for implementation, particularly those planned for later phases (Stage 3)."[112]

Q: How can the Commission hold PG&E accountable for billing system efficiency improvements and ensure PG&E's investments in BMI result in an improved billing experience for customers?

A: The Commission should not approve PG&E's request for such substantial investments in its billing system without establishing clear performance and timeline targets that PG&E must meet in its end-state billing system. By requiring PG&E to track, report, and improve upon its key billing system efficiency metrics, the Commission can hold PG&E

---

[110] Attachment KJC-2 (PG&E Response to PCE DR 2.09).
[111] *Id.*
[112] Attachment KJC-2 (PG&E Response to PCE DR 2.10).

accountable for actually effectuating the efficiency improvements it claims the BMI will provide.

Q: Do you have recommendations regarding the specific billing metrics PG&E should track and improve upon?

A: Yes. The following metrics are ones that PG&E currently tracks; it should be required to continue to track, report on, and improve upon these metrics.[113] These metrics are:

- Unbilled Revenues – monitors billed revenue that is uncollectible due to timing, system constraints, or limitations defined under Rule 17.1.[114]
- Quality Assurance Standard – late commencing bills; tracks bills issued more than 60 days after service start.[115]
- Delayed Bills – identifies bills not generated within 35 days of the previous bill date.[116]
- Customer Initiated Request Open > 45 Days – measures the percentage of service or billing-related request that remain unresolved more than 45 days after initiation.[117]

Q: What levels of improvement in these metrics should the Commission order PG&E to target through its BMI?

A: I am not aware of how PG&E is performing regarding these metrics with its current billing system. However, the Commission should order PG&E to file a report identifying the results of these metrics as of the end of 2023 and 2024, and quarterly going forward. PG&E should be required to file quarterly reports on these metrics, with the additional requirement that each quarter, improvements should be achieved over the previous quarter metrics until PG&E can justify that any further improvements in the metrics are economically infeasible. The Commission should also ensure reporting on these targets incentives improvements by adopting consequences for PG&E's failure to continue to improve upon these metrics on a quarterly basis.

Finally, it is critical that these metrics are tracked by bundled versus unbundled customer status for a few reasons. First, this will allow the CCA-only data to be shared

113 *Id.*
114 Attachment KJC-2 (PG&E Response to PCE DR 2.10(b)).
115 *Id.*
116 *Id.*
117 *Id.*

with the CCAs' billing providers as a regular course of business. Second, this will provide transparency into any discrepancies in service level between the two customer types.

G. PG&E Should be Held Accountable for Achieving Certain Timing Targets in the BMI Rollout.

Q: How else can the Commission hold PG&E accountable for ensuring its BMI achieves its stated goals and improves customer experience?

A: In addition to my recommendations above regarding how to ensure PG&E is accountable for addressing the problems with its current billing system and improving its performance on key efficiency metrics, I also recommend the Commission hold PG&E accountable by enforcing set timelines within which PG&E must achieve specific goals as it rolls out its BMI. Specifically, with respect to the rollout of the BMI, the Commission should order PG&E to: (1) commit to specific dates certain for achieving implementation of its backlogged rate projects, and (2) commit to a specific timeline of seven business days for resolving any CCA billing and revenue delays arising out of the BMI deployment.

Q: Are there specific implementation items for which PG&E does not currently provide target implementation dates?

A: Yes, there are a lot. In its Testimony, PG&E provides a table with 26 different backlogged rate implementation projects, designating the "planned completion year" for each. Of these 26 items, PG&E states that the completion year for 16 of them is "not yet planned."[118]

Q: Is it reasonable for PG&E to decline to commit to a timeframe for implementation of all these items?

A: No, it is not. The limitations of PG&E's current billing system—combined with PG&E's delay in transitioning to a newer, more functional system—have contributed to this significant backlog of rate implementation projects. PG&E asserts that one of the benefits of the BMI is that it will allow PG&E to implement these backlogged projects "more efficiently."[119] If PG&E is requesting that ratepayers spend nearly $400 million on its BMI, it should be required to assess the efficiencies that the BMI will bring and commit to completing these projects on a designated timeline.

---

[118] PG&E Testimony, Chapter 4, pp. 4-18 to 4-19.
[119] PG&E Testimony, Chapter 6, pp. 6-9 to 6-10.

Q: What customer harm might result if PG&E is not held to specific deadlines for completing these projects?

A: When PG&E faces resource limitations, it often deprioritizes projects that are of high importance to CCAs and CCA customers. One example of this is PG&E's long delay in breaking out the PCIA as a line-item on customer bills, discussed above. This pattern highlights that PG&E does not have any incentive to prioritize projects that are important to CCAs. However, CCA customers represent over half of PG&E's customer base; deprioritizing items of concern to these customers harms the majority of PG&E's customers.

Q: What is your specific recommendation with respect to these backlogged rate implementation projects?

A: The Commission should order PG&E to submit supplemental testimony designating specific dates certain for achieving implementation of these 16 rate implementation projects.

Q: Do you have any other concerns regarding PG&E's timelines—or lack thereof—for addressing items that may arise in the course of the BMI rollout?

A: Yes. Based on its Testimony, it does not appear that PG&E is has any contingency plans for handling any delays to the issuance of CCA bills or to the remittance of CCA revenues caused by the BMI deployment.

Q: Why might such delays occur, and how would such delays affect CCAs?

A: PG&E's Testimony regarding the BMI implementation does not appear to include any testing plans to ensure that post billing activities occur without delay or issue. PG&E notes that defects are expected to occur in the conversion process and must also be thoroughly tested and remediated;[120] however, the list of testing does not appear to include testing for this type of activity.[121] The proposed list of testing includes testing to ensure the data has converted properly, the PG&E employees have completed user acceptance testing, and that disaster recovery testing is complete. However, there is no testing identified to ensure post billing activities do not result in delays to data sharing with the CCAs, billing for CCAs, or the remittance of funds to CCAs. Depending on the magnitude of the delay, these kinds

---

120 PG&E Testimony, Chapter 5, p. 5-42.

121 *Id.*

of issues could be hugely impactful to the CCAs' financial health as well as their ability to serve their customers.

Q: What do you recommend to protect against this kind of CCA and customer harm?

A: The Commission should order PG&E to ensure via its planned testing processes that all post billing processes are unaffected and that there are no delays to data sharing with the CCAs, billing for CCAs, or the remittance of funds to CCAs. In the event that the go-live of the BMI results in any unforeseen issues that affect the issuance of CCA generation bills or the remittance of CCA revenues, PG&E should be required to resolve the issue within seven business days. To ensure this kind of timeline is feasible, the Commission should order PG&E to submit supplemental testimony that outlines its contingency plan for these scenarios, including how it plans to resolve any such deployment issues within seven business days.

VI. THE COMMISSION SHOULD REQUIRE PG&E TO CLEARLY OUTLINE THE BMI'S LIKELY IMPACT ON CCA SERVICE FEES AND COMMIT TO SERVICE FEE UPDATES POST-BMI IMPLEMENTATION.

Q: What are CCA service fees?

A: There are various services that PG&E charges CCAs fees for, including the establishment of CCA service, notifying customers, customer enrollments, opt-out requests, meter data management services, billing services, termination of CCA service, phase-in services, and specialized services. These services are outlined in PG&E's Electric Schedule E-CCA. These fees are developed based on the estimated materials, labor time, system usages, and administrative effort needed to perform each service.[122]

Additionally, the customer re-entry fee—currently $4.24 per account—for customers switching back to PG&E bundled service after the CCA opt-out period has expired, is used to forecast the administrative cost component of the Financial Security Requirement (FSR) for CCAs.[123] The re-entry fee for SCE is $0.40 per account and for SDG&E is $0.56 per account.[124] The FSR is the amount CCAs are responsible to post with

---

122 Attachment KJC-2 (PG&E Response to PCE DR 2.11).

123 PG&E Electric Rule No. 23, Sheet 76.

124 SCE Schedule CCA-SF, Section H.1; SDG&E Schedule CCA, line 14.

their local IOU or Provider of Last Result (POLR) to ensure that a POLR can recover costs and expenses incurred to re-enroll and serve CCA customers returning to bundled service in case of a CCA's failure.

Q: Does PG&E provide any insight through its testimony or discovery responses into whether the BMI will lead to lower CCA service fees?

A: PG&E anticipates that it will continue to use a cost-based methodology similar to the methodology it uses currently for CCA fees after the BMI is implemented, and it has not committed to any specific changes in CCA fees post-implementation. Instead, PG&E has indicated that some aspects of the BMI upgrades may cause fee decreases, while others could cause fee increases.

In terms of factors possibly leading to fee reductions, PG&E explained the upgrades associated with the BMI are expected to drive operational efficiency in supporting CCA-related services due to increased automation, data standardization, and streamlined workflows.[125] In particular, reduced manual intervention is expected to improve efficiency and reduce the risk of human error for certain processes, although the reductions in administrative effort may not directly translate into lower service fees, according to PG&E.[126] Additionally, PG&E expects that the transition to C2M will improve efficiency in managing and supporting third-party energy services, although PG&E could not confirm at this time if these improvements will directly result in lower CCA service fees.[127]

However, PG&E has also indicated that other factors weigh in favor of CCA service fees increasing post-BMI implementation. PG&E explained there could be incremental regulatory requirements associated with POLR implementation, new data privacy and compliance mandates, and customer billing and notification enhancements that may increase costs associated with system enhancements and workload. Additionally, PG&E confirmed that it will continue to apply an inflation or escalation factor to CCA service

---

[125] Attachment KJC-2 (PG&E Response to PCE DR 2.11).

[126] *Id.*

[127] Attachment KJC-2 (PG&E Response to PCE DR 1.06).

fees to reflect expected labor cost growth, which could increase certain CCA service fees over time.[128]

Q: Has PG&E made a sufficient showing regarding the potential impacts of the BMI upgrades on CCA service fees?

A: No. The Commission should require PG&E to outline the likely impacts to CCA service fees in more detail in a supplemental filing. Many if not all of PG&E's CCA service fees are calculated based on the labor time associated with the service.[129] PG&E should be required to lay out its forecasts regarding (1) how, if at all, the BMI will impact how each service is performed, (2) any efficiencies PG&E hopes to capture with respect to its provision of each service as a result of the BMI investments, and (3) how, if at all, PG&E anticipates the fee level may change as a result. While there is no dispute that PG&E cannot commit to specific fee reductions at this point, PG&E nonetheless can and should provide more detail regarding how it intends through these upgrades to improve upon its current CCA services.

Q: Has the Commission provided any guidance on this issue?

A: Yes, specifically in the context of the customer re-entry fee. The POLR Phase 1 Decision (D.24-04-009) states: "As part of any future showing for its Billing System Upgrade Project, PG&E should describe whether the project is expected to increase the level of automation associated with CCA and ESP customers returning to PG&E's bundled service."[130] PG&E notes in Testimony that the development of the Market Transaction Management (MTM) Module "will enable customers to seamlessly transition to bundled services if a third-party provider voluntarily or involuntarily leaves the market, minimizing service disruptions and maintaining reliable customer experiences. MTM introduces functionality that is expected to allow PG&E to return an entire CCA population to bundled service next day with minimal impacts on billing and the customer experience."[131]

---

128 Attachment KJC-2 (PG&E Response to PCE DR 2.11).

129 *See* PG&E Electric Schedule E-CCA.

130 D.24-04-009, p. 43.

131 PG&E Testimony, Chapter 4, p. 4-45.

Thus while PG&E has provided some information in this case on how the BMI will increase automation associated with the return to bundled service, it has not explicitly discussed or committed to any particular timeline for passing along the savings of those efficiencies to customers. Currently, the re-entry fee used to estimate the administrative cost component of a CCA's FSR is based on the salary and time it would take a PG&E customer service employee to manually transfer a CCA customer back to bundled services. If BMI implementation automates a customer's transition from unbundled to bundled, the re-entry fee should either be reduced or become obsolete, therefore reducing or eliminating the administrative cost component of FSR.

This example illustrates the importance of PG&E detailing how the BMI might impact CCA service fees, and committing to a timeline for reviewing the costs associated with these services promptly post-BMI implementation to ensure these cost savings are passed on to customers. While this example is in the context of the re-entry fee, this same reasoning applies to the other CCA service fees as well.

Q: What should the Commission do to ensure any efficiencies achieved by the BMI translate into concrete customer benefits?

A: The Commission should order PG&E to file testimony in a formal proceeding (via a GRC or through a separate Application) within a year of final implementation of the end-state BMI billing system that reviews PG&E's CCA service fees. This testimony should provide PG&E's new proposed CCA service fee levels and justify these fee levels based on the costs PG&E incurs to perform the services in its new billing system.

Q: Does this conclude your testimony?

A: Yes.

Attachment KJC-1

CV of Kyra J. Coyle

KYRA J. COYLE

Principal

Ms. Kyra Coyle has over 15 years of experience in the utility, mining, and public accounting sectors and joined NewGen as a Senior Manager in December 2023 and has been promoted to a Principal as of January 2025. Her expertise includes utility revenue requirement analyses, strategic planning, project management, contract negotiations, financial modeling, regulatory affairs, budgeting, forecasting, and regulatory accounting. Her rate-related projects have included studies to develop retail electric, natural gas, transmission, ancillary service, standby and special contract rates.

Ms. Coyle has provided expert witness testimony on revenue requirement cost of service issues before public utility commissions and the Federal Energy Regulatory Commission. She has also offered other types of cost of service and rate-related litigation support.

CONTACT

225 Union Blvd., Ste 450
Lakewood, Colorado 80228
kcoyle@newgenstrategies.net
www.newgenstrategies.net

EDUCATION

Bachelor of Arts, Business Administration with emphasis in Accounting, Dakota Wesleyan University

Minor, Computer Applications, Dakota Wesleyan University

KEY EXPERTISE

Accounting

Budgeting

Contract Negotiations

Financial Modeling

Forecasting

Project Management

Regulatory Affairs

Strategic Planning

PRIOR RELEVANT EXPERIENCE

Black Hills Corporation

Director of Regulatory/Finance – Wyoming, Montana and South Dakota Electric and Natural Gas Utilities

- Provide strategic leadership for all financial and regulatory matters for electric and natural gas utilities.
- Direct the development and filing of rate case applications and other regulatory filings supporting the Company's strategic plan, including new and innovative tariff offerings to incentivize economic development.
- Financial leader executing strategy for long-term success, responsible for $1.9 billion of rate base. Received approval for a large transmission project (~260 miles).
- Contract negotiations with large, high density, power customers, including cost allocations for generation and transmission.
- Direct, develop, and maintain trusted relationships with regulatory, legislative, and other stakeholders.
- Expert witness for policy and financial matters to regulatory and legislative agencies.

Senior Manager of Finance and Regulatory Electric/Natural Gas Utilities

- Responsible for all forecasting and strategic planning aspects for Gas and Electric utilities and Non-Regulated companies, which requires positive working relationships with cross-functional teams.
- Part of the state-level executive leadership team; participate in operational initiatives – capital deployment, personnel plans, long-term strategic plans, and culture changes.
- Financial leader executing strategy for long-term success.
- Strong partnerships with operations and other matrix teams to execute key strategies.

KYRA J. COYLE

Principal

- Financial modeling of purchase power agreements and strategic capital projects.
- Financial team member in the divestiture of 49.9% interest in a non-regulated entity.
- Lead, develop, and mentor coworkers.

Professional Finance Senior/Principal

- Responsible for budgeting, forecasting, and reporting for power generation assets. This included developing innovative ways to earn on PPAs and maximizing value by working with the operations team to maintain availability and reliability.
- Budget, forecast, and report on capital and O&M spending over $50M annually.
- The key contact person for generation operations staff; helped educate the operations team on the optimal timing of associated expenditures and investments.
- Monitor and report to third-party owners on capital and O&M.

U.S Bentonite Processing, Inc.

Accounting Manager

- Led and supervised the accounting support staff, delegating duties and reviewing and approving invoices, payments, and other activities. Completed performance reviews and co-supervising the purchasing and logistics roles.
- Prepare and distribute financial statements to the board of directors monthly.
- Responsible for closing, consolidation, and budgeting of three U.S.-based companies.
- As the first point of contact during the annual audit, Ms. Coyle provided all the data needed and any adjustments made after the closing of the last period of the fiscal year.
- Business SME for NetSuite. Responsible for creating a new chart of accounts, departments, and locations for three companies, training all software users, and answering questions.

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. El Paso Electric Company	SOAH Docket No. 473-25-11219 PUC Docket No. 57568	Application of El Paso Electric Company for Authority to Change Rates	Public Utility Commission of Texas	Office of Public Utility Counsel (OPUC)	2025
2. Southwestern Electric Power Company	SOAH Docket No. 473-24-22136 PUC Docket No. 56643	Application of Southwestern Electric Power Company for Authority to Reconcile Fuel Costs	Public Utility Commission of Texas	OPUC	2025
3. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-25-05323 PUC Docket No. 57271	Application of CenterPoint Energy Houston Electric, LLC for Determination of System Restoration Costs	Public Utility Commission of Texas	OPUC	2025
4. PacifiCorp	Docket No. 24-035-04	Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations	Public Service Commission of Utah	Stadion, LLC	2024
5. PacifiCorp	Docket No. UE 433	PacifiCorp d/b/a Pacific Power Request for General Rate Revision	Public Utility Commission of Oregon	Vitesse, LLC	2024
6. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-24-13232 PUC Docket No. 56211	Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates	Public Utility Commission of Texas	OPUC	2024
7. Constellation Mystic Power, LLC.	Docket No. ER18-1639-027	Annual Fixed Revenue Requirement, Capital Expense Recovery, and Stipulated Variable Cost Recovery for Mystic 8 & 9 Fuel Security System	Federal Regulatory Commission	Eastern New England Consumer-Owned Systems (ENECOS)	2024
8. Peoples Gas Light and Coke Company	Docket No. 23-0069	Proposed General Increase in Gas Rates and Revisions to Other Terms and Conditions of Service	Illinois Commerce Commission	City of Chicago	2024

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
9. Southern Indiana Gas and Electric Company DBA CenterPoint Energy Indiana South	Cause No. 45990	Authority to Modify its Rates and Charges for Electric Utility Service Through a Phase-In of Rates…	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mount Vernon, LLC	2024
10. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-228-EN-23	Certificate of Public Convenience and Necessity to Construct and Operate a New 115 kV Substation, Two New 115 kV Transmission Lines, Modification and Extension of Four 115 kV Transmission Lines, Four New 115 kV Load-Serving Transmission Lines and Related Facilities	Wyoming Public Service Commission	--	2023
11. Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-131-EA-23	Proposed Modification of the Neil Simpson II Generation Facility to a Dual Fuel Source and Request for a Determination Regarding the Need to File for a Certificate of Public Convenience and Necessity	Wyoming Public Service Commission	--	2023
12. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-225-EM-23	Authority to Increase Its Power Cost Adjustment by $0.00872 per Kilowatt Hour	Wyoming Public Service Commission	--	2023
13. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20003-223-ET-23	Authority to Establish a Low-Carbon Surcharge Tariff and Rate	Wyoming Public Service Commission	--	2023
14. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-127-ET-23	Authority to Establish a Low-Carbon Surcharge Tariff and Rate	Wyoming Public Service Commission	--	2023
15. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-221-EA-23	Establish Intermediate Low-Carbon Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2023

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
16. Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-126-EA-23	Establish Intermediate Low-Carbon Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2023
17. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-217-EM-23	Authority to Decrease Its Power Cost Adjustment by $0.03149 per Kilowatt-Hour	Wyoming Public Service Commission	--	2023
18. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-78-GR-23	Authority to Implement a General Rate Increase of $19,262,412 per Annum and Extend Its Wyoming Integrity Rider	Wyoming Public Service Commission	--	2023
19. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-214-ER-22	A General Rate Increase of $15,366,026 per Annum and Authority to Revise Its Power Cost Adjustment Mechanism	Wyoming Public Service Commission	--	2022
20. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-213-EM-22	Authority to Increase Its Power Cost Adjustment by $0.00129 per Kilowatt-Hour	Wyoming Public Service Commission	--	2022
21. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-211-EM-22	Authority to Pass on a Blockchain Interruptible Service Customer Credit Adjustment Rate of $0.00 per Kilowatt-Hour Effective June 1, 2022	Wyoming Public Service Commission	--	2022
22. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-210-ET-22	Revise the Demand Side Management Surcharge Rate, Effective June 1, 2022	Wyoming Public Service Commission	--	2022
23. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20003-209-EA-22	Establish Intermediate Low-Carbon Energy Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2022

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
24. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-123-EA-22	Establish Intermediate Low-Carbon Energy Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2022
25. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-208-EA-22	Authority to Increase Its Voluntary Renewable Energy Rider Rate to $0.47 per Month per 100-KWh Block, Effective April 1, 2022	Wyoming Public Service Commission	--	2022
26. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-206-EN-22	A Certificate of Public Convenience and Necessity to Construct and Operate One New 230 kV Substation, Two Replacement 115 kV Substations, Three 230 kV Transmission Lines, Two 115 kV Transmission Lines and Related Facilities in Converse, Laramie, Goshen and Platte Counties on Wyoming and Scotts Bluff County in Nebraska	Wyoming Public Service Commission	--	2022
27. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-68-GM-22	Authority to Implement Wyoming Integrity Rider Rates of $0.0231 per Therm for Residential General Service, $0.0139 per Therm for Small General Service, $0.0148 per Therm for Medium General Service, $0.0092 per Therm for Large General Service, and $0.0285 per Therm for On-System Transportation Service	Wyoming Public Service Commission	--	2022
28. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-67-GM-22	Authority to Decrease the Revenue Adjustment Mechanism Rate By $0.0058 per Therm	Wyoming Public Service Commission	--	2022

