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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Energization Timelines. (U 39 E)	Rulemaking 24-01-018 (Filed January 25, 2024)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) MOTION TO REVISE 2025 AND 2026 ENERGIZATION COST CAPS

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SUBJECT INDEX OF RECOMMENDATIONS

Pacific Gas and Electric Company (PG&E) submits the following Subject Index of Recommendations presented in PG&E's Motion to Revise 2025 and 2026 Energization Cost Caps (Motion). For the reasons discussed in the Motion, we respectfully recommend the Commission:

1. Increase the 2025 capital costs cap from $618 million to $2.115 billion;
2. Increase the 2026 capital costs cap from $669 million to $2.302 billion;
3. Authorize the ability to spend authorized amounts across 2025 and 2026; and
4. Eliminate the secondary revenue requirement (RRQ) caps for 2024-2026.

We discuss these recommended changes in the following sections of this Motion:

Section I – Introduction
Section II – Background
Section III – Legal Authority and Standard of Review
Section IV – Revenue Requirement Impacts
Section V – Updated Energization Forecasts
Section VI – Energization Timelines
Section VII – Work Execution
Section VIII – Flexibility in Spending Across 2025 and 2026 Caps
Section IX – Revenue Requirement Caps
Section X – Proposed Schedule

We also provide the following attachment supporting this Motion:

1. Attachment 1 – Declaration of Bryon Winget (including attached workpapers).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Energization Timelines. (U 39 E)	Rulemaking 24-01-018 (Filed January 25, 2024)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) MOTION TO REVISE 2025 AND 2026 ENERGIZATION COST CAPS

Pursuant to Rule 11.1 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), Ordering Paragraph 1 of the *Administrative Law Judges' Ruling Addressing Pacific Gas and Electric Company's Senate Bill 410 and Assembly Bill 50 Compliance Costs Caps* (Filed September 25, 2024), and Decision (D.) 24-07-008,[1] Pacific Gas and Electric Company (PG&E) respectfully submits this Motion requesting that the Commission revise the capital costs caps for the Electric Capacity New Business Interim Memorandum Account (ECNBIMA) approved in D. 24-07-008.[2] In brief, we request the Commission approve the following:

(1) Increase the 2025 capital costs cap from $618 million to $2.115 billion;

(2) Increase the 2026 capital costs cap from $669 million to $2.302 billion;

(3) Authorize the ability to spend authorized amounts across 2025 and 2026; and

(4) Eliminate the secondary revenue requirement (RRQ) caps for 2024-2026.

As explained in further detail below, the proposed cap increases will allow us to complete more than double the amount of customer-requested energization work than can be completed under the current caps. In particular, the additional funding will allow us to complete 18,750 more projects to eliminate our existing backlog, as well as address new applications and emergent energization projects. The primary customer complaint related to energization is dissatisfaction with delays and the impacts those delays have on their lives. Additional funding will allow us to address customer concerns, comply

[1] Decision 24-07-008, p. 80 ("[T]he Commission will have the option to consider revising the 2025 and 2026 cap based on additional evidence submitted by motion…").

[2] In Section X, PG&E proposes extending certain response deadlines under Commission Rule 11.1 in order to provide parties additional time to review PG&E's motion and supporting materials. PG&E respectfully requests a decision on this Motion by first-quarter 2025 to maximize our ability to plan and coordinate 2025-2026 energization work.

with AB 50,and meet Energization OIR targets by 2027. The requested cap increases, if approved, would result in a bundled average rate impact of 1.8% and a typical residential bill impact of $3.65/month; these impacts would be mitigated by additional revenue resulting from increased load that puts downward pressure on rates.

This Motion is supported by Attachment 1 – Declaration of Bryon Winget (Winget Declaration). Mr. Winget serves as Vice President, Electric System Planning for PG&E, and in this role, he is responsible for the planning and engineering of PG&E's electric distribution system, including determining the necessity, timing, scope, and location of new electric distribution assets and system upgrades. In Attachment B to the Winget Declaration, PG&E presents a revised version of D.24-07-008 Appendix A with the updated forecasts for each eligible Maintenance Activity Type (MAT) and the resulting proposed cap, as requested in this Motion.

I. INTRODUCTION

A. Increasing The Caps Allows Us To Fulfill Our Obligation To Serve Customers And Provides A Broad Array Of Customer Benefits

Revising the caps as proposed above is necessary to fulfill our obligation to serve customers,[3] and achieve California's policy objectives to upgrade electrical distribution systems to achieve the state's decarbonization goals and promptly energize new housing, businesses, electric vehicle charging facilities, in accordance with the Powering Up Californians Act (Pub. Util Code §§ 930-939.5, which codified Senate Bill (SB) 410 and Assembly Bill (AB) 50). We appreciate the incremental funding for energization activities granted in D.24-07-008 and acknowledge that the Commission's decision reflects a substantial commitment to continued progress on critically important energization work. We share that commitment. However, as explained in further detail below, we simply cannot fulfill customers' connection requests under the incremental funding levels adopted in D.24-07-008. An increase to the 2025 and 2026 energization cost caps is required to meet these objectives.

The proposed increases to the 2025 and 2026 costs caps presented in this Motion will allow us to reduce our customer-connections backlog to zero by the end of 2026. Specifically, with additional funding provided by the proposed increased caps, we could complete 18,758 more customer connections, 129 more capacity projects, and 690 more work-at-the-request-of-others (WRO) projects

[3] Pub. Util. Code § 451 (stating in part, "Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, . . ., as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

than could otherwise be completed.[4] Further, by facilitating the reduction of the backlog to zero, the proposed cap increases will allow us to meet the energization targets set forth in the Energization OIR, including the requirement to complete new customer connections (including Electric Rule 15 and Electric Rule 16) within no more than 125 business days, on average.[5] Table 1 summarizes the amount of additional energization work we could complete if the Commission grants our request to increase 2025-2026 cost caps, compared to the work amounts we could complete under existing approved funding levels.

Table 1[6]
Additional 2025-2026 Units and Projects

Activity	Units/Projects With Current Funding Level (D.23-11-069 and D.24-07-008)	Additional Units/Projects with Increased Caps Proposed In Motion	Total Units/Projects With Total New Overall Funding Levels
MWC 16 (New Business) Customer Connections	19,454	18,758	38,212
MWC 06 (Distribution Line Capacity) Projects	267	121	388
MWC 46 (Substation Capacity) Projects	49	8	57
MWC 10 (Work Requested by Others) Relocations	564	690	1,254

The energization work we plan to complete benefits customers directly and achieves California's stated policy goals in many ways:[7]

Backlog Elimination and Quicker Customer Connections: There is a direct causal link between backlogs and our ability to improve energization timelines. Persistent backlogs directly lead to lengthier customer connection timelines. Due in part to additional costs for energization work as a result of the Energization OIR, we estimate that under current approved funding, our backlog will continue to grow to nearly 19,000 uncompleted projects by the end of 2026.[8] This backlog, unaddressed, will hinder our ability to improve customer-connection timelines, which could increase to as much as 395 business days on average unless additional funding is authorized. In contrast, the funding increase requested in our

[4] See Declaration of Bryon Winget ¶ 6.

[5] D.24-09-020, OP 1.

[6] Winget Decl. ¶ 6 (Table 1).

[7] Winget Decl. ¶ 7.

[8] Winget Decl. ¶ 7.

Motion, will allow us to eliminate the backlog and reduce energization timelines to 125 business days, consistent with California's state policy to promptly upgrade service when needed,[9] and consistent with the timelines established in the Energization OIR.

Revenues from Additional Load: We expect that the customer connections and capacity work we plan to complete will result in additional customer usage each year. The additional sales to customers each year will yield revenues that over time have the potential to put downward pressure on rates, consistent with the California Legislature's findings in SB 410.[10] We address this issue further below in Section IV.

Improved Grid Health: Under the total funding requested, we will make a series of load-enabling investments that will prevent approximately 300 circuits from becoming overloaded. Hundreds of capacity projects are required to ready the grid for near-term new connections and larger loads in 2025-2026. This grid-readiness work will allow us to timely connect both pending and future connections in areas currently with limited capacity, to ensure PG&E can meet its obligation to serve as set forth Public Utilities Code Section 451.[11] Without increased funding we would not be able to complete about one-third of the capacity projects we need to complete.

Lower Emissions: The California Legislature has determined that widespread electrification is vital to achieving California's decarbonization and air quality goals. Public Utilities Code Section 932 provides in part:

> (1) It is the policy of the state to reach carbon neutrality no later than 2045 and to maintain net negative emissions of greenhouse gases after 2045. To meet these goals and federal, state, regional, and local air quality and decarbonization standards, plans, and regulations, projections from the commission and the Energy Commission show the need for a large increase in both the quantity of electricity used and the functions for which electricity will be used.[12]
>
> (2) To meet these decarbonization goals and federal, state, regional, and local air quality and decarbonization standards, plans, and regulations, the state's electrical distribution systems must be substantially upgraded, new customers must promptly connect to the

[9] Pub. Util. Code § 933(d).

[10] Pub. Util. Code § 932(a)(7) and (8).

[11] Pub. Util. Code § 451. See also Pub. Util. Code § 933(b) (noting that it is state policy that each utility "[c]omply with its obligation to serve, as provided in Section 451, by conducting sufficient advance planning, engineering, and construction of increased distribution system capacity so that customers can be energized without substantial delay.")

[12] Pub. Util. Code § 932(a)(1) (emphasis added).

electrical distribution system, and existing customers must have their service level promptly upgraded.[13]

Our planned work advances these objectives.

Other Community-Wide Benefits: The capacity work we plan to complete in 2025-2026 with increased funding is necessary for housing projects, electric vehicle charging stations, high-speed rail construction, data centers, internet-order delivery hubs, commercial redevelopment projects, and local infrastructure such as hospitals and water treatment plants, as contemplated in Public Utilities Code Section 933(c). These projects broadly benefit all customers. Without additional funding, these benefits will either not occur or will be greatly reduced.

Without an increase to the caps established in D.24-07-008, PG&E will not have adequate funding to achieve California's clearly articulated policies to serve our customers timely and build the grid needed to achieve greenhouse gas reductions.

B. Increasing the Cap is Necessary To Comply with The Legal Requirement That Utilities Have Sufficient And Timely Recovery of Energization Costs

Not only is increasing the caps for 2025 and 2026 necessary to achieve the state's policy objectives and meet the Energization OIR timelines, increasing the caps is necessary to ensure that there is sufficient and timely recovery of costs to energize projects, as required by Public Utilities Code Section 937(a). The current funding available under the 2025 and 2026 caps is not sufficient. To be sufficient, the caps must be increased, at a minimum, to $2.115 million and $2,302 million for 2025 and 2026, respectively, to reflect the most up-to-date cost forecast and to achieve the state's policy objectives.

Ultimately, the Commission should adopt the proposed caps, *at the minimum*, in light of this statutory requirement. The requirement that utilities be provided sufficient funding for energization costs is the primary goal of Public Utilities Code Section 937. However, in recognizing that there is an upper bound to reasonable impacts resulting from SB 410 interim rates, the California Legislature included an annual cap requirement.[14] Here, the proposed caps would result in a bundled average rate impact of 1.8% if PG&E placed-in service the full cap amount. Moreso, this rate impact calculation does not factor in the contribution of revenue received from energized customers. This is all to say, the caps are

[13] Pub. Util. Code § 932(a)(2) (emphasis added).

[14] Pub. Util. Code § 937(b)(2).

not meant to undercut achievement of the state's objective, so long as the impact to customers is not untenable. PG&E's request here is reasonable, given that it is necessary to fulfill our obligation to serve and meet customers' connection requests, and to achieve the objectives established in the Powering Up Californians Act.

C. Increasing Cap Flexibility Allows Us To Maximize Our Use Of The Approved Funding

As the Commission considers our request to increase the 2025-2026 caps, the Commission should provide us operational and financial flexibility to spend authorized cap amounts across years to ensure sufficient funding to serve our forecasted need. Under the rigid annual cap structure adopting in D.24-07-008, funding is unnecessarily constrained when work moves from one year to the next. As discussed in Section VIII, cap flexibility that allows for spending across 2025 and 2026 will allow us to energize customers who could not be energized within the 2025 cap to be energized in 2026, without being arbitrary limited by the 2026 cap.

This proposal is consistent with Public Utilities Code Section 937(b)(2) because there will still be an up-front cap. The proposal simply seeks flexibility to adjust the up-front annual capital expenditures cap in 2026, based on 2025 activities. In fact, providing this flexibility is consistent with the legislative intent to ensure funding is available for PG&E to promptly energize customers.

D. Eliminating the Multi-Layered Cap Framework Enables PG&E To Better Manage Spending and Make Work Execution Decisions

As explained in Section IX, D. 24-07-008 established both capital expenditure caps and revenue requirement caps. This multi-layer cap approach unnecessarily constrains our planning and ability to accelerate projects The Commission should eliminate the multi-layer cost cap structure by removing the revenue requirement cost caps. Using annual cost caps solely based on capital costs is the most straightforward way for us to manage capital spending. It also clearly defines the amount of eligible capital costs for the eventual recording of RRQs to the approved memorandum account once those projects become operative.

Public Utilities Code Section 937 does not contemplate a multi-layered cost cap approach. Rather, the purpose of this statute is to ensure sufficient funding to meet the findings and policy objectives stated in the Powering Up Californians Act. Because the multi-layered is not required and complicates the stated objectives of the legislation, it should be eliminated in favor of a single capital expenditures-based cap.

II. BACKGROUND

On June 30, 2021, Pacific Gas and Electric Company (PG&E) filed Application (A.) 21-06-021 requesting approval of its Test Year (TY) 2023 general rate case (2023 GRC). On September 5, 2023, the assigned Commissioner issued an amended scoping memo and ruling establishing a second phase of the GRC (referred to as the 2023 GRC Capacity Phase) to determine whether the Commission should adopt a ratemaking mechanism for PG&E to track and recover certain energization costs for new business connections and electric distribution capacity work, pursuant to Senate Bill (SB) 410 and Assembly Bill (AB) 50.

On July 16, 2024, the Commission issued D.24-07-008 in the 2023 GRC Capacity Phase authorizing PG&E to establish the ECNBIMA to record costs for energization projects that exceed amounts adopted in D.23-11-069 for specific eligible activities within: (i) Major Work Category (MWC) 16 – New Business; (ii) MWC 06 – Distribution Line Capacity; (iii) MWC 46 – Substation Capacity; and (iv) MWC 10 – Work Requested by Others.[15] Decision 24-07-008 capped the incremental capital costs and associated revenue requirements that may be recorded to the ECNBIMA as shown in Table 2.[16]

Table 2
Annual Caps Approved in D.24-07-008
(Millions)

	2024	2025	2026	Total
Incremental Capital Cost Cap	$975	$619	$669	$2,263
Incremental Revenue Requirements	$144.31	$91.57	$99.07	$715.14[17]

Decision 24-07-008 allows PG&E the opportunity to request revisions to the adopted cost caps based on new evidence and any other relevant information, including the adoption of energization

[15] See Winget Decl. Attachment A (listing the specific eligible Maintenance Activity Types (MATs) identified in D.24-07-008 and the annual authorized amounts for these MATs adopted in D.23-11-069 (2023 GRC Decision).

[16] D.24-07-008, p. 51.

[17] D.24-07-008, p. 82, states the decision was modified to clarify that revenue requirements (RRQ) approved under this ratemaking mechanism not only apply to the year after the capital additions are made, but also to subsequent years of this mechanism. D.24-07-008, p. 3, explains that the maximum 202[4]-2026 revenue requirements include the annual incremental 2024-2026 revenue requirements plus the ongoing revenue requirements associated with prior year capital additions. Capital costs are recovered through the remaining life of the capital assets consistent with cost-of-service ratemaking. Assuming PG&E spends all the incremental funding approved in the decision, the recoverable RRQ associated with that spending is $144.3 million in 2024; $235.9 million in 2025, and $335.0 million in 2026, for a combined $715 million RRQ over 2024-2026.

timelines and other requirements in the Energization OIR).[18, 19] On September 25, 2024, the ALJs for the Energization OIR and 2023 GRC Capacity Phase issued a joint ruling directing that PG&E "shall submit any future requests to modify the 2025 and 2026 cost caps on its Electric Capacity and New Business Interim Memorandum Account, as authorized in Ordering Paragraph 28 of Decision 24-07-008, in Rulemaking 24-01-018."[20]

III. LEGAL AUTHORITY AND STANDARD OF REVIEW

PG&E has the burden to prove the reasonableness of the proposed cap increases and other relief requested in this Motion.[21] All rates and charges collected by a public utility must be "just and reasonable,"[22] based upon the preponderance of the evidence.[23]

In meeting this standard, PG&E does not have to show that other positions (i.e. other funding levels) are unreasonable, untenable, or impossible to accept.[24] Indeed, parties opposing the request have the burden of going forward to produce evidence to support their position and raise reasonable doubt as to PG&E's request.[25] This "burden of going forward to produce evidence relates to raising a reasonable doubt as to the utility's position and presenting evidence explaining the counterpoint position."[26] In other words, mere assertions raised by parties objecting to PG&E's request are not enough to warrant a different result than the one proposed by PG&E, so long as PG&E has made a *prima facie* showing of reasonableness; an intervenor must put forward evidence to support an alternative outcome.

Finally, when considering the reasonableness of PG&E's requested cost cap increases and other requests, the Commission should consider SB 410's reasonableness-review framework. The point of the

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18 D.24-09-020, OP 1.

19 D.24-07-008, OP 28.

20 R.24-01-018 and A.21-06-021, Administrative Law Judge's Ruling Addressing Pacific Gas and Electric Company's Senate Bill 410 and Assembly Bill 50 Compliance Costs Caps (Sept. 25, 2024), p. 5.

21 D.20-07-038, p. 3.

22 Pub. Util. Code § 451.

23 D.19-05-020, p. 7 (citing D.15-11-021, pp. 8-9).

24 D.19-03-025, p. 19.

25 D.20-07-038, pp. 3-4 (finding that an intervening party must meet its "burden of going forward" to prevail on arguments opposing the utilities' request); See also D.18-12-009, p. 12; D.18-07-006, p. 15; D.16-05-024, p. 10; D.08-01-022, p. 4; and D.15-03-049, p. 6. (Each decision cites D.87-12-067, 27 CPUC2d 1, 22.).