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
29. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-66-GP-22	Authority to Pass on a Gas Cost Rate Decrease of $0.1155 per Therm	Wyoming Public Service Commission	--	2022
30. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-65-GN-22	Determination of CPCN Requirements Regarding the Relocation of an Existing Transmission Pipeline and Related Facilities	Wyoming Public Service Commission	--	2022
31. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-63-GP-22	Authority to Pass on a Gas Cost Rate Decrease of $0.0026 per Therm	Wyoming Public Service Commission	--	2022
32. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-60-GM-22	Authority to Increase the Revenue Adjustment Mechanism Rate by $0.0022 Per Therm	Wyoming Public Service Commission	--	2022
33. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-57-GT-22	Authority to Decrease the Energy Efficiency Surcharge for Residential Customers by $0.0034 per Therm and Increase It by $0.0006 per Therm for Non-Residential Customers	Wyoming Public Service Commission	--	2022
34. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-55-GP-22	Authority to Pass on a Wholesale Gas Cost Increase of $0.0669 per Therm	Wyoming Public Service Commission	--	2022
35. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-205-ET-21	Approval of the 2022-2024 Demand Side Management Program Plan by November 1, 2021, for Implementation on January 1, 2022	Wyoming Public Service Commission	--	2021
36. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-203-EM-21	Authority to Pass on a Blockchain Interruptible Service Customer Credit Adjustment Rate Of $0.00 Per KWh Effective June 1, 2021	Wyoming Public Service Commission	--	2021

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
37. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-202-EM-21	Authority to Increase Its Power Cost Adjustment by $0.00246 per Kilowatt-Hour	Wyoming Public Service Commission	--	2021
38. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-201-EN-21	Certificate of Public Convenience and Necessity to Construct and Operate Two 115 kV Substations, Associated Transmission Lines, and Related Facilities in Laramie County, Wyoming	Wyoming Public Service Commission	--	2021
39. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-200-ET-21	Authority to Update Its Demand Side Management Surcharge Rate, Effective June 1, 2021	Wyoming Public Service Commission	--	2021
40. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-199-EA-21	Authority to Increase Its Voluntary Renewable Energy Rider Rate to $0.43 per Month per 100-KWh Block, Effective April 1, 2021	Wyoming Public Service Commission	--	2021
41. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-198-EN-21	Certificate of Public Convenience and Necessity to Construct and Operate a 115 kV Substation, Associated Transmission Lines, and Related Facilities in Laramie County, Wyoming	Wyoming Public Service Commission	--	2021
42. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-194-EM-20	Authority to Increase Its Power Cost Adjustment by $0.00243 per Kilowatt-Hour Effective July 1, 2020	Wyoming Public Service Commission	--	2020
43. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-193-EN-20	Certificate of Public Convenience and Necessity to Rebuild an Existing 115 kV Transmission Line from Skyline Substation to East Business Park Substation in Laramie County, Wyoming	Wyoming Public Service Commission	--	2020

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
44. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-190-ET-20	Authority to Update Its Tariff Applicable to the Demand Side Management Margin Revenue Recovery, the Balancing Account and Program Costs	Wyoming Public Service Commission	--	2020
45. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-188-ET-20	Authority to Decrease Its Electric Voluntary Renewable Energy Rider Rate to $0.03 per Month per 100-KWh Block	Wyoming Public Service Commission	--	2020
46. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-182-ET-19	Authority to Update Its Electric and Gas Tariffs Applicable to the Demand Side Management Margin Revenue Recovery, the Balancing Account and Program Costs	Wyoming Public Service Commission	--	2019
47. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-173-ET-18	Authority to Implement a Blockchain Interruptible Service Tariff	Wyoming Public Service Commission	--	2018

Attachment KJC-2

PG&E Responses to PCE Data Requests

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q001
PG&E File Name:	BillingModernization_DR_PCE_001-Q001Supp01
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 15, 2025 Supp01: April 22, 2025
PG&E Witness(es):	

QUESTION 001

Please provide all workpapers associated with PG&E's Application and Prepared Testimony, including all confidential workpapers.

ANSWER 001 SUPPLEMENTAL 01

An attachment to this response contains CONFIDENTIAL information provided pursuant to the Non-Disclosure Agreement between PG&E and Peninsula Clean Energy Authority dated April 22, 2025 in this proceeding.

Please see "BillingModernization_DR_PCE_001-Q001Supp01Atch01CONF.zip" for the confidential workpapers.

ANSWER 001

Please see "BillingModernization_DR_PCE_001-Q001Atch01.zip" for the public workpapers. PG&E can supplement with confidential workpapers once it receives a signed Non Disclosure Agreement.

Line	Revenue Requirement Summary by Capital and Expense									
	Total RRQ (Supports Table 7-1 in Opening Testimony)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2023-2030**
1	Capital Revenue Requirement	$0	$1,724,426	$9,976,643	$36,792,969	$59,157,475	$53,713,725	$29,757,165	$120,085,303	$311,207,706
2	Expense Revenue Requirement	$804,392	$3,929,281	$6,995,416	$12,041,923	$7,105,522	$8,191,219	$23,306,117	$19,567,626	$81,941,496
3	**Total RRQ (without RF&U)** [1]	**$804,392**	**$5,653,707**	**$16,972,058**	**$48,834,893**	**$66,262,997**	**$61,904,944**	**$53,063,282**	**$139,652,929**	**$393,149,203**

Revenue Requirement Summary by Functional Area

Line	**RRQ by Functional Area** (Supports Table 7-4 in Opening Testimony)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2023-2030**
4	Electric Distribution (ED)	$344,930	$2,424,356	$7,886,196	$24,761,634	$33,598,519	$31,388,777	$26,905,630	$70,810,737	$198,120,780
5	Electric Generation (EG)	$190,365	$1,337,992	$2,933,454	$4,755,492	$6,452,623	$6,028,240	$5,167,248	$13,599,260	$40,464,675
6	Gas Distribution (GD)	$182,239	$1,280,877	$4,166,569	$13,082,488	$17,751,342	$16,583,853	$14,215,241	$37,411,934	$104,674,544
7	Gas Transmission & Storage (GT&S)	$86,858	$610,482	$1,985,839	$6,235,278	$8,460,513	$7,904,073	$6,775,162	$17,830,998	$49,889,203
9	**Total RRQ (without RF&U)**[1]	**$804,392**	**$5,653,707**	**$16,972,058**	**$48,834,893**	**$66,262,997**	**$61,904,944**	**$53,063,282**	**$139,652,929**	**$393,149,203**

Line									
10	**Fuctional Area Allocation Percentages**	**Alloc Fctr 2023**	**Alloc Fctr 2024**	**Alloc Fctr 2025**	**Alloc Fctr 2026**	**Alloc Fctr 2027**	**Alloc Fctr 2028**	**Alloc Fctr 2029**	**Alloc Fctr 2030**
11	Electric Distribution (ED)	38.772%	38.772%	41.679%	45.058%	45.058%	45.058%	45.058%	45.058%
12	Electric Generation (EG)	21.398%	21.398%	15.504%	8.653%	8.653%	8.653%	8.653%	8.653%
13	Gas Dsitribution (GD)	20.484%	20.484%	22.021%	23.806%	23.806%	23.806%	23.806%	23.806%
14	Gas Transmission and Storage (GT&S)	9.763%	9.763%	10.495%	11.346%	11.346%	11.346%	11.346%	11.346%
15	*Electric Transmission (ET)* [2]	*9.583%*	*9.583%*	*10.302%*	*11.137%*	*11.137%*	*11.137%*	*11.137%*	*11.137%*
16	Total[1]	90.417%	90.417%	89.698%	88.863%	88.863%	88.863%	88.863%	88.863%

Line										
17	**RRQ by Program**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2023-2030**
18	Billing Cloud Service (BCS)	$0	$904,171	$5,301,195	$31,396,240	$26,651,053	$25,450,807	$24,127,031	$22,310,480	$136,140,978
19	Customer Care and Billing (CC&B) 25.1	$0	$26,930	$4,505,887	$5,321,987	$27,988,139	$24,398,518	$23,334,864	$20,719,569	$106,295,895
20	Customer-to-Meter (C2M)	$804,392	$4,722,606	$7,164,976	$12,116,665	$11,623,805	$12,055,619	$5,601,387	$96,622,880	$150,712,330
21	**Total RRQ (without RF&U)**[1]	**$804,392**	**$5,653,707**	**$16,972,058**	**$48,834,893**	**$66,262,997**	**$61,904,944**	**$53,063,282**	**$139,652,929**	**$393,149,203**

Notes

[1] Excludes Electric Transmission (ET) - This filing excludes costs allocated to Electric Transmission, which are recovered under separate FERC-jurisdictional Transmission Owner (TO) cases.

[2] Electric Transmission (ET) allocation percentages are provided for illustrative purposes.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q003
PG&E File Name:	BillingModernization_DR_PCE_001-Q003
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

QUESTION 003

Referring to PG&E's Application at pp. 7-8:

a. Please confirm that the Oracle billing system CC&B 25.1 that PG&E proposes to implement during the second stage of its BMI implementation plan will be replaced by the implementation of Oracle's C2M product during the third stage of PG&E's BMI implementation plan. If not confirmed, please explain.

b. If part (a) is confirmed, please provide PG&E's justification for implementing the CC&B 25.1 system when the CC&B 25.1 system will eventually be replaced by the C2M product during the third phase of PG&E's BMI implementation plan.

c. If part (a) is confirmed, please explain if it was feasible for PG&E to have upgraded its billing system directly from the CC&B 2.4 system to the C2M product without having to implement the CC&B 25.1 upgrade. Additionally, please explain if PG&E explored or considered this alternative option, providing any analyses conducted to explore this option.

ANSWER 003

a. Confirmed. PG&E's current plan based on the market analysis completed by both Accenture and Utilligent indicate that C2M is the target state solution. PG&E plans to re-evaluate that assessment at the end of Stage 2 (CC&B 25.1).

b. Within PG&E's prepared testimony Chapter 4, p. 4-26 through p. 4-34, various upgrade paths are discussed along with PG&E rationale to include CC&B 25.1 into the upgrade path.

c. Please refer to response "b" above.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q005
PG&E File Name:	BillingModernization_DR_PCE_001-Q005
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

QUESTION 005

Referring to PG&E's Application at pp. 9-10:

a. Please outline the specific "investments related to the BCS and CC&B 25.1 upgrade that will not be utilized in the final C2M end state system." Additionally, please explain why these investments are necessary and why they will not be used in the C2M end state system.

b. Please provide the costs associated with the specific investments outlined in part (a).

ANSWER 005

a. The BCS project can be broadly divided into functionality related to rate calculation and functionality related to interfaces. The major interface functionality relates to interfacing between BCS and CC&B and other systems. These interfaces are necessary to exchange and update information between systems for purposes of billing, bill presentment, reporting, and others. When C2M replaces BCS, these interfaces will no longer be necessary.

   For CC&B 25.1, the work can broadly be divided into hardware, integration, and system component upgrades. The hardware and integration work will be usable in C2M, while 75 percent of the system component upgrades will be used in C2M, as C2M will replace much of the customizations and introduce some new system features compared to CC&B. The components are necessary for the CC&B 25.1 project because they are needed for CC&B to perform correctly.

b. For BCS, PG&E estimates the interface work to be 40 percent of the total capital investment, or $49.9 million.

   For CC&B 25.1, PG&E estimates 25 percent of the system component upgrade cost, or $24.7 million.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q006
PG&E File Name:	BillingModernization_DR_PCE_001-Q006
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

QUESTION 006

Referring to PG&E's Prepared Testimony, Chapter 2, p. 2-6, lines 16 to 34, and p. 2-7, lines 1 to 2: Please confirm if improvements to the Third-Party Energy Service Provider Management system under PG&E's BMI will lead to lower CCA service fees. If confirmed, please explain, outlining the specific CCA service fees that will be lowered and the estimated reduction amount for each service fee.

ANSWER 006

While PG&E's BMI (Billing Modernization Initiative), including the transition to the C2M platform, is expected to improve efficiency in managing and supporting third-party energy service providers such as Community Choice Aggregators (CCAs), it is not possible at this time to confirm whether those improvements will directly result in lower CCA service fees.

Although the new C2M platform introduces streamlined processes, reduced reliance on manual interventions, and consolidated systems, which collectively create operational efficiencies the potential impact on CCA service fees is subject to several factors. These include regulatory requirements, future operational needs, and unforeseen system complexities that may emerge as the new platform is implemented and scaled.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q010
PG&E File Name:	BillingModernization_DR_PCE_001-Q010
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

QUESTION 010

Referring to PG&E's Prepared Testimony, Chapter 2, p. 2-18, lines 14 to 16, and p. 2-19, lines 1 to 13:

a. Please explain any expected differences in the presentation of bill components or rates for bundled and CCA customer bills between PG&E's current bill presentment structure and the new bill presentment structure under PG&E's BMI.

b. Please explain how the PCIA rate will be presented on bundled and CCA customer bills through the new bill presentment structure under PG&E's BMI, compared to PG&E's current bill presentment structure.

c. Please explain if the upgrades proposed under PG&E's BMI will enable both bundled and CCA customer bills to show the customer's kWh Usage and $/kWh Rate used to determine the monthly PCIA.

d. If subpart (c) is confirmed, please identify the upgrades that will enable this PCIA bill presentment and identify the stage in which those upgrades will be implemented.

e. If subpart (c) is confirmed, please explain whether PG&E will adopt a bill presentment structure showing both bundled and CCA customers' kWh Usage and $/kWh Rate used to determine the monthly PCIA charge. If not, please explain why not.

ANSWER 010

a. At this stage of PG&E's Billing Modernization Initiative, we are still several years away from reaching Stage 3 (our target state) where the full capabilities of the new system including enhancing bill presentment will be implemented. Because the system design and customer bill format are still in the initial stages, we cannot yet confirm what specific changes in bill presentment will look like for bundled versus CCA customers. With that said, PG&E's initial review of the bill extract functionality from the C2M product indicates that the functionality allows for increased flexibility. If that turns out to be true, PG&E would work with CCAs for bill presentment improvements.

b. As with other billing elements, the way in which the PCIA (Power Charge Indifference Adjustment) is presented may change under the new system. However, at this point in the Initiative, we are not able to confirm whether or how the presentation will differ from the current format.

c. The project is still in the early stages, and we are several years away from reaching Stage 3, the target state where the system's full bill presentment functionality will be implemented. At this time, it is too early to confirm whether customer bills for either bundled or CCA customers will display both the kwh usage and specific price per kWh rate used to calculate the monthly PCIA charge.

d. See response for c.

e. See response for c.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q011
PG&E File Name:	BillingModernization_DR_PCE_001-Q011
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

QUESTION 011

Referring to PG&E's Prepared Testimony, Chapter 2, p. 2-18, lines 14 to 16, and p. 2-19, lines 1 to 13: Please explain any expected differences in the presentation of CARE and FERA discounts for bundled and CCA customer bills between PG&E's current bill presentment structure and the new bill presentment structure under PG&E's BMI.

ANSWER 011

At this point, it is too early to confirm what changes, if any, will be made to the presentation of CARE and FERA discounts or how those changes might differ between bundled and unbundled customer bills. As we move closer to Stage 3, PG&E will have more clarity on potential upgrades to bill formatting and discount display.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q013
PG&E File Name:	BillingModernization_DR_PCE_001-Q013
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Emily Bartman – Customer and Enterprise Solutions Matt Hedges – Information Technology

QUESTION 013

Referring to PG&E's Prepared Testimony, Chapter 4 at Table 4-1: Please identify the specific rate implementation projects or updates to rate schedules that are on-hold due to the need for billing system upgrades, as proposed under PG&E's BMI.

ANSWER 013

Please see Table 1 below for identification of the specific rate implementation projects or updates to rate schedules that are, as of 4/17/25, on hold due to the need for billing system upgrades, as proposed under PG&E's BMI.

Table 1
PG&E's Rate Projects On Hold Due to The Need for Billing System Upgrades

Rate Implementation Project	Planned Completion Year	Target Delivery Date / Reference
Residential Net Billing for Paired Storage, SmartMeter Opt-out and MV-90 customers in ABS	2025 (in BCS)	Target delivery date: 12/31/25 CPUC Executive Director Approval of Request for Additional Time to Comply under Rule 16.6 dated 4/8/2024.
E-ELEC Standard NEM 1.0, 2.0 and Paired Storage customers in ABS	2025 (in BCS)	Target delivery date: 01/2026 CPUC Executive Director Approval of Request for Additional Time to Comply under Rule 16.6 dated 9/19/2024.

Non-Residential Net Billing Simple NEM, Paired Storage, ~~and Medical Discount~~	2026 (in BCS and CC&B)	Target delivery date: 03/31/26 CPUC Executive Director Approval of Request for Additional Time to Comply under Rule 16.6 dated 6/20/2024.
E-ELEC Complex NEM 1.0 and 2.0 for Virtual NEM, NEM Aggregation and NEM Multi-Tariff in ABS	2027 (in BCS)	Target delivery date: 09/2027 CPUC Executive Director Approval of Request for Additional Time to Comply under Rule 16.6 dated 9/19/2024.
Net Billing for Complex NEM Aggregation and Virtual NEM	2027 (in BCS)	Target delivery date: 06/30/25 D. 23-11-068, OP 12 D. PG&E plans to file a Rule 16.6 request to extend implementation to 11/30/2027.
New Agricultural Rates (AG-A3 and AG-B2)	2027 (in BCS)	No specific compliance timing (as soon as practicable) D.21-11-016, OP 19.
Including a breakout of PCIA on bundled customers billing statements	2028 (in BCS and CC&B)	Target delivery date: 12/31/27 (workaround currently in place) CPUC Executive Director Approval of Request for Additional Time to Comply under Rule 16.6 dated 4/26/23
B-20R Solar Rate	2028 (in BCS)	No specific compliance timing (as soon as practicable) D.21-11-016, p. 152.
Commercial Electric Vehicle Opt-in RTP rate	Not Yet Planned - Current Compliance 2/28/25	Target delivery date: 02/28/26 CPUC Executive Director Approval of Request for Additional Time to Comply under Rule 16.6 dated 2/20/25. Petition for Modification to remove this requirement is under consideration by the CPUC.
Commercial Electric Vehicle Non-NEM Export Rate Pilot	Not Yet Planned - Current Compliance 2/28/25	Target delivery date: 02/28/26 CPUC Executive Director Approval of Request for Additional Time to Comply under Rule 16.6 dated 2/20/25. Petition for Modification to remove this requirement is under consideration by the CPUC.
Modified Cost Allocation Methodology for Resource Adequacy for other Load Serving Entities (CCAs, ESPs)	Not Yet Planned – Commitment 2027	No specific compliance requirement. PG&E indicated plans to implement in 2027. PG&E's 2024 ERRA Testimony A.23-05-012 pp. 19-14 to 19-15.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q017
PG&E File Name:	BillingModernization_DR_PCE_001-Q017
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Leo Yang – Finance

QUESTION 017

Referring to PG&E's Prepared Testimony, Chapter 7, p. 7-7, lines 25 to 33 and p. 7-8, lines 1 to 4:

a. Please confirm if CCA customers will be responsible for the costs associated with PG&E's BMI under the common cost allocation methodology defined in D.23-11-069 or D.24-12-038. If not, please explain.

b. If CCA customers will be responsible for the costs associated with PG&E's BMI through the common cost methodology set forth in either D.23-11-069 or D.24-12-038, please outline what portion of the costs associated with PG&E's BMI will be allocated to CCA customers relative to bundled customers.

c. If CCA customers will be responsible for the costs associated with PG&E's BMI through the common cost methodology set forth in either D.23-11-069 or D.24-12-038, please explain how PG&E's cost recovery for its BMI will flow into bundled and CCA customer rates, including the PCIA vintage(s) that the BMI costs will be assigned to.

ANSWER 017

a. For Electric Distribution, Gas Distribution, Gas Transmission and Storage, and Gas Local Transmission, the common cost allocation methodology defined in D.23-11-069 is the only applicable allocation methodology that will apply and the authorized base revenue requirements for these cost categories are not subject to distinguishing between bundled and CCA customers. PG&E serves all retail load responsible for these charges. Electric Generation is the only revenue adjustment category subject to the common cost allocation methodology of D.23-11-069 that distinguishes between bundled and CCA customers, and other types of departing load. The BMI costs allocated to Electric Generation revenue adjustment mechanisms governed by D.23-11-069 are further broken out based on the common cost allocation approved in D.24-12-038, which allocates costs between Energy Resource Recovery Account (ERRA), Portfolio Allocation Balancing Account

(PABA), and New System Generation Balancing Account (NSGBA) based on where the GRC authorized base revenue requirement for utility-owned generation is recorded. Thus, CCA customers will share the costs allocated to PABA and NSGBA, along with non-exempt direct access customers and bundled customers.

b. PG&E only addresses the Electric Generation revenue adjustment category in this response. PG&E's workpapers for Chapter 7 provide the details of the allocation to Electric Generation, based on the D.23-11-069 common cost allocation methodology, an excerpt of which is shown below. Electric Generation allocation percentages are shown on line 12 and range between 21.4% in 2023 dropping to 8.7% between 2028 – 2030.

Revenue Requirement Summary by Functional Area

	RRQ by Functional Area (Supports Table	2023	2024	2025	2026	2027	2028	2029	2030	2023-2030
4	Electric Distribution (ED)	$344,930	$2,424,356	$7,886,196	$24,761,634	$33,598,519	$31,388,777	$26,905,630	$70,810,737	$198,120,780
5	Electric Generation (EG)	$190,365	$1,337,992	$2,933,454	$4,755,492	$6,452,623	$6,028,240	$5,167,248	$13,599,260	$40,464,675
6	Gas Distribution (GD)	$182,239	$1,280,877	$4,166,569	$13,082,488	$17,751,342	$16,583,853	$14,215,241	$37,411,934	$104,674,544
7	Gas Transmission & Storage (GT&S)	$86,858	$610,482	$1,985,839	$6,235,278	$8,460,513	$7,904,073	$6,775,162	$17,830,998	$49,889,203
9	**Total RRQ (without RF&U)[1]**	**$804,392**	**$5,653,707**	**$16,972,058**	**$48,834,893**	**$66,262,997**	**$61,904,944**	**$53,063,282**	**$139,652,929**	**$393,149,203**

10	Fuctional Area Allocation Percentages	Alloc Fctr 2023	Alloc Fctr 2024	Alloc Fctr 2025	Alloc Fctr 2026	Alloc Fctr 2027	Alloc Fctr 2028	Alloc Fctr 2029	Alloc Fctr 2030
11	Electric Distribution (ED)	38.772%	38.772%	41.679%	45.058%	45.058%	45.058%	45.058%	45.058%
12	Electric Generation (EG)	21.398%	21.398%	15.504%	8.653%	8.653%	8.653%	8.653%	8.653%
13	Gas Dsitribution (GD)	20.484%	20.484%	22.021%	23.806%	23.806%	23.806%	23.806%	23.806%
14	Gas Transmission and Storage (GT&S)	9.763%	9.763%	10.495%	11.346%	11.346%	11.346%	11.346%	11.346%
15	*Electric Transmission (ET)[2]*	*9.583%*	*9.583%*	*10.302%*	*11.137%*	*11.137%*	*11.137%*	*11.137%*	*11.137%*
16	Total[1]	90.417%	90.417%	89.698%	88.863%	88.863%	88.863%	88.863%	88.863%

As noted above, these amounts are then further broken out based on the common cost allocation approved in D.24-12-038, which allocates costs between ERRA, PABA, and NSGBA. Allocation percentages that applied in 2025 under the D.24-12-038 methodology are shown in the table below. The allocation percentages are subject to updates as the underlying authorized revenue requirement for utility-owned generation costs are updated.

For costs allocated to PABA, in 2025, the bundled load share was approximately 37 percent and the non-exempt departing load that pays the PCIA is approximately 63 percent. The departing load consists of both CCA load and non-exempt Direct Access load and breaks out as 53 percent CCA load and approximately 10 percent non-exempt DA load. For costs allocated to NSGBA the percentage of CCA load is approximately 49 percent based on PG&E's 2025 ERRA Forecast billing determinants.

COMMON COST ALLOCATION
Decision 24-12-038
Effective January 1, 2025

	Cost Recovery		ESA Cost Allocation Factors
	ERRA	ERRA	0.074766
	NSGBA	CAM	0.033574
UOG Legacy	PCIA	UOG Legacy	0.661768
2009	PCIA	Vin 2009	0.181903
2010	PCIA	Vin 2010	0.015892
2011	PCIA	Vin 2011	0.013866
2012	PCIA	Vin 2012	0.018231
2013	PCIA	Vin 2013	
2014	PCIA	Vin 2014	
2015	PCIA	Vin 2015	
2016	PCIA	Vin 2016	
2017	PCIA	Vin 2017	
2018	PCIA	Vin 2018	
2019	PCIA	Vin 2019	
2020	PCIA	Vin 2020	
2021	PCIA	Vin 2021	
2022	PCIA	Vin 2022	
2023	PCIA	Vin 2023	
	Total		1.000000

c. PG&E's response only addresses the Electric Generation revenue adjustment category given this revenue component does distinguish between bundled and other types of departing load, like CCA. The BMI costs will flow into the identified rate components just as any other cost does – a forecast or authorized amount will be included in the total revenue requirement to be recovered in rates. For Electric Generation revenue adjustment mechanism, those rates are set in the Annual ERRA Forecast proceeding. To estimate what those costs would be, the costs presented in the table above for Electric Generation (line 5) can be allocated between the three revenue adjustment mechanisms (ERRA, PABA, and NSGBA) identified for Electric Generation by applying the percentages used in 2025 for the common cost allocation methodology approved in D.24-12-038. The percentages identified for 2025 are subject to change but for illustrative purposes, these can be used to estimate what the incremental revenue requirement would be. PCE can derive its own estimate of those costs based on the data above, which will be subject to change as the allocation factors and other estimates or variables are updated.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q019
PG&E File Name:	BillingModernization_DR_PCE_001-Q019
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

QUESTION 019

Referring to PG&E's Prepared Testimony, Chapter 1, p. 1-6, Figure 1-2, and Chapter 6 generally:

a. Did PG&E consider a scenario in which it proceeded immediately with the Stage 3 C2M Implementation (foregoing Stage 1 and Stage 2 of the currently contemplated BMI process)? As part of PG&E's response, please confirm whether PG&E conducted a cost-benefit analysis of such a scenario, and if so, please provide that analysis. If not, why not?

b. If PG&E proceeded immediately with Stage 3 now and un-paused any currently paused work on Stage 3, when could PG&E expect to deploy C2M to customers?

c. If PG&E had never paused its work on Stage 3 C2M implementation, when could PG&E expect to deploy C2M to customers?

ANSWER 019

a. No. PG&E's plan was always to replace ABS with BCS and move CC&B to C2M. Please refer to chapter 5 for a detailed explanation of the challenges faced with that approach.

b. PG&E does not have the analysis for the present-day scenario.

c. Prior to pausing the C2M project, the anticipated deployment date was in Q4 2026.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q020
PG&E File Name:	BillingModernization_DR_PCE_001-Q020
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 23, 2025
PG&E Witness(es):	Kellie Reem – Information Technology

QUESTION 020

Referring to PG&E's Prepared Testimony, Chapter 2, p. 2-15, lines 8-12:

a. Please identify the originally anticipated end of life dates associated with PG&E's legacy billing systems and the year(s) in which those systems became fully depreciated.

b. At what point in these assets' expected service life did PG&E begin to analyze the most cost-effective way to replace these assets? Please explain PG&E's rationale behind undertaking these analyses at that point in time (as opposed to previously).

c. Generally, what is PG&E's view of the optimal timeline for analyzing IT asset replacement options relative to the lifespan of the current aging system?

d. Generally, what is PG&E's view of the optimal timeline for undertaking a replacement of its IT assets relative to the lifespan of the current aging system?

ANSWER 020

a. PG&E assumes that the legacy systems refers to the Advanced Billing System and the CC&B version currently used today. PG&E's Chapter 2 section B, p.2-9 describes the Billing systems' history. See Chapter 2, section B, p.2-15 which describes the years the legacy billing systems were put into service as well as the years they became depreciated.

b. PG&E began to analyze the most cost-effective way to replace these assets in 2018. Refer to Accenture case study WP 4-2.

c. Generally, PG&E's optimal timeline for analyzing IT asset replacement options is typically after the asset has been deployed and is operating without significant defects. As a routine part of asset and system maintenance, PG&E periodically conducts asset and system inspections to validate if there are any performance issues or vendor defects that could lead to asset replacement.

d. Generally, PG&E’s optimal timeline for undertaking a replacement is within the operational lifespan of the asset. For most software and hardware, this is typically between 3 to 10 years. However, in cases where routine maintenance inspections prove replacement is warranted, PG&E will escalate these asset replacements ahead of schedule and within operational budget constraints.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q022
PG&E File Name:	BillingModernization_DR_PCE_001-Q022
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Briel – Customer and Enterprise Solutions

QUESTION 022

Referring to PG&E's Prepared Testimony, Chapter 3, p. 3-1, lines 13 to 30, and Chapter 4, p. 4-13, lines 9 to 27, and p. 4-22, lines 25 to 30:

a. In its 2018 evaluation, what did Accenture ultimately recommend PG&E do (as a target state solution) to address the risks it identified, and on what timeline?

b. In its 2022 evaluation, what did Accenture recommend PG&E do (as a target state solution) to address the risks it identified, and on what timeline?

c. If PG&E's current BMI proposal is on a different timeline than those identified in PG&E's responses to part (a) and/or (b), please explain why.

ANSWER 022

a. As a target state solution the recommendation from Accenture, in 2018, was to re-platform to a next generation CIS within the 2024 timeframe. Accenture states, "In this scenario, PG&E would select a fully integrated CIS technology suite from one of the market leaders in the industry – Oracle or SAP."

b. The 2022 evaluation from Accenture acknowledges phase 1: BCS – ABS Electric Replacement was already underway and "PG&E should build on its momentum to re-platform its meter to cash solution." The only mention of timeframe was to note the BCS – ABS Electric Replacement phase had a target completion date of 2023.

c. PG&E provided context for why the original BCS – ABS Electric Replacement target completion date was not met in PG&E's Prepared Testimony, Chapter 5, p. 5-10 line 26 through p. 5-22 line 18.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_001-Q026
PG&E File Name:	BillingModernization_DR_PCE_001-Q026
Request Date:	April 4, 2025
Requester DR No.:	001
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	April 18, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

QUESTION 026

Referring to PG&E's Prepared Testimony, Chapter 5, p. 5-52, line 25 to p.5-53, line 20: please explain how this forecasted stranded cost analysis would change if PG&E transitioned directly from the legacy systems to the C2M?

ANSWER 026

There would be no stranded costs if PG&E transitions directly from the legacy systems to C2M and the BCS or CC&B 25.1 projects were not implemented.

As described in Chapter 5, page 5-52, lines 25-28 and Chapter 2, section B, the original capital legacy billing system and related capital upgrades have been fully depreciated. There are no stranded costs associated with the legacy billing systems (CC&B, ABS, and MDMS). Thus, there would be no stranded costs if the BCS or CC&B 25.1 projects were not implemented, since the stranded costs included in testimony are related to those projects.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q003
PG&E File Name:	BillingModernization_DR_PCE_002-Q003
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 2, 2025
PG&E Witness(es):	Kellie Reem – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 003

Referring to PG&E's Prepared Testimony, Chapter 4, p. 4-28, lines 4 to 10:

a. Please provide a timeline for when PG&E implemented CC&B 2.4.

b. Please explain if there were any CC&B version releases between the releases of CC&B 2.4 and CC&B 25.1, documenting each version's release date.

c. Please provide timelines for the implementation of any CC&B version releases completed by PG&E between the releases of CC&B 2.4 and CC&B 25.1.

ANSWER 003

a. In 2017, PG&E upgraded CC&B from version 2.3 to version 2.4, which is the version currently in use.

b. Oracle has released 6 updated versions of the software since 2.4. CC&B Release Dates are follows:

CC&B 2.4	October 2013
CC&B 2.5	October 2015
CC&B 2.6	May 2017
CC&B 2.7	August 2018
CC&B 2.8	April 2021
CC&B 2.9	April 2022
CC&B 25.4	April 2025

c. PG&E has not upgraded CC&B since 2017 to a newer version since 2017.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q009
PG&E File Name:	BillingModernization_DR_PCE_002-Q009
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 3, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 009

Referring to PG&E's response to PCE_001_Q006: Please explain if any of the fees featured on PG&E's Schedule E-CCA will be impacted by the BMI (or are likely to be impacted by the BMI). If yes, please identify the specific fee and how the fee will be (or is likely to be) impacted.

ANSWER 009

BMI is expected to enhance the efficiency and automation of several processes related to CCA services, as outlined in PG&E's Electric Schedule E-CCA. As these improvements are implemented over the course of the initiative particularly as the system transitions to its target state in Stage 3, PG&E anticipates that certain activities currently require manual intervention may become more streamlined and system driven.

While it is premature to identify specific changes to fee structures at this time, these services are expected to benefit from automation, improved data handling, and reduced administrative effort under the upgraded system. Any proposed adjustments to these fees would be evaluated upon completion of the relevant BMI phases and submitted for review and approval through the appropriate regulatory processes.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q010
PG&E File Name:	BillingModernization_DR_PCE_002-Q010
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 3, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 010

Referring to PG&E's response to PCE_001_Q006:

a. Please itemize the specific changes or upgrades in PG&E's BMI process that could potentially "improve efficiency in managing and supporting third-party energy service providers such as Community Choice Aggregators (CCAs)."

b. Please provide a list of the billing system efficiency metrics that PG&E currently tracks for either/both its CCA and bundled service customers.

ANSWER 010

a. Billing Modernization Initiative, as described in Chapter 4 of its testimony in the BMI filing is expected to improve operational efficiency in managing and supporting third-party energy service providers including CCAs. The initiative includes a transition to an integrated platform that is intended to modernize PG&E's customer, billing and metering systems. While the following list outlines potential areas of improvement, it is not a comprehensive or final list, as PG&E is still in the early stages of the BMI program. Many specific features have not yet been finalized, confirmed, or prioritized for implementation, particularly those planned for later phases (Stage 3). Subject to those qualifications, anticipated upgrades include:

- Market Transaction Management (MTM) Module: enables centralized, rule-based processing of enrollment, usage, and billing data exchanges with CCA, replacing decades worth of custom code and integrations
- Integrated Meter and Data management (via MDM and ODM Modules): streamlines the collection, validation, and transfer of meter data that will improve accuracy and reduce exception handling, benefiting third party ESPs

- Consolidated Billing Capabilities: enhance support for both rate-ready and bill-ready billing models through improved system configuration and more consistent application of third-party rates and charges
- Exception Handling and Validation Tools: introduces near real-time processing logic to identify and resolve data mismatches or incomplete transactions, minimizing delays and manual corrections

b. PG&E tracks a variety of internal billing system efficiency metrics to monitor operational performance across all residential and commercial customer segments. These metrics are not disaggregated by CCA or bundled service customers, as billing processes are largely shared across customer types. Examples of billing efficiency metrics currently tracked include, but are not limited to:

- Unbilled Revenue: monitors billed revenue that is uncollectible due to timing, system constraints, or limitations defined under Rule 17.1
- Quality Assurance Standard – Late Commencing Bills: tracks bills issued more than 60 days after service start
- Delayed Bills: identifies bills not generated within 35 days of the previous bill date
- Customer Initiated Request Open > 45 Days: measures the percentage of service or billing-related request that remain unresolved 45 days after initiation.

These metrics are drawn from various operational reports used to manage billing accuracy, timeliness, and customer responsiveness. Additional metrics maybe also be used internally for system performance and compliance monitoring.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q011
PG&E File Name:	BillingModernization_DR_PCE_002-Q011
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 3, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 011

Referring to PG&E's response to PCE_001_Q006:

a. Please explain how PG&E currently sets these CCA service fees (i.e., PG&E's methodology for determining the appropriate fee amounts).

b. Does PG&E anticipate continuing to use this same methodology referenced in part (a) after the BMI upgrades? If not, please explain any anticipated changes to PG&E's methodology.

c. Please confirm if PG&E applies and will continue to apply an inflation factor to determine CCA service fees. If confirmed, please explain how this inflation factor is calculated.

d. If part (c) is confirmed, please explain if PG&E expects CCA service fees to increase over time due to the application of an inflation factor.

e. Does PG&E anticipate that its implementation of the BMI will, on balance, improve efficiency in supporting CCAs? If not answered in the affirmative, please explain why.

f. All else being equal, would the referenced "streamlined processes" lead to reduced CCA service fees? If not, why not.

g. All else being equal, would the referenced "reduced reliance on manual interventions" lead to reduced CCA service fees? If not, why not.

h. All else being equal, would the referenced "consolidated systems" lead to reduced CCA service fees? If not, why not.

i. Please provide examples of the kinds of "regulatory requirements" that might raise CCA service fees in the future. What does PG&E mean by that phrase in this context?

j. Please provide examples of the kinds of “future operational needs” that might raise CCA service fees in the future. What does PG&E mean by that phrase in this context?

k. Please provide examples of the kinds of “unforeseen system complexities” that might raise CCA service fees in the future. What does PG&E mean by that phrase in this context?

l. Referring also to PG&E’s response to PCE_001_Q007, please explain what PG&E means by “the complexity of cost allocation”, and specifically, how that complexity could raise CCA service fees in the future.

ANSWER 011

a. PG&E’s CCA service fees listed in Electric Schedule E-CCA are developed based on the estimated labor time, materials, system usage, and administrative effort required to perform each service. Fee calculations typically reflect internal cost-of-service estimates, consistent with principles used in other unbundled service fee determinations. Fees are reviewed and approved through applicable regulatory proceedings and are maintained by various operational groups across the company.

b. PG&E anticipates continuing to use a similar cost-based methodology post-BMI. Once BMI is fully implemented and the new system has stabilized, PG&E may revisit the inputs and assumptions behind the fee calculations to reflect changes in system design, automation, and labor effort associated with performing the underlying services.

c. Yes, in applicable proceedings PG&E has applied an inflation or escalation factors based on expected labor cost growth. This typically reflects enterprise-wide labor escalation rates or other cost forecast factors reviewed in general rate case (GRC) proceedings.

d. Yes, if the inflation factor continues to be applied, PG&E would expect that certain CCA service fees could increase over time, subject to regulatory approval.

e. Yes, PG&E anticipates that, once fully implemented, the BMI will improve operational efficiency in supporting CCA-related services. These improvements are expected to stem from increased automation, data standardization, and streamlined workflows. The full benefits of BMI are not expected to be realized until the final stages of BMI.

f. While the BMI is designed to streamline many operational processes, not every process will be streamlined. As PG&E retires decades of custom code and adopts standardized base-product workflows, certain services may experience increased processing time or operational complexity. In some cases, efficiencies in one area may be offset by additional steps or requirements in another. The overall impact is expected to vary across services and may balance out across multiple processes. Any potential impact on service fees would be assessed through a comprehensive cost review and subject to Commission approval.

g. Reduced manual intervention is expected to improve efficiency and reduce the risk of human error for certain processes. The extent of cost savings will vary depending on service complexity, volume, and system design. Reductions in administrative effort may not directly translate into lower service fees without a post-implementation cost analysis.

h. Consolidating systems may reduce data duplication, streamline reporting, and lower maintenance burdens. However, initial implementation and transition costs may offset these efficiencies in the near term. Any long-term fee adjustments would depend on operational cost impacts following full deployment and would be subject to Commission review.

i. Regulatory requirements that could increase CCA service fees in the future may include, but are not limited to, new or evolving obligations that introduce additional complexity, system enhancements, or administrative workload. Examples include:

    a. Provider of Last Resort (POLR) Implementation: as PG&E steps into new roles related to POLR, including mass transitioning CCA customers back to bundled service in the event of a CCA failure or market exit, new processes are being developed that do not currently exist within legacy systems.

    b. Data Privacy and Compliance Mandates: regulations such as California Consumer Privacy Act (CCPA) and potential future legislation may require enhancements to data handling processes, consent tracking, customer communication protocols and data reporting. Compliance with these lays may lead to increased system and labor costs associated with managing CCA customer data in a compliant manner.

    c. Customer Billing and Notification Enhancements: Commission directives requiring changes to bill presentment (e.g., inclusion of dynamic rate components or standardizing messaging)

   These examples reflect that CCA services fees may affect not only by system efficiencies but also by additional complexity introduced by emerging regulatory frameworks.

j. “Future operational needs” refer to changes in business practices, staffing, systems, or support processes that may arise to maintain or improve service delivery that could impact CCA service fees.

k. “Unforeseen system complexities” refer to technical or integration challenges that are not identified until after system implementation that may increase service costs

l. “Complexity of cost allocation” refers to the challenge of assigning shared systems or operational costs across various customer groups and services. Example: determining the appropriate portion of shared IT infrastructure costs attributable to CCA related services.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q013
PG&E File Name:	BillingModernization_DR_PCE_002-Q013
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 3, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 013

Referring to PG&E's response to PCE_001_Q010:

a. Please provide a sample of a current PG&E bill for a bundled electric service residential customer, redacting any Protected Personal Information if needed.

b. Please provide a sample of a current PG&E bill for a departed electric service residential customer (CCA customer), redacting any Protected Personal Information if needed.

ANSWER 013

a. See attachment: *BillingModernization_DR_PCE_002-Q013Atch01.pdf*

b. See attachment: *BillingModernization_DR_PCE_002-Q013Atch02.pdf*

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/20/2025
Due Date: 06/10/2025

Service For:

REDACTED - Customer Info

Questions about your bill?

Mon-Fri 7 a.m.-7 p.m.
Saturday 8 a.m.-5 p.m.
Phone: 1-800-743-5000
www.pge.com/MyEnergy

Ways To Pay

www.pge.com/waystopay

Your Enrolled Programs

FERA Discount

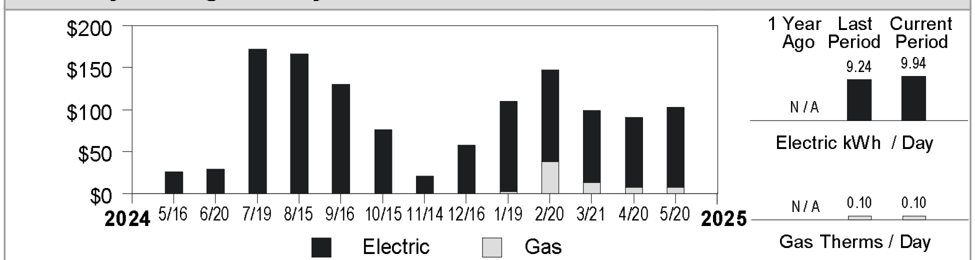
Your Account Summary

Credit Balance on Previous Statement	-$35.62
Payment(s) Received Since Last Statement	0.00
Outstanding Credit Balance	-$35.62
Current Electric Charges	$95.87
Current Gas Charges	7.68
Total Amount Due by 06/10/2025	**$67.93**

Current charges include a discount of $20.82 for FERA.

Monthly Billing History

Daily Usage Comparison



*Visit **www.pge.com/MyEnergy** for a detailed bill comparison*

Important Messages

TOU Rate: You are currently on a time-of-use (TOU) rate schedule. Beginning June 1, the TOU rate charges higher prices in the summer for electric usage on summer evenings.

Please return this portion with your payment. No staples or paper clips. Do not fold. Thank you.

REDACTED - Customer Info

PG&E

Account Number:	Due Date:	Total Amount Due:	Amount Enclosed:
REDACTED - Customer Info	**06/10/2025**	**$67.93**	$

REDACTED - Customer Info

PG&E
BOX 997300
SACRAMENTO, CA 95899-7300

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/20/2025
Due Date: 06/10/2025

Important Phone Numbers - Monday-Friday 7 a.m.-7 p.m., Saturday 8 a.m.-5 p.m.