26 D.08-01-022, p. 4.

SB 410 was to allow for a ratemaking mechanism that would allow utilities to annually recover costs not accounted for in the normal GRC cycle, subject to a reasonableness review to be conducted in the *following* GRC cycle after costs in the authorized account had been incurred. While the Commission certainly must evaluate the merits of the cost-cap revisions requested in this Motion, the reasonableness determination of actual costs will occur later.

IV. REVENUE REQUIREMENT IMPACTS

A. Revenue Requirements Associated With The Proposed Cap Increases

Table 3 shows the *incremental* capital RRQ associated with the proposed 2025-2026 cap increases compared to the RRQ associated with the annual caps approved in D.24-07-008, using a 14.8% rule-of-thumb for the respective RRQ calculations.

Table 3[27]
Incremental RRQ Impact Associated With Increase of Proposed Revised 2025 and 2026 Cost Caps compared to Annual Cost Caps Approved in D.24-07-008
(Millions)

	2025	2026	Total
PG&E's Proposed Capital Cost Cap (a)	$2,115	$2,302	$4,417
Annual Caps Approved in D.24-07-008 (b)	$619	$669	$1,288
Increase of Proposed Capital Cost Cap (c = a – b)	$1,496	$1,633	$3,129
RRQ Rule of Thumb (d)	14.8%	14.8%	
Annual RRQ Impact (= c x d)	$221	$242	
Cumulative Incremental RRQ Impact by Year	$221	$463	$684

The average bundled rate impact associated with this incremental RRQ is 1.8%. As explained in further detail below, energization investments will enable increased load on PG&E's system that has the potential to put downward pressure on rates.

B. Revenues From Additional Load Enabled by Energization Investments

As acknowledged by the California Legislature, when considering energization investments, it is important to consider the potential downward pressure on rates resulting from increased load and associated revenues.[28] The energization projects enabled by PG&E's proposed cap increases will facilitate new, additional customer usage that over time will be reflected in PG&E's annual sales forecasts used to determine customer rates.[29] Standing alone, the additional customer usage will provide

[27] Winget Decl. ¶ 13.

[28] Pub. Util. Code § 932(a)(7) and (8).

[29] Winget Decl. ¶ 14.

additional revenue that would tend to decrease rates, all other factors remaining equal.[30] This conclusion is supported by the California Legislature's express findings in SB 410 that "[e]lectrifying transportation and buildings may put downward pressure on rates by spreading fixed costs over more kilowatthours of usage,"[31] and "[d]elays in energization, including service upgrades, are costly both to the customers awaiting service and to other customers deprived of the downward pressure on rates."[32] The conclusion is also consistent with the Public Advocates Office's Distribution Grid Electrification Model, which acknowledges that upward pressure on rates due to increased electrification-related infrastructure costs is offset in part by increased consumption of electricity resulting from electrification.[33] PG&E is planning to conduct Part 2 of the Electrification Impact Study (EIS) as part of the High DER Proceeding, that will provide an additional analysis of the long-term rate impacts of electrification, including the impact on revenue requirements from additional load enabled by energization investments.[34]

V. UPDATED ENERGIZATION FORECASTS

The updated forecasts presented below reflect PG&E's two-year plan to: (1) complete over 38,000 customer-connection projects and eliminate our customer connection backlog to zero by the end of 2026; (2) complete almost 450 distribution and substation capacity projects necessary to resolve system deficiencies necessary to timely connect customers; (3) complete nearly 1,200 relocations necessary to support customer connections; and (4) reduce energization timelines consistent with requirements set forth in the Energization OIR.[35] As previously noted above in Table 1, this is substantially more work than could be completed with current approved funding levels.

To be transparent, PG&E will not use the full amount funding approved for 2024. The 2024 cost cap is $975 million. Of this cap amount, we anticipate incurring approximately $709 million by year-

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[30] Winget Decl. ¶ 14.

[31] Pub. Util. Code § 932(a)(7).

[32] Pub. Util. Code § 932(a)(8).

[33] Public Advocates Office, Distribution Grid Electrification Model – Study and Report, 2023, p. ES-2.

[34] Winget Decl. ¶ 14. EIS Part 2 Study proposed to be completed by end of 2025. See *Proposed Decision of Commissioner Houck* for "Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps" (R.21-06-017), pp. 94-96. Dated September 13, 2024.

[35] Winget Decl. ¶ 15.

end, $266 million below the cap.[36] As explained in Section VII, this underspending is due to the uncertainty of the incremental funding levels that would be approved and the timing of Commission's mid-year issuance of D.24-07-008, which impacted the advance planning and coordination necessary to execute work. The updated forecasts therefore reflect, in part, the movement of uncompleted 2024 work into 2025-2026.[37] Attachment B to the Winget Declaration presents a Revised D.24-07-008 Appendix A to show the updated forecasts by MAT category, including the 2024 work, to arrive at the proposed caps in this Motion.

A. MWC 16 – New Business

1. Description of Activities

New Business (MWC 16) activities involve installing electric infrastructure to connect new customers to our distribution system and accommodate increased load from existing customers. MWC 16 activities are described in more detail in PG&E's 2023 GRC testimony, Exhibit (PG&E-4), Chapter 18.[38]

Decision 24-07-008 determined that the New Business MWC 16 activities listed in Table 4 are eligible for cost recovery the ECNBIMA:[39]

Table 4
Eligible New Business MWC 16 Activities

Major Work Category	Eligible Activities
16	Residential Connects (D.24-07-008 Eligible as Proposed)
	Nonresidential Connects (D.24-07-008 Eligible as Proposed)
	PEV (D.24-07-008 Eligible with Exceptions)
	Transformer Purchases (D.24-07-008 Eligible Contingent on Energization percentages)
	Transformer Scrapping (i.e. Transformer Decommissioning) (D.24-07-008 Eligible Contingent on Energization percentage)s
	AB50 Connects (D.24-07-008 Eligible with Exceptions)

[36] Winget Decl. footnote 27.

[37] Winget Decl. ¶ 15.

[38] A.21-06-021, Exhibit PG&E-4, Chapter 18.

[39] D.24-07-008, pp. 35-36, Table 6-D.

2. Updated Forecast And Forecasting Methodology

Table 5 summarizes the updated forecast for New Business MWC 16 for eligible activities (listed above) and the corresponding amount of work that PG&E will be able to complete in comparison to both GRC authorized funding and D.24-07-008 incremental funding.

Table 5[40]
Updated Forecast and Associated Units for Eligible New Business MWC 16 Activities
(Cost in Thousands)

		Units[41]			Cost (Less Transformer Purchases and Scrapping)			Cost (Including Transformer Purchases and Scrapping)		
		2025	**2026**	**Total**	**2025**	**2026**	**Total**	**2025**	**2026**	**Total**
1	Updated Forecast for Eligible MWC 16 Activities	18,464	19,748	38,212	$2,022,674	$2,243,538	$4,267,428	$2,260,294	$2,495,055	$4,756,565
2	2023 GRC Imputed	6,117	6,117	12,234	$508,942	$517,045	$1,025,987	$702,148	$713,327	$1,415,475
3	D.24-07-008 Incremental Funding	4,400	2,819	7,220	$366,096	$238,324	$604,421	$396,883	$279,650	$676,533
4	Current Available Funding (Line 2 + 3)	10,518	8,936	19,454	$875,038	$755,369	$1,630,408	$1,099,031	$992,977	$2,092,008
5	Proposed Cap Increase Above Current Available Funding (Line 1 - Line 4)	7,946	10,812	18,758	$1,147,635	$1,488,169	$2,635,804	$1,161,263	$1,502,078	$2,663,340

Note: For unit cost details, please see Attachment C (p. C-6) to the Declaration of Bryon Winget.

As shown in Table 5, by increasing funding for eligible MWC 16 activities to $4.8 billion, PG&E can complete approximately 38,000 jobs in 2025-2026.[42] Without this increased funding, PG&E would be only able to complete approximately 19,500 jobs, leaving a backlog of nearly 19,000 jobs at the start of 2027.[43]

The MWC 16 forecast provided in testimony and data request responses for the 2023 GRC Capacity Phase were developed in October 2023. Since that time, D.24-09-020 established energization targets and PG&E updated its forecasts. The updated MWC 16 forecast includes:[44]

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[40] Winget Decl. ¶ 18 (Table 5).

[41] Table 5 shows the number of units that can be completed based upon costs (less transformer purchases and scrapping) provided under various funding scenarios.

[42] Winget Decl. ¶ 19.

[43] Winget Decl. ¶ 19.

[44] Winget Decl. ¶ 20.

a) **Removal of ineligible MAT codes per D.24-07-008.[45]**

b) **Updates to unit costs to complete all backlog work.** The assumption for unit costs has been updated to reflect the resource mix of contractor and internal PG&E labor necessary to eliminate any backlog of customer connection projects by the end of 2026. This includes the elimination of not only backlog required to be complete under AB 50 (AB 50 backlog),[46] but also includes the completion of all backlog work (including non-AB 50 backlog). It is imperative to complete all backlog work to be able to meet energization timelines required under D.24-09-020.

c) **Assumed project completions in 2025-2026 include carryover from 2024.** The forecast has been updated to assume customer-connection projects received in 2025-2026 will be completed by end of 2026, within the 125-business day energization timelines required by D.24-09-020. Additionally, 2025-2026 cost forecasts have been updated to include expected costs from 2024 customer-connection projects that will not be completed in 2024. This increases the anticipated forecasted spend in 2025 and 2026.

d) **Increase in customer demand.** The forecast has been updated to reflect a trend of a ten percent increase in customer demand expected in 2025 and in 2026. PG&E is forecasting to receive approximately 1,000 more applications each year in 2025 and 2026 compared to 2024.

The updated forecast for eligible MWC 16 activities (Table 5, Line 1) is roughly $2.7 billion more than the current approved MWC 16 funding level of $2.1 billion (Table 5, Line 4). The drivers for this proposed $2.7 billion increase are: (1) $2.4 billion to eliminate all backlog work; (2) $74 million associated with meeting Energization OIR requirements; and (3) $170 million for escalation.[47] These drivers are discussed in detail below.

First, it bears repeating, eliminating the backlog is a prerequisite to reducing energization timelines. The $2.1 billion in currently-approved funding contemplates completing a portion of the AB 50 backlog,[48] but does not address non-AB 50 backlog nor the steady-state completion of any new applications, thus perpetuating a backlog.[49] The updated forecast includes $2.4 billion in additional funding necessary to complete nearly 19,000 additional units that will address the non-AB 50 backlog

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45 PG&E removed the following MAT codes, as required in D.24-07-008: PEV NonRes (Rule 29).

46 Pub. Util. Code § 933.5(b)(1) requires PG&E to complete by December 1, 2024 at least 80 percent of customer applications submitted prior to January 31, 2023.

47 Winget Decl. ¶ 21.

48 D.24-07-008, p. 51 ("The 2025 cap reflects forecasted connection request numbers and the final 20 percent of AB 50 projects.").

49 Winget Decl. ¶ 22.

and increase steady state completion level to meet all new customer connection requests by end of 2026.[50]

Second, to complete this additional amount of work, the updated 2025 and 2026 MWC 16 forecasts reflect PG&E's plan to utilize a mix of internal and external resources, which in turn increases unit costs. In the updated forecasts, Residential and Non-Residential unit costs increase in 2025 by 38% (i.e. base connects unit costs of $78,000 in 2024 will increase to $107,000 in 2025 – a $29,000 increase).[51] There is an additional 2% increase in 2026.[52] The $29,000 unit cost increase in 2025 is due the following factors:[53]

Project size and Contractor Resources: Of the $29,000 increase, unit costs will increase by about $24,000 due to the increased average size of PG&E's residential connection projects and the need to use additional qualified contractor construction resources, which are more expensive compared to PG&E construction resources. Contractor resources are comprised of large crew sizes, which are better staffed to handle larger projects. Additionally, assigning contract resources to larger-duration projects allows PG&E crews to be nimbler to move to emergencies when needed and limit impacts on scheduled customer energizations. Projects are increasing in scope and complexity, requiring PG&E to build more system reinforcements and upgrades to serve new electric loads safely and reliably. Indeed, from 2019 to 2023, the number of labor hours required to complete MWC 16 – New Business connections has nearly doubled.[54] Because of these added complexities and challenges, PG&E does not have enough internal resources, nor the time to hire and train more internal staff, to complete all forecasted and backlog work in a timely manner. It is important to note, the increased throughput needed in 2025-2026 is a temporary increase to complete the backlog. It is not prudent to hire permanent staff, which also

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[50] Winget Decl. ¶ 22.

[51] Winget Decl. ¶ 23.

[52] Winget Decl. ¶ 23.

[53] Winget Decl. ¶ 23.

[54] An example is a single-family residential energization request for a panel upgrade due to added load where the current transformer and local infrastructure is at capacity. The project scope grows from a small simple service upgrade to a much larger project of installing a larger transformer, which may also need a larger size pole and additional system reinforcements. Additionally, if a customer or municipality requires the service to be relocated from overhead to underground, there are significant costs and increased scope (i.e., engineering, trenching, permits, restoration, etc.).

requires purchasing additional vehicles, equipment, tools, etc., when this temporary level of staffing is not needed after the backlog is eliminated. Rather, it is prudent to use external qualified contractor construction resources.[55]

Energization OIR Requirements (D.24-09-020): The Energization OIR includes various customer-notification processes that will require additional staffing resources.[56] PG&E estimates these additional processes will increase unit costs by an estimated $2,000. Overall, the unit cost increases associated with complying with the Energization OIR corresponds to approximately $74 million to meet the customer-notification requirements ($37 million per year from 2025-2026). PG&E will use its online customer portal and automated notifications when possible, but an additional 122 project management employees ($37 million per year) will also be needed to complete the increased communication and project management activities required to comply with the Energization OIR's customer-notification requirements.

Escalation: The forecast assumes an additional unit cost escalation rate of 3.4% for 2025 and 1.6% for 2026.[57] This unit cost increase corresponds to approximately $170 million of the updated MWC 16 forecast.

PG&E also updated unit forecasts of transformer purchases/scrapping to support energization projects that will be needed to support increased grid demand.[58] In the updated forecasts, 2025-2026 transformer purchases/scrapping costs eligible to be tracked in the ECNBIMA increase approximately $28 million relative to the amount approved in D.24-07-008.[59]

While not reflected in the updated forecast presented in this Motion, it is important to note that MWC 16 – New Business energization work may result from customer activity other than a formal

[55] To use contract and PG&E resources efficiently, PG&E plans to assign contract resources to larger projects and PG&E resources to smaller projects and emergent project issues. Doing so will enable PG&E to address emergent project issues and avoid schedule impacts on customer energization projects. For example, PG&E crews may need to move from a scheduled or in-process customer energization project to address an emergency, which could create delays or scheduling cancelations for longer duration projects.

[56] D.24-09-020, OP 1. The requirements include but are not limited to: (1) providing all customers with written notice of approval or rejection of their application within an average of 10 business days and a maximum of 45 business days; and (2) if a customer's application for new or upgraded electric service is denied, providing the customer a list of the reason(s) for the denial, what the customer could do to resolve the issue(s) and providing a list of resources the customer can utilize to ensure their application is complete prior to refiling.

[57] Winget Decl. ¶ 23.

[58] Winget Decl. ¶ 24.

[59] Winget Decl. ¶ 24.

customer-connection application.[60] For example, we must complete energization work based upon customer notifications requesting to move to an EV rate schedule. PG&E has approximately 25,000 pending EV-rate notifications and an incoming request rate of approximately 500 per week. These notifications are submitted by customers who have not submitted a formal application for a PEV service connection, but who are charging PEVs at their homes and thus are seeking an EV rate. PG&E must validate customer eligibility for the rate and assess whether any energization work will be required to meet the increased demand. As PG&E completes these assessments, a portion of the notifications will require energization projects to address the added PEV load on the system. PG&E may seek funding for this additional energization work if needed.

3. Justification For Proposed Cap Increase To MWC 16

PG&E has demonstrated the ability to complete increased levels of energization work. PG&E has completed over 7,000 customer connections as of July 2024 and expects to complete more than 5,000 additional customer connections by the end of the year.[61] More energization work needs to be done in 2025-2026, both on pending applications and new applications received as electrification demands increase. PG&E's efforts in 2024 confirm the desire for more connections from our customers, shows that we can complete large volumes of work, and supports our proposed cap increases for 2025 and 2026 work.

To clear the backlog of in-process customer connection applications by the end of 2026 while meeting new customer requests, PG&E needs to complete approximately 38,000 projects in 2025 and 2026.[62] As previously noted above, with the funding levels approved in D.23-11-069 and D.24-07-008, PG&E will be able to energize only about 19,500 projects and would carry a backlog of nearly 19,000 projects into 2027. These numbers do not include any additional customer applications above the amount we have assumed in our updated forecast that may arise in intervening years as customers' electrification demands increase. With the increased cost caps, we will be able to reduce the backlog to zero by the end of 2026, assuming applications do not exceed the forecasted amount.

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[60] Winget Decl. ¶ 25.

[61] Winget Decl. ¶ 26.

[62] Winget Decl. ¶ 27. The backlog excludes PEV NonRes (Rule 29) projects.

The persistence of any energization backlog in 2027 and beyond is inconsistent with the Powering Up Californians Act policy objectives for utilities to have sufficient funding needed to reduce existing backlogs and complete any new energization projects without delay.[63] As noted above, the backlog includes a range of community-benefiting projects, including housing, vehicle charging stations, hospitals and medical facilities, and water treatment plants.

Further, if the backlog continues, PG&E will not be able to meet energization timelines established in the Energization OIR.[64] Clearing the backlog enables us to reduce energization timelines. PG&E provides further information about reducing energization timelines in Section VI.

B. MWCs 06 and 46 – Distribution Line and Substation Capacity

1. Description of Activities

Distribution Line Capacity (MWC 06) includes capacity expansion work outside of substations. MWC 06 projects address specific capacity deficiencies or overload conditions, as well as voltage conditions outside of Electric Rule 2 criteria on distribution lines and equipment. PG&E performs this work to prevent equipment damage or failure due to excessive heating and to prevent outages. Distribution Substation Capacity (MWC 46) work consists of upgrades to various distribution substation equipment with a forecasted capacity deficiency. To the extent possible, PG&E coordinates MWC 06 projects with substation work under MWC 46 to jointly address specific overloads or capacity deficiencies. MWC 06 and 46 activities are described in more detail in PG&E's 2023 GRC testimony, Exhibit (PG&E-4), Chapter 17.