Customer Service (All Languages; Relay Calls Accepted) 1-800-743-5000
TTY 7-1-1

Servicio al Cliente en Español (Spanish)	1-800-660-6789	Dịch vụ khách tiếng Việt (Vietnamese)	1-800-298-8438
華語客戶服務 (Chinese)	1-800-893-9555	Business Customer Service	1-800-468-4743

Rules and rates

You may be eligible for a lower rate. To learn more about optional rates or view a complete list of rules and rates, visit www.pge.com or call 1-800-743-5000.

If you believe there is an error on your bill, please call **1-800-743-5000** to speak with a representative. If you are not satisfied with our response, contact the California Public Utilities Commission (CPUC), Consumer Affairs Branch (CAB), 505 Van Ness Avenue, Room 2003, San Francisco, CA 94102, 1-800-649-7570 or 7-1-1 (8:30 AM to 4:30 PM, Monday through Friday) or by visiting www.cpuc.ca.gov/complaints/.

To avoid having service turned off while you wait for the outcome of a complaint to the CPUC specifically regarding the accuracy of your bill, please contact CAB for assistance. If your case meets the eligibility criteria, CAB will provide you with instructions on how to mail a check or money order to be impounded pending resolution of your case. You must continue to pay your current charges while your complaint is under review to keep your service turned on.

If you are not able to pay your bill, call PG&E to discuss how we can help. You may qualify for reduced rates under PG&E's CARE program or other special programs and agencies may be available to assist you. You may qualify for PG&E's Energy Savings Assistance Program which is an energy efficiency program for income-qualified residential customers.

Important definitions

Rotating outage blocks are subject to change without advance notice due to operational conditions.

Tier 1/Baseline allowance: Some residential rates are given a Tier 1/Baseline allowance - a CPUC approved percentage of average customer usage during summer and winter months. Your Tier 1/Baseline allowance provides for basic needs at an affordable price and encourages conservation. Your allowance is assigned based on the climate where you live, the season and your heat source. As you use more energy, you pay more for usage. Any usage over your baseline allowance will be charged at a higher price.

Wildfire Fund Charge: Charge on behalf of the State of California Department of Water Resources (DWR) to fund the California Wildfire Fund. For usage prior to October 1, 2020, this charge included costs related to the 2001 California energy crisis, also collected on behalf of the DWR. These charges belong to DWR, not PG&E.

Power Charge Indifference Adjustment (PCIA): The PCIA is a charge to ensure that both PG&E customers and those who have left PG&E service to purchase electricity from other providers pay for the above market costs for electric generation resources that were procured by PG&E on their behalf. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. Visit www.pge.com/cca.

Wildfire Hardening Charge: PG&E has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. Your bill for electric service includes a fixed recovery charge called the Wildfire Hardening Charge that has been approved by the CPUC to repay those bonds. The right to recover the Wildfire Hardening Charge has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and does not belong to PG&E. PG&E is collecting the Wildfire Hardening Charge on behalf of the Special Purpose Entity. For details visit: www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_JF.pdf.

Recovery Bond Charge/Credit: Your bill for electric service includes a charge that has been approved by the CPUC to repay bonds issued for certain costs related to catastrophic wildfires. The Recovery Bond Charge (RBC) rate is currently $0.00647 per kWh. PG&E has also contributed certain amounts to a trust fund which is used to provide a customer credit equal to $0.00647 per kWh (Recovery Bond Credit). The right to recover the RBC has been transferred to one or more Special Purpose Entities that issued the bonds and does not belong to PG&E. PG&E is collecting that portion of the RBC on behalf of the Special Purpose Entities.

Gas Public Purpose Program (PPP) Surcharge. Used to fund state-mandated gas assistance programs for low-income customers, energy efficiency programs, and public-interest research and development.

Visit www.pge.com/billexplanation for more definitions. To view most recent bill inserts including legal or mandated notices, visit www.pge.com/billinserts.

See the table reflecting "Your Electric Charges Breakdown" on the last page

Please do not mark in box. For system use only.

Update My Information (English Only)

Please allow 1-2 billing cycles for changes to take effect

Account Number: REDACTED - Customer Info

Change my mailing address to: ______________________

City ______________ State ______ ZIP code ______

Primary Phone # ______________ Primary Email ______________

Ways To Pay

- **Online via web or mobile at www.pge.com/waystopay**
- **By mail:** Send your payment along with this payment stub in the envelope provided.
- **By debit card, Visa, MasterCard, American Express, or Discover:** Call 877-704-8470 at any time. (Our independent service provider charges a fee per transaction.)
- **At a neighborhood payment center**: To find a neighborhood payment center near you, please visit www.pge.com or call 800-743-5000. Please bring a copy of your bill with you.

ENERGY STATEMENT

www.pge.com/MyEnergy

Details of Electric Charges

04/18/2025 - 05/18/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED -
Rate Schedule: Time-of-Use (Peak Pricing 4 - 9 p.m. Every Day)
Enrolled Programs: FERA

04/18/2025 – 05/18/2025

Baseline Allowance	303.80	kWh	(31 days x 9.8 kWh/day)		
Energy Charges					
Peak	62.934300	kWh	@	$0.50086	$31.52
Off Peak	245.126600	kWh	@	$0.47086	115.42
Baseline Credit	303.800000	kWh	@	-$0.10301	-31.29
FERA Discount					-20.82
Energy Commission Tax					0.09
Bakersfield Franchise Surcharge					0.95

Total Electric Charges **$95.87**

Rate Identification Number

USCA-PGPG-0100-0000
www.pge.com/rin
To program your smart device, scan the QR code or enter the RIN code above and follow the on-screen instructions.

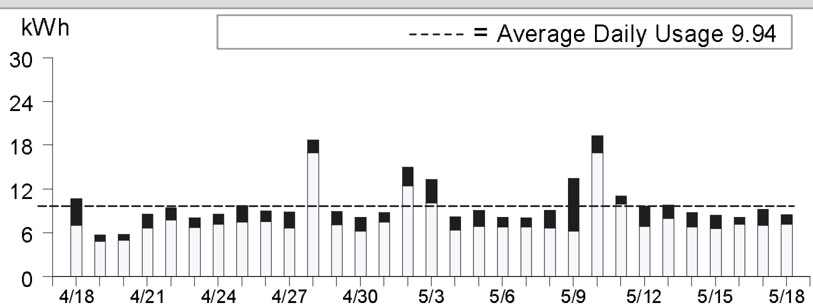
Service Information

Meter #	REDACTED - Customer Info
Total Usage	308.060900 kWh
Baseline Territory	W
Heat Source	B - Not Electric
Serial	Y
Rotating Outage Block	6I

Additional Messages

As a customer who receives electricity directly from PG&E, a portion of your electric charges currently includes the Power Charge Indifference Adjustment (PCIA). To learn more, review page 2 of this Energy Statement or visit **www.pge.com/cca**.

Electric Usage This Period: 308.060900 kWh, 31 billing days



	Usage	Energy Charges
Peak[1]	20.42%	$31.52
Off Peak[2]	79.58%	$115.42

[1]**Peak:** 4:00pm-9:00pm, Every Day;
[2]**Off Peak:** All Other Hours

Visit ***www.pge.com/MyEnergy*** *for a detailed bill comparison.*

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/20/2025
Due Date: 06/10/2025

Details of Gas Charges

04/19/2025 - 05/19/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: G1 WB Residential Service

04/19/2025 – 04/30/2025	**Your Tier Usage**	**1**	2

Tier 1 Allowance	4.68 Therms (12 days x 0.39 Therms/day)	
Tier 1 Usage	1.161290 Therms @ $2.36480	$2.75
Gas PPP Surcharge ($0.14324 /Therm)		0.16
Bakersfield Franchise Surcharge		0.03

05/01/2025 – 05/19/2025	**Your Tier Usage**	**1**	2

Tier 1 Allowance	7.41 Therms (19 days x 0.39 Therms/day)	
Tier 1 Usage	1.838710 Therms @ $2.40729	$4.43
Gas PPP Surcharge ($0.14324 /Therm)		0.27
Bakersfield Franchise Surcharge		0.04

Total Gas Charges **$7.68**

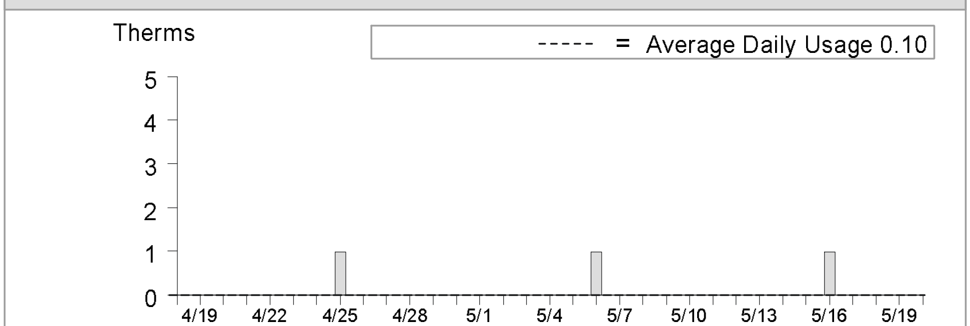
Service Information

Meter #	REDACTED - Customer Info
Current Meter Reading	42
Prior Meter Reading	39
Difference	3
Multiplier	1.004246
Total Usage	3.000000 Therms
Baseline Territory	W
Serial	Y

Gas Procurement Costs ($/Therm)

04/19/2025 - 04/30/2025	$0.24481
05/01/2025 - 05/19/2025	$0.28730

Gas Usage This Period: 3.000000 Therms, 31 billing days



Your Electric Charges Breakdown (from page 2)	
Conservation Incentive	-$10.52
Generation	43.98
Transmission	12.14
Distribution	39.57
Electric Public Purpose Programs	8.14
Nuclear Decommissioning	-0.08
Wildfire Fund Charge	1.83
Competition Transition Charges (CTC)	-0.23
Taxes and Other	1.04
Total Electric Charges	**$95.87**

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: [redacted]
Statement Date: 04/18/2025
Due Date: 05/09/2025

Service For:

[redacted]

Questions about your bill?

Mon-Fri 7 a.m.-7 p.m.
Saturday 8 a.m.-5 p.m.
Phone: 1-800-743-5000
www.pge.com/MyEnergy

Ways To Pay

www.pge.com/waystopay

Your Enrolled Programs

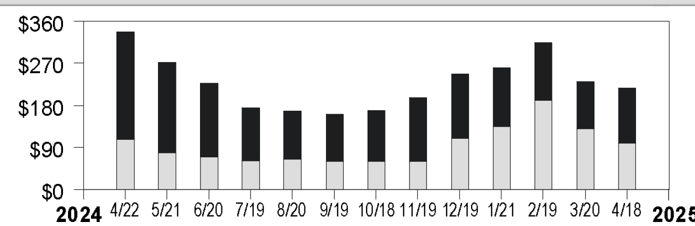
CARE Discount

Your Account Summary

Amount Due on Previous Statement	$232.14
Payment(s) Received Since Last Statement	-232.14
Previous Unpaid Balance	$0.00
Current PG&E Electric Delivery Charges	$61.50
Electric Adjustments	-58.23
Peninsula Clean Energy Electric Generation Charges	57.76
Current Gas Charges	98.99
Gas Adjustments	-67.03
Total Amount Due by 05/09/2025	**$92.99**

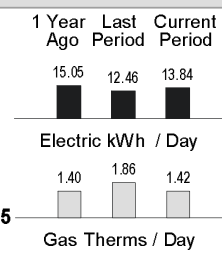
Current charges include discounts of $222.74 for CARE and CA Climate Credit.

Monthly Billing History



Visit ***www.pge.com/MyEnergy*** *for a detailed bill comparison*

Daily Usage Comparison



Important Messages

California is fighting climate change and so can you! Your bill includes a Climate Credit from a state program to cut carbon pollution while also reducing your energy costs. Find out how at **cpuc.ca.gov/climatecredit**.

The gas summer Tier 1 (baseline) season begins on April 1. Your total Tier 1 quantities shown were calculated using your daily summer baseline allowance starting April 1 and your daily winter baseline allowance for any days in your billing period before April 1.

Continued on page 0

Please return this portion with your payment. No staples or paper clips. Do not fold. Thank you.

[redacted]

Account Number:	Due Date:	Total Amount Due:	Amount Enclosed:
[redacted]	**05/09/2025**	**$92.99**	$

[redacted]

PG&E
BOX 997300
SACRAMENTO, CA 95899-7300

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 04/18/2025
Due Date: 05/09/2025

Important Phone Numbers - Monday-Friday 7 a.m.-7 p.m., Saturday 8 a.m.-5 p.m.

Customer Service (All Languages; Relay Calls Accepted) 1-800-743-5000
TTY 7-1-1

Servicio al Cliente en Español (Spanish)	1-800-660-6789	Dịch vụ khách tiếng Việt (Vietnamese)	1-800-298-8438
華語客戶服務 (Chinese)	1-800-893-9555	Business Customer Service	1-800-468-4743

Rules and rates

You may be eligible for a lower rate. To learn more about optional rates or view a complete list of rules and rates, visit www.pge.com or call 1-800-743-5000.

If you believe there is an error on your bill, please call **1-800-743-5000** to speak with a representative. If you are not satisfied with our response, contact the California Public Utilities Commission (CPUC), Consumer Affairs Branch (CAB), 505 Van Ness Avenue, Room 2003, San Francisco, CA 94102, 1-800-649-7570 or 7-1-1 (8:30 AM to 4:30 PM, Monday through Friday) or by visiting www.cpuc.ca.gov/complaints/.

To avoid having service turned off while you wait for the outcome of a complaint to the CPUC specifically regarding the accuracy of your bill, please contact CAB for assistance. If your case meets the eligibility criteria, CAB will provide you with instructions on how to mail a check or money order to be impounded pending resolution of your case. You must continue to pay your current charges while your complaint is under review to keep your service turned on.

If you are not able to pay your bill, call PG&E to discuss how we can help. You may qualify for reduced rates under PG&E's CARE program or other special programs and agencies may be available to assist you. You may qualify for PG&E's Energy Savings Assistance Program which is an energy efficiency program for income-qualified residential customers.

Important definitions

Rotating outage blocks are subject to change without advance notice due to operational conditions.

Tier 1/Baseline allowance: Some residential rates are given a Tier 1/Baseline allowance - a CPUC approved percentage of average customer usage during summer and winter months. Your Tier 1/Baseline allowance provides for basic needs at an affordable price and encourages conservation. Your allowance is assigned based on the climate where you live, the season and your heat source. As you use more energy, you pay more for usage. Any usage over your baseline allowance will be charged at a higher price.

Wildfire Fund Charge: Charge on behalf of the State of California Department of Water Resources (DWR) to fund the California Wildfire Fund. For usage prior to October 1, 2020, this charge included costs related to the 2001 California energy crisis, also collected on behalf of the DWR. These charges belong to DWR, not PG&E.

Power Charge Indifference Adjustment (PCIA): The PCIA is a charge to ensure that both PG&E customers and those who have left PG&E service to purchase electricity from other providers pay for the above market costs for electric generation resources that were procured by PG&E on their behalf. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. Visit www.pge.com/cca.

Wildfire Hardening Charge: PG&E has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. Your bill for electric service includes a fixed recovery charge called the Wildfire Hardening Charge that has been approved by the CPUC to repay those bonds. The right to recover the Wildfire Hardening Charge has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and does not belong to PG&E. PG&E is collecting the Wildfire Hardening Charge on behalf of the Special Purpose Entity. For details visit: www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_JF.pdf.

Recovery Bond Charge/Credit: Your bill for electric service includes a charge that has been approved by the CPUC to repay bonds issued for certain costs related to catastrophic wildfires. The Recovery Bond Charge (RBC) rate is currently $0.00647 per kWh. PG&E has also contributed certain amounts to a trust fund which is used to provide a customer credit equal to $0.00647 per kWh (Recovery Bond Credit). The right to recover the RBC has been transferred to one or more Special Purpose Entities that issued the bonds and does not belong to PG&E. PG&E is collecting that portion of the RBC on behalf of the Special Purpose Entities.

Gas Public Purpose Program (PPP) Surcharge. Used to fund state-mandated gas assistance programs for low-income customers, energy efficiency programs, and public-interest research and development.

Visit www.pge.com/billexplanation for more definitions. To view most recent bill inserts including legal or mandated notices, visit www.pge.com/billinserts.

See the table reflecting "Your Electric Charges Breakdown" on the last page

Please do not mark in box. For system use only.

Update My Information (English Only)

Please allow 1-2 billing cycles for changes to take effect

Account Number: 5734154760-2

Change my mailing address to: ____________________

City ____________ State ______ ZIP code ______

Primary Phone # ____________ Primary Email ____________

Ways To Pay

- **Online via web or mobile at www.pge.com/waystopay**
- **By mail:** Send your payment along with this payment stub in the envelope provided.
- **By debit card, Visa, MasterCard, American Express, or Discover:** Call 877-704-8470 at any time. (Our independent service provider charges a fee per transaction.)
- **At a neighborhood payment center**: To find a neighborhood payment center near you, please visit www.pge.com or call 800-743-5000. Please bring a copy of your bill with you.

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 04/18/2025
Due Date: 05/09/2025

Details of PG&E Electric Delivery Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: E1 TB Residential Service
Enrolled Programs: CARE (Renew by 04/04/2025)

03/14/2025 – 04/13/2025 Your Tier Usage | 1 | **2** |

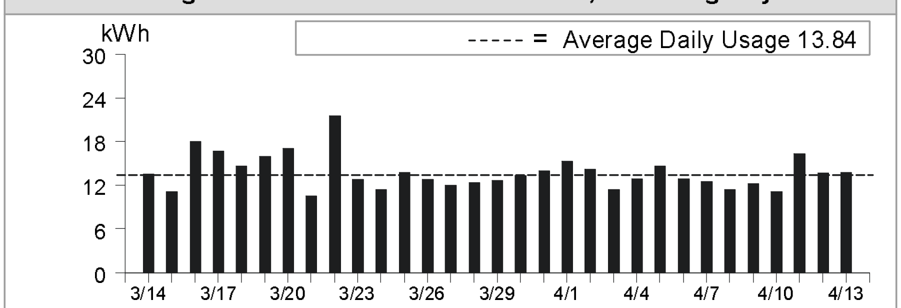
Tier 1 Allowance	232.50	kWh	(31 days x 7.5 kWh/day)		
Tier 1 Usage	232.500000	kWh	@	$0.40730	$94.70
Tier 2 Usage	196.440000	kWh	@	$0.51031	100.25
CARE Discount					-74.79
Generation Credit					-66.78
Power Charge Indifference Adjustment					4.76
Franchise Fee Surcharge					0.45
Daly City Utility Users' Tax (5.000%)					2.91
Total PG&E Electric Delivery Charges					**$61.50**

2016 Vintaged Power Charge Indifference Adjustment

Adjustments

California Climate Credit	-$58.23
Total Adjustments	**-$58.23**

Electric Usage This Period: 428.940000 kWh, 31 billing days



Service Information

Meter #	REDACTED - Customer Info
Total Usage	428.940000 kWh
Baseline Territory	T
Heat Source	B - Not Electric
Serial	T
Rotating Outage Block	9P

Your CARE usage is charged at these rates ($/kWh). Differences may occur due to rounding.

03/14/2025 - 04/13/2025	
Tier 1	0.24947
Tier 2	0.31643
Tier 2 Usage continued	0.31643

Additional Messages

You received a **California Climate Credit** on your electric bill. Learn how you can use these savings to further reduce your energy costs and help fight climate change at **cpuc.ca.gov/climatecredit.**

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 04/18/2025
Due Date: 05/09/2025

Details of Peninsula Clean Energy Electric Generation Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: REDACTED - Customer Info

Service Agreement ID: REDACTED - Customer Info ESP Customer Number: REDACTED - Customer Info

03/14/2025 – 04/13/2025

Rate Schedule: **E-1**

Generation - Total	428.940000 kWh	@	$0.12797	$54.89
	Net Charges		54.89	
Local Utility Users Tax				2.74
Energy Commission Surcharge				0.13

Peninsula Clean Energy is your community's official electricity provider. You are receiving clean electricity at low rates!

Total Peninsula Clean Energy Electric Generation Charges **$57.76**

Service Information

Total Usage 428.940000 kWh

For questions regarding charges on this page, please contact:

PENINSULA CLEAN ENERGY
2075 WOODSIDE RD
REDWOOD CITY CA 94061
1-866-966-0110
PenCleanEnergy.com
info@PeninsulaCleanEnergy.com

Additional Messages

Your city has chosen to receive electricity sourced by Peninsula Clean Energy. Peninsula Clean Energy is a not-for-profit, public agency that sources energy that is least 50% renewable and 100% clean. Its energy generation charge replaces that of PG&E's, but at a lower rate.

Energy **generation** is one component of your overall electric bill. PG&E continues to own and operate the infrastructure and charge for the **delivery** of the electricity. PG&E is responsible for all gas services and gas charges.

Please do not hesitate to contact us at **info@PeninsulaCleanEnergy.com** or **866-966-0110** or visit our web site at **PenCleanEnergy.com** if you have any questions.

Peninsula Clean Energy is committed to protecting customer privacy. Learn more at **PenCleanEnergy.com/privacy**.

Details of Gas Charges

03/15/2025 - 04/14/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: G1 TB Residential Service
Enrolled Programs: CARE (Renew by 04/04/2025)

03/15/2025 – 03/31/2025 Your Tier Usage 1 **2**

Tier 1 Allowance	22.27 Therms (17 days x 1.31 Therms/day)	
Tier 1 Usage	22.270000 Therms @ $2.46291	$54.85
Tier 2 Usage	1.859032 Therms @ $2.97989	5.54
CARE Discount		-12.06
CSI Solar Thermal Exemption		-0.09
Gas PPP Surcharge ($0.08425 /Therm)		2.03
Daly City Utility Users' Tax (5.000%)		2.41

04/01/2025 – 04/14/2025 Your Tier Usage 1 **2**

Tier 1 Allowance	7.84 Therms (14 days x 0.56 Therms/day)	
Tier 1 Usage	7.840000 Therms @ $2.36480	$18.54
Tier 2 Usage	12.030968 Therms @ $2.88178	34.67
CARE Discount		-10.63
CSI Solar Thermal Exemption		-0.08
Gas PPP Surcharge ($0.08425 /Therm)		1.68
Daly City Utility Users' Tax (5.000%)		2.13

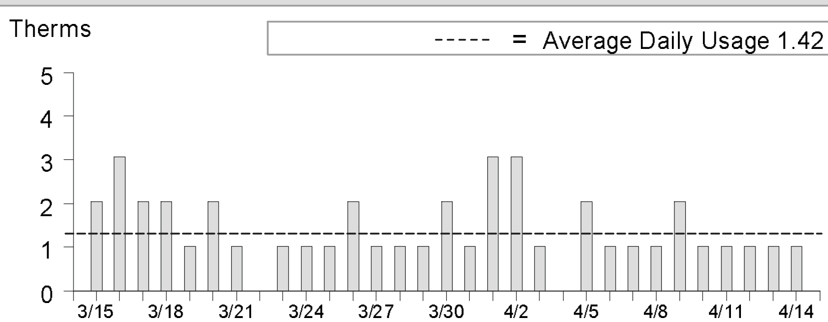
Total Gas Charges **$98.99**

Adjustments

California Climate Credit -$67.03

Total Adjustments **-$67.03**

Gas Usage This Period: 44.000000 Therms, 31 billing days



Service Information

Meter #	REDACTED - Customer Info
Current Meter Reading	1,954
Prior Meter Reading	1,911
Difference	43
Multiplier	1.025132
Total Usage	44.000000 Therms
Baseline Territory	T
Serial	T

Your CARE usage is charged at these rates ($/Therm). Differences may occur due to rounding.

03/15/2025 - 03/31/2025	
Tier 1	1.96729
Tier 2	2.38087
04/01/2025 - 04/14/2025	
Tier 1	1.88880
Tier 2	2.30238

Gas Procurement Costs ($/Therm)

03/15/2025 - 03/31/2025	$0.34292
04/01/2025 - 04/14/2025	$0.24481

Additional Messages

You received a **California Climate Credit** on your natural gas bill. Households receive the natural gas credit once a year. Learn how you can use these savings to further reduce your energy costs and help fight climate change at **cpuc.ca.gov/climatecredit.**

Important Messages (continued from page 1)

Low-Income Home Energy Assistance Program (LIHEAP) is a federally funded assistance program that provides a one-time payment to help income-qualified customers pay their past due energy bills. PG&E does not administer this program. To find the local LIHEAP agency in your area, visit **www.csd.ca.gov/energybills**, or call the help line at **1-866-675-6623**.

Energy Savings Assistance Program: provides free home improvements to help keep your home more energy efficient, safe and comfortable. Apply by answering a few simple questions at **www.pge.com/energysavings** or call **1-800-989-9744**.

Programa Energy Savings Assistance: proporciona mejoras al hogar sin costo para ayudar a que este sea más eficiente en el consumo de energía, más seguro y más cómodo. Solicite respondiendo a unas pocas preguntas simples en **www.pge.com/ahorreenergia** o llamando al **1-800-989-9744**.

Electric power line safety PG&E cares about your safety. Be aware of your surroundings and keep yourself, tools, equipment and antennas at least 10 feet away from overhead power lines. If you see an electric power line fall to the ground, keep yourself and others away. Call **9-1-1**.

Call 811 before you dig. A common cause of pipeline accidents is damage from digging. If you plan on doing any digging, such as planting a tree or installing a fence, please call **811** at least two working days before you dig. One free call will notify underground utilities to mark the location of underground lines, helping you to plan a safe project.

Your Electric Charges Breakdown (from page 2)	
Conservation Incentive	$8.43
Transmission	16.91
Distribution	22.60
Electric Public Purpose Programs	5.85
Nuclear Decommissioning	-0.10
Competition Transition Charges (CTC)	-0.31
PCIA	4.76
Taxes and Other	3.36
Total Electric Charges	**$61.50**

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q014
PG&E File Name:	BillingModernization_DR_PCE_002-Q014
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 2, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 014

Referring to PG&E's response to PCE_001_Q010:

a. What is the general timeline, currently, for PG&E to implement a CCA's request for an on-bill message change? Please provide any form(s) or document(s) used by PG&E to implement these changes.

b. Please explain if the upgrades associated with PG&E's BMI are anticipated to reduce the time it takes PG&E to implement a CCA's request for an on-bill message change. Why or why not?

c. Please explain if PG&E is generally aware of the timelines for other IOUs (e.g., SCE or SDG&E) to complete a CCA's request for an on-bill message change.

d. Referring also to Attachment 1 hereto, is PG&E aware that SCE's timeline for completing a CCA request for an on-bill message change is two business days? If so, what is PG&E's understanding of the reason(s) for the discrepancy between PG&E's and SCE's processing times?

ANSWER 014

a. PG&E does not utilize a standardized or formalized form for CCA on-bill message change request. Requests are submitted via email directly to PG&E CCA team. PG&E is in the process of developing a formal request form to standardize and improve the intake and tracking of such requests. The current timeline to implement a CCA on-bill messaging request is typically two to three months, depending on internal review, legal compliance changes and scheduling of IT development work.

b. PG&E is currently in the early stages of BMI, and the system capabilities that may support improved message configuration and scheduling are not expected to be available until Stage 3. As such, PG&E does not anticipate immediate changes to the processing timeline until those future-stage functionalities are implemented.

c. PG&E is aware that other IOUs such as SCE and SD&E may follow different internal processes and timelines for processing on-bill message change requests from CCAs. PG&E understands that timelines can vary based on each utility's system architecture, resource availability, and messaging policies.

d. PG&E is aware that SCE reportedly processes on-bill messaging requests from CCAs within two business days, as referenced in attached (Attachment 1 - SCE Bill Message Request Template.pdf). PG&E understands that the shorter processing time may be due to differences in system architecture, configuration and integrations and processes.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q015
PG&E File Name:	BillingModernization_DR_PCE_002-Q015
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 3, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 015

Referring to PG&E's response to PCE_001_Q010:

a. Please describe and provide an example bill showing the portion(s) of a current CCA customer bill that can include messaging/content from a CCA.

b. Does PG&E anticipate redesigning CCA customer bills after implementing (or as part of its implementation of) the upgrades associated with PG&E's BMI? If not, why not? If unknown, please explain why PG&E is not prioritizing this kind of redesign in its upgrade.

c. At what point in the BMI upgrade process would it be most efficient for PG&E to undertake a bill redesign (if it was ordered to do so by the Commission)? Please explain.

d. Please explain if the upgrades associated with PG&E's BMI will allow CCA messaging on customer bills to be more specific to customer types. If not, why not? If unknown, please explain why PG&E is not prioritizing this change in its upgrade.

e. Please explain if the upgrades associated with PG&E's BMI will allow CCA messaging on customer bills to be larger in size (i.e., more text allowed). If not, why not? If unknown, please explain why PG&E is not prioritizing this change in its upgrade.

f. Please explain if the upgrades associated with PG&E's BMI will allow CCA messaging on customer bills to address all customers. If not, why not? If unknown, please explain why PG&E is not prioritizing this change in its upgrade.

g. Please explain if the upgrades associated with PG&E's BMI will allow CCAs to send messages directly to specific customer groups (e.g., residential, commercial, etc.). If not, why not? If unknown, please explain why PG&E is not prioritizing this change in its upgrade.

Answer 015

a. See attachment: *BillingModernization_DR_PCE_002-Q015Atch01.pdf*

ENERGY STATEMENT
www.pge.com/MyEnergy

Account No: [redacted]
Statement Date: 04/18/2025
Due Date: 05/09/2025

Details of Peninsula Clean Energy Electric Generation Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: [redacted]
Service Agreement ID: [redacted] ESP Customer Number: [redacted]

03/14/2025 – 04/13/2025

Rate Schedule: E-1

Generation - Total	428.940000 kWh @ $0.12797		$54.89
	Net Charges	54.89	
Local Utility Users Tax			2.74
Energy Commission Surcharge			0.13

Peninsula Clean Energy is your community's official electricity provider.
You are receiving clean electricity at low rates!

Total Peninsula Clean Energy Electric Generation Charges $57.76

Service Information
Total Usage 428.940000 kWh

For questions regarding charges on this page, please contact:
PENINSULA CLEAN ENERGY
2075 WOODSIDE RD
REDWOOD CITY CA 94061
1-866-966-0110
PenCleanEnergy.com
info@PeninsulaCleanEnergy.com

Additional Messages
Your city has chosen to receive electricity sourced by Peninsula Clean Energy. Peninsula Clean Energy is a not-for-profit, public agency that sources energy that is least 50% renewable and 100% clean. Its energy generation charge replaces that of PG&E's, but at a lower rate.

Energy **generation** is one component of your overall electric bill. PG&E continues to own and operate the infrastructure and charge for the **delivery** of the electricity. PG&E is responsible for all gas services and gas charges.

Please do not hesitate to contact us at **info@PeninsulaCleanEnergy.com** or **866-966-0110** or visit our web site at **PenCleanEnergy.com** if you have any questions.

Peninsula Clean Energy is committed to protecting customer privacy. Learn more at **PenCleanEnergy.com/privacy**.

b. PG&E does not currently anticipate a full bill redesign as part of the current scope of the BMI. While system functionality will be enhanced, bill redesign elements such as layout, font, size and formatting would be considered secondary features and have not been prioritized in the initial phases of implementation.

c. If directed by the Commission, it would be most efficient for PG&E to undertake a CCA bill redesign after initial go-live, during post-implementation phases of BMI (Stage 3 and beyond). By that point, core functionality will be stabilized, and PG&E will be better positioned to leverage new features, evaluate presentment capabilities, and integrate any redesign with operational regulatory, and rate implementation requirements. Attempting a full redesign during initial deployment may introduce risk to program timelines and increase complexity during system stabilization.

d. The current system already supports some level of customer-specific messaging via text inserted in the charge lines (e.g. within the CCA generation section of the bill), where messaging can vary depending on what CCAs submit for each customer. No specific functionality has been confirmed or prioritized at this stage to further segment messages based on customer class (e.g. residential, commercial).

e. BMI platform may technically offer greater flexibility in the future, however an increase in content length has not yet been defined or prioritized. Text volume and formatting changes are not currently part of the initial implementation scope, as PG&E has prioritized foundational system capabilities and compliance-related functions.

f. The current system allows CCAs to message all customers via the static message area or customer-specific charge line text, depending on the data provided by the CCA. BMI may enhance how this functionality is delivered and managed, but as of now, no specific change has been defined or implemented to expand the addressability of all customers beyond current methods. The ability to improve message reach and formatting may be evaluated in later stages, once implementation is complete and new tools are assessed.

g. At this stage, PG&E has not finalized or prioritized enhancements to allow CCAs to directly target specific customer groups for messaging purposes. Current messaging capability depends on the data provided by the CCA and supported by legacy systems.

ENERGY STATEMENT
www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 04/18/2025
Due Date: 05/09/2025

Service For:
REDACTED - Customer Info

Questions about your bill?
Mon-Fri 7 a.m.-7 p.m.
Saturday 8 a.m.-5 p.m.
Phone: 1-800-743-5000
www.pge.com/MyEnergy

Ways To Pay
www.pge.com/waystopay

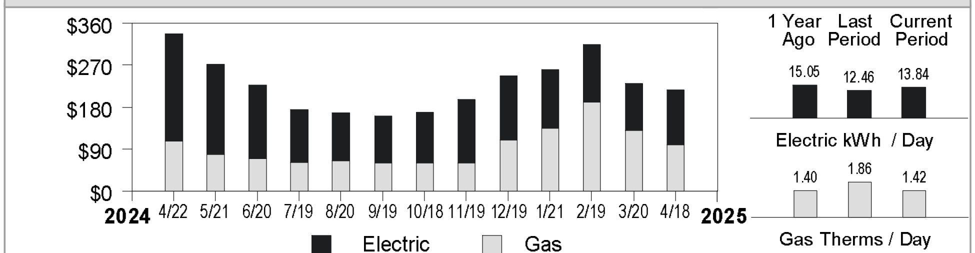
Your Enrolled Programs
CARE Discount

Your Account Summary

Amount Due on Previous Statement	$232.14
Payment(s) Received Since Last Statement	-232.14
Previous Unpaid Balance	$0.00
Current PG&E Electric Delivery Charges	$61.50
Electric Adjustments	-58.23
Peninsula Clean Energy Electric Generation Charges	57.76
Current Gas Charges	98.99
Gas Adjustments	-67.03
Total Amount Due by 05/09/2025	**$92.99**

Current charges include discounts of $222.74 for CARE and CA Climate Credit.

Monthly Billing History
Daily Usage Comparison



Visit **www.pge.com/MyEnergy** *for a detailed bill comparison*

Important Messages
California is fighting climate change and so can you! Your bill includes a Climate Credit from a state program to cut carbon pollution while also reducing your energy costs. Find out how at **cpuc.ca.gov/climatecredit**.

The gas summer Tier 1 (baseline) season begins on April 1. Your total Tier 1 quantities shown were calculated using your daily summer baseline allowance starting April 1 and your daily winter baseline allowance for any days in your billing period before April 1.

Continued on page 0

Please return this portion with your payment. No staples or paper clips. Do not fold. Thank you.

REDACTED - Customer Info

Account Number:	Due Date:	Total Amount Due:	Amount Enclosed:
REDACTED - Customer Info	**05/09/2025**	**$92.99**	$.

REDACTED - Customer Info

PG&E
BOX 997300
SACRAMENTO, CA 95899-7300

ENERGY STATEMENT
www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 04/18/2025
Due Date: 05/09/2025

Important Phone Numbers - Monday-Friday 7 a.m.-7 p.m., Saturday 8 a.m.-5 p.m.

Customer Service (All Languages; Relay Calls Accepted) 1-800-743-5000
TTY 7-1-1

Servicio al Cliente en Español (Spanish)	1-800-660-6789	Dịch vụ khách tiếng Việt (Vietnamese)	1-800-298-8438
華語客戶服務 (Chinese)	1-800-893-9555	Business Customer Service	1-800-468-4743

Rules and rates

You may be eligible for a lower rate. To learn more about optional rates or view a complete list of rules and rates, visit www.pge.com or call 1-800-743-5000.

If you believe there is an error on your bill, please call **1-800-743-5000** to speak with a representative. If you are not satisfied with our response, contact the California Public Utilities Commission (CPUC), Consumer Affairs Branch (CAB), 505 Van Ness Avenue, Room 2003, San Francisco, CA 94102, 1-800-649-7570 or 7-1-1 (8:30 AM to 4:30 PM, Monday through Friday) or by visiting www.cpuc.ca.gov/complaints/.

To avoid having service turned off while you wait for the outcome of a complaint to the CPUC specifically regarding the accuracy of your bill, please contact CAB for assistance. If your case meets the eligibility criteria, CAB will provide you with instructions on how to mail a check or money order to be impounded pending resolution of your case. You must continue to pay your current charges while your complaint is under review to keep your service turned on.

If you are not able to pay your bill, call PG&E to discuss how we can help. You may qualify for reduced rates under PG&E's CARE program or other special programs and agencies may be available to assist you. You may qualify for PG&E's Energy Savings Assistance Program which is an energy efficiency program for income-qualified residential customers.

Important definitions

Rotating outage blocks are subject to change without advance notice due to operational conditions.

Tier 1/Baseline allowance: Some residential rates are given a Tier 1/Baseline allowance - a CPUC approved percentage of average customer usage during summer and winter months. Your Tier 1/Baseline allowance provides for basic needs at an affordable price and encourages conservation. Your allowance is assigned based on the climate where you live, the season and your heat source. As you use more energy, you pay more for usage. Any usage over your baseline allowance will be charged at a higher price.

Wildfire Fund Charge: Charge on behalf of the State of California Department of Water Resources (DWR) to fund the California Wildfire Fund. For usage prior to October 1, 2020, this charge included costs related to the 2001 California energy crisis, also collected on behalf of the DWR. These charges belong to DWR, not PG&E.

Power Charge Indifference Adjustment (PCIA): The PCIA is a charge to ensure that both PG&E customers and those who have left PG&E service to purchase electricity from other providers pay for the above market costs for electric generation resources that were procured by PG&E on their behalf. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. Visit www.pge.com/cca.

Wildfire Hardening Charge: PG&E has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. Your bill for electric service includes a fixed recovery charge called the Wildfire Hardening Charge that has been approved by the CPUC to repay those bonds. The right to recover the Wildfire Hardening Charge has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and does not belong to PG&E. PG&E is collecting the Wildfire Hardening Charge on behalf of the Special Purpose Entity. For details visit: www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_JF.pdf.

Recovery Bond Charge/Credit: Your bill for electric service includes a charge that has been approved by the CPUC to repay bonds issued for certain costs related to catastrophic wildfires. The Recovery Bond Charge (RBC) rate is currently $0.00647 per kWh. PG&E has also contributed certain amounts to a trust fund which is used to provide a customer credit equal to $0.00647 per kWh (Recovery Bond Credit). The right to recover the RBC has been transferred to one or more Special Purpose Entities that issued the bonds and does not belong to PG&E. PG&E is collecting that portion of the RBC on behalf of the Special Purpose Entities.

Gas Public Purpose Program (PPP) Surcharge. Used to fund state-mandated gas assistance programs for low-income customers, energy efficiency programs, and public-interest research and development.

Visit www.pge.com/billexplanation for more definitions. To view most recent bill inserts including legal or mandated notices, visit www.pge.com/billinserts.

See the table reflecting "Your Electric Charges Breakdown" on the last page

Please do not mark in box. For system use only.

Update My Information (English Only)

Please allow 1-2 billing cycles for changes to take effect

Account Number: REDACTED - Customer Info

Change my mailing address to: ______________________

City ____________ State ______ ZIP code ______

Primary Phone # ____________ Primary Email ____________

Ways To Pay

- **Online via web or mobile at www.pge.com/waystopay**
- **By mail:** Send your payment along with this payment stub in the envelope provided.
- **By debit card, Visa, MasterCard, American Express, or Discover:** Call 877-704-8470 at any time. (Our independent service provider charges a fee per transaction.)
- **At a neighborhood payment center**: To find a neighborhood payment center near you, please visit www.pge.com or call 800-743-5000. Please bring a copy of your bill with you.

Details of PG&E Electric Delivery Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: E1 TB Residential Service
Enrolled Programs: CARE (Renew by 04/04/2025)

03/14/2025 – 04/13/2025	Your Tier Usage	1	**2**

Tier 1 Allowance	232.50	kWh	(31 days x 7.5 kWh/day)		
Tier 1 Usage	232.500000	kWh	@	$0.40730	$94.70
Tier 2 Usage	196.440000	kWh	@	$0.51031	100.25
CARE Discount					-74.79
Generation Credit					-66.78
Power Charge Indifference Adjustment					4.76
Franchise Fee Surcharge					0.45
Daly City Utility Users' Tax (5.000%)					2.91

Total PG&E Electric Delivery Charges **$61.50**

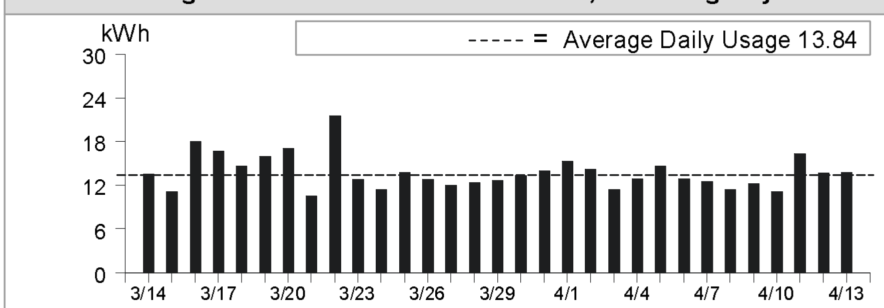
2016 Vintaged Power Charge Indifference Adjustment

Adjustments

California Climate Credit -$58.23

Total Adjustments **-$58.23**

Electric Usage This Period: 428.940000 kWh, 31 billing days



Service Information

Meter #	REDACTED - Customer Info
Total Usage	428.940000 kWh
Baseline Territory	T
Heat Source	B - Not Electric
Serial	T
Rotating Outage Block	9P

Your CARE usage is charged at these rates ($/kWh). Differences may occur due to rounding.

03/14/2025 - 04/13/2025	
Tier 1	0.24947
Tier 2	0.31643
Tier 2 Usage continued	0.31643

Additional Messages

You received a **California Climate Credit** on your electric bill. Learn how you can use these savings to further reduce your energy costs and help fight climate change at **cpuc.ca.gov/climatecredit.**

Details of Peninsula Clean Energy Electric Generation Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: [redacted]
Service Agreement ID: [redacted] SP Customer Number: [redacted]

03/14/2025 – 04/13/2025

Rate Schedule: **E-1**

Generation - Total	428.940000	kWh	@	$0.12797	$54.89
		Net Charges		54.89	
Local Utility Users Tax					2.74
Energy Commission Surcharge					0.13

Peninsula Clean Energy is your community's official electricity provider.
You are receiving clean electricity at low rates!

Total Peninsula Clean Energy Electric Generation Charges **$57.76**

Service Information

Total Usage 428.940000 kWh

For questions regarding charges on this page, please contact:
PENINSULA CLEAN ENERGY
2075 WOODSIDE RD
REDWOOD CITY CA 94061
1-866-966-0110
PenCleanEnergy.com
info@PeninsulaCleanEnergy.com

Additional Messages

Your city has chosen to receive electricity sourced by Peninsula Clean Energy. Peninsula Clean Energy is a not-for-profit, public agency that sources energy that is least 50% renewable and 100% clean. Its energy generation charge replaces that of PG&E's, but at a lower rate.

Energy **generation** is one component of your overall electric bill. PG&E continues to own and operate the infrastructure and charge for the **delivery** of the electricity. PG&E is responsible for all gas services and gas charges.

Please do not hesitate to contact us at **info@PeninsulaCleanEnergy.com** or **866-966-0110** or visit our web site at **PenCleanEnergy.com** if you have any questions.