Decision 24-07-008 determined that the MWC 06 activities listed in Table 6 are eligible for tracking in the ECNBIMA:[65]

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[63] Pub. Util. Code § 937(a).

[64] Winget Decl. ¶ 29.

[65] D.24-07-008, pp. 35-36, Table 6-D.

Table 6
Eligible Distribution Line Capacity MWC 06 Activities

Major Work Category	Eligible Activities
06	06A – Feeder Projects Associated with Substation Work[66]
	06B – Overloaded Transformers
	06D – DP Managed Circuit Reinforcement
	06E – PS Managed Circuit Reinforcement
	06H – New Business Related Capacity and Emergent

Decision 24-07-008 determined that the MWC 46 activities listed in Table 7 are eligible for tracking in the ECNBIMA:[67]

Table 7
Eligible Distribution Substation Capacity MWC 46 Activities

Major Work Category	Eligible Activities
46	46A – Normal Capacity[68]
	46H – New Business Related Capacity
	46N – New Business Substation Land Purchases[69]

2. Updated Forecasts and Forecasting Methodology

As electrification increases in our service territory, the additional load strains existing electric distribution assets, thus requiring additional distribution reinforcement and upgrades. These required reinforcements and upgrades, in turn, contribute to increasing the scope, complexity, and costs of PG&E's energization activities in MWCs 06 and 46.[70]

Tables 8 and 9 summarize the updated forecasts for MWCs 06 and 46 respectively, and the corresponding amount of work that PG&E will be able to complete, in comparison to D.24-07-008 funding and corresponding work amounts.

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[66] MAT 06A capital expenditures (line work associated with substation work) that are driven by substation operational or emergency capacity (MAT 46F) are removed.

[67] D.24-07-008, pp. 35-36, Table 6-D.

[68] MAT 46A activities do not include any projects proposed to address supply-side deficiencies or issues caused by distributed generation.

[69] No recovery of MAT 46N costs is permitted until the substation constructed on purchase land has energized significant load.

[70] Winget Decl. ¶ 33.

Table 8[71]
Updated Forecast and Associated Units for Eligible Distribution Line Capacity MWC 06 Activities
(Cost in Thousands)

		Projects			Cost		
		2025	**2026**	**Total**	**2025**	**2026**	**Total**
1	Updated Forecast for Eligible MWC 06 Activities	123	265	388	$479,845	$503,771	$983,616
2	Current Available Funding (2023 GRC Imputed + D.24-07-008)[72]	81	186	267	$306,403	$282,246	$588,649
3	Proposed Cap Increase Above Current Available Funding (line 1 - line 2)	42	79	121	$173,442	$221,525	$394,967

Table 9[73]
Updated Forecast and Associated Units for Eligible Distribution Substation Capacity MWC 46 Activities
(Cost in Thousands)

		Projects			Cost		
		2025	**2026**	**Total**	**2025**	**2026**	**Total**
1	Updated Forecast for Eligible MWC 46 Activities	19	38	57	$214,045	$165,590	$379,635
2	Current Available Funding (2023 GRC Imputed + D.24-07-008)[74]	17	32	49	$107,900	$301,618	$409,518
3	Proposed Cap Increase Above Current Available Funding (line 1 - line 2)	2	6	8	$106,146	$(136,028)[75]	$(29,883)

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71 Winget Decl. ¶ 34 (Table 8).

72 In Tables 8 and 9, project counts forecasted for 2025 and 2026 for the "GRC Imputed and Existing D.24-07-008 Caps" correspond to the distribution plan published in PG&E's 2024 Distribution Deferral Opportunity Report (DDOR) submitted September 6, 2024. The numbers vary slightly from the DDOR because the DDOR includes ineligible MAT codes and counts some projects that may include both MWC 06 and MWC 46 work as one project, whereas Tables 7 and 8 counts these orders separately. PG&E is unable to provide Tables 7 and 8 in a format that identifies GRC Imputed and Existing D.24-07-008 project numbers in separate line items (similar to the format of Tables 4 and 10), because PG&E did not create a distribution plan for capacity projects based on the GRC Imputed amount (i.e., without D.24-07-008). To create a hypothetical GRC-funding-only distribution plan would require significant resources that would not be utilized in any event because D.24-07-008 has superseded it.

73 Winget Decl. ¶ 34 (Table 9).

74 See corresponding footnote 72 for MWC 06 above which applies to MWC 46 as well.

75 The decrease reflects the shifting capital expenditures into 2025, updates to the forecast described in this section, and the exclusion of capital expenditures incurred for projects placed in service after January 1, 2027 that

The MWC 06 and 46 forecasts provided in testimony and data request responses for the 2023 GRC Capacity Phase) were developed in October 2023. Since that time, PG&E has continued to assess system-upgrade needs due to increasing electrification and have updated our forecasts via our electric distribution planning process.[76] The updated MWC 06 and MWC 46 forecasts include:[77]

a) **Removal of ineligible MAT codes per D.24-07-008.**[78]

b) **New customer applications for service.** New customer applications for service have been received and added to the latest forecast.[79] Some of these new applications have created grid needs that require upstream capacity work to fully energize the new customer loads (i.e., the updated forecasts reflect the additional capacity work resulting from these new customer applications).

c) **Updates to system level load and DER growth to reflect the 2022 California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) forecast**.[80] Each distribution planning cycle uses updated CEC IEPR forecast system-level load and DER growth, which is disaggregated to distribution circuits. Updates include revised forecasts for load, solar generation, small and medium/heavy duty vehicle electrification, and fuel substitution (i.e., electric versus natural gas heating).

d) **Removal of projects that are no longer needed**. Changes to the forecast can result in new grid needs or in previous grid needs that have dematerialized. For example, if a customer has cancelled an application for service and that application was the only driver of the capacity project, that project is no longer necessary and has been removed.

e) **Moving of 2024 carryover to 2025**. 2025 cost forecasts have been updated to include expected costs from 2024 projects that will be completed in 2025. This has increased the forecasted capacity spend in 2025.

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are not eligible for the ECNBIMA per D.24-07-008 (corresponding to the field "SB-410 Ineligible" in MWCs 06 and 46 Workpaper Table 1).

[76] PG&E's Distribution Planning Process is detailed annually in its Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR).

[77] Winget Decl. ¶ 35.

[78] PG&E removed the following MAT codes, as required in D.24-07-008: 46F, 06G, 06I, 06K, 06P, 06#. Additionally, PG&E removed MAT 46N because all MAT 46N expenditures involve new substations that are expected to be in service after January 1, 2027. MAT 06A capital expenditures (line work associated with substation work) that are driven by substation operational or emergency capacity (MAT 46F) were also removed. Lastly, MAT 46A activities do not include any projects proposed to address supply-side deficiencies or issues caused by distributed generation.

[79] Additional customer applications for service are added to the forecast as "known loads," as documented in PG&E's 2024 DDOR submitted September 5, 2024, and supplemented on September 10, 2024.

[80] May 12, 2023, Joint Utilities (SCE, SDG&E and PG&E) Letter to Energy Division seeking approval of the 2024-2025 GNA and DDOR, approved by Energy Division in the High DER Proceeding.

f) **Addition of emergent energization work.** Emergent Energization Capital Expenditures are to start new projects that are not yet identified. Emergent work would begin when customers submit new applications that are accepted and approved by the utility, in accordance with the Energization OIR. A revised forecast for MAT 06H includes Eligible Emergent Energization Capital Expenditures for 2025 and 2026. Emergent work for MWC 46 is not included because substation work takes 2-3 years plus and so it is unlikely to be completed by January 1, 2027.

In addition, the MWC 46 updated forecast includes approximately $98 million for additional projects brought forward from 2027 and later.[81] While included in the forecast, these dollars would not be recovered from customers until 2027 or beyond depending on when the project goes operational.

3. Justification For Proposed Cap Increases To MWCs 06 and 46

Table 10 summarizes the number of distribution line and substation projects forecasted to be placed into service by region and by year.[82] With revised 2025 and 2026 caps as proposed, PG&E forecasts placing into service: (1) 123 Line Capacity and 19 Substation Capacity projects in 2025; and (2) 265 Line Capacity and 38 Substation Capacity projects in 2026.[83] This plan reflects identified work necessary to address system deficiencies and facilitate our completion of pending and future energization projects. PG&E will complete these capacity projects *throughout* the service territory, meaning that all customers broadly benefit from this additional work. Specific examples of community-benefiting energization projects enabled by these capacity projects include hospitals, schools, housing developments, electric vehicle charging stations, and agricultural pumping.

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[81] Winget Decl. ¶ 36.

[82] Winget Decl. ¶ 37.

[83] Winget Decl. ¶ 37.

Table 10[84]
Total Number and Location of Capacity Projects

	Total Number of Capacity Projects That Can Be Completed with Revised Cost Caps			
	2025		2026	
Region	**MWC 06**	**MWC 46**	**MWC 06**	**MWC 46**
Bay Area	30	8	29	9
Central Valley[85]	47	6	119	17
North Coast	13	2	48	3
North Valley and Sierra	13	1	25	4
South Bay and Central Coast	20	2	44	5
Total	**123**	**19**	**265**	**38**

Furthermore, with the revised caps as proposed, PG&E will be able to place in-service over 80% of all pending MWC 06 projects by 2026 (i.e., known projects) while also addressing emergent energization projects to prevent the formation of a new backlog.[86] For MWC 46 projects, not all known substation capacity projects can be placed into service by 2026 given the multi-year nature of the projects.

C. MWC 10 – Work at the Request of Others

1. Description of Activities

PG&E's MWC 10, Work at the Request of Others (WRO), involves the relocation/removal of PG&E's existing electric distribution facilities, including overhead-to-overhead relocations, underground-to-underground relocations, overhead-to-underground conversions, pole relocations, and removal of idle PG&E facilities. MWC 10 activities are described in more detail in PG&E's 2023 GRC testimony, Exhibit (PG&E-4), Chapter 18.[87]

[84] Winget Decl. ¶ 37 (Table 10).

[85] The relatively high number of MWC 06 projects forecasted to be placed in-service in 2026 are heavily concentrated in the Central Valley, which has experienced recent load growth due to deeper agricultural pumping and increased air conditioning usage. Circuits in the Central Valley region are often long and far apart, making it particularly difficult to maintain voltage during increased loading without additional equipment such as regulators. These projects typically can be completed in less than a year as they are typically smaller in scope. For example, many of these projects require only the installation of a single voltage regulator to resolve a low voltage problem.

[86] Winget Decl. ¶ 38.

[87] A.21-06-021, Exhibit PG&E-4, Chapter 18.

Decision 24-07-008 provides that WRO activities that support energization projects are eligible for recovery in the ECNBIMA.[88]

2. Updated MWC 10 Forecast and Forecasting Methodology

Table 11 summarizes the MWC 10 updated forecast and the corresponding amount of work that PG&E will be able to complete, in comparison to D.24-07-008 funding and corresponding work amounts.

Table 11[89]
Updated Forecast and Associated Units for Eligible Work Requested by Others (WRO) MWC 10 Activities
(Cost in Thousands)

		Units			Cost		
		2025	2026	Total	2025	2026	Total
1	Updated Forecast for Eligible MWC 10 Activities	660	594	1254	$95,538	$87,360	$182,898
2	2023 GRC Imputed	247	247	494	$35,699	$36,267	$71,966
3	D.24-07-008 Incremental Funding	30	40	70	$4,349	$5,848	$10,198
4	Currently Available Funding[90] (line 2 + line 3)	277	287	564	$40,048	$42,116	$82,164
5	Proposed Cap Increase Above Currently Available Funding (line 1 - line 4)	383	307	690	$55,490	$45,245	$100,734

Note: For unit cost information, see Winget Declaration, Attachment E, p. E-3 (Line 8).

As shown in Table 11, by increasing funding for MWC 10 to $182.9 million ($100.7 million above currently available funding), PG&E will be able to complete more than 1,250 WRO jobs in the 2025-2026 period. Without this increased funding, PG&E would be only able to complete less than half this amount.[91]

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[88] D.24-07-008, pp. 53-54.

[89] Winget Decl. ¶ 41 (Table 11).

[90] D.24-07-008, Appendix A (adding D.23-11-069 Authorized Capital Expenditures and Forecasted SB 410 Capital Cost Incremental to D.23-11-069 columns for MWC 10 for years 2025-2026).

[91] Winget Decl. ¶ 42.

The methodology to calculate project volume and incremental funding amounts necessary to complete WRO energization activities was not changed.[92] The incremental funding proposed for WRO will cover the additional costs that PG&E expects to incur due to additional MWC 16 (New Business) work discussed in Section V.A above. PG&E will record to the ECNBIMA only those amounts that are above the 24% imputed/adopted amounts for WRO work supporting energization, as authorized in D.24-07-008.

To determine the incremental amount required to support energization beyond those amounts approved for WRO in D.24-07-008, PG&E reviewed the incremental volume of energization projects expected above current funding levels and calculated the volume of WRO work that supports energization. This volume was split between residential and non-residential projects utilizing historical data and then multiplied against residential and non-residential unit costs to determine the incremental funding request. The forecast uses a 2024 year-to-date energization WRO unit cost with a 3.4% in escalation 2025 and a 1.6% escalation in 2026.[93] The forecast provided in Table 11 (Line 1) is derived by applying these unit costs to the expected volumes.[94]

The incremental WRO units and costs for these 2025 and 2026 activities relative to GRC Imputed and D.24-07-008 combined funding are shown in Table 11 above (Line 5).

3. Justification For Proposed Cap Increases To MWC 10

The proposed additional funding for MWC 10 will support 690 additional WRO energization projects in 2025 and 2026.[95] Without this funding, there is a risk that WRO projects become an impediment to energizing customers in a timely manner.

VI. ENERGIZATION TIMELINES

A. MWC 16 – New Business

The additional funding requested for MWC 16 in this Motion will allow PG&E to reduce the backlog and meet current customer demand, and in turn timely complete customer connections.[96] The Energization OIR decision directs the investor-owned utilities (IOUs) to achieve a 125 business day

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[92] Winget Decl. ¶ 43.

[93] Winget Decl. ¶ 44.

[94] Winget Decl. ¶ 44.

[95] Winget Decl. ¶ 46.

[96] Winget Decl. ¶ 47.

average energization timeline for Rule 15, Rule 15/16, and Rule 16 projects within a 12 month calendar time period.[97] However, carrying a backlog into 2027 means that PG&E would not be able to meet the Energization OIR targets.

Current funding provided by D.23-11-069 and D.24-07-008 will be insufficient to keep up with the customer demand for new energization requests in 2025-2026. The gap in funding will create an additional backlog of customer work beginning in 2025 and grow into 2026 and 2027. The backlog of customer-requested work will prevent PG&E from being able to meet 95% of projects in less than the maximum allowable time. In order to have less than 5% of projects over the maximum allowable time, PG&E will need to be able to recover 100% of the funds needed to address backlog customers along with meeting the steady-state customer demand.[98]

As noted above, carrying a backlog impacts PG&E's ability to meet energization timelines. PG&E anticipates that it will meet energization timeline requirements for 95% of applications when funding is aligned to customer demand. Once the backlog is addressed, funding will need to be maintained at levels to meet yearly customer demand or PG&E will be unable to energize 95% of customers within the maximum timelines and risk creating a new backlog.[99]

B. MWC 06 and 46 – Distribution Line and Substation Capacity

Increased funding for MWC 06 and MWC 46 also will shorten energization timelines for upstream capacity projects. The increased funding for 2025 and 2026 will enable:[100]

1) **Earlier project kick-offs**. This will allow project management and design teams to scope the project earlier, order materials earlier (e.g., regulators), and enter into construction sooner.

2) **Emergent work.** PG&E will be able to start upstream capacity projects once there is a signed contract and required customer payment is received for energization request(s),[101] rather than waiting until the project is approved and funded.[102] Insufficient funding has added an average of

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[97] D.24-09-020, OP 1.

[98] Winget Decl. ¶ 48.

[99] Winget Decl. ¶ 49.

[100] Winget Decl. ¶ 50.

[101] D.24-09-020, p. 45.

[102] D.24-09-020, p. 45 (The Commission states: "Put simply, there should not be a 'pre-funding' period where SCE, SDG&E and PG&E are awaiting Commission funding decisions to energize customers.").

318 calendar days for Line/Circuit Upgrades (MWC 06),[103] demonstrating the impact of funding for emergent energization work on overall energization timelines.

Without an increased cap, PG&E's lack of funding will continue to extend the upstream capacity timelines.[104] Many of the capacity projects at risk of having their timelines extended are in the Central Valley, where there are load increases from existing customers for air conditioning and for agricultural pumping to reach deeper aquifers. Loading on these assets will mean that new applications for service in these areas may be load limited until upstream capacity upgrades are completed.[105]

VII. WORK EXECUTION

PG&E executes its work through advance planning and coordination that is captured in an annual work plan. The detailed annual work plan is based on the allocated budget for the year. The budget informs not only how many projects PG&E's work execution teams will serve that year, but also the timing to execute each project. This work plan is critical for several reasons, including:[106]

1) Ensures PG&E's resources are utilized efficiently. Resources and work steams are planned at full utilization levels, to ensure crews are not underutilized and there is no idle capacity in work streams.

2) Informs customer construction timelines. The detailed work plan provides customers with information they can use for their own planning. For example, the customer may not want to leave open trenches or half constructed projects for long period of time. If a project is later in the work plan, or perhaps not included in that year's budget-constrained work plan, the customer can adjust its timelines accordingly. The work plan helps customers to plan their project to be coordinated with PG&E.

3) Maximizes permitting efficiencies. Many government agencies require PG&E to obtain permits for energization work. Advance planning helps PG&E from applying too early, which can lead to situations were permit expires and require costly renewals or resubmissions. Advance

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[103] See R.24-01-018, San Diego Gas & Electric Company (U 902-E), Pacific Gas and Electric Company (U 39 E), and Southern California Edison Company (U 338-E) Response to Administrative Law Judge Ruling Directing Utility Responses to Questions regarding Energization Timeline (April 22, 2024) (Joint IOU Response to Mar 21, 2024 Ruling), pp. 32-33.

[104] D.24-09-020, p. 39.

[105] Winget Decl. ¶ 51.