Peninsula Clean Energy is committed to protecting customer privacy. Learn more at **PenCleanEnergy.com/privacy**.

Details of Gas Charges

03/15/2025 - 04/14/2025 (31 billing days)

Service For: [redacted]
Service Agreement ID: [redacted]
Rate Schedule: G1 TB Residential Service
Enrolled Programs: CARE (Renew by 04/04/2025)

03/15/2025 – 03/31/2025 Your Tier Usage 1 **2**

Tier 1 Allowance	22.27 Therms	(17 days x 1.31 Therms/day)	
Tier 1 Usage	22.270000 Therms @ $2.46291		$54.85
Tier 2 Usage	1.859032 Therms @ $2.97989		5.54
CARE Discount			-12.06
CSI Solar Thermal Exemption			-0.09
Gas PPP Surcharge ($0.08425 /Therm)			2.03
Daly City Utility Users' Tax (5.000%)			2.41

04/01/2025 – 04/14/2025 Your Tier Usage 1 **2**

Tier 1 Allowance	7.84 Therms	(14 days x 0.56 Therms/day)	
Tier 1 Usage	7.840000 Therms @ $2.36480		$18.54
Tier 2 Usage	12.030968 Therms @ $2.88178		34.67
CARE Discount			-10.63
CSI Solar Thermal Exemption			-0.08
Gas PPP Surcharge ($0.08425 /Therm)			1.68
Daly City Utility Users' Tax (5.000%)			2.13

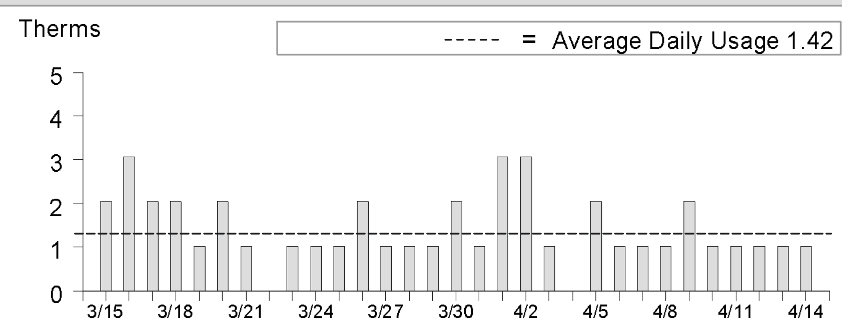
Total Gas Charges $98.99

Adjustments

California Climate Credit -$67.03

Total Adjustments -$67.03

Gas Usage This Period: 44.000000 Therms, 31 billing days



Service Information

Meter #	[redacted]
Current Meter Reading	1,954
Prior Meter Reading	1,911
Difference	43
Multiplier	1.025132
Total Usage	44.000000 Therms
Baseline Territory	T
Serial	T

Your CARE usage is charged at these rates ($/Therm). Differences may occur due to rounding.

03/15/2025 - 03/31/2025	
Tier 1	1.96729
Tier 2	2.38087
04/01/2025 - 04/14/2025	
Tier 1	1.88880
Tier 2	2.30238

Gas Procurement Costs ($/Therm)

03/15/2025 - 03/31/2025	$0.34292
04/01/2025 - 04/14/2025	$0.24481

Additional Messages

You received a **California Climate Credit** on your natural gas bill. Households receive the natural gas credit once a year. Learn how you can use these savings to further reduce your energy costs and help fight climate change at **cpuc.ca.gov/climatecredit.**

Important Messages (continued from page 1)

Low-Income Home Energy Assistance Program (LIHEAP) is a federally funded assistance program that provides a one-time payment to help income-qualified customers pay their past due energy bills. PG&E does not administer this program. To find the local LIHEAP agency in your area, visit **www.csd.ca.gov/energybills**, or call the help line at **1-866-675-6623**.

Energy Savings Assistance Program: provides free home improvements to help keep your home more energy efficient, safe and comfortable. Apply by answering a few simple questions at **www.pge.com/energysavings** or call **1-800-989-9744**.

Programa Energy Savings Assistance: proporciona mejoras al hogar sin costo para ayudar a que este sea más eficiente en el consumo de energía, más seguro y más cómodo. Solicite respondiendo a unas pocas preguntas simples en **www.pge.com/ahorreenergia** o llamando al **1-800-989-9744**.

Electric power line safety PG&E cares about your safety. Be aware of your surroundings and keep yourself, tools, equipment and antennas at least 10 feet away from overhead power lines. If you see an electric power line fall to the ground, keep yourself and others away. Call **9-1-1**.

Call 811 before you dig. A common cause of pipeline accidents is damage from digging. If you plan on doing any digging, such as planting a tree or installing a fence, please call **811** at least two working days before you dig. One free call will notify underground utilities to mark the location of underground lines, helping you to plan a safe project.

Your Electric Charges Breakdown (from page 2)	
Conservation Incentive	$8.43
Transmission	16.91
Distribution	22.60
Electric Public Purpose Programs	5.85
Nuclear Decommissioning	-0.10
Competition Transition Charges (CTC)	-0.31
PCIA	4.76
Taxes and Other	3.36
Total Electric Charges	**$61.50**

*Visit **www.pge.com/MyEnergy** for a detailed bill comparison.*

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q016
PG&E File Name:	BillingModernization_DR_PCE_002-Q016
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 2, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 016

Referring to PG&E's response to PCE_001_Q010:

a. Please explain if the upgrades associated with PG&E's BMI will allow for CCAs to include clickable URLs on customer bills. If not, why not? If unknown, please explain why PG&E is not prioritizing this change in its upgrade.

b. Please explain if the upgrades associated with PG&E's BMI will allow CCAs the ability to use logo and color branding on customer bills. If not, why not? If unknown, please explain why PG&E is not prioritizing this change in its upgrade.

c. Please explain if the upgrades associated with PG&E's BMI will allow the bill detail received by solar customers with batteries to be included in the blue and white bill. If not, why not? If unknown, please explain why PG&E is not prioritizing this change in its upgrade.

ANSWER 016

a. PG&E's bill output is generated in IBM AFP (Advanced Function Presentation) format, which does not support clickable links. This format is then converted to PDF by one of PG&E's external vendors, which also does not have the capability to render clickable links in the final bill output. As a result, the inclusion of clickable URLs is not currently supported.

b. CCA specific logo or color branding is not currently part of the initial scope. PG&E produces a standardized bill with PG&E as the billing agent for all customers, including those served by CCAs. Branding changes, including the addition of third-party logos or colors, would require significant design, compliance, and print processing changes. Most bill formatting capabilities reside downstream of the billing system, and changes to support branding would require updates to external rendering systems and design templates. These enhancements are not prioritized in the current phase of BMI.

c. Detailed billing information for solar customers with battery systems is provided in supplemental formats due to current system constraints. As PG&E progresses through the BMI, it anticipates consolidating bill formats, which may enable the inclusion of this detail within the standard bill layout. This functionality has not yet been finalized or prioritized for early implementation. Full evaluation of formatting changes and expended content integration will occur in future stages of the initiative.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q017
PG&E File Name:	BillingModernization_DR_PCE_002-Q017
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 2, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 017

Referring to PG&E's response to PCE_001_Q010: Please explain how dynamic rates will be presented in customer bills after the completion of PG&E's BMI. Please explain any differences between bundled and unbundled bills for this item.

ANSWER 017

PG&E is still in the early stages of implementing the initiative. Final bill presentment features, including the display of dynamic rate components, have not yet been designed or finalized, and the most billing presentation changes are not expected to occur until Stage 3, the target state of the initiative, which remains several years away. PGE&E is not able to confirm the final format or level of detail that will be presented on customer bills related to dynamic rates. These decisions will be determined later in the program, based on system capabilities, customer needs, and regulatory guidance.

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q018
PG&E File Name:	BillingModernization_DR_PCE_002-Q018
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 3, 2025
PG&E Witness(es):	Matt Hedges – Information Technology

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 018

Referring to PG&E's response to PCE_001_Q011:

a. Please provide a sample of a current PG&E bill for (i) a CARE bundled electric service residential customer, redacting any Protected Personal Information if needed, and (ii) a CARE unbundled electric service residential customer, redacting any Protected Personal Information if needed.

b. Please provide a sample of a current PG&E bill for (i) a FERA bundled electric service residential customer, redacting any Protected Personal Information if needed, and (ii) a FERA unbundled electric service residential customer, redacting any Protected Personal Information if needed.

c. To the extent there are differences in the presentation of the CARE and/or FERA discounts on bundled versus unbundled bills, please explain why.

ANSWER 018

a. CARE Bundled: *BillingModernization_DR_PCE_002-Q018Atch01.pdf*

CARE Unbundled: *BillingModernization_DR_PCE_002-Q018Atch02.pdf*

b. FERA Bundled: *BillingModernization_DR_PCE_002-Q018Atch03.pdf*

FERA Unbundled: *BillingModernization_DR_PCE_002-Q018Atch04.pdf*

c. Overall CARE and FERA discount is shown on PG&E page of the bill, so there are no differences in presentation.

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/18/2025
Due Date: 06/09/2025

Service For:

REDACTED - Customer Info

Questions about your bill?

Mon-Fri 7 a.m.-7 p.m.
Saturday 8 a.m.-5 p.m.
Phone: 1-800-743-5000
www.pge.com/MyEnergy

Ways To Pay

www.pge.com/waystopay

Your Enrolled Programs

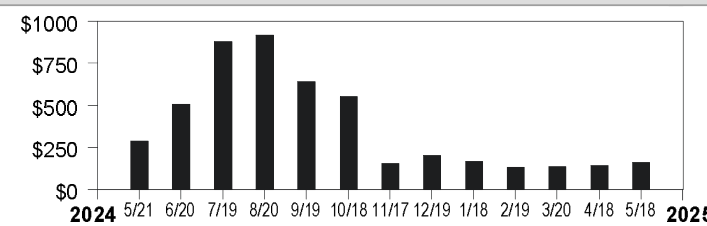
CARE Discount

Your Account Summary

Amount Due on Previous Statement	$16.06
Payment(s) Received Since Last Statement	-16.06
Previous Unpaid Balance	$0.00
Current Electric Charges	$161.13
Current Gas Charges	0.00
Total Amount Due by 06/09/2025	**$161.13**

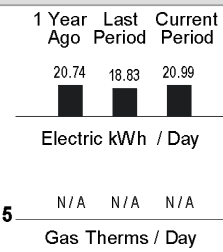
Current charges include a discount of $100.96 for CARE.

Monthly Billing History



Visit ***www.pge.com/MyEnergy*** *for a detailed bill comparison*

Daily Usage Comparison



Important Messages

Low-Income Home Energy Assistance Program (LIHEAP) is a federally funded assistance program that provides a one-time payment to help income-qualified customers pay their past due energy bills. PG&E does not administer this program. To find the local LIHEAP agency in your area, visit **www.csd.ca.gov/energybills**, or call the help line at **1-866-675-6623**.

Your account has been enrolled in **Arrearage Management Plan** for **6** months. Thank you for participating and payment.

Continued on last page

Please return this portion with your payment. No staples or paper clips. Do not fold. Thank you.

REDACTED - Customer Info

Account Number:	Due Date:	Total Amount Due:	Amount Enclosed:
REDACTED - Customer Info	**06/09/2025**	**$161.13**	$

REDACTED - Customer Info

PG&E
BOX 997300
SACRAMENTO, CA 95899-7300

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/18/2025
Due Date: 06/09/2025

Important Phone Numbers - Monday-Friday 7 a.m.-7 p.m., Saturday 8 a.m.-5 p.m.

Customer Service (All Languages; Relay Calls Accepted) 1-800-743-5000
TTY 7-1-1

Servicio al Cliente en Español (Spanish)	1-800-660-6789	Dịch vụ khách tiếng Việt (Vietnamese)	1-800-298-8438
華語客戶服務 (Chinese)	1-800-893-9555	Business Customer Service	1-800-468-4743

Rules and rates

You may be eligible for a lower rate. To learn more about optional rates or view a complete list of rules and rates, visit www.pge.com or call 1-800-743-5000.

If you believe there is an error on your bill, please call **1-800-743-5000** to speak with a representative. If you are not satisfied with our response, contact the California Public Utilities Commission (CPUC), Consumer Affairs Branch (CAB), 505 Van Ness Avenue, Room 2003, San Francisco, CA 94102, 1-800-649-7570 or 7-1-1 (8:30 AM to 4:30 PM, Monday through Friday) or by visiting www.cpuc.ca.gov/complaints/.

To avoid having service turned off while you wait for the outcome of a complaint to the CPUC specifically regarding the accuracy of your bill, please contact CAB for assistance. If your case meets the eligibility criteria, CAB will provide you with instructions on how to mail a check or money order to be impounded pending resolution of your case. You must continue to pay your current charges while your complaint is under review to keep your service turned on.

If you are not able to pay your bill, call PG&E to discuss how we can help. You may qualify for reduced rates under PG&E's CARE program or other special programs and agencies may be available to assist you. You may qualify for PG&E's Energy Savings Assistance Program which is an energy efficiency program for income-qualified residential customers.

Important definitions

Rotating outage blocks are subject to change without advance notice due to operational conditions.

Tier 1/Baseline allowance: Some residential rates are given a Tier 1/Baseline allowance - a CPUC approved percentage of average customer usage during summer and winter months. Your Tier 1/Baseline allowance provides for basic needs at an affordable price and encourages conservation. Your allowance is assigned based on the climate where you live, the season and your heat source. As you use more energy, you pay more for usage. Any usage over your baseline allowance will be charged at a higher price.

Wildfire Fund Charge: Charge on behalf of the State of California Department of Water Resources (DWR) to fund the California Wildfire Fund. For usage prior to October 1, 2020, this charge included costs related to the 2001 California energy crisis, also collected on behalf of the DWR. These charges belong to DWR, not PG&E.

Power Charge Indifference Adjustment (PCIA): The PCIA is a charge to ensure that both PG&E customers and those who have left PG&E service to purchase electricity from other providers pay for the above market costs for electric generation resources that were procured by PG&E on their behalf. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. Visit www.pge.com/cca.

Wildfire Hardening Charge: PG&E has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. Your bill for electric service includes a fixed recovery charge called the Wildfire Hardening Charge that has been approved by the CPUC to repay those bonds. The right to recover the Wildfire Hardening Charge has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and does not belong to PG&E. PG&E is collecting the Wildfire Hardening Charge on behalf of the Special Purpose Entity. For details visit: www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_JF.pdf.

Recovery Bond Charge/Credit: Your bill for electric service includes a charge that has been approved by the CPUC to repay bonds issued for certain costs related to catastrophic wildfires. The Recovery Bond Charge (RBC) rate is currently $0.00647 per kWh. PG&E has also contributed certain amounts to a trust fund which is used to provide a customer credit equal to $0.00647 per kWh (Recovery Bond Credit). The right to recover the RBC has been transferred to one or more Special Purpose Entities that issued the bonds and does not belong to PG&E. PG&E is collecting that portion of the RBC on behalf of the Special Purpose Entities.

Gas Public Purpose Program (PPP) Surcharge. Used to fund state-mandated gas assistance programs for low-income customers, energy efficiency programs, and public-interest research and development.

Visit www.pge.com/billexplanation for more definitions. To view most recent bill inserts including legal or mandated notices, visit www.pge.com/billinserts.

See the table reflecting "Your Electric Charges Breakdown" on the last page

Please do not mark in box. For system use only.

Update My Information (English Only)

Please allow 1-2 billing cycles for changes to take effect

Account Number: REDACTED - Customer Info

Change my mailing address to: ______________________

City ______________ State ______ ZIP code ______

Primary Phone # ______________ Primary Email ______________

Ways To Pay

- **Online via web or mobile at www.pge.com/waystopay**
- **By mail:** Send your payment along with this payment stub in the envelope provided.
- **By debit card, Visa, MasterCard, American Express, or Discover:** Call 877-704-8470 at any time. (Our independent service provider charges a fee per transaction.)
- **At a neighborhood payment center**: To find a neighborhood payment center near you, please visit www.pge.com or call 800-743-5000. Please bring a copy of your bill with you.

ENERGY STATEMENT
www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/18/2025
Due Date: 06/09/2025

Details of Electric Charges

04/17/2025 - 05/15/2025 (29 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: Time-of-Use (Peak Pricing 4 - 9 p.m. Every Day)
Enrolled Programs: CARE (Renew by 02/16/2029)

04/17/2025 – 05/15/2025

Baseline Allowance	301.60	kWh	(29 days x 10.4 kWh/day)		
Energy Charges					
Peak	213.030800	kWh	@	$0.50086	$106.70
Off Peak	395.622400	kWh	@	$0.47086	186.28
Baseline Credit	301.600000	kWh	@	-$0.10301	-31.07
CARE Discount					-100.96
Energy Commission Tax					0.18
Total Electric Charges					**$161.13**

Rate Identification Number

USCA-PGPG-0100-0000
www.pge.com/rin
To program your smart device, scan the QR code or enter the RIN code above and follow the on-screen instructions.

Service Information

Meter #	REDACTED - Customer Info
Total Usage	608.653200 kWh
Baseline Territory	R
Heat Source	B - Not Electric
Serial	X
Rotating Outage Block	50

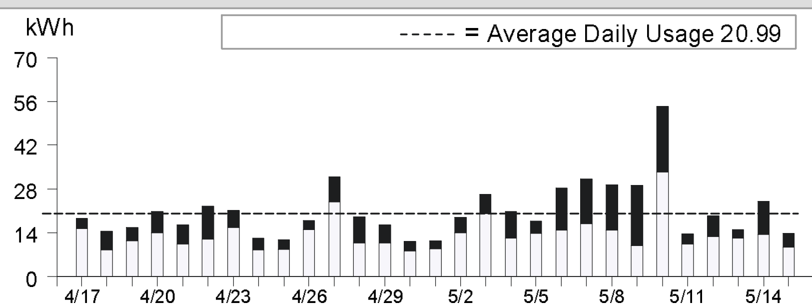
Your CARE usage is charged at these rates ($/kWh). Differences may occur due to rounding.

04/17/2025 - 05/15/2025	
Peak	0.31029
Off Peak	0.29079
Baseline Credit	-0.06695

Additional Messages

As a customer who receives electricity directly from PG&E, a portion of your electric charges currently includes the Power Charge Indifference Adjustment (PCIA). To learn more, review page 2 of this Energy Statement or visit **www.pge.com/cca**.

Electric Usage This Period: 608.653200 kWh, 29 billing days



	Usage	Energy Charges
Peak[1]	35.00%	$106.70
Off Peak[2]	65.00%	$186.28

[1]**Peak:** 4:00pm-9:00pm, Every Day;
[2]**Off Peak:** All Other Hours

Visit ***www.pge.com/MyEnergy*** *for a detailed bill comparison.*

Details of Gas Charges

04/18/2025 - 05/16/2025 (29 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: G1 RB Residential Service
Enrolled Programs: CARE (Renew by 02/16/2029)

04/18/2025 – 04/30/2025	**Your Tier Usage**	**1**	2

Tier 1 Allowance	4.68 Therms	(13 days x 0.36 Therms/day)	
Tier 1 Usage	0.000000 Therms @ $2.36480		$0.00

05/01/2025 – 05/16/2025	**Your Tier Usage**	**1**	2

Tier 1 Allowance	5.76 Therms	(16 days x 0.36 Therms/day)	
Tier 1 Usage	0.000000 Therms @ $2.40729		$0.00

Total Gas Charges **$0.00**

Service Information

Meter #	REDACTED - Customer Info
Current Meter Reading	4,531
Prior Meter Reading	4,531
Total Usage	0.000000 Therms
Baseline Territory	R
Serial	X

Your CARE usage is charged at these rates ($/Therm). Differences may occur due to rounding.

04/18/2025 - 04/30/2025

Tier 1	1.88880
Tier 2	2.30238

05/01/2025 - 05/16/2025

Tier 1	1.92279
Tier 2	2.33638

Important Messages (continued from page 1)

TOU Rate: You are currently on a time-of-use (TOU) rate schedule. Beginning June 1, the TOU rate charges higher prices in the summer for electric usage on summer evenings.

Your Electric Charges Breakdown (from page 2)	
Conservation Incentive	-$37.70
Generation	89.25
Transmission	23.99
Distribution	77.69
Electric Public Purpose Programs	8.29
Nuclear Decommissioning	-0.14
Competition Transition Charges (CTC)	-0.43
Taxes and Other	0.18
Total Electric Charges	**$161.13**

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: [redacted]
Statement Date: 04/18/2025
Due Date: 05/09/2025

Service For:

[redacted]

Questions about your bill?

Mon-Fri 7 a.m.-7 p.m.
Saturday 8 a.m.-5 p.m.
Phone: 1-800-743-5000
www.pge.com/MyEnergy

Ways To Pay

www.pge.com/waystopay

Your Enrolled Programs

CARE Discount

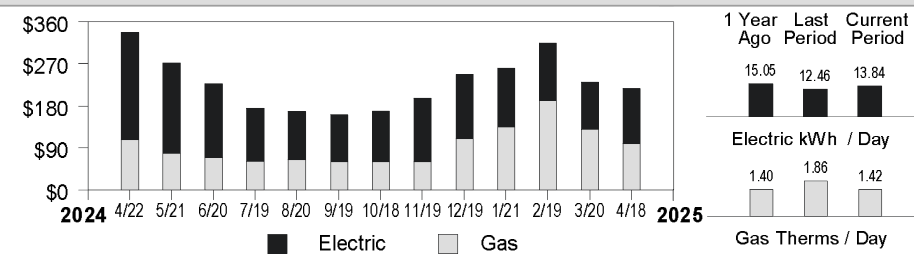
Your Account Summary

Amount Due on Previous Statement	$232.14
Payment(s) Received Since Last Statement	-232.14
Previous Unpaid Balance	$0.00
Current PG&E Electric Delivery Charges	$61.50
Electric Adjustments	-58.23
Peninsula Clean Energy Electric Generation Charges	57.76
Current Gas Charges	98.99
Gas Adjustments	-67.03
Total Amount Due by 05/09/2025	**$92.99**

Current charges include discounts of $222.74 for CARE and CA Climate Credit.