[106] Winget Decl. ¶ 52.

planning also helps PG&E from applying too late and not obtaining permit approval in time, which can lead to changing and delaying construction schedules.

4) Ensures materials are available at the right place at the right time. Many materials and equipment needed for energization project are not "off the shelf" and require lead times to procure bulk quantities. Moreso, supply chain shortages often occur, which can delay projects for months or more. Work plans help mitigate possible delays due to material procurement lead times or supply chain issues. Furthermore, the work plan helps ensure the materials are dispersed across PG&E's warehouses to ensure local crews have the appropriate inventory to complete projects. This advance planning and coordination through the work plan helps ensure materials are ordered and available to PG&E and contractor crews in the right place at the right time.

While PG&E updates its work plans as emergent issues arise, these work plan changes do not have the same advance planning and coordination benefits as projects that were part of the original detailed work plan. For instance, a customer may not be construction ready on short notice. Or PG&E may need to wait for permit approval or materials to arrive to begin a project, leaving crews underutilized.[107]

This is also true when additional budget is allocated to the workplan. While PG&E can hire contractor crews to complete the work, certain steps in project execution require advance planning and coordination (notably customer readiness, materials procurement, and permitting). This means there is a lag between the budget allocation and executing on the updated work plan initially. Over time, the projects in the updated work plan will benefit from the advance planning and coordination benefits. In the near term, however, it will take time to execute projects commensurate with the total budget.[108]

The 2023 GRC imputed funding for New Business (MWC 16) in 2024 is $683 million. PG&E determined that this amount was insufficient for the 2024 work plan and allocated $1,071 million to MWC 16 activities instead. PG&E built detailed work plans to execute on these budgets. Then, in July 2024, PG&E received D.24-07-008, which provided up to an additional $846 million for certain MWC 16 activities.[109] This meant PG&E's work plan could support a budget of $1,529 million ($683 million imputed GRC amount + $846 million incremental), which is $458 million above the original 2024 work

[107] Winget Decl. ¶ 53.

[108] Winget Decl. ¶ 54.

[109] This represents the share of eligible MWC 16 MAT code funding used to set the overall 2024 cap of $975 million in D.24-07-008.

plan. Consistent with the reasons discussed above, PG&E projects it will not spend to the 2024 cap because it cannot complete incremental projects under the updated work plan within the remaining 5-6 months in 2024, especially without the full advanced planning and coordination benefits described above.[110]

The sooner PG&E has certainty of its budget, the sooner it can adopt updated work plans and begin the advanced planning and coordination to deliver on its existing and forecasted customer energization requests.

That said, the Powering Up Californians Act requires electrical utilities to improve energization processes.[111] PG&E acknowledges past inefficiencies and its responsibility to meet statutory performance-improvement requirements. Striving toward this objective, PG&E has already implemented a number of process improvements this year discussed below, and continues to evaluate how to improve, working with customers, the Commission-approved auditor (Ernst & Young), Energy Division staff, and other stakeholders. These improvements reduced costs by tens of millions of dollars annually and will help PG&E to complete forecasted work, subject to obtaining sufficient funding through approval of increasing the annual caps in the ECNBIMA as proposed in this Motion.[112] The process improvements include the following:[113]

1) **Application portal improvements**. In late 2023, PG&E identified that more than half of customer applications did not result in a completed project due to customers abandoning or cancelling the project. By improving the application portal, implementing improved screening tools, and requiring document submission in the application portal, PG&E has reduced customer-initiated-cancellations by about 30% percent. This in turn allows for more efficient use of internal resources on projects that will actually be completed.

2) **Pre-application process improvements**. In May 2024, PG&E updated its document-collection process to reduce the intake timeline and ensure correct information is collected early in the project scoping phase. PG&E is also in the process of redesigning the application intake process and introducing a pre-application process to streamline the collection of project information and documents. This new pre-application process will enable PG&E to engage and consult with customers prior to their

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[110] Winget Decl. ¶ 55.

[111] Pub. Util. Code § 932(a)(5).

[112] Winget Decl. ¶ 57.

[113] Winget Decl. ¶ 58-63.

completing a full application. Currently, approximately 55% of customer applications never progress to the next step in the process due to customer cancellation or abandonment, yet PG&E representatives spend time working on those applications, which is wasted effort. PG&E estimates that the pre-application process will reduce the customer cancellation rate by as much as 70%. The execution of this enhancement involves a redesign of the PG&E application portal and changes how we interact with customers at this early project stage. This enhancement is scheduled to be launched at the end of October 2024.

3) **Estimating and operating rhythm improvements**. Through improved visual management and operating reviews, PG&E reduced the customer wait time for a design and estimate from four months to four weeks. The estimating teams establish clear production targets and track progress against those targets daily.

4) **Job-package-preparation and estimating process improvements**. When customers submit New Business connection applications, PG&E's engineers must create internal orders, job packages, and estimates for the work. In 2024, PG&E improved its job-package-preparation and estimating processes. These improvements include creating job-package checklists and enhancing training for our engineers to improve the quality of the job packages and estimates, which avoids project-delaying re-work. These process improvements decreased the time it takes to complete an electric design by 40%.

5) **Customer readiness and communications improvements**. In 2023, the New Business team initiated a customer-outreach campaign on delayed applications. PG&E contacted the customer of record and the project representative to determine if the project was active, cancelled, or completed. If initial outreach efforts were unsuccessful, PG&E attempted to reach the customers at least two more times. When contacted, if the customer or representative indicated that the project was active, PG&E connected the customer with our Service Planning organization to assist the customer with next steps. When customers indicated the project was cancelled or previously completed, PG&E updated its records to free-up resources. If PG&E was unable to contact the customer or representative within 90 days, the application was cancelled. Identifying applications that are no longer active or needed enabled PG&E to direct its resources to active customer applications.

6) **New Business Project Management Office:** In 2024, PG&E established a New Business Project Management Office (NB PMO) to manage this capital-intensive program. The NB PMO structure is similar to PG&E's Undergrounding PMO, which was able to deliver more underground miles at a lower unit cost than forecasted in 2023. The NB PMO will provide oversight over the New

Business program and will be responsible for the New Business workplan throughout PG&E's service territory. The PMO structure will allow PG&E to leverage economies of scale to deploy contractor resources to complete energization projects. The PMO structure also leverages PG&E's Performance Playbook and many of the lessons learned from the Undergrounding PMO. Similar to the Undergrounding PMO, the NB PMO has implemented the 5 Lean Plays to drive operational excellence across multiple interdependent work groups. This includes: (1) visual management, (2) cascading operating reviews, (3) robust problem solving, (4) enhanced standard work, and (5) waste elimination identification.

VIII. FLEXIBILITY IN SPENDING ACROSS 2025 AND 2026 CAPS

Under the annual cap structure adopting in D.24-07-008, PG&E's funding is unnecessarily constrained when work moves from one year to the next. For example, if work cannot be completed by the end of 2025, it will move to the following year and the capital expenditure will count towards the 2026 cap. However, the 2026 capital expenditures cap is set based only on a forecast of work that would be completed in that year, and does not take into consideration any rollover work from 2025.

As explained above, PG&E has made several process improvements to timely complete the energization work and best mitigate various challenges outside of PG&E's control, such as: permitting agencies timelines; permitting agencies' staffing capacity to process requests; land rights disputes; customer readiness; and material availability. However, as discussed in Section VII, PG&E's ability to execute work efficiently relies on advance planning and coordination to ensure customer, materials, and permit readiness. PG&E therefore respectfully request a decision on this Motion by first-quarter 2025 to maximize this planning and coordination. A decision on the Motion later in 2025 will increase the likelihood that PG&E cannot complete all the 2025 projects included in the updated forecasts because of the time lag between a budget increase, planning and coordination efforts, and work execution..[114]

PG&E requests operational and financial flexibility to spend authorized cap amounts across years to ensure sufficient funding to serve forecasted demand. Specifically, the requested cap amounts for 2025 and 2026 should be adjustable based upon spending in preceding years to enable as many customers as possible to be energized within a total cumulative cap. Flexibility across 2025 and 2026 will allow for customers that could not be energized within the 2025 cap to be energized in 2026, without being arbitrary limited by the 2026 cap.

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[114] Winget Decl. ¶ 65.

IX. REVENUE REQUIREMENT CAPS

Decision 24-07-008 adopts both incremental annual capital cost caps and annual revenue requirement (RRQ) caps. In comments, PG&E had urged the Commission to eliminate the RRQ caps for two reasons. First, PG&E argued that the combination of capital cost caps and RRQ caps created unnecessary ambiguity and confusion. Second, PG&E argued that RRQ caps could inhibit our ability to accelerate project work as envisioned in the Powering Up Californians Act. In revisiting the caps here, the Commission should reconsider this issue and eliminate the annual RRQ caps. Public Utilities Code Section 937 does not require a multi-layered annual cap structure. PG&E provides the following new evidence to support this request.

While D.24-07-008 allows PG&E to count capital expenditures towards the cap for the year in which the expenditures were accrued,[115] the RRQ cap presents an additional, unnecessary constraint. If PG&E completes energization projects ahead of schedule and incur costs exceeding the RRQ cap, we will be unable to recover these costs, despite adhering to the capital expenditure limits. Table 12 illustrates this constraint for MWC 06 Distribution Line Capacity based upon a hypothetical where $10 million of work forecasted for 2025 is accelerated to move into 2024.

Table 12
Capital Expenditure Versus RRQ Cap Example
(Cost in Thousands)

Year	MWC 06 Authorized Capital Expenditure Cap	MWC 06 Annual Additional RRQ Cap[116]	MWC 06 Hypothetical Recorded Capital Expenditures	MWC 06 Annual RRQ Based on Hypothetical Recorded Capital Expenditures[52]
2024	$89,968	$13,315	$99,968	$14,795
2024 – Over Cap Amount				$1,480
2025	$173,549	$25,685	$163,549	$24,205
2026	$147,276	$21,797	$147,276	$21,797
Total Capital Expenditure	$410,793		$410,793	

As shown by this hypothetical, if PG&E incurs a $10 million capital expenditure one year early in 2024 (i.e. accelerates a project), the associated 2024 RRQ would exceed the corresponding annual RRQ cap by $1.48 million even though the 2024-2026 total capital expenditures remains within the

[115] D.24-07-008, Findings of Fact 28.

[116] Assumes $1 of capital cost = $0.148 of Revenue Requirement.

authorized cap. This dual-cap system creates a financial roadblock, hindering our ability to efficiently manage and accelerate energization projects as warranted. For example, at times it may be prudent for us to accelerate a project based on the availability of materials and resources. But the dual caps would work to discourage prudent project management.

To correct for ambiguity and encourage the timely completion of projects, PG&E requests the Commission establish annual caps based only on capital costs, and eliminate the RRQ caps. Setting the annual cost caps based on capital costs only is the most straightforward way for us to manage capital spending and support our project-acceleration efforts. It also clearly defines the amount of eligible capital costs for the eventual recording of RRQs to the approved memorandum account once those projects become operative.

X. PROPOSED SCHEDULE

PG&E respectfully requests the following schedule for Commission's consideration of this motion. PG&E proposes extending certain response deadlines under Commission Rule 11.1 in order to provide parties additional time to review PG&E's motion and supporting materials. To further assist parties' ability to timely review the filing, PG&E has provided the Excel format of Attachments B, C, D, and E to the Winget Declaration, on PG&E's Public Case Documents website.[117]

Proposed Motion Schedule

Activity	Proposed Date
PG&E Moton to Revise 2025 and 2026 Funding Limits	Filed October 4, 2024
Discovery Deadline	November 15, 2024
Responses to Motion	December 2, 2024
PG&E Reply to Responses	December 23, 2024
Draft Proposed Decision	Early February, 2025
Final Decision (effective January 1, 2025)	Early March, 2025

[117] To access the documents:

1. Go to: https://pgera.azurewebsites.net/Regulation/search
2. Select "GRC 2023 Ph I [A.21-06-021]" from the case dropdown menu
3. Select "Other Doc" from the Document Type dropdown menu
4. Select "PGE" from the party dropdown menu
5. Input the date from "10/04/24" to "10/04/24"
6. Click Search

*PG&E will agree to respond to data requests within 5 business days when possible.

XI. CONCLUSION

PG&E respectfully requests the Commission (1) increase the 2025 and 2026 caps as presented in the revised version of D.24-07-008 Appendix A presented in Attachment B to the Winget Declaration, (2) provide for flexibility between 2025 and 2026 cap years, and (3) eliminate the secondary RRQ cap.

Respectfully Submitted,

By: *____/s/ Walker A. Matthews________________*
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PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 4, 2024

ATTACHMENT 1

SUPPORTING DECLARATION OF BRYON WINGET

DECLARATION OF BRYON WINGET IN SUPPORT OF THE MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) TO REVISE 2025 AND 2026 ENERGIZATION COST CAPS

1. I, Bryon Winget, am a Vice President, Electric System Planning, for Pacific Gas and Electric Company (PG&E). In this role, I am responsible for the planning and engineering of PG&E's electric distribution system, including determining the necessity, timing, scope, and location of new electric distribution assets and system upgrades. I make this declaration to support PG&E's Motion to Revise 2025 and 2026 Energization Cost Caps (Motion) set for the Electric Capacity New Business Interim Memorandum Account (ECNBIMA) in Decision (D.) 24-07-008. The statements in this declaration are true and correct to the best of my knowledge.

2. Decision 24-07-008 provides that PG&E may request that the Commission revisit and change the 2025 and 2026 caps based on new evidence and any other relevant information, including the adoption of energization timelines and other requirements in Rulemaking (R.) 24-01-018 (Energization OIR).[1, 2]

3. In brief, we request the Commission approve the following:

a. Increase the 2025 capital costs cap from $619 million to $2.115 billion;
b. Increase the 2026 capital costs cap from $669 million to $2.302 billion;
c. Authorize the ability to spend authorized amounts across 2025 and 2026; and
d. Eliminate the secondary revenue requirement (RRQ) caps for 2024-2026.

This declaration provides new evidence and information supporting our requests. As explained in further detail below, the proposed increase will allow us to complete more than double the amount of customer-requested energization work than can be completed under the current caps. In particular, the additional funding will allow us to complete nearly 19,000 more projects to eliminate our existing backlog, as well as address new applications and emergent energization projects. The primary customer complaint related to energization is dissatisfaction with delays

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[1] D.24-09-020, Ordering Paragraph (OP) 1.

[2] D.24-07-008, OP 28.

and the impacts those delays have on their lives. Additional funding will allow us to address customer concerns, comply with AB 50, and meet the Energization OIR Decision 24-09-020 requirements by 2027. The requested incremental cap increases, if approved, would result in a bundled average rate impact of 1.8% and a typical residential bill impact of $3.65/month;[3] these impacts would be mitigated by additional revenue resulting from increased load that puts downward pressure on rates.

4. This declaration is organized as follows:

- Section I summarizes the broad customer benefits gained by increasing the 2025-2026 energization cost caps.
- Section II explains the operation of the ratemaking mechanism approved in D.24-07-008.
- Section III discusses the revenue requirement (RRQ) associated with the proposed cap increases and the link between additional load and revenues from energization investments.
- Section IV discusses our updated energization forecasts and proposed increases to the 2025 and 2026 cost caps. This includes a discussion regarding the additional energization work we will be able to complete if the Commission adopts the proposed cost cap increases.
- Section V further explains how the additional funding will enable us to reduce energization timelines to meet Commission requirements in the Energization OIR Decision 24-09-020.
- Section VI discusses our ability to execute work when increased funding is approved, as well as our work process improvements on energization activities.

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[3] Average bundled residential rate increase of $0.0073/kWh multiplied by 500 kWh.

- Section VII discusses our proposal to provide flexibility to spend authorized amounts between 2025 and 2026.
- Section VIII discusses our proposal to eliminate the RRQ caps.
- Section IX concludes this declaration.

I. SUMMARY

5. Revising the caps as proposed above is necessary to fulfill our obligation to serve customers,[4] and achieve California's policy objectives to upgrade the state's electrical distribution systems and energize new customers without delay, in accordance with Senate Bill (SB) 410 and Assembly Bill (AB) 50.[5] We appreciate the incremental funding for energization activities granted in D.24-07-008 and acknowledge that the Commission's decision reflects a substantial commitment to continued progress on critically important energization work. We share that commitment and are not seeking changes to D.24-07-008 related to the eligible MAT codes, the SB 410 auditor selection, the SB 410 auditor reporting requirements, the memo account ECNBIMA cost tracking requirements, or the cost reasonableness review process. However, as explained in further detail below, we simply cannot fulfill customers' connection requests under the incremental funding levels adopted in D.24-07-008, contrary to our obligation to serve and the California Legislature's intent in AB 50 to eliminate the backlog of projects[6] and in SB 410 to require the Commission to ensure that there is sufficient and timely recovery of costs to energize projects.[7] An increase to the 2025 and 2026 energization cost caps is required to meet these

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[4] Pub. Util. Code § 451 (stating in part, "Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, . . ., as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

[5] SB 410 and AB 50 are codified together as the Powering Up Californians Act (Pub. Util. Code §§ 930-939.5).

[6] Pub. Util. Code § 933.5(b).

[7] Pub. Util. Code § 937(a).

objectives. Here is a summary of the updates discussed in this declaration in comparison to what has been approved in D.24-07-008:

MWC	Issue	Related Declaration Section
MWC 16 New Business	Update forecast with increased units and unit costs	IV.A, ¶¶ 18 to 20, and Attachment C
MWC 16 New Business	Unit costs	IV.A, ¶ 23, and Attachment C
MWC 16 New Business	Customer outreach costs from the Energization OIR D.24-09-020	IV.A, ¶ 23, and Attachment C,
MWC 16 New Business	Eliminate backlog, accelerate projects into 2025-2026	IV.A, ¶¶ 27 to 29 and Attachment C
MWC 06 Distribution Line Capacity **MWC 46** Substation Capacity	Update forecast with 2022 IEPR, emergent work, and refreshed list of customer applications	IV.B, ¶¶ 34 to 36, and Attachment D
MWC 06 Distribution Line Capacity **MWC 46** Substation Capacity	Geographical breakdown of projects	IV.B, ¶ 37
MWC 10 Work at Request of Others	Update forecast based on a percent of MWC16	IV.C, ¶¶ 41 to 42, and Attachment E
MWC 16 New Business	Compliance with energization targets from D.24-09-020	V.A, ¶¶ 47 to 49
MWC 06 Distribution Line Capacity **MWC 46** Substation Capacity	Compliance with upstream capacity upgrade timelines from D.24-09-020	V.B, ¶¶ 50 to 51
MWC 16 New Business	Work execution and process improvements	VI
All	Flexibility in spending for 2025-2026	VII
All	Elimination of RRQ caps	VIII
All	Eligible MAT codes	No change requested
All	SB410 auditor selection	No change requested
All	SB410 audit requirements	No change requested
All	ECNBIMA parameters	No change requested
All	Tracking costs in ECNBIMA	No change requested
All	Cost recovery and reasonableness review requirements	No change requested

6. The proposed increases to the 2025 and 2026 costs caps presented in our Motion will allow us to reduce the customer-connections backlog to zero by the end of 2026.[8] Specifically, with additional funding provided by the proposed increased caps, we could complete 18,758 more customer connections, 129 more capacity projects, and 690 more work-at-the-request-of-others (WRO) projects than could otherwise be completed.[9] Further, by facilitating the reduction of the backlog to zero, the proposed cap increases will allow us to meet the energization targets set forth in the Energization OIR (Decision 24-09-020), including the requirement to complete new customer connections (including Electric Rule 15 and Electric Rule 16) within no more than 125 business days, on average.[10] Table 1 summarizes the amount of additional energization work we could complete if the Commission grants our request to increase 2025-2026 cost caps, compared to the work amounts we could complete under existing approved funding levels.

Table 1
Additional 2025-2026 Units and Projects

Activity	Units/Projects With Current Funding Level (D.23-11-069 and D.24-07-008)	Additional Units/Projects with Increased Caps Proposed In Motion	Total Units/Projects With Total New Overall Funding Levels
MWC 16 (New Business) Customer Connections	19,454	18,758	38,212
MWC 06 (Distribution Line Capacity) Projects	267	121	388
MWC 46 (Substation Capacity) Projects	49	8	57
MWC 10 (Work Requested by Others) Relocations	564	690	1,254

7. The energization work we plan to complete benefits customers directly in many ways:

[8] Attachment C, p. C-8.

[9] Attachment C, p. C-1 (Line 5); Attachment D, p. D-1 (Sum of Lines 3 and 10); Attachment E, p. E-1 (Line 5).

[10] D.24-09-020, OP 1.

Backlog Elimination and Quicker Customer Connections: There is a direct causal link between backlogs and our ability to improve energization timelines. Persistent backlogs directly lead to lengthier customer connection timelines. Due in part to additional costs for energization work as a result of the Energization OIR, we estimate that under current approved funding, our backlog will continue to grow to nearly 19,000 uncompleted projects by the end of 2026. These delays will hinder our ability to improve customer connection timelines, which could increase to as much as 395 business days on average. In contrast, the funding increase requested in our Motion, will allow us to eliminate the backlog and reduce energization timelines to 125 business days, consistent with the Energization OIR.

Revenues from Additional Load: We expect that the customer connections and capacity work we plan to complete will result in additional customer usage each year. The additional sales to customers each year will yield revenues that over time have the potential to put downward pressure on rates, consistent with the California Legislature's findings in SB 410.[11] We address this issue further below in Section III.

Improved Grid Health: Under the total funding requested, we will make a series of load-enabling investments that will prevent approximately 300 circuits from becoming overloaded. Hundreds of capacity projects are required to ready the grid for near-term new connections and larger loads in 2025-2026. This grid-readiness work will allow us to timely connect both pending and future connections in areas currently with limited capacity. Without increased funding we would not be able to complete about one-third of the capacity projects we need to complete.

Lower Emissions: The California Legislature has determined that widespread electrification is vital to achieving California's decarbonization and air quality goals. Public Utilities Code Section 932 provides in part:

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[11] Pub. Util. Code § 932(a)(7) and (8).

> (1) It is the policy of the state to reach carbon neutrality no later than 2045 and to maintain net negative emissions of greenhouse gases after 2045. To meet these goals and federal, state, regional, and local air quality and decarbonization standards, plans, and regulations, projections from the commission and the Energy Commission show the need for a large increase in both the quantity of electricity used and the functions for which electricity will be used.[12]
>
> (2) To meet these decarbonization goals and federal, state, regional, and local air quality and decarbonization standards, plans, and regulations, the state's electrical distribution systems must be substantially upgraded, new customers must promptly connect to the electrical distribution system, and existing customers must have their service level promptly upgraded.[13]

Our planned work advances these objectives.

Other Community-Wide Benefits: The capacity work we plan to complete in 2025-2026 with increased funding is necessary for housing projects, electric vehicle charging stations, high-speed rail construction, data centers, internet-order delivery hubs, commercial redevelopment projects, and local infrastructure such as hospitals and water treatment plants. These projects broadly benefit all customers.

II. OPERATION OF THE ELECTRIC CAPACITY NEW BUSINESS INTERIM MEMORANDUM ACCOUNT (ECNBIMA)

8. On July 16, 2025, the Commission issued D.24-07-008 authorizing PG&E to establish the Electric Capacity New Business Interim Memorandum Account (ECNBIMA) to record costs for specific eligible energization activities within Maintenance Activity Types (MATs) for the following Major Work Categories (MWC): MWC 16 – New Business, MWC 06 – Distribution Line Capacity; MWC 46 – Substation Capacity; and MWC 10 – Work Requested

[12] Pub. Util. Code § 932(a)(1) (emphasis added).

[13] Pub. Util. Code § 932(a)(2) (emphasis added).

by Others.[14] Attachment A lists the ECNBIMA-eligible MATs identified in D.24-07-008 and associated funding levels adopted by the Commission in D.23-11-069.[15]

9. Decision 24-07-008 capped the incremental capital costs and associated revenue requirements that may be recorded to the ECNBIMA as shown in Table 2.

Table 2
Annual Caps Approved in D.24-07-008
(Millions)

	2024	2025	2026	Total
Incremental Capital Cost Cap	$975	$619	$669	$2,263
Incremental Revenue Requirements	$144.31	$91.57	$99.07	$715.14[16]

10. In D.24-07-008, the Commission expressly provided PG&E flexibility to maximize PG&E's use of available funding under the caps by allowing capital additions when placed into service or capital expenditures when incurred to be counted towards the cap.[17] This flexibility allows PG&E to count capital additions or capital expenditures toward the annual caps. In all instances, PG&E may only recover capital expenditures through the ECNBIMA once the projects are placed into service. Only capital expenditures incurred for projects placed in service

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[14] D.24-07-008, Appendix A (listing eligible MWCs, MATs, and the adopted GRC capital expenditure amounts).

[15] D.24-07-008, OP 2 and Section 12 (Conclusion), p. 81.

[16] D. 24-07-008, p. 82, states the decision was modified to clarify that revenue requirements (RRQ) approved under this ratemaking mechanism not only apply to the year after the capital additions are made, but also to subsequent years of this mechanism. D.24-07-008, p. 3, explains that the maximum 202[4]-2026 revenue requirements include the annual incremental 2024-2026 revenue requirements plus the ongoing revenue requirements associated with prior year capital additions. Capital costs are recovered through the remaining life of the capital assets consistent with cost-of-service ratemaking. Assuming PG&E spends all the incremental funding approved in the decision, the recoverable RRQ associated with that spending is $144.3 million in 2024; $235.9 million in 2025, and $335.0 million in 2026, for a combined $715 million RRQ over 2024-2026.

[17] D.24-07-008, p. 82 ("This decision was modified to provide additional flexibility in tracking both capital expenditures and capital additions within the ECNBIMA and to clarify the manner of their inclusion within the AET ALs. Capital additions will be recovered through the AET ALs. Capital expenditures can count against the cap in the year they are incurred, but cannot be recovered until and unless the project is placed into service.").

by January 1, 2027 are eligible for recovery through the ECNBIMA.[18] Finally, PG&E is authorized to include costs recorded to the memorandum account in its Annual Electric True Up (AET) Advice Letters as the ratemaking mechanism granting interim rate recovery for the costs recorded in the account, subject to reasonableness review in PG&E's next GRC.[19]

11. The amounts authorized in D.24-07-008 equate to an increase in electric distribution revenue requirement of 1.98 percent for 2024, 1.18 percent for 2025, and 1.19 percent for 2026, and 4.03 percent cumulatively.[20]

12. As noted above, D.24-07-008 allows PG&E the opportunity to request revisions to the adopted cost caps "based on additional evidence submitted by motion including evidence that may support accelerated work on energization projects and a higher cap on energization projects in those years."[21] In accordance with this direction, PG&E provides updated energization forecasts in Section IV below. Prior to this discussion, Section III discusses the RRQ impact of our request in this Motion, including a discussion regarding incremental revenues resulting from our planned energization work that has the potential to put downward pressure on rates over time.

III. REVENUE REQUIREMENT IMPACTS

A. Revenue Requirements Associated With The Proposed Cap Increases

13. Table 3 shows the *incremental* capital RRQ associated with the proposed 2025-2026 cap increases compared to the RRQ associated with the annual caps approved in D.24-07-008, using a 14.8% rule-of-thumb for the respective RRQ calculations.

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[18] D.24-07-008, p. 82.

[19] D.24-07-008, OP 1.

[20] D.24-07-008, pp. 2 and 80.

[21] D.24-07-008, p. 80.

Table 3
Incremental RRQ Impact Associated With Increase of Proposed Revised 2025 and 2026 Cost Caps compared to Annual Cost Caps Approved in D.24-07-008
(Millions)

	2025	2026	Total
PG&E's Proposed Capital Cost Cap (a)	$2,115	$2,302	$4,417
Annual Caps Approved in D.24-07-008 (b)	$619	$669	$1,288
Increase of Proposed Capital Cost Cap (c = a – b)	$1,496	$1,633	$3,129
RRQ Rule of Thumb (d)	14.8%	14.8%	
Annual RRQ Impact (= c x d)	$221	$242	$463
Cumulative Incremental RRQ Impact by Year	$221	$463	$684

The average bundled rate impact associated with this incremental RRQ is 1.8%. As explained in further detail below, energization investments will enable increased load on PG&E's system that has the potential to put downward pressure on rates.

B. Revenues from Additional Load Enabled by Energization Investments

14. As acknowledged by the California Legislature, when considering energization investments, it is important to consider the potential downward pressure on rates resulting from increased load and associated revenues.[22] The energization projects enabled by PG&E's proposed cap increases will facilitate new, additional customer usage that over time will be reflected in PG&E's annual sales forecasts used to determine customer rates. Standing alone, the additional customer usage will provide additional revenue that would tend to decrease rates, all other factors remaining equal. This conclusion is supported by the California Legislature's express findings in SB 410 that "[e]lectrifying transportation and buildings may put downward pressure on rates by spreading fixed costs over more kilowatthours of usage,"[23] and "[d]elays in energization, including service upgrades, are costly both to the customers awaiting service and to

[22] Pub. Util. Code § 932(a)(7) and (8).

[23] Pub. Util. Code § 932(a)(7).

other customers deprived of the downward pressure on rates."[24] The conclusion is also consistent with the Public Advocates Office's Distribution Grid Electrification Model, which acknowledges that upward pressure on rates due to increased electrification-related infrastructure costs is offset in part by increased consumption of electricity resulting from electrification.[25] PG&E is planning to conduct Part 2 of the Electrification Impact Study (EIS) as part of the High DER Proceeding, that will provide an additional analysis of the long term rate impacts of electrification, including the impact on revenue requirements from additional load enabled by energization investments.[26]

IV. UPDATED ENERGIZATION FORECASTS

15. The updated forecasts presented below reflect our two-year plan to: (1) complete over 38,000 customer-connection projects and eliminate our customer connection backlog to zero by the end of 2026; (2) complete almost 450 distribution and substation capacity projects necessary to resolve system deficiencies so that we can timely connect customers; (3) complete nearly 1,200 relocations necessary to support customer connections; and (4) reduce energization timelines consistent with requirements set forth in the Energization OIR. As previously noted above in Table 1, this is substantially more work than could be completed with current approved funding levels. Please note that due to the uncertainty of incremental funding levels that would be adopted, the timing of Commission's mid-year issuance of D.24-07-008, and advanced planning and coordination necessary to execute work, we were unable to complete the full volume of energization activities originally forecasted for 2024 in our SB 410 testimony for this proceeding,

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[24] Pub. Util. Code § 932(a)(8).

[25] Public Advocates Office, Distribution Grid Electrification Model – Study and Report, 2023, p. ES-2.

[26] EIS Part 2 Study proposed to be completed by end of 2025. See R.21-06-017, *Proposed Decision of Commissioner Houck* for "Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps" (September 13, 2024), pp. 94-96.

as explained in Section VI.[27] Our updated forecasts therefore reflect, in part, the movement of uncompleted 2024 work into 2025-2026. Attachment B presents a Revised D.24-07-008 Appendix A to show the updated forecasts by MAT category, including this 2024 work, to arrive at the proposed caps in the Motion.

A. MWC 16 – New Business

1. Description of Activities

16. New Business (MWC 16) activities involve installing electric infrastructure to connect new customers to our distribution system and accommodate increased load from existing customers. MWC 16 activities are described in more detail in PG&E's 2023 GRC testimony, Exhibit (PG&E-4), Chapter 18.[28]

17. Decision 24-07-008 determined that the New Business MWC 16 activities listed in Table 4 are eligible for cost recovery the ECNBIMA:[29]

Table 4
Eligible New Business MWC 16 Activities

Major Work Category	Eligible Activities
16	Residential Connects (D.24-07-008 Eligible as Proposed)
	Nonresidential Connects (D.24-07-008 Eligible as Proposed)
	PEV (D.24-07-008 Eligible with Exceptions)
	Transformer Purchases (D.24-07-008 Eligible Contingent on Energization percentages)
	Transformer Scrapping (i.e. Transformer Decommissioning) (D.24-07-008 Eligible Contingent on Energization percentage)s
	AB50 Connects (D.24-07-008 Eligible with Exceptions)

[27] For this reason, we will not use the full amount funding approved for 2024. The 2024 cost cap is $975 million. Of this cap amount, we anticipate incurring approximately $709 million by year-end, which is $266 million below the cap. *See* Attachment B, p. B-2.

[28] A.21-06-021, Exhibit PG&E-4, Chapter 18.

[29] D.24-07-008, pp. 35-36, Table 6-D.

2. Updated Forecast And Forecasting Methodology

18. Table 5 summarizes our updated forecast for New Business MWC 16 for eligible activities (listed above) and the corresponding amount of work that we will be able to complete in comparison to both GRC authorized funding and D.24-07-008 incremental funding. [30] Workpapers supporting the forecast are provided in Attachment C.

Table 5
Updated Forecast and Associated Units for Eligible New Business MWC 16 Activities
(Cost in Thousands)

		Units[31]			Cost (Less Transformer Purchases and Scrapping)			Cost (Including Transformer Purchases and Scrapping)		
		2025	**2026**	**Total**	**2025**	**2026**	**Total**	**2025**	**2026**	**Total**
1	Updated Forecast for Eligible MWC 16 Activities	18,464	19,748	38,212	$2,022,674	$2,243,538	$4,267,428	$2,260,294	$2,495,055	$4,756,565
2	2023 GRC Imputed	6,117	6,117	12,234	$508,942	$517,045	$1,025,987	$702,148	$713,327	$1,415,475
3	D.24-07-008 Incremental Funding	4,400	2,819	7,220	$366,096	$238,324	$604,421	$396,883	$279,650	$676,533
4	Current Available Funding (Line 2 + 3)	10,518	8,936	19,454	$875,038	$755,369	$1,630,408	$1,099,031	$992,977	$2,092,008
5	Proposed Cap Increase Above Current Available Funding (Line 1 - Line 4)	7,946	10,812	18,758	$1,147,635	$1,488,169	$2,635,804	$1,161,263	$1,502,078	$2,663,340

Note: Transformer Purchases and Scrapping are separate line items not a part of unit costs. See Attachment C, p. C-6 for unit cost details used to develop PG&E's request,

19. As shown in Table 5, by increasing funding for eligible MWC 16 activities to $4.8 billion, we will be able to complete approximately 38,000 jobs in this period. Without this increased funding, we would be only able to complete approximately 19,500 jobs, leaving a backlog of nearly 19,000 jobs at the start of 2027.

20. The MWC 16 forecast provided in testimony and data request responses for the Capacity Phase of the 2023 General Rate Case (A.21-06-021) were developed in October

[30] Attachment C, p. C-1.

[31] Table 5 shows the number of units that can be completed based upon costs (less transformer purchases and scrapping) provided under various funding scenarios.

2023. Since that time, D.24-09-020 established energization targets and PG&E updated its forecasts. Our updated MWC 16 forecast includes:

a) **Removal of ineligible MAT codes per D.24-07-008.[32]**
b) **Updates to unit costs to complete all backlog work.** The assumption for unit costs has been updated to reflect the resource mix of contractor and internal PG&E labor necessary to eliminate any backlog of customer connection projects by the end of 2026. This includes the elimination of not only backlog required to be complete under AB 50 (AB 50 backlog),[33] but also includes the completion of all backlog work (including non-AB 50 backlog). It is imperative to complete all backlog work to be able to meet energization timelines required under D.24-09-020. We discuss the updated unit costs and the completion of all backlog work in Paragraphs 21 to 29.
c) **Assumed project completions in 2025-2026 include carryover from 2024.** The forecast has been updated to assume customer connection projects received in 2025-2026 will be completed by end of 2026, within the 125-business day energization timelines required by D.24-09-020. Additionally, 2025-2026 cost forecasts have been updated to include expected costs from 2024 customer connection projects that will not be completed in 2024. This increases the anticipated forecasted spend in 2025 and 2026.
d) **Increase in customer demand.** The forecast has been updated to reflect a trend of a ten percent increase in customer demand expected in 2025 and in 2026. We are forecasting to receive approximately 1,000 more applications each year in 2025 and 2026 compared to 2024.

21. Our updated forecast for eligible MWC 16 activities (Table 5, Line 1) is roughly $2.7 billion more than the current approved MWC 16 funding level of $2.1 billion (Table 5, Line 4). The drivers for this proposed $2.7 billion increase are: (1) $2.4 billion to eliminate all backlog work; (2) $74 million associated with meeting Energization OIR requirements; and (3) $170 million for escalation. We discuss these drivers in detail below.