Monthly Billing History

Daily Usage Comparison



Visit ***www.pge.com/MyEnergy*** *for a detailed bill comparison*

Important Messages

California is fighting climate change and so can you! Your bill includes a Climate Credit from a state program to cut carbon pollution while also reducing your energy costs. Find out how at **cpuc.ca.gov/climatecredit**.

The gas summer Tier 1 (baseline) season begins on April 1. Your total Tier 1 quantities shown were calculated using your daily summer baseline allowance starting April 1 and your daily winter baseline allowance for any days in your billing period before April 1.

Continued on page 0

Please return this portion with your payment. No staples or paper clips. Do not fold. Thank you.

[redacted]

Account Number:	Due Date:	Total Amount Due:	Amount Enclosed:
[redacted]	**05/09/2025**	**$92.99**	$.

[redacted]

PG&E
BOX 997300
SACRAMENTO, CA 95899-7300

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 04/18/2025
Due Date: 05/09/2025

Important Phone Numbers - Monday-Friday 7 a.m.-7 p.m., Saturday 8 a.m.-5 p.m.

Customer Service (All Languages; Relay Calls Accepted) 1-800-743-5000
TTY 7-1-1

Servicio al Cliente en Español (Spanish)	1-800-660-6789	Dịch vụ khách tiếng Việt (Vietnamese)	1-800-298-8438
華語客戶服務 (Chinese)	1-800-893-9555	Business Customer Service	1-800-468-4743

Rules and rates

You may be eligible for a lower rate. To learn more about optional rates or view a complete list of rules and rates, visit www.pge.com or call 1-800-743-5000.

If you believe there is an error on your bill, please call **1-800-743-5000** to speak with a representative. If you are not satisfied with our response, contact the California Public Utilities Commission (CPUC), Consumer Affairs Branch (CAB), 505 Van Ness Avenue, Room 2003, San Francisco, CA 94102, 1-800-649-7570 or 7-1-1 (8:30 AM to 4:30 PM, Monday through Friday) or by visiting www.cpuc.ca.gov/complaints/.

To avoid having service turned off while you wait for the outcome of a complaint to the CPUC specifically regarding the accuracy of your bill, please contact CAB for assistance. If your case meets the eligibility criteria, CAB will provide you with instructions on how to mail a check or money order to be impounded pending resolution of your case. You must continue to pay your current charges while your complaint is under review to keep your service turned on.

If you are not able to pay your bill, call PG&E to discuss how we can help. You may qualify for reduced rates under PG&E's CARE program or other special programs and agencies may be available to assist you. You may qualify for PG&E's Energy Savings Assistance Program which is an energy efficiency program for income-qualified residential customers.

Important definitions

Rotating outage blocks are subject to change without advance notice due to operational conditions.

Tier 1/Baseline allowance: Some residential rates are given a Tier 1/Baseline allowance - a CPUC approved percentage of average customer usage during summer and winter months. Your Tier 1/Baseline allowance provides for basic needs at an affordable price and encourages conservation. Your allowance is assigned based on the climate where you live, the season and your heat source. As you use more energy, you pay more for usage. Any usage over your baseline allowance will be charged at a higher price.

Wildfire Fund Charge: Charge on behalf of the State of California Department of Water Resources (DWR) to fund the California Wildfire Fund. For usage prior to October 1, 2020, this charge included costs related to the 2001 California energy crisis, also collected on behalf of the DWR. These charges belong to DWR, not PG&E.

Power Charge Indifference Adjustment (PCIA): The PCIA is a charge to ensure that both PG&E customers and those who have left PG&E service to purchase electricity from other providers pay for the above market costs for electric generation resources that were procured by PG&E on their behalf. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. Visit www.pge.com/cca.

Wildfire Hardening Charge: PG&E has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. Your bill for electric service includes a fixed recovery charge called the Wildfire Hardening Charge that has been approved by the CPUC to repay those bonds. The right to recover the Wildfire Hardening Charge has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and does not belong to PG&E. PG&E is collecting the Wildfire Hardening Charge on behalf of the Special Purpose Entity. For details visit: www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_JF.pdf.

Recovery Bond Charge/Credit: Your bill for electric service includes a charge that has been approved by the CPUC to repay bonds issued for certain costs related to catastrophic wildfires. The Recovery Bond Charge (RBC) rate is currently $0.00647 per kWh. PG&E has also contributed certain amounts to a trust fund which is used to provide a customer credit equal to $0.00647 per kWh (Recovery Bond Credit). The right to recover the RBC has been transferred to one or more Special Purpose Entities that issued the bonds and does not belong to PG&E. PG&E is collecting that portion of the RBC on behalf of the Special Purpose Entities.

Gas Public Purpose Program (PPP) Surcharge. Used to fund state-mandated gas assistance programs for low-income customers, energy efficiency programs, and public-interest research and development.

Visit www.pge.com/billexplanation for more definitions. To view most recent bill inserts including legal or mandated notices, visit www.pge.com/billinserts.

See the table reflecting "Your Electric Charges Breakdown" on the last page

Please do not mark in box. For system use only.

Update My Information (English Only)

Please allow 1-2 billing cycles for changes to take effect

Account Number: REDACTED - Customer Info

Change my mailing address to: ______________________

City ______________ State ______ ZIP code ______

Primary Phone # ______________ Primary Email ______________

Ways To Pay

- **Online via web or mobile at www.pge.com/waystopay**
- **By mail:** Send your payment along with this payment stub in the envelope provided.
- **By debit card, Visa, MasterCard, American Express, or Discover:** Call 877-704-8470 at any time. (Our independent service provider charges a fee per transaction.)
- **At a neighborhood payment center**: To find a neighborhood payment center near you, please visit www.pge.com or call 800-743-5000. Please bring a copy of your bill with you.

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 04/18/2025
Due Date: 05/09/2025

Details of PG&E Electric Delivery Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: E1 TB Residential Service
Enrolled Programs: CARE (Renew by 04/04/2025)

03/14/2025 – 04/13/2025	**Your Tier Usage**	1	**2** ▼

Tier 1 Allowance	232.50	kWh	(31 days x 7.5 kWh/day)		
Tier 1 Usage	232.500000	kWh	@	$0.40730	$94.70
Tier 2 Usage	196.440000	kWh	@	$0.51031	100.25
CARE Discount					-74.79
Generation Credit					-66.78
Power Charge Indifference Adjustment					4.76
Franchise Fee Surcharge					0.45
Daly City Utility Users' Tax (5.000%)					2.91

Total PG&E Electric Delivery Charges **$61.50**

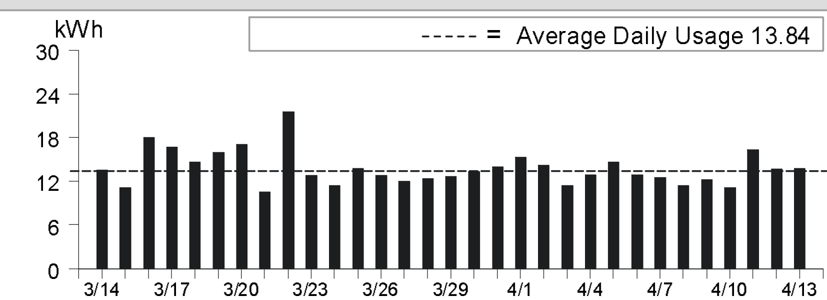
2016 Vintaged Power Charge Indifference Adjustment

Adjustments

California Climate Credit -$58.23

Total Adjustments **-$58.23**

Electric Usage This Period: 428.940000 kWh, 31 billing days



Service Information

Meter #	REDACTED - Customer Info
Total Usage	428.940000 kWh
Baseline Territory	T
Heat Source	B - Not Electric
Serial	T
Rotating Outage Block	9P

Your CARE usage is charged at these rates ($/kWh). Differences may occur due to rounding.

03/14/2025 - 04/13/2025	
Tier 1	0.24947
Tier 2	0.31643
Tier 2 Usage continued	0.31643

Additional Messages

You received a **California Climate Credit** on your electric bill. Learn how you can use these savings to further reduce your energy costs and help fight climate change at **cpuc.ca.gov/climatecredit.**

Visit **www.pge.com/MyEnergy** *for a detailed bill comparison.*

Details of Peninsula Clean Energy Electric Generation Charges

03/14/2025 - 04/13/2025 (31 billing days)

Service For: [redacted]
Service Agreement ID: [redacted] SP Customer Number: [redacted]

03/14/2025 – 04/13/2025

Rate Schedule: **E-1**

Generation - Total	428.940000	kWh	@	$0.12797	$54.89
		Net Charges		54.89	
Local Utility Users Tax					2.74
Energy Commission Surcharge					0.13

Peninsula Clean Energy is your community's official electricity provider. You are receiving clean electricity at low rates!

Total Peninsula Clean Energy Electric Generation Charges **$57.76**

Service Information

Total Usage 428.940000 kWh

For questions regarding charges on this page, please contact:

PENINSULA CLEAN ENERGY
2075 WOODSIDE RD
REDWOOD CITY CA 94061
1-866-966-0110
PenCleanEnergy.com
info@PeninsulaCleanEnergy.com

Additional Messages

Your city has chosen to receive electricity sourced by Peninsula Clean Energy. Peninsula Clean Energy is a not-for-profit, public agency that sources energy that is least 50% renewable and 100% clean. Its energy generation charge replaces that of PG&E's, but at a lower rate.

Energy **generation** is one component of your overall electric bill. PG&E continues to own and operate the infrastructure and charge for the **delivery** of the electricity. PG&E is responsible for all gas services and gas charges.

Please do not hesitate to contact us at **info@PeninsulaCleanEnergy.com** or **866-966-0110** or visit our web site at **PenCleanEnergy.com** if you have any questions.

Peninsula Clean Energy is committed to protecting customer privacy. Learn more at **PenCleanEnergy.com/privacy**.

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 04/18/2025
Due Date: 05/09/2025

Details of Gas Charges

03/15/2025 - 04/14/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: G1 TB Residential Service
Enrolled Programs: CARE (Renew by 04/04/2025)

03/15/2025 – 03/31/2025 Your Tier Usage 1 **2**

Tier 1 Allowance	22.27 Therms (17 days x 1.31 Therms/day)	
Tier 1 Usage	22.270000 Therms @ $2.46291	$54.85
Tier 2 Usage	1.859032 Therms @ $2.97989	5.54
CARE Discount		-12.06
CSI Solar Thermal Exemption		-0.09
Gas PPP Surcharge ($0.08425 /Therm)		2.03
Daly City Utility Users' Tax (5.000%)		2.41

04/01/2025 – 04/14/2025 Your Tier Usage 1 **2**

Tier 1 Allowance	7.84 Therms (14 days x 0.56 Therms/day)	
Tier 1 Usage	7.840000 Therms @ $2.36480	$18.54
Tier 2 Usage	12.030968 Therms @ $2.88178	34.67
CARE Discount		-10.63
CSI Solar Thermal Exemption		-0.08
Gas PPP Surcharge ($0.08425 /Therm)		1.68
Daly City Utility Users' Tax (5.000%)		2.13

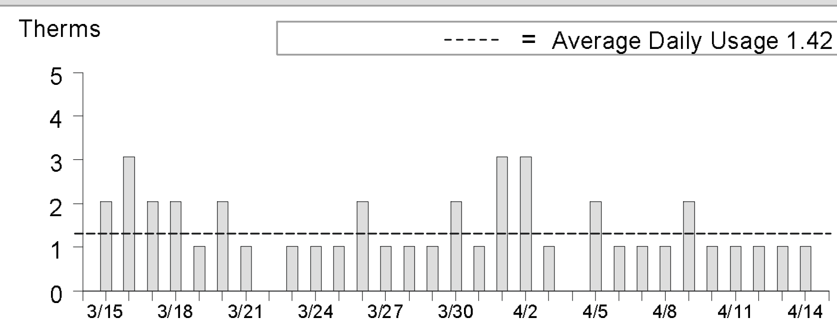
Total Gas Charges $98.99

Adjustments

California Climate Credit -$67.03

Total Adjustments -$67.03

Gas Usage This Period: 44.000000 Therms, 31 billing days



Service Information

Meter #	REDACTED - Customer Info
Current Meter Reading	1,954
Prior Meter Reading	1,911
Difference	43
Multiplier	1.025132
Total Usage	44.000000 Therms
Baseline Territory	T
Serial	T

Your CARE usage is charged at these rates ($/Therm). Differences may occur due to rounding.

03/15/2025 - 03/31/2025
Tier 1 1.96729
Tier 2 2.38087
04/01/2025 - 04/14/2025
Tier 1 1.88880
Tier 2 2.30238

Gas Procurement Costs ($/Therm)

03/15/2025 - 03/31/2025 $0.34292
04/01/2025 - 04/14/2025 $0.24481

Additional Messages

You received a **California Climate Credit** on your natural gas bill. Households receive the natural gas credit once a year. Learn how you can use these savings to further reduce your energy costs and help fight climate change at **cpuc.ca.gov/climatecredit.**

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 04/18/2025
Due Date: 05/09/2025

Important Messages (continued from page 1)

Low-Income Home Energy Assistance Program (LIHEAP) is a federally funded assistance program that provides a one-time payment to help income-qualified customers pay their past due energy bills. PG&E does not administer this program. To find the local LIHEAP agency in your area, visit **www.csd.ca.gov/energybills**, or call the help line at **1-866-675-6623**.

Energy Savings Assistance Program: provides free home improvements to help keep your home more energy efficient, safe and comfortable. Apply by answering a few simple questions at **www.pge.com/energysavings** or call **1-800-989-9744**.

Programa Energy Savings Assistance: proporciona mejoras al hogar sin costo para ayudar a que este sea más eficiente en el consumo de energía, más seguro y más cómodo. Solicite respondiendo a unas pocas preguntas simples en **www.pge.com/ahorreenergia** o llamando al **1-800-989-9744**.

Electric power line safety PG&E cares about your safety. Be aware of your surroundings and keep yourself, tools, equipment and antennas at least 10 feet away from overhead power lines. If you see an electric power line fall to the ground, keep yourself and others away. Call **9-1-1**.

Call 811 before you dig. A common cause of pipeline accidents is damage from digging. If you plan on doing any digging, such as planting a tree or installing a fence, please call **811** at least two working days before you dig. One free call will notify underground utilities to mark the location of underground lines, helping you to plan a safe project.

Your Electric Charges Breakdown (from page 2)	
Conservation Incentive	$8.43
Transmission	16.91
Distribution	22.60
Electric Public Purpose Programs	5.85
Nuclear Decommissioning	-0.10
Competition Transition Charges (CTC)	-0.31
PCIA	4.76
Taxes and Other	3.36
Total Electric Charges	**$61.50**

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/20/2025
Due Date: 06/10/2025

Service For:

REDACTED - Customer Info

Questions about your bill?

Mon-Fri 7 a.m.-7 p.m.
Saturday 8 a.m.-5 p.m.
Phone: 1-800-743-5000
www.pge.com/MyEnergy

Ways To Pay

www.pge.com/waystopay

Your Enrolled Programs

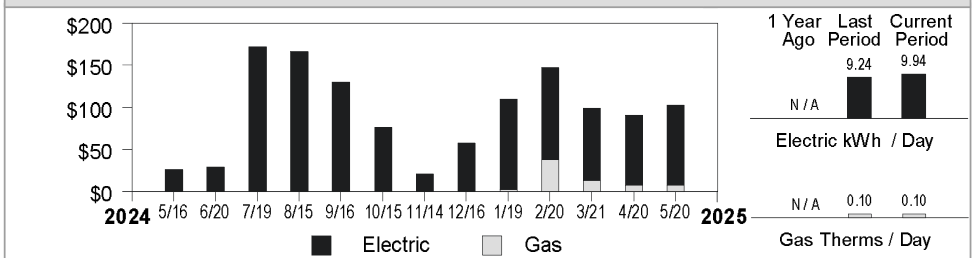
FERA Discount

Your Account Summary

Credit Balance on Previous Statement	-$35.62
Payment(s) Received Since Last Statement	0.00
Outstanding Credit Balance	-$35.62
Current Electric Charges	$95.87
Current Gas Charges	7.68
Total Amount Due by 06/10/2025	**$67.93**

Current charges include a discount of $20.82 for FERA.

Monthly Billing History



Visit ***www.pge.com/MyEnergy*** *for a detailed bill comparison*

Important Messages

TOU Rate: You are currently on a time-of-use (TOU) rate schedule. Beginning June 1, the TOU rate charges higher prices in the summer for electric usage on summer evenings.

Please return this portion with your payment. No staples or paper clips. Do not fold. Thank you.

REDACTED - Customer Info

Account Number:	Due Date:	Total Amount Due:	Amount Enclosed:
REDACTED - Customer Info	**06/10/2025**	**$67.93**	$

REDACTED - Customer Info

PG&E
BOX 997300
SACRAMENTO, CA 95899-7300

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/20/2025
Due Date: 06/10/2025

Important Phone Numbers - Monday-Friday 7 a.m.-7 p.m., Saturday 8 a.m.-5 p.m.

Customer Service (All Languages; Relay Calls Accepted) 1-800-743-5000
TTY 7-1-1

Servicio al Cliente en Español (Spanish)	1-800-660-6789	Dịch vụ khách tiếng Việt (Vietnamese)	1-800-298-8438
華語客戶服務 (Chinese)	1-800-893-9555	Business Customer Service	1-800-468-4743

Rules and rates

You may be eligible for a lower rate. To learn more about optional rates or view a complete list of rules and rates, visit www.pge.com or call 1-800-743-5000.

If you believe there is an error on your bill, please call **1-800-743-5000** to speak with a representative. If you are not satisfied with our response, contact the California Public Utilities Commission (CPUC), Consumer Affairs Branch (CAB), 505 Van Ness Avenue, Room 2003, San Francisco, CA 94102, 1-800-649-7570 or 7-1-1 (8:30 AM to 4:30 PM, Monday through Friday) or by visiting www.cpuc.ca.gov/complaints/.

To avoid having service turned off while you wait for the outcome of a complaint to the CPUC specifically regarding the accuracy of your bill, please contact CAB for assistance. If your case meets the eligibility criteria, CAB will provide you with instructions on how to mail a check or money order to be impounded pending resolution of your case. You must continue to pay your current charges while your complaint is under review to keep your service turned on.

If you are not able to pay your bill, call PG&E to discuss how we can help. You may qualify for reduced rates under PG&E's CARE program or other special programs and agencies may be available to assist you. You may qualify for PG&E's Energy Savings Assistance Program which is an energy efficiency program for income-qualified residential customers.

Important definitions

Rotating outage blocks are subject to change without advance notice due to operational conditions.

Tier 1/Baseline allowance: Some residential rates are given a Tier 1/Baseline allowance - a CPUC approved percentage of average customer usage during summer and winter months. Your Tier 1/Baseline allowance provides for basic needs at an affordable price and encourages conservation. Your allowance is assigned based on the climate where you live, the season and your heat source. As you use more energy, you pay more for usage. Any usage over your baseline allowance will be charged at a higher price.

Wildfire Fund Charge: Charge on behalf of the State of California Department of Water Resources (DWR) to fund the California Wildfire Fund. For usage prior to October 1, 2020, this charge included costs related to the 2001 California energy crisis, also collected on behalf of the DWR. These charges belong to DWR, not PG&E.

Power Charge Indifference Adjustment (PCIA): The PCIA is a charge to ensure that both PG&E customers and those who have left PG&E service to purchase electricity from other providers pay for the above market costs for electric generation resources that were procured by PG&E on their behalf. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. Visit www.pge.com/cca.

Wildfire Hardening Charge: PG&E has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. Your bill for electric service includes a fixed recovery charge called the Wildfire Hardening Charge that has been approved by the CPUC to repay those bonds. The right to recover the Wildfire Hardening Charge has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and does not belong to PG&E. PG&E is collecting the Wildfire Hardening Charge on behalf of the Special Purpose Entity. For details visit: www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_JF.pdf.

Recovery Bond Charge/Credit: Your bill for electric service includes a charge that has been approved by the CPUC to repay bonds issued for certain costs related to catastrophic wildfires. The Recovery Bond Charge (RBC) rate is currently $0.00647 per kWh. PG&E has also contributed certain amounts to a trust fund which is used to provide a customer credit equal to $0.00647 per kWh (Recovery Bond Credit). The right to recover the RBC has been transferred to one or more Special Purpose Entities that issued the bonds and does not belong to PG&E. PG&E is collecting that portion of the RBC on behalf of the Special Purpose Entities.

Gas Public Purpose Program (PPP) Surcharge. Used to fund state-mandated gas assistance programs for low-income customers, energy efficiency programs, and public-interest research and development.

Visit www.pge.com/billexplanation for more definitions. To view most recent bill inserts including legal or mandated notices, visit www.pge.com/billinserts.

See the table reflecting "Your Electric Charges Breakdown" on the last page

Please do not mark in box. For system use only.

Update My Information (English Only)

Please allow 1-2 billing cycles for changes to take effect

Account Number: REDACTED - Customer Info

Change my mailing address to: ______________________

City ______________ State ______ ZIP code ______

Primary Phone # ______________ Primary Email ______________

Ways To Pay

- **Online via web or mobile at www.pge.com/waystopay**
- **By mail:** Send your payment along with this payment stub in the envelope provided.
- **By debit card, Visa, MasterCard, American Express, or Discover:** Call 877-704-8470 at any time. (Our independent service provider charges a fee per transaction.)
- **At a neighborhood payment center**: To find a neighborhood payment center near you, please visit www.pge.com or call 800-743-5000. Please bring a copy of your bill with you.