22. First, it bears repeating, eliminating the backlog is a prerequisite to reducing energization timelines. The $2.1 billion in currently-approved funding contemplates completing a

[32] PG&E removed the following MAT codes, as required in D.24-07-008: PEV NonRes (Rule 29).

[33] Pub. Util. Code § 933.5(b)(1) requires PG&E to complete by December 1, 2024 at least 80 percent of customer applications submitted prior to January 31, 2023.

portion of the AB 50 backlog,[34] but does not address non-AB 50 backlog nor the steady-state completion of any new applications, thus perpetuating a backlog. Our updated forecast includes $2.4 billion in additional funding necessary to complete nearly 19,000 additional units that will address the non-AB 50 backlog and increase steady state completion level to meet all new customer connection requests by end of 2026.[35]

23. Second, to complete this additional amount of work, the updated 2025 and 2026 MWC 16 forecasts reflect our plan to utilize a mix of internal and external resources, which in turn increases unit costs. In our updated forecasts, Residential and Non-Residential unit costs increase in 2025 by 38% (i.e. base connects unit costs of $78,000 in 2024 will increase to $107,000 in 2025 – a $29,000 increase).[36] There is an additional 2% increase in 2026. The $29,000 unit cost increase in 2025 is due the following factors:

> <u>Project size and Contractor Resources</u>: Of the $29,000 increase, unit costs will increase by about $24,000 due to the increased average size of our residential connection projects and the need to use additional qualified contractor construction resources, which are more expensive compared to PG&E construction resources. Contractor resources are comprised of large crew sizes, which are better staffed to handle larger projects. Additionally, assigning contract resources to larger-duration projects allows PG&E crews to be nimbler to move to emergencies when needed and limit impacts on scheduled customer energizations. Projects are increasing in scope and complexity, requiring us to build more system reinforcements and upgrades to serve new electric loads safely and reliably. Indeed, from 2019 to 2023, the number of labor hours required to complete MWC 16 – New Business connections has nearly doubled. An example is a single-family

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[34] D.24-07-008, p. 51 ("The 2025 cap reflects forecasted connection request numbers and the final 20 percent of AB 50 projects.").

[35] Attachment C, p. C-8.

[36] Attachment C, p. C-6.

residential energization request for a panel upgrade due to added load where the current transformer and local infrastructure is at capacity. The project scope grows from a small simple service upgrade to a much larger project of installing a larger transformer, which may also need a larger size pole and additional system reinforcements. Additionally, if a customer or municipality requires the service to be relocated from overhead to underground, there are significant costs and increased scope (i.e., engineering, trenching, permits, restoration, etc.). Because of these added complexities and challenges, we do not have enough internal resources, nor the time to hire and train more internal staff, to complete all forecasted and backlog work in a timely manner. It is important to note, the increased throughput needed in 2025-2026 is a temporary increase to complete the backlog. It is not prudent to hire permanent staff, which also requires purchasing additional vehicles, equipment, tools, etc., when this temporary level of staffing is not needed after the backlog is eliminated. Rather, it is prudent to use external qualified contractor construction resources.[37]

Energization OIR Requirements (D.24-09-020): The Energization OIR includes various customer-notification processes that will require additional staffing resources.[38] We estimate these additional processes will increase unit costs by an estimated $2,000.[39]

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[37] To use contract and PG&E resources efficiently, PG&E plans to assign contract resources to larger projects and PG&E resources to smaller projects and emergent project issues. Doing so will enable PG&E to address emergent project issues and avoid schedule impacts on customer energization projects. For example, PG&E crews may need to move from a scheduled or in-process customer energization project to address an emergency, which could create delays or scheduling cancelations for longer duration projects.

[38] D.24-09-020, OP 1. The requirements include but are not limited to: (1) providing all customers with written notice of approval or rejection of their application within an average of 10 business days and a maximum of 45 business days; and (2) if a customer's application for new or upgraded electric service is denied, providing the customer a list of the reason(s) for the denial, what the customer could do to resolve the issue(s) and providing a list of resources the customer can utilize to ensure their application is complete prior to refiling.

[39] Attachment C, p. C-6 (Line 14).

Overall, the unit cost increases associated with complying with the Energization OIR corresponds to approximately $74 million to meet the customer-notification requirements ($37 million per year from 2025-2026). We will use our online customer portal and automated notifications when possible, but an additional 122 project management employees will also be needed to complete the increased communication and project management activities required to comply with the Energization OIR's customer-notification requirements.

Escalation: Finally, our forecast assumes an additional unit cost escalation rate of 3.4% for 2025 and 1.6% for 2026.[40] This unit cost increase corresponds to approximately $170 million of the updated MWC 16 forecast.

24. We also updated unit forecasts of transformer purchases/scrapping to support energization projects that will be needed to support increased grid demand.[41] In our updated forecasts, 2025-2026 transformer purchases/scrapping costs eligible to be tracked in the ECNBIMA increase approximately $28 million relative to the amount approved in D.24-07-008.[42]

25. While not reflected in our updated forecast presented in the Motion, it is important to note that MWC 16 – New Business energization work may result from customer activity other than a formal customer-connection application. For example, we must complete energization work based upon customer notifications requesting to move to an EV rate schedule. PG&E has approximately 25,000 pending EV-rate notifications and an incoming request rate of approximately 500 per week. These notifications are submitted by customers who have not submitted a formal application for a PEV service connection, but who are charging PEVs at their

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[40] S&P IHS Markit Q1 2024 Forecast; Attachment C, p. C-6.

[41] Attachment C, p. C-4 (Table E – Forecast Transformer Cost per New Business Job).

[42] Attachment C, p. C-2 (Lines 4 and 5, comparing 2025-2026 Updated Forecast for Eligible MWC 16 Activities to Currently Available Funding).

homes and thus are seeking an EV rate. PG&E must validate customer eligibility for the rate and assess whether any energization work will be required to meet the increased demand. As we complete our assessments, a portion of the notifications will require energization projects to address the added PEV load on the system. PG&E may seek funding for this additional energization work if needed.

3. Justification For Proposed Cap Increase To MWC 16

26. We have demonstrated the ability to complete increased levels of work. As of July 2024, we completed over 7,000 customer connections this year. We also expect to complete more than 5,000 additional customer connections by the end of the year. More energization work needs to be done in 2025-2026, both on pending applications and new applications we will receive as electrification demands increase. Our efforts in 2024 confirm the desire for more connections from our customers, shows that we can complete large volumes of work, and supports our proposed cap increases for 2025 and 2026 work.

27. To clear the backlog of in-process customer connection applications by the end of 2026 while meeting new customer requests, we need to complete approximately 38,000 projects in 2025 and 2026.[43] As previously noted above, with the funding levels approved in D.23-11-069 and D.24-07-008, we will be able to energize only about 19,500 projects and would carry a backlog of nearly 19,000 projects into 2027. These numbers do not include any additional customer applications above the amount we have assumed in our updated forecast that may arise in intervening years as customers' electrification demands increase. With the increased cost caps, we will be able to reduce the backlog to zero by the end of 2026, assuming applications do not exceed the forecasted amount.

28. The persistence of any energization backlog in 2027 and beyond is inconsistent with the statutory policy objectives for utilities to have sufficient funding needed to reduce

[43] The backlog excludes PEV NonRes (Rule 29) projects.

existing backlogs and complete any new energization projects without delay.[44] As noted above, the backlog includes a range of community-benefiting projects, including housing, vehicle charging stations, hospitals and medical facilities, and water treatment plants.

29. Further, if we continue to carry a backlog of customer connection projects, we will not be able to meet energization timelines established in the Energization OIR. Clearing the backlog enables us to reduce energization timelines. We provide further information about reducing energization timelines in Section V.

B. MWCs 06 and 46 – Distribution Line and Substation Capacity

1. Description of Activities

30. Distribution Line Capacity (MWC 06) includes capacity expansion work outside of substations. MWC 06 projects address specific capacity deficiencies or overload conditions, as well as voltage conditions outside of Electric Rule 2 criteria on distribution lines and equipment. We perform this work to prevent equipment damage or failure due to excessive heating and to prevent outages. Distribution Substation Capacity (MWC 46) work consists of upgrades to various distribution substation equipment with a forecasted capacity deficiency. To the extent possible, we coordinate MWC 06 projects with substation work under MWC 46 to jointly address specific overloads or capacity deficiencies. MWC 06 and 46 activities are described in more detail in PG&E's 2023 GRC testimony, Exhibit (PG&E-4), Chapter 17.

31. Decision 24-07-008 determined that the MWC 06 activities listed in Table 6 are eligible for tracking in the ECNBIMA:[45]

[44] Pub. Util. Code § 937(a).

[45] D.24-07-008, pp. 35-36, Table 6-D.

Table 6
Eligible Distribution Line Capacity MWC 06 Activities

Major Work Category	Eligible Activities
06	06A – Feeder Projects Associated with Substation Work[46]
	06B – Overloaded Transformers
	06D – DP Managed Circuit Reinforcement
	06E – PS Managed Circuit Reinforcement
	06H – New Business Related Capacity and Emergent

32. Decision 24-07-008 determined that the MWC 46 activities listed in Table 7 are eligible for tracking in the ECNBIMA:[47]

Table 7
Eligible Distribution Substation Capacity MWC 46 Activities

Major Work Category	Eligible Activities
46	46A – Normal Capacity[48]
	46H – New Business Related Capacity
	46N – New Business Substation Land Purchases[49]

2. Updated Forecasts and Forecasting Methodology

33. As electrification increases in our service territory, the additional load strains existing electric distribution assets, thus requiring additional distribution reinforcement and upgrades. These required reinforcements and upgrades, in turn, contribute to increasing the scope, complexity, and costs of our energization activities in MWCs 06 and 46.

34. Tables 8 and 9 summarize the updated forecasts for MWCs 06 and 46 respectively, and the corresponding amount of work that we will be able to complete, in comparison to D.24-

[46] MAT 06A capital expenditures (line work associated with substation work) that are driven by substation operational or emergency capacity (MAT 46F) are removed.

[47] D.24-07-008, pp. 35-36, Table 6-D.

[48] MAT 46A activities do not include any projects proposed to address supply-side deficiencies or issues caused by distributed generation.

[49] No recovery of MAT 46N costs is permitted until the substation constructed on purchase land has energized significant load.

07-008 funding and corresponding work amounts. Workpapers supporting the forecasts are provided in Attachment D.

Table 8
Updated Forecast and Associated Units for Eligible Distribution Line Capacity MWC 06 Activities
(Cost in Thousands)

		Projects			Cost		
		2025	2026	Total	2025	2026	Total
1	Updated Forecast for Eligible MWC 06 Activities	123	265	388	$479,845	$503,771	$983,616
2	Current Available Funding (2023 GRC Imputed + D.24-07-008)[50]	81	186	267	$306,403	$282,246	$588,649
3	Proposed Cap Increase Above Current Available Funding (line 1 - line 2)	42	79	121	$173,442	$221,525	$394,967

Table 9
Updated Forecast and Associated Units for Eligible Distribution Substation Capacity MWC 46 Activities
(Cost in Thousands)

		Projects			Cost		
		2025	2026	Total	2025	2026	Total
1	Updated Forecast for Eligible MWC 46 Activities	19	38	57	$214,045	$165,590	$379,635
2	Current Available Funding (2023 GRC Imputed + D.24-07-008)[51]	17	32	49	$107,900	$301,618	$409,518
3	Proposed Cap Increase Above Current Available Funding (line 1 - line 2)	2	6	8	$106,146	$(136,028)[52]	$(29,883)

[50] In Tables 8 and 9, project counts forecasted for 2025 and 2026 for Lines 2 ("Current Available Funding") correspond to the distribution plan published in PG&E's 2024 Distribution Deferral Opportunity Report (DDOR) submitted September 6, 2024, and supplemented September 10, 2024. The numbers vary slightly from the DDOR because the DDOR includes ineligible MAT codes and counts some projects that may include both MWC 06 and MWC 46 work as one project, whereas Tables 8 and 9 count these orders separately. PG&E is unable to provide Tables 8 and 9 in a format that identifies GRC Imputed and Existing D.24-07-008 project numbers in separate line items (similar to the format of Tables 4 and 10), because PG&E did not create a distribution plan for capacity projects based on the GRC Imputed amount (i.e., without D.24-07-008). To create a hypothetical GRC-funding-only distribution plan would require significant resources that would not be utilized in any event because D.24-07-008 has superseded it.

[51] See corresponding footnote 50 for MWC 06 above which applies to MWC 46 as well.

[52] The decrease reflects the shifting capital expenditures into 2025, updates to the forecast described in Paragraph 35, and the exclusion of capital expenditures incurred for projects placed in service after January 1, 2027 that are not eligible for the ECNBIMA per D.24-07-008.

35. The MWC 06 and 46 forecasts provided in testimony and data request responses for the Capacity Phase of the 2023 General Rate Case (A.21-06-021) were developed in October 2023. Since that time, we have continued to assess system-upgrade needs due to increasing electrification and have updated our forecasts via our electric distribution planning process.[53] Our updated MWC 06 and MWC 46 forecasts include:

a) **Removal of ineligible MAT codes per D.24-07-008.**[54]
b) **New customer applications for service.** New customer applications for service have been received and added to the latest forecast.[55] Some of these new applications have created grid needs that require upstream capacity work to fully energize the new customer loads (i.e., the updated forecasts reflect the additional capacity work resulting from these new customer applications).
c) **Updates to system level load and DER growth to reflect the 2022 California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) forecast**.[56] Each distribution planning cycle uses updated CEC IEPR forecast system-level load and DER growth, which is disaggregated to distribution circuits. Updates include revised forecasts for load, solar generation, small and medium/heavy duty vehicle electrification, and fuel substitution (i.e., electric versus natural gas heating).
d) **Removal of projects that are no longer needed**. Changes to the forecast can result in new grid needs or in previous grid needs that have dematerialized. For example, if a customer has cancelled an application for service and that application was the only driver of the capacity project, that project is no longer necessary and has been removed.
e) **Moving of 2024 carryover to 2025**. 2025 cost forecasts have been updated to include expected costs from 2024 projects that will be completed in 2025. This has increased the forecasted capacity spend in 2025.

[53] PG&E's Distribution Planning Process is detailed annually in its Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR).

[54] PG&E removed the following MAT codes, as required in D.24-07-008: 46F, 06G, 06I, 06K, 06P, 06#. Additionally, PG&E removed MAT 46N because all MAT 46N expenditures involve new substations that are expected to be in service after January 1, 2027. MAT 06A capital expenditures (line work associated with substation work) that are driven by substation operational or emergency capacity (MAT 46F) were also removed. Lastly, MAT 46A activities do not include any projects proposed to address supply-side deficiencies or issues caused by distributed generation.

[55] Additional customer applications for service are added to the forecast as "known loads," as documented in PG&E's 2024 DDOR submitted September 5, 2024, and supplemented on September 10, 2024.

[56] May 12, 2023, Joint Utilities (SCE, SDG&E and PG&E) Letter to Energy Division seeking approval of the 2024-2025 GNA and DDOR, approved by Energy Division in the High DER Proceeding.

f) **Addition of emergent energization work.** Emergent Energization Capital Expenditures are to start new projects that are not yet identified. Emergent work would begin once there is a signed contract and required customer payment is received for energization request(s), in accordance with the Energization OIR.[57] A revised forecast for MAT 06H includes Eligible Emergent Energization Capital Expenditures for 2025 and 2026.[58] Emergent work for MWC 46 is not included because substation work takes 2-3 years plus and so it is unlikely to be completed by January 1, 2027.

36. In addition, the MWC 46 updated forecast includes approximately $98 million for additional projects brought forward to start, but not completed, prior to 2027.[59] While included in the forecast, these dollars would not be recovered via the ECNBIMA and would not be recovered from customers until 2027 or beyond depending on when the project goes operational.

3. Justification For Proposed Cap Increases To MWCs 06 and 46

37. Table 10 summarizes the number of distribution line and substation projects forecasted to be placed into service by region and by year.[60] With revised 2025 and 2026 caps as proposed, PG&E forecasts placing into service: (1) 123 Line Capacity and 19 Substation Capacity projects in 2025; and (2) 265 Line Capacity and 38 Substation Capacity projects in 2026.[61] This plan reflects identified work necessary to address system deficiencies and facilitate our completion of pending and future energization projects. We will complete these capacity projects *throughout* PG&E's service territory, meaning that all customers broadly benefit from this additional work. Specific examples of community-benefiting energization projects enabled by these capacity projects include hospitals, schools, housing developments, electric vehicle charging stations, and agricultural pumping.

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[57] D.24-09-020, p. 45.

[58] *See* Attachment D, p. D-5.

[59] *See* Attachment D, p. D-3. $98 million is equal to the difference between the "Capacity (MWC 46) Updated Forecast (All Activities)" and "Capacity (MWC 46) Updated Forecast (ECNBIMA or Threshold Eligible Activities)" on Line 10 for 2025 and 2026.

[60] *See* Attachment D, p. D-4-1 to D-4-2 (listing capacity projects for MWCs 06 and 46).

[61] *Id.*

Table 10
Total Number and Location of Capacity Projects

	Total Number of Capacity Projects That Can Be Completed with Revised Cost Caps			
	2025		**2026**	
Region	**MWC 06**	**MWC 46**	**MWC 06**	**MWC 46**
Bay Area	30	8	29	9
Central Valley[62]	47	6	119	17
North Coast	13	2	48	3
North Valley and Sierra	13	1	25	4
South Bay and Central Coast	20	2	44	5
Total	**123**	**19**	**265**	**38**

38. Furthermore, with the revised caps as proposed, we will be able to place in-service over 80% of all pending MWC 06 projects by 2026 (i.e., known projects) while also addressing emergent energization projects to prevent the formation of a new backlog. For MWC 46 projects, not all known substation capacity projects can be placed into service by 2026 given the multi-year nature of the projects.