ENERGY STATEMENT
www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/20/2025
Due Date: 06/10/2025

Details of Electric Charges

04/18/2025 - 05/18/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: Time-of-Use (Peak Pricing 4 - 9 p.m. Every Day)
Enrolled Programs: FERA

04/18/2025 – 05/18/2025

Baseline Allowance	303.80	kWh	(31 days x 9.8 kWh/day)		
Energy Charges					
Peak	62.934300	kWh	@	$0.50086	$31.52
Off Peak	245.126600	kWh	@	$0.47086	115.42
Baseline Credit	303.800000	kWh	@	-$0.10301	-31.29
FERA Discount					-20.82
Energy Commission Tax					0.09
Bakersfield Franchise Surcharge					0.95

Total Electric Charges **$95.87**

Rate Identification Number

USCA-PGPG-0100-0000
www.pge.com/rin
To program your smart device, scan the QR code or enter the RIN code above and follow the on-screen instructions.

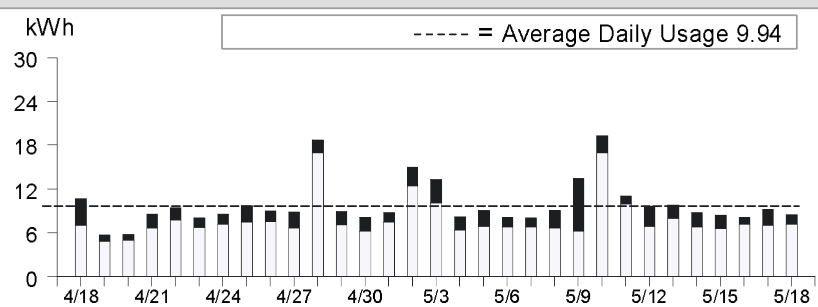
Service Information

Meter #	REDACTED - Customer Info
Total Usage	308.060900 kWh
Baseline Territory	W
Heat Source	B - Not Electric
Serial	Y
Rotating Outage Block	6I

Additional Messages

As a customer who receives electricity directly from PG&E, a portion of your electric charges currently includes the Power Charge Indifference Adjustment (PCIA). To learn more, review page 2 of this Energy Statement or visit **www.pge.com/cca**.

Electric Usage This Period: 308.060900 kWh, 31 billing days



	Usage	Energy Charges
Peak[1]	20.42%	$31.52
Off Peak[2]	79.58%	$115.42

[1]**Peak:** 4:00pm-9:00pm, Every Day;
[2]**Off Peak:** All Other Hours

Visit **www.pge.com/MyEnergy** *for a detailed bill comparison.*

ENERGY STATEMENT
www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/20/2025
Due Date: 06/10/2025

Details of Gas Charges

04/19/2025 - 05/19/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: G1 WB Residential Service

04/19/2025 – 04/30/2025	**Your Tier Usage**	**1**	2

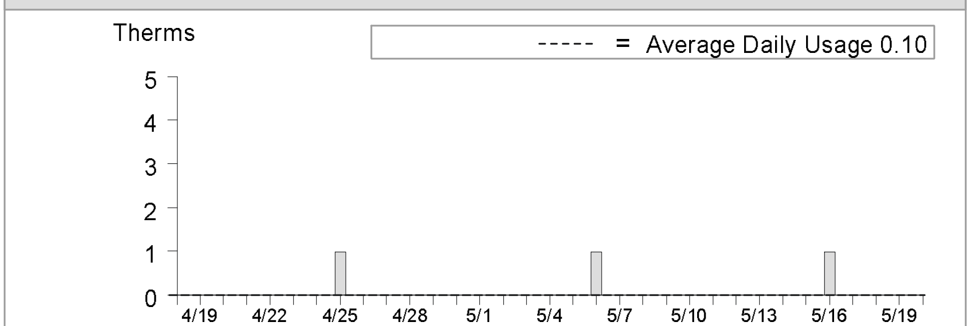
Tier 1 Allowance	4.68 Therms (12 days x 0.39 Therms/day)	
Tier 1 Usage	1.161290 Therms @ $2.36480	$2.75
Gas PPP Surcharge ($0.14324 /Therm)		0.16
Bakersfield Franchise Surcharge		0.03

05/01/2025 – 05/19/2025	**Your Tier Usage**	**1**	2

Tier 1 Allowance	7.41 Therms (19 days x 0.39 Therms/day)	
Tier 1 Usage	1.838710 Therms @ $2.40729	$4.43
Gas PPP Surcharge ($0.14324 /Therm)		0.27
Bakersfield Franchise Surcharge		0.04

Total Gas Charges **$7.68**

Gas Usage This Period: 3.000000 Therms, 31 billing days



Service Information

Meter #	REDACTED - Customer Info
Current Meter Reading	42
Prior Meter Reading	39
Difference	3
Multiplier	1.004246
Total Usage	3.000000 Therms
Baseline Territory	W
Serial	Y

Gas Procurement Costs ($/Therm)

04/19/2025 - 04/30/2025	$0.24481
05/01/2025 - 05/19/2025	$0.28730

Your Electric Charges Breakdown (from page 2)	
Conservation Incentive	-$10.52
Generation	43.98
Transmission	12.14
Distribution	39.57
Electric Public Purpose Programs	8.14
Nuclear Decommissioning	-0.08
Wildfire Fund Charge	1.83
Competition Transition Charges (CTC)	-0.23
Taxes and Other	1.04
Total Electric Charges	**$95.87**

ENERGY STATEMENT
www.pge.com/MyEnergy

Account No: [redacted]
Statement Date: 05/09/2025
Due Date: 05/30/2025

Service For:
[redacted]

Questions about your bill?
Mon-Fri 7 a.m.-7 p.m.
Saturday 8 a.m.-5 p.m.
Phone: 1-800-743-5000
www.pge.com/MyEnergy

Ways To Pay
www.pge.com/waystopay

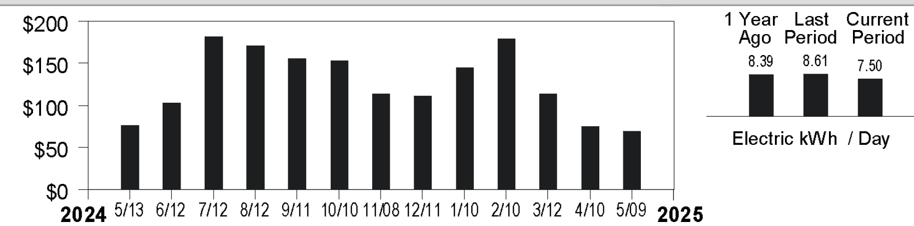
Your Enrolled Programs
FERA Discount

Your Account Summary

Amount Due on Previous Statement	$16.43
Payment(s) Received Since Last Statement	0.00
Previous Unpaid Balance	$16.43
Current PG&E Electric Delivery Charges	$42.03
San Jose Clean Energy Electric Generation Charges	27.62
Total Amount Due by 05/30/2025	**$86.08**

Current charges include a discount of $15.69 for FERA.

Electric Monthly Billing History
Daily Usage Comparison



Visit ***www.pge.com/MyEnergy*** *for a detailed bill comparison*

Important Messages
Your account has an unpaid balance from a prior bill. To avoid missing a future payment, you may wish to sign up for our recurring payment service. Please visit **www.pge.com/waystopay** for all your payment options.

TOU Rate: You are currently on a time-of-use (TOU) rate schedule. Beginning June 1, the TOU rate charges higher prices in the summer for electric usage on summer evenings.

Please return this portion with your payment. No staples or paper clips. Do not fold. Thank you.

[redacted]

Account Number:	Due Date:	Total Amount Due:	Amount Enclosed:
0090265294-0	**05/30/2025**	**$86.08**	$.

[redacted]

PG&E
BOX 997300
SACRAMENTO, CA 95899-7300

Important Phone Numbers - Monday-Friday 7 a.m.-7 p.m., Saturday 8 a.m.-5 p.m.

Customer Service (All Languages; Relay Calls Accepted) 1-800-743-5000
TTY 7-1-1

Servicio al Cliente en Español (Spanish)	1-800-660-6789	Dịch vụ khách tiếng Việt (Vietnamese)	1-800-298-8438
華語客戶服務 (Chinese)	1-800-893-9555	Business Customer Service	1-800-468-4743

Rules and rates

You may be eligible for a lower rate. To learn more about optional rates or view a complete list of rules and rates, visit www.pge.com or call 1-800-743-5000.

If you believe there is an error on your bill, please call **1-800-743-5000** to speak with a representative. If you are not satisfied with our response, contact the California Public Utilities Commission (CPUC), Consumer Affairs Branch (CAB), 505 Van Ness Avenue, Room 2003, San Francisco, CA 94102, 1-800-649-7570 or 7-1-1 (8:30 AM to 4:30 PM, Monday through Friday) or by visiting www.cpuc.ca.gov/complaints/.

To avoid having service turned off while you wait for the outcome of a complaint to the CPUC specifically regarding the accuracy of your bill, please contact CAB for assistance. If your case meets the eligibility criteria, CAB will provide you with instructions on how to mail a check or money order to be impounded pending resolution of your case. You must continue to pay your current charges while your complaint is under review to keep your service turned on.

If you are not able to pay your bill, call PG&E to discuss how we can help. You may qualify for reduced rates under PG&E's CARE program or other special programs and agencies may be available to assist you. You may qualify for PG&E's Energy Savings Assistance Program which is an energy efficiency program for income-qualified residential customers.

Important definitions

Rotating outage blocks are subject to change without advance notice due to operational conditions.

Tier 1/Baseline allowance: Some residential rates are given a Tier 1/Baseline allowance - a CPUC approved percentage of average customer usage during summer and winter months. Your Tier 1/Baseline allowance provides for basic needs at an affordable price and encourages conservation. Your allowance is assigned based on the climate where you live, the season and your heat source. As you use more energy, you pay more for usage. Any usage over your baseline allowance will be charged at a higher price.

Wildfire Fund Charge: Charge on behalf of the State of California Department of Water Resources (DWR) to fund the California Wildfire Fund. For usage prior to October 1, 2020, this charge included costs related to the 2001 California energy crisis, also collected on behalf of the DWR. These charges belong to DWR, not PG&E.

Power Charge Indifference Adjustment (PCIA): The PCIA is a charge to ensure that both PG&E customers and those who have left PG&E service to purchase electricity from other providers pay for the above market costs for electric generation resources that were procured by PG&E on their behalf. 'Above market' refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. Visit www.pge.com/cca.

Wildfire Hardening Charge: PG&E has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. Your bill for electric service includes a fixed recovery charge called the Wildfire Hardening Charge that has been approved by the CPUC to repay those bonds. The right to recover the Wildfire Hardening Charge has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and does not belong to PG&E. PG&E is collecting the Wildfire Hardening Charge on behalf of the Special Purpose Entity. For details visit: www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_JF.pdf.

Recovery Bond Charge/Credit: Your bill for electric service includes a charge that has been approved by the CPUC to repay bonds issued for certain costs related to catastrophic wildfires. The Recovery Bond Charge (RBC) rate is currently $0.00647 per kWh. PG&E has also contributed certain amounts to a trust fund which is used to provide a customer credit equal to $0.00647 per kWh (Recovery Bond Credit). The right to recover the RBC has been transferred to one or more Special Purpose Entities that issued the bonds and does not belong to PG&E. PG&E is collecting that portion of the RBC on behalf of the Special Purpose Entities.

Gas Public Purpose Program (PPP) Surcharge. Used to fund state-mandated gas assistance programs for low-income customers, energy efficiency programs, and public-interest research and development.

Visit www.pge.com/billexplanation for more definitions. To view most recent bill inserts including legal or mandated notices, visit www.pge.com/billinserts.

See the table reflecting "Your Electric Charges Breakdown" on the last page

Please do not mark in box. For system use only.

Update My Information (English Only)

Please allow 1-2 billing cycles for changes to take effect

Account Number: REDACTED - Customer Info

Change my mailing address to: ______________________

City ____________ State ______ ZIP code ______

Primary Phone # ____________ Primary Email ____________

Ways To Pay

- **Online via web or mobile at www.pge.com/waystopay**
- **By mail:** Send your payment along with this payment stub in the envelope provided.
- **By debit card, Visa, MasterCard, American Express, or Discover:** Call 877-704-8470 at any time. (Our independent service provider charges a fee per transaction.)
- **At a neighborhood payment center**: To find a neighborhood payment center near you, please visit www.pge.com or call 800-743-5000. Please bring a copy of your bill with you.

ENERGY STATEMENT

www.pge.com/MyEnergy

Account No: REDACTED - Customer Info
Statement Date: 05/09/2025
Due Date: 05/30/2025

Details of PG&E Electric Delivery Charges

04/04/2025 - 05/04/2025 (31 billing days)

Service For: REDACTED - Customer Info
Service Agreement ID: REDACTED - Customer Info
Rate Schedule: Time-of-Use (Peak Pricing 4 - 9 p.m. Every Day)
Enrolled Programs: FERA

04/04/2025 – 05/04/2025

Baseline Allowance	452.60	kWh	(31 days x 14.6 kWh/day)		
Energy Charges					
Peak	52.454000	kWh	@	$0.50086	$26.27
Off Peak	180.198000	kWh	@	$0.47086	84.85
Baseline Credit	232.652000	kWh	@	-$0.10301	-23.97
FERA Discount					-15.69
Generation Credit					-33.34
Power Charge Indifference Adjustment					1.56
Franchise Fee Surcharge					0.25
San Jose Utility Users' Tax (5.000%)					1.98
San Jose Franchise Surcharge					0.12

Total PG&E Electric Delivery Charges $42.03

2018 Vintaged Power Charge Indifference Adjustment

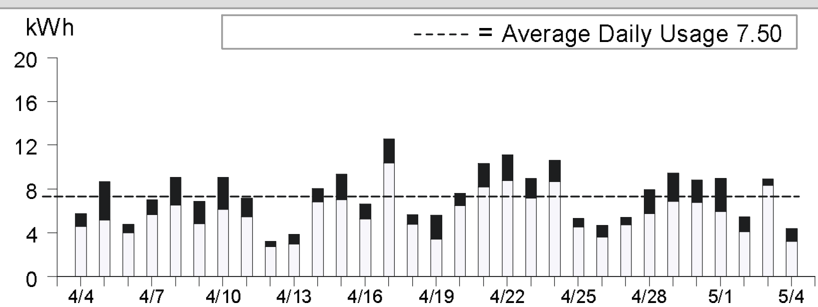
Rate Identification Number

USCA-PGXX-0100-0000
www.pge.com/rin
To program your smart device, scan the QR code or enter the RIN code above and follow the on-screen instructions.

Service Information

Meter #	REDACTED - Customer Info
Total Usage	232.652000 kWh
Baseline Territory	X
Heat Source	H - Electric
Serial	M
Rotating Outage Block	5I

Electric Usage This Period: 232.652000 kWh, 31 billing days



	Usage	Energy Charges
Peak[1]	22.54%	$26.27
Off Peak[2]	77.46%	$84.85

[1]**Peak:** 4:00pm-9:00pm, Every Day;
[2]**Off Peak:** All Other Hours

Visit ***www.pge.com/MyEnergy*** *for a detailed bill comparison.*

Details of San Jose Clean Energy Electric Generation Charges

04/04/2025 - 05/04/2025 (31 billing days)

Service For: [redacted]
Service Agreement ID: [redacted] ESP Customer Number [redacted]

04/04/2025 – 05/04/2025

Rate Schedule: **E-TOU-C**

Generation - Off Peak - Winter	180.198000	kWh	@	$0.10762	$19.39
Generation - On Peak - Winter	52.454000	kWh	@	$0.13050	6.85
		Net Charges		26.24	
Local Utility Users Tax					1.31
Energy Commission Surcharge					0.07

SJ Cares Discount: you're receiving more renewable energy at SJCE's lowest rates
For more detail on your San Jose Clean Energy bill, call us at 833-432-2454

Total San Jose Clean Energy Electric Generation Charges **$27.62**

Rate Identification Number

USCA-XXSJ-0454-0000
www.pge.com/rin
To program your smart device, scan the QR code or enter the RIN code above and follow the on-screen instructions.

Service Information

Total Usage 232.652000 kWh

For questions regarding charges on this page, please contact:
SAN JOSE CLEAN ENERGY
200 E SANTA CLARA ST
SAN JOSE CA 95113
1-833-432-2454
www.sanjosecleanenergy.org
info@SanJoseCleanEnergy.org

Additional Messages

About San José Clean Energy (SJCE)
San José Clean Energy is a program of the City of San José and provides its residents and businesses with electricity from sources like solar, wind, and hydropower. SJCE offers the additional benefits of customer choice, community programs, local control, transparency, and accountability.

SJCE's standard electricity generation service, GreenSource, provides customers with more renewable power. SJCE also offers a 100% renewable product, TotalGreen, for a small premium. Learn more: **www.SanJoseCleanEnergy.org/TotalGreen**.

Understanding SJCE Charges
SJCE replaces PG&E Generation Charges. PG&E continues to provide all electric delivery, billing, and gas services. Under PG&E Electric Delivery Charges, note the Generation Credit. This is what PG&E would have charged for power, and now credits back to you. The PG&E Power Charge Indifference Adjustment and Franchise Fee are factored into SJCE's rate-setting. Learn more: **www.SanJoseCleanEnergy.org/Understanding-Your-Bill**.

SJ Cares is SJCE's program that allows customers enrolled in CARE or FERA financial assistance programs to receive cleaner energy at the lowest possible rates. Learn more: **www.SanJoseCleanEnergy.org/Discount-Programs**.

Please pay your SJCE charges directly to PG&E (see page 1 of this bill). Do not send payment to San José Clean Energy.

Your Electric Charges Breakdown (from page 2)	
Conservation Incentive	-$8.31
Transmission	9.18
Distribution	29.94
Electric Public Purpose Programs	6.15
Nuclear Decommissioning	-0.05
Wildfire Fund Charge	1.38
Competition Transition Charges (CTC)	-0.17
PCIA	1.56
Taxes and Other	2.35
Total Electric Charges	**$42.03**

PACIFIC GAS AND ELECTRIC COMPANY
Billing Modernization
Application 24-10-014
Data Response

PG&E Data Request No.:	PCE_002-Q028
PG&E File Name:	BillingModernization_DR_PCE_002-Q028
Request Date:	May 20, 2025
Requester DR No.:	002
Requesting Party:	Peninsula Clean Energy
Requester:	Julia Kantor
Date Sent:	June 2, 2025
PG&E Witness(es):	Leo Yang - Finance Matt Briel – Customer and Enterprise Solutions

SUBJECT: SECOND DATA REQUEST OF PCE

QUESTION 028

Referring to PG&E's response to PCE_001_Q017:

a. Please confirm if PG&E believes that the potential benefits of the BMI upgrades will be the same for all CCAs. If not, please explain why not.

b. Please explain why, under PG&E's proposed cost allocation, there are specific PCIA vintages responsible for BMI costs, even though the BMI will theoretically benefit all bundled and unbundled customers.

ANSWER 028

a. Yes, benefits are accrued to all retail customers, which include Bundled, CCA, Direct Access customers.

b. PG&E used the common cost allocation methodology recently approved in PG&E's 2025 ERRA Forecast Decision, D.24-12-038, for allocation of Electric Supply Administration (ESA) costs. The basis for the ESA allocation is described in Compliance Advice Letter 7488-E, filed January 17, 2025, as:

   - ESA Cost shall be allocated to the PABA, ERRA and NSGBA based on the account and vintage assignment for the utility owned generation revenue requirement approved in PG&E's most recent General Rate Case.

   A helpful insight into determining the fairness of the PABA vintage allocation methodology is to understand that ALL bundled and non-exempt departing load customers pay for costs allocated to the Legacy utility-owned generation (UOG) vintage and 2009 vintage PABA subaccount. Those two vintage subaccounts account for 84.4 percent of all allocated generation-related billing modernization costs.

For the remaining 4.8 percent of costs allocated to Vintage 2010 – 2012 PABA subaccounts, ALL bundled and most non-exempt departing load customers pay for the costs in the vintage subaccounts between 2010 and 2012.

There are limited exemptions for the Vintage 2010 PABA subaccount, i.e., 2009 vintage customers will not be obligated to pay for costs allocated to this subaccount. Similarly, there are limited exemptions for the 2011 PABA subaccount, i.e., 2009 and 2010 vintage customers will not be obligated to pay for costs allocated to this subaccount.

Bottom line, the PABA allocation factors broadly allocate the costs to all customers responsible for PABA costs, which include bundled and non-exempt departing load customers.

Attachment KJC-3

SCE Bill Message Request Template

BILL MESSAGE REQUEST TEMPLATE

It is the client's responsibility to verify that the bill message content is accurate, the target audience is appropriate, and that all appropriate stakeholders have reviewed and approved (e.g., Management, Law, Regulatory, etc. as applicable). RSO Compliance may request validation of these stakeholder approvals prior to implementation. RSO Compliance is not responsible for the development of any content (FAQs, Fact Sheets, links to SCE.com, etc.) related to the bill message. Please contact RSO Compliance with questions on any section of this template prior to submittal.

NOTE – This completed form must be sent to RSO Compliance at least 2 full business days (48 hours) prior to the start of the bill message. This will allow RSO Compliance sufficient time to review the form and program bill messages in the sytem.

SECTION 1: BILL MESSAGE OVERVIEW

Title of Bill Message:				**Requester:**	
Date:		**Was message used previously?**		**Message Request #:** (to be completed by RSO Compliance)	

SECTION 2: BILL MESSAGE DETAIL

Bill Message Title and Body: (typically, no more than five lines)					
Describe Purpose of Message:					
Date Message is to begin appearring on the Bill:			**Duration:** (for how long?)		
Priority Level: (legal, regulatory, or emergency messages are high priority)		**Target Audience:** (Specific to rate class)		**Account Level:**	

SECTION 3: STAKEHOLDER APPROVALS (Client to obtain approvals)

Department:		**Name & Title:**		**Date:**	
Department:		**Name & Title:**		**Date:**	
Department:		**Name & Title:**		**Date:**	
Department:		**Name & Title:**		**Date:**	

SECTION 4: To be completed by RSO Compliance

Facilitator:		**Date Submitted to SAP:**	
After Message Implementation			
Production Verified by:		**Production Verification Date:**	
Notification to client made by:		**Notification to Client Date:**	