C. MWC 10 – Work at the Request of Others

1. Description of Activities

39. PG&E's MWC 10, Work at the Request of Others (WRO), involves the relocation/removal of PG&E's existing electric distribution facilities, including overhead-to-overhead relocations, underground-to-underground relocations, overhead-to-underground

[62] The relatively high number of MWC 06 projects forecasted to be placed in-service in 2026 are heavily concentrated in the Central Valley, which has experienced recent load growth due to deeper agricultural pumping and increased air conditioning usage. Circuits in the Central Valley region are often long and far apart, making it particularly difficult to maintain voltage during increased loading without additional equipment such as regulators. These projects typically can be completed in less than a year as they are typically smaller in scope. For example, many of these projects require only the installation of a single voltage regulator to resolve a low voltage problem.

conversions, pole relocations, and removal of idle PG&E facilities. MWC 10 activities are described in more detail in PG&E's 2023 GRC testimony, Exhibit (PG&E-4), Chapter 18.[63]

40. Decision 24-07-008 provides that WRO activities that support energization projects are eligible for recovery in the ECNBIMA.[64]

2. Updated MWC 10 Forecast and Forecasting Methodology

41. Table 11 summarizes the MWC 10 updated forecast and the corresponding amount of work that we will be able to complete, in comparison to D.24-07-008 funding and corresponding work amounts. Workpapers supporting the forecasts are provided in Attachment E.

Table 11[65]
Updated Forecast and Associated Units for Eligible Work Requested by Others (WRO) MWC 10 Activities
(Cost in Thousands)

		Units			Cost		
		2025	2026	Total	2025	2026	Total
1	Updated Forecast for Eligible MWC 10 Activities	660	594	1254	$95,538	$87,360	$182,898
2	2023 GRC Imputed	247	247	494	$35,699	$36,267	$71,966
3	D.24-07-008 Incremental Funding	30	40	70	$4,349	$5,848	$10,198
4	Currently Available Funding[66] (line 2 + line 3)	277	287	564	$40,048	$42,116	$82,164
5	Proposed Cap Increase Above Currently Available Funding (line 1 - line 4)	383	307	690	$55,490	$45,245	$100,734

[63] A.21-06-021, Exhibit PG&E-4, Chapter 18.

[64] D.24-07-008, pp. 53-54.

[65] Attachment E, p. E-1.

[66] D.24-07-008, Appendix A (adding D.23-11-069 Authorized Capital Expenditures and Forecasted SB 410 Capital Cost Incremental to D.23-11-069 columns for MWC 10 for years 2025-2026).

Note: For unit cost information, see Attachment E, p. E-3 (Line 8).[67]

42. As shown in Table 11, by increasing funding for MWC 10 to $182.9 million ($100.7 million above currently available funding), we will be able to complete more than 1,250 WRO jobs in the 2025-2026 period. Without this increased funding, we would be only able to complete less than half this amount.

43. We did not change the methodology to calculate project volume and incremental funding amounts necessary to complete WRO energization activities. The incremental funding proposed for WRO will cover the additional costs that we expect to incur due to additional MWC 16 (New Business) work discussed in Section IV.A above. We would record to the ECNBIMA only those amounts that are above the 24% imputed/adopted amounts for WRO work supporting energization, as authorized in D.24-07-008.

44. To determine the incremental amount required to support energization beyond those amounts approved for WRO in D.24-07-008, we reviewed the incremental volume of energization projects expected above current funding levels and calculated the volume of WRO work that supports energization. This volume was split between residential and non-residential projects utilizing historical data and then multiplied against residential and non-residential unit costs to determine the incremental funding request. Our forecast uses a 2024 year-to-date energization WRO unit cost with a 3.4% in escalation 2025 and a 1.6% escalation in 2026.[68] Our forecast provided in Table 10 (Line 1) is derived by applying these unit costs to the expected volumes.[69]

45. The incremental WRO units and costs for these 2025 and 2026 activities relative to GRC Imputed and D.24-07-008 combined funding are shown in Table 11 above (Line 5).

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[67] Unit cost for 2025 is $144,755 and unit cost for 2026 is $147,071. These unit costs are the combined unit costs for residential and non-residential.

[68] S&P IHS Markit Q1 2024 Forecast.

[69] Attachment E, p. E-1 and p. E-3.

3. Justification For Proposed Cap Increases To MWC 10

46. The proposed additional funding for MWC 10 will support 690 additional WRO energization projects in 2025 and 2026.[70] Without this funding, there is a risk that WRO projects become an impediment to energizing customers in a timely manner.

V. ENERGIZATION TIMELINES

A. MWC 16 – New Business

47. The additional funding requested for MWC 16 in our Motion will allow PG&E to reduce the backlog and meet current customer demand, and in turn timely complete customer connections. The Energization OIR decision directs the investor-owned utilities (IOUs) to achieve a 125 business day average energization timeline for Rule 15, Rule 15/16, and Rule 16 projects within a 12 month calendar time period.[71] However, carrying a backlog into 2027 means that we will not be able to meet the Energization OIR targets.

48. Current funding provided by D.23-11-069 and D.24-07-008 will be insufficient to keep up with the customer demand for new energization requests in 2025-2026. The gap in funding will create an additional backlog of customer work beginning in 2025 and grow into 2026 and 2027. The backlog of customer-requested work will prevent PG&E from being able to meet 95% of projects in less than the maximum allowable time. In order to have less than 5% of projects over the maximum allowable time, PG&E will need to fund 100% of the backlog projects and the steady-state customer demand.

49. As noted above, carrying a backlog impacts our ability to meet energization timelines. We anticipate that we will meet energization timeline requirements for 95% of applications when funding is aligned to customer demand. Once the backlog is addressed, funding will need to be maintained at levels to meet yearly customer demand or we will be unable to energize 95% of customers within the maximum timelines and risk creating a new backlog.

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[70] Attachment E, p. E-1 (Line 5).

[71] D.24-09-020, OP 1.

B. MWC 06 and 46 – Distribution Line and Substation Capacity

50. Increased funding for MWC 06 and MWC 46 also will shorten energization timelines for upstream capacity projects. The increased funding for 2025 and 2026 will enable:

- **Earlier project kick-offs**. This will allow project management and design teams to scope the project earlier, order materials earlier (e.g., regulators), and enter into construction sooner.
- **Emergent work.**[72] We will be able to start upstream capacity projects once there is a signed contract and required customer payment is received for energization request(s), [73] rather than waiting until the project is approved and funded. [74] Insufficient funding has added an average of 318 calendar days for Line/Circuit Upgrades (MWC 06),[75] demonstrating the impact of funding for emergent energization work on overall energization timelines.

51. Without an increased cap, PG&E's lack of funding will continue to extend the upstream capacity timelines.[76] Many of the projects at risk of having their timelines extended are in the Central Valley, where there are load increases from existing customers for air conditioning and for agricultural pumping to reach deeper aquifers. Loading on these assets will mean that

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[72] Attachment D, p. D-5.

[73] D.24-09-020, p. 45.

[74] D.24-09-020, p. 45 (The Commission states: "Put simply, there should not be a 'pre-funding' period where SCE, SDG&E and PG&E are awaiting Commission funding decisions to energize customers.").

[75] See R.24-01-018, San Diego Gas & Electric Company (U 902-E), Pacific Gas and Electric Company (U 39 E), and Southern California Edison Company (U 338-E) Response to Administrative Law Judge Ruling Directing Utility Responses to Questions regarding Energization Timeline (April 22, 2024) (Joint IOU Response to Mar 21, 2024 Ruling), pp. 32-33.

[76] D.24-09-020, p. 44.

new applications for service in these areas may be load limited until upstream capacity upgrades are completed.

VI. WORK EXECUTION

52. PG&E executes its work through advance planning and coordination that is captured in an annual work plan. The detailed annual work plan is based on the allocated budget for the year. The budget informs not only how many projects PG&E's work execution teams will serve that year, but also the timing to execute each project. This work plan is critical for several reasons, including:

1) Ensures PG&E's resources are utilized efficiently. Resources and work steams are planned at full utilization levels, to ensure crews are not underutilized and there is no idle capacity in work streams.

2) Informs customer construction timelines. The detailed work plan provides customers with information they can use for their own planning. For example, the customer may not want to leave open trenches or half constructed projects for long periods of time. If a project is later in the work plan, or perhaps not included in that year's budget-constrained work plan, the customer can adjust their timelines accordingly. The work plan helps customers to plan their project to be coordinated with PG&E.

3) Maximizes permitting efficiencies. Many government agencies require PG&E to obtain permits for energization work. Advance planning helps PG&E from applying too early, which can lead to situations where the permit expires and requires costly renewals or resubmissions. Advance planning also helps PG&E from applying too late and not obtaining permit approval in time, which can lead to changing and delaying construction schedules.

4) Ensures materials are available at the right place at the right time. Many materials and equipment needed for energization projects are not "off the shelf" and require lead times to procure bulk quantities. Moreso, supply chain shortages often occur, which can delay

projects for months or more. Work plans help mitigate possible delays due to material procurement lead times or supply chain issues. Furthermore, the work plan helps ensure the materials are dispersed across PG&E's warehouses to ensure local crews have the appropriate inventory to complete projects. This advance planning and coordination through the work plan helps ensure materials are ordered and available to PG&E and contractor crews in the right place at the right time.

53. While PG&E updates its work plans as emergent issues arise, these work plan changes do not have the same advance planning and coordination benefits as projects that were part of the original detailed work plan. For instance, a customer may not be construction ready on short notice. Or PG&E may need to wait for permit approval or materials to arrive to begin a project, which can leave crews underutilized.

54. This is also true when additional budget is allocated to the workplan. While PG&E can hire contractor crews to complete the work, certain steps in project execution require advance planning and coordination (notably customer readiness, materials procurement, and permitting). This means there is a lag between the budget allocation and executing on the updated work plan initially. Over time, the projects in the updated work plan will benefit from the advance planning and coordination benefits. In the near term, however, it will take time to execute projects commensurate with the total budget.

55. The 2023 GRC imputed funding for New Business (MWC 16) in 2024 is $683 million. PG&E determined that this amount was insufficient for the 2024 work plan and allocated $1,071 million to MWC 16 activities instead. PG&E built detailed work plans to execute on these budgets. Then, in July 2024, PG&E received D.24-07-008, which provided up to an additional $846 million for certain MWC 16 activities.[77] This meant PG&E's work plan could support a

[77] This represents the share of eligible MWC 16 MAT code funding used to set the overall 2024 cap of $975 million in D.24-07-008.

budget of $1,529 million ($683 million imputed GRC amount + $846 million incremental), which is $458 million above the original 2024 work plan. Consistent with the reasons discussed above, PG&E projects it will not spend to the 2024 cap because it cannot complete incremental projects under the updated work plan within the remaining 5-6 months in 2024, especially without the full advanced planning and coordination benefits described above.

56. The sooner PG&E has certainty of its budget, the sooner it can adopt updated work plans and begin the advanced planning and coordination to deliver on its existing and forecasted customer energization requests.

57. That said, SB 410 requires electrical utilities to improve energization processes.[78] We acknowledge past inefficiencies and our responsibility to meet statutory performance-improvement requirements. Striving toward this objective, we have already implemented several process improvements this year and are continuing to evaluate how we can improve. We also are eager to work with our customers, the SB 410 auditor (Ernst & Young), Energy Division staff, and other stakeholders to develop and incorporate additional process improvements based on their input. These improvements have allowed us to reduce costs by tens of millions of dollars annually and will allow us to complete our forecasted work, subject to obtaining sufficient funding as proposed in the Motion. The process improvements include the following:

58. **Application portal improvements**: In late 2023, we identified that more than half of customer applications did not result in a completed project due to customers abandoning or cancelling the project. By improving our application portal, implementing improved screening tools, and requiring document submission in the application portal, we have reduced customer-initiated-cancellations by about 30% percent. This in turn allows for more efficient use of our internal resources on projects that will actually be completed.

[78] Pub. Util. Code § 932(a)(5).

59. **Pre-application process improvements**: In May 2024, we updated our document-collection process to reduce the intake timeline and ensure we collect correct information early in the project scoping phase. To that end, we are also in the process of redesigning the application intake process and introducing a pre-application process to streamline the collection of project information and documents. This new pre-application process will enable us to engage and consult with our customers prior to their completing a full application. Currently, approximately 55% of customer applications never progress to the next step in the process due to customer cancellation or abandonment, however PG&E representatives spend time working on those applications which is wasted effort. We estimate the pre-application process will reduce the customer cancellation rate by as much as 70%. The execution of this enhancement involves a redesign of the PG&E application portal and changes how our coworkers interact with customers at this early project stage. This enhancement is scheduled to be launched at the end of October 2024.

60. **Estimating and operating rhythm improvements**: Through improved visual management and operating reviews, we reduced the customer wait time for a design and estimate from four months to four weeks. Our estimating teams establish clear production targets and track progress against those targets daily.

61. **Job-package-preparation and estimating process improvements**: When customers submit New Business connection applications, our engineers must create internal orders, job packages, and estimates for the work. In 2024, we improved our job-package-preparation and estimating processes. These improvements include creating job-package checklists and enhancing training for our engineers to improve the quality of the job packages and estimates, which avoids project-delaying re-work. These process improvements have decreased the time it takes to complete an electric design by 40%.

62. **Customer readiness and communications improvements**: In 2023, our New Business team initiated a customer-outreach campaign on delayed applications. We contacted the

customer of record and the project representative to determine if the project was active, cancelled, or completed. If initial outreach efforts were unsuccessful, we attempted to reach the customers at least two more times. When contacted, if the customer or representative informed us the project was active, we connected the customer with our Service Planning organization to assist the customer with next steps. Some customers also let us know if the project was cancelled or previously completed, enabling us to update our records and free-up resources. If we were unable to contact the customer or representative within 90 days, the application was cancelled. By identifying applications that are no longer active or needed it enables PG&E to direct its resources to active customer applications.

63. **New Business Project Management Office:** In 2024, we established a New Business Project Management Office (NB PMO) to manage this capital-intensive program. The NB PMO structure is similar to our Undergrounding PMO, which was able to deliver more underground miles at a lower unit cost than forecasted in 2023. The NB PMO will provide oversight over the New Business program and will be responsible for the New Business workplan throughout our service territory. The PMO structure will allow us to leverage economies of scale to deploy contractor resources to complete energization projects. The PMO structure also leverages our Performance Playbook and many of the lessons learned from the Undergrounding PMO. Similar to the Undergrounding PMO, the NB PMO has implemented the 5 Lean Plays to drive operational excellence across multiple interdependent work groups. This includes: (1) visual management, (2) cascading operating reviews, (3) robust problem solving, (4) enhanced standard work, and (5) waste elimination identification.

VII. FLEXIBILITY IN SPENDING ACROSS 2025 AND 2026 CAPS

64. Under the annual cap structure adopted in D.24-07-008, PG&E's funding is unnecessarily constrained when work moves from one year to the next. For example, if work cannot be completed by the end of 2025, it will move to the following year and the capital expenditure will count towards the 2026 cap. However, the 2026 capital expenditures cap is set

based only on a forecast of work that would be completed in that year, and does not take into consideration any rollover work from 2025.

65. As explained above, we have made several process improvements that will help us to timely complete the energization work forecast above and mitigate various challenges outside of our control, such as: permitting agencies timelines; permitting agencies' staffing capacity to process requests; land rights disputes; customer readiness; and material availability. As discussed in Section VI, our ability to execute work efficiently relies on advance planning and coordination to ensure customer, materials, and permit readiness. We therefore respectfully request a decision on our Motion by first-quarter 2025 to maximize this planning and coordination. A decision on the Motion later in 2025 will increase the likelihood that PG&E cannot complete all the 2025 projects included in the updated forecasts because of the time lag between a budget increase, planning and coordination efforts, and work execution.

66. We request operational and financial flexibility to spend authorized cap amounts across years to ensure sufficient funding to serve our forecasted need. Specifically, the requested cap amounts for 2025 and 2026 should be adjustable based upon spending in preceding years so that we can energize as many customers as possible within a total cumulative cap. Flexibility across 2025 and 2026 will allow for customers that could not be energized within the 2025 cap to be energized in 2026, without being arbitrarily limited by the 2026 cap.

VIII. REVENUE REQUIREMENT CAPS

67. Decision 24-07-008 adopts both incremental annual capital cost caps and annual revenue requirement (RRQ) caps. In comments, we urged the Commission to eliminate the RRQ caps for two reasons. First, we argued that the combination of capital cost caps and RRQ caps created unnecessary ambiguity and confusion. Second, we argued that RRQ caps could inhibit our ability to accelerate project work as envisioned in SB 410. In revisiting the caps here, the Commission should reconsider this issue and eliminate the annual RRQ caps. SB 410 does not

require a multi-layered annual cap structure. PG&E provides the following new evidence to support this request.

68. While D.24-07-008 allows PG&E to count capital expenditures towards the cap for the year in which the expenditures were accrued,[79] the RRQ cap presents an additional, unnecessary constraint. If we complete energization projects ahead of schedule and incur costs exceeding the RRQ cap, we will be unable to recover these costs, despite adhering to the capital expenditure limits. Table 12 illustrates this constraint for MWC 06 Distribution Line Capacity based upon a hypothetical where $10 million of work forecasted for 2025 is accelerated to move into 2024.

Table 12
Capital Expenditure Versus RRQ Cap Example
(Cost in Thousands)

Year	MWC 06 Authorized Capital Expenditure Cap	MWC 06 Annual Additional RRQ Cap[80]	MWC 06 Hypothetical Recorded Capital Expenditures	MWC 06 Annual RRQ Based on Hypothetical Recorded Capital Expenditures[52]
2024	$89,968	$13,315	$99,968	$14,795
2024 – Over Cap Amount				$1,480
2025	$173,549	$25,685	$163,549	$24,205
2026	$147,276	$21,797	$147,276	$21,797
Total Capital Expenditure	$410,793		$410,793	

69. As shown by this hypothetical, if PG&E incurs a $10 million capital expenditure one year early in 2024 (i.e. accelerates a project), the associated 2024 RRQ would exceed the corresponding annual RRQ cap by $1.48 million even though the 2024-2026 total capital expenditures remains within the authorized cap. This dual-cap system creates a financial roadblock, hindering our ability to efficiently manage and accelerate energization projects as

[79] D.24-07-008, Findings of Fact 28.

[80] Assumes $1 of capital cost = $0.148 of Revenue Requirement.

warranted. For example, at times it may be prudent for us to accelerate a project based on the availability of materials and resources. But the dual caps would work to discourage prudent project management.

70. To correct for ambiguity and encourage the timely completion of projects, we request the Commission establish annual caps based only on capital costs and eliminate the RRQ caps. Setting the annual cost caps based on capital costs only is the most straightforward way for us to manage capital spending and support our project-acceleration efforts. It also clearly defines the amount of eligible capital costs for the eventual recording of RRQs to the approved memorandum account once those projects become operative.

IX. CONCLUSION

71. For the foregoing reasons, the Commission should approve the following:

a. Increase the 2025 capital costs cap from $619 million to $2.115 billion;
b. Increase the 2026 capital costs cap from $669 million to $2.302 billion;
c. Authorize the ability to spend authorized amounts across 2025 and 2026; and
d. Eliminate the secondary revenue requirement (RRQ) caps for 2024-2026.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on October 4, 2024, at Pleasanton, California

*/s/*Bryon Winget
Bryon Winget
Vice President, Electric System Planning, PG&E

ATTACHMENT A

Attachment A

Eligible Maintenance Activity Types (MATs) identified in D.24-07-008 and Associated Funding Amounts Adopted in D. 23-11-069

D.23-11-069 Adopted Capital Expenditure (000's)					
	MWC	**Eligible MATs**	**2024**	**2025**	**2026**
CapEx	10	Energization Related WRO	$34,711	$35,699	$36,267
	46	46A - Normal Capacity	$17,149	$17,637	$17,918
		46H - New Business Related Capacity	$45,059	$46,340	$47,077
		46N - New Substation Land Purchase	$ -	$ -	$ -
	6	06A - Feeder Projects Associated with Substation Work	$10,965	$11,277	$11,456
		06B - Overloaded Transformers	$8,902	$9,155	$9,301
		06D - DP Managed Circuit Reinforcement	$4,882	$5,021	$5,101
		06E - PS Managed Circuit Reinforcement	$26,137	$26,880	$27,308
		06H - New Business Related Capacity and Emergent	$78,294	$80,521	$81,803
	16	Residential Connects	$284,851	$292,954	$297,618
		Nonresidential Connects	$210,014	$215,988	$219,427
		PEV – Rule 15 & 16	$ -	$ -	$ -
		Transformer Purchases	$182,365	$187,552	$190,538
		Transformer Scrapping	$5,498	$5,654	$5,744
		"AB 50 Projects" - Forecasting and Escalation Adjustment	$ -	$ -	$ -

ATTACHMENT B

REVISED D.24-07-008 Appendix A
Updated 2025-2026 Forecasts Compared to D.23-11-069 Authorized

			D.23-11-069 Authorized Capital Expenditure		Updated 2025-2026 Forecasts SB 410 Capital Expenditure		SB 410 Capital Cost Incremental to D.23-11-069		
Metric	**MWC**	**MAT**	**2025**	**2026**	**2025**	**2026**	**2025**	**2026**	**Notes:**
Capital Expenditures	10 (WRO)	Energization Related WRO	**$35,699**	**$36,267**	**$95,538**	**$87,360**	**$59,839**	**$51,093**	See OP3 for conditions
	46 (Substation)	46A - Normal Capacity	$17,637	$17,918	$29,452	$22,521	$11,815	$4,603	
		46F - Emergency and Operational Capacity	ineligible per D.24-07-008		ineligible per D.24-07-008		ineligible per D.24-07-008		Disallowed per FoF 6
		46H - New Business Related Capacity	$46,340	$47,077	$184,593	$143,069	$138,253	$95,992	
		46N - New Substation Land Purchase	$0	$0	$0	$0	$0	$0	Eligible if substation is placed into service prior to 1/1/27
		MWC Total	**$63,977**	**$64,995**	**$214,045**	**$165,590**	**$150,068**	**$100,595**	
	6 (D-Line)	06A - Feeder Projects Associated with Substation Work	$11,277	$11,456	$59,059	$44,105	$47,782	$32,649	
		06B - Overloaded Transformers	$9,155	$9,301	$11,321	$11,730	$2,166	$2,429	
		06D - DP Managed Circuit Reinforcement	$5,021	$5,101	$109	$5,217	($4,912)	$116	
		06E - PS Managed Circuit Reinforcement	$26,880	$27,308	$44,437	$109,838	$17,557	$82,530	
		06G - Voltage Complaints	ineligible per D.24-07-008		ineligible per D.24-07-008		ineligible per D.24-07-008		Disallowed per FoF 14
		06H - New Business Related Capacity and Emergent	$80,521	$81,803	$364,919	$332,881	$284,398	$251,078	
		06I - Operational Capacity	ineligible per D.24-07-008		ineligible per D.24-07-008		ineligible per D.24-07-008		Disallowed per FoF 16
		06K - Power Factor	ineligible per D.24-07-008		ineligible per D.24-07-008		ineligible per D.24-07-008		Disallowed per FoF 17
		06P - Enable DG	ineligible per D.24-07-008		ineligible per D.24-07-008		ineligible per D.24-07-008		Disallowed per FoF 18
		06# - Line Regulator Revolving Stock	ineligible per D.24-07-008		ineligible per D.24-07-008		ineligible per D.24-07-008		Disallowed per FoF 19
		MWC Total	**$132,854**	**$134,969**	**$479,845**	**$503,771**	**$346,991**	**$368,802**	
	16 (NB)	Residential Connects	$292,954	$297,618	$1,041,729	$1,190,801	$748,775	$893,183	
		Nonresidential Connects	$215,988	$219,427	$528,026	$661,361	$312,038	$441,934	
		PEV Rule 29	ineligible per D.24-07-008		ineligible per D.24-07-008		ineligible per D.24-07-008		Disallowed per OP7
		PEV Rule 15/16	$0	$0	$181,662	$331,334	$181,662	$331,334	
		Transformer Purchases	$187,552	$190,538	$231,966	$245,772	$44,414	$55,234	Amounts in columns F-G contigent on 30% of GRC Imputted met for Energization per OP5
		Transformer Scrapping	$5,654	$5,744	$5,654	$5,744	$0	$0	Amounts in columns F-G contigent on 30% of GRC Imputted met for Energization per OP5
		"AB 50 Projects" - Forecasting and Escalation Adjustment	$0	$0	$271,258	$60,042	$271,258	$60,042	
		MWC Total	**$702,148**	**$713,327**	**$2,260,294**	**$2,495,055**	**$1,558,146**	**$1,781,728**	
		Capital Total	**$934,678**	**$949,558**	**$3,049,722**	**$3,251,776**	**$2,115,044**	**$2,302,218**	
		Cumulative Capital Total					$2,115,044	$4,417,262	Cumulative dollars (not incremental)
		Annual Revenue Requirement (assuming $1 of capital costs = $0.148 of Revenue Requirement)					**$313,027**	**$340,728**	
		Cumulative Annual Revenue Requirement Increase					$313,027	$653,755	
		Authorized Electric Distribution Revenue Requirement	$7,762,000	$8,311,000			$7,762,000	$8,311,000	
		Annual Revenue Requirement Rate Impact					**4.03%**	**4.10%**	
		Cumulative Revenue Requirement Rate Impact					**4.03%**	**7.87%**	

2024 Energization Costs

Metric	MWC	MAT	A 2024 GRC Imputed 2024	B SB410 FD 2024	C Total Authorized 2024	D 2024 Actuals + Remaining Forecast 2024	E Variance to Total Authorized (C-D) 2024
Capital Expenditures	10 (WRO)	Energization Related WRO	$34,711	$77,601	$112,312	$71,257	$41,055
	46 (Substation)	46A - Normal Capacity	$17,149	($6,680)	$10,469	$19,619	($9,150)
		46F - Emergency and Operational Capacity	ineligible per D.24-07-008				
		46H - New Business Related Capacity	$45,059	($31,385)	$13,674	$69,618	($55,944)
		46N - New Substation Land Purchase	$0	$0	$0	$0	$0
		MWC Total	**$63,273**	**($38,065)**	**$63,273**	**$89,237**	**($65,094)**
	6 (D-Line)	06A - Feeder Projects Associated with Substation Work	$10,965	$35,075	$46,040	$50,236	($4,197)
		06B - Overloaded Transformers	$8,902	$1,820	$10,722	$10,722	($1)
		06D - DP Managed Circuit Reinforcement	$4,882	($4,725)	$157	$1,964	($1,807)
		06E - PS Managed Circuit Reinforcement	$26,137	($15,505)	$10,632	$28,154	($17,522)
		06G - Voltage Complaints	ineligible per D.24-07-008				
		06H - New Business Related Capacity and Emergent	$78,294	$73,302	$151,596	$160,184	($8,588)
		06I - Operational Capacity	ineligible per D.24-07-008				
		06K - Power Factor	ineligible per D.24-07-008				
		06P - Enable DG	ineligible per D.24-07-008				
		06# - Line Regulator Revolving Stock	ineligible per D.24-07-008				
		MWC Total	**$129,180**	**$89,966**	**$219,146**	**$251,260**	**($32,114)**
	16 (NB)	Residential Connects	$284,851	$150,819	$435,670	$363,009	$72,661
		Nonresidential Connects	$210,014	$52,673	$262,687	$162,971	$99,716
		PEV - Non-Residential Rule 29	ineligible per D.24-07-008				
		PEV - Residential Rule 15/16	$0	$0	$0	$64,893	($64,893)
		Transformer Purchases	$182,365	$28,907	$211,272	$210,415	$857
		Transformer Scrapping	$5,498	$99	$5,597	$6,180	($583)
		"AB 50 Projects" - Forecasting and Escalation Adjustment	$0	$613,065	$613,065	$398,435	$214,630
		MWC Total	**$682,728**	**$845,563**	**$1,528,291**	**$1,205,903**	**$322,388**
		Capital Total	**$909,892**	**$975,065**	**$1,923,022**	**$1,617,657**	**$266,235**

ATTACHMENT C

ATTACHMENT C INDEX
Pacific Gas and Electric Company
New Business - MWC 16

Table Links	Title	Description
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MWC 16 Workpaper Table C-2	Summary of New Cap by Category - MWC 16	The walk from GRC Imputed to the New Cap
MWC 16 Workpaper Table C-3	Updated Forecast for Eligible MWC 16 Activities - MWC 16	The walk from the Updated Forecast (All In) to the Updated Forecast for Eligible MWC 16 Activities
MWC 16 Workpaper Table C-4	Capital Expenditure Request Forecast by Category Details - MWC 16	Calculation details for Updated Forecast (All In) Units, Unit Costs & Costs by Category
MWC 16 Workpaper Table C-5	2024 Year-to-Date July Costs and 2024 August thru December Forecast - MWC 16	Calculation details for 2024 YTD July Units and Costs & 2024 Aug-Dec Forecasted Units and Costs by Category
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MWC 16 Workpaper Table C-7	Calculation of Gap Increase above GRC Imputed and Existing D.24-07-008 - MWC 16	Calculation details for 2025 & 2026 Units for GRC Imputed and Existing D.24-07-008
MWC 16 Workpaper Table C-8	Updated Forecast for Eligible MWC 16 Activities Variance from Currently Available Funding - MWC 16	Calculation details for 2025 & 2026 Units and Cost for Updated Forecast for Eligible MWC 16 Activities versus Currently Available Funding

Workpaper Table C-1
Pacific Gas and Electric Company
New Business
Updated Forecast and Associated Units for Elgible MWC 16 Activities
(Thousands of Dollars)

Line No.	Line Description	2025	2026	Total	2025	2026	Total	2025	2026	Total
		Units			Cost (000's) (Less Transformer Purchases and Scrapping)			Cost (000's) (Including Transformer Purchases and Scrapping)		
1	Updated Forecast for Eligible MWC 16 Activities	18,464	19,748	**38,212**	$ 2,022,674	$ 2,243,538	**4,266,212**	$ 2,260,294	$ 2,495,055	**4,755,348**
2	2023 GRC Imputed	6,117	6,117	**12,234**	$ 508,942	$ 517,045	**1,025,987**	$ 702,148	$ 713,327	**1,415,475**
3	D.24-07-008 Incremental Funding	4,400	2,819	**7,220**	$ 366,096	$ 238,324	**604,421**	$ 396,883	$ 279,650	**676,533**
4	Current Available Funding (Line 2 + 3)	10,518	8,936	**19,454**	$ 875,038	$ 755,369	**1,630,408**	$ 1,099,031	$ 992,977	**2,092,008**
5	Cap Increase Above Current Available Funding (Line 1 - Line 4)	**7,946**	**10,812**	**18,758**	**1,147,635**	**1,488,169**	**2,635,804**	**1,161,263**	**1,502,078**	**2,663,340**

Assumptions and Details

Transformer Purchases and Scrapping are separate costs and not part the unit cost calculations.

Updated Forecast for Eligible MWC 16 Activitives exclude PEV Non Res (Rule 29). Units in 2025 & 2026 are based on Customer Demand by MATs. (Reference Assumption and Details in Workpaper Table 4)

Unit Costs for 2023 GRC Imputed and Exisiting D.24-07-008 Caps are derived based upon revised average unit costs used to develop the updated MWC 16 forecast. Does not account for additional contract resources. Reference WP Table 7.

Workpaper Table C-2
Pacific Gas and Electric Company
New Business
Summary of New Cap by Category - MWC 16
(Thousands of Dollars)

Line No.	Line Description	2024 Informational	2025 Updated Forecast for Eligible MWC 16 Activities	2026 Updated Forecast for Eligible MWC 16 Activities	Total Updated Forecast for Eligible MWC 16 Activities
1	Residential Connects	$ 363,009	$ 1,041,729	$ 1,190,801	**$ 2,232,529**
2	Non-Residential Connects	$ 162,971	$ 528,026	$ 661,361	**$ 1,189,387**
3	PEV	$ 64,893	$ 181,662	$ 331,334	**$ 512,996**
4	Transformer Purchases	$ 210,415	$ 231,966	$ 245,772	**$ 477,738**
5	Transformer Scrapping	$ 6,180	$ 5,654	$ 5,744	**$ 11,398**
6	AB50 Connects	$ 398,435	$ 271,258	$ 60,042	**$ 331,300**
7	**MWC 16 Total**	**$ 1,205,903**	**$ 2,260,294**	**$ 2,495,055**	**$ 4,755,348**

Line No.	Line Description	2024 Informational	2025 2023 GRC Imputed	2026 2023 GRC Imputed	Total 2023 GRC Imputed
1	Residential Connects	$ 284,851	$ 292,954	$ 297,618	**$ 590,572**
2	Non-Residential Connects	$ 210,014	$ 215,988	$ 219,427	**$ 435,415**
3	PEV	$ -	$ -	$ -	**$ -**
4	Transformer Purchases	$ 182,365	$ 187,552	$ 190,538	**$ 378,090**
5	Transformer Scrapping	$ 5,498	$ 5,654	$ 5,744	**$ 11,398**
6	AB50 Connects	$ -	$ -	$ -	**$ -**
7	**MWC 16 Total**	**$ 682,728**	**$ 702,148**	**$ 713,327**	**$ 1,415,475**

Line No.	Line Description	2024 Informational	2025 D.24-07-008 Incremental Funding	2026 D.24-07-008 Incremental Funding	Total D.24-07-008 Incremental Funding
1	Residential Connects	$ 150,819	$ 150,204	$ 169,662	**$ 319,866**
2	Non-Residential Connects	$ 52,673	$ 62,626	$ 68,662	**$ 131,288**
3	PEV	$ -	$ -	$ -	**$ -**
4	Transformer Purchases	$ 28,907	$ 30,250	$ 40,844	**$ 71,093**
5	Transformer Scrapping	$ 99	$ 537	$ 482	**$ 1,019**
6	AB50 Connects	$ 613,065	$ 153,266	$ -	**$ 153,266**
7	**MWC 16 Total**	**$ 845,562**	**$ 396,883**	**$ 279,650**	**$ 676,533**

Line No.	Line Description	2024 Informational	2025 Currently Available Funding	2026 Currently Available Funding	Total Currently Available Funding
1	Residential Connects	$ 435,670	$ 443,158	$ 467,280	**$ 910,438**
2	Non-Residential Connects	$ 262,687	$ 278,614	$ 288,089	**$ 566,703**
3	PEV	$ -	$ -	$ -	**$ -**
4	Transformer Purchases	$ 211,272	$ 217,802	$ 231,382	**$ 449,183**
5	Transformer Scrapping	$ 5,597	$ 6,191	$ 6,226	**$ 12,417**
6	AB50 Connects	$ 613,065	$ 153,266	$ -	**$ 153,266**
7	**MWC 16 Total**	**$ 1,528,290**	**$ 1,099,031**	**$ 992,977**	**$ 2,092,008**

Line No.	Line Description	2024 Informational	2025 Cap Increase Above Currently Available Funding	2026 Cap Increase Above Currently Available Funding	Total Cap Increase Above Currently Available Funding
1	Residential Connects	$ (72,661)	$ 598,570	$ 723,521	**$ 1,322,091**
2	Non-Residential Connects	$ (99,716)	$ 249,412	$ 373,272	**$ 622,684**
3	PEV	$ 64,893	$ 181,662	$ 331,334	**$ 512,996**
4	Transformer Purchases	$ (856)	$ 14,164	$ 14,391	**$ 28,555**
5	Transformer Scrapping	$ 583	$ (537)	$ (482)	**$ (1,019)**
6	AB50 Connects	$ (214,630)	$ 117,992	$ 60,042	**$ 178,034**
7	**MWC 16 Total**	**$ (322,387)**	**$ 1,161,263**	**$ 1,502,078**	**$ 2,663,340**

Line No.	Line Description	2024 Informational	2025 New Cap	2026 New Cap	Total New Cap
1	Residential Connects	$ 78,158	$ 748,775	$ 893,183	**$ 1,641,957**
2	Non-Residential Connects	$ (47,043)	$ 312,038	$ 441,934	**$ 753,972**
3	PEV	$ 64,893	$ 181,662	$ 331,334	**$ 512,996**
4	Transformer Purchases	$ 28,050	$ 44,414	$ 55,234	**$ 99,648**
5	Transformer Scrapping	$ 682	$ -	$ -	**$ -**
6	AB50 Connects	$ 398,435	$ 271,258	$ 60,042	**$ 331,300**
7	**MWC 16 Total**	**$ 523,175**	**$ 1,558,146**	**$ 1,781,728**	**$ 3,339,873**

Assumptions and Details

Including 2024 as informational to lead into deriving 2025-2026 forecast and is not part of the Updated Forecast for Eligible MWC 16 Activities
New Cap Eligible:

(1) All MATs except PEV NonRes (Rule 29)
(2) "PG&E may include MWC 16 transformer costs in the ratemaking mechanism once it satisfies three conditions. First, the cost must be related to the installation of transformers that increase capacity in response to an actual or projected increase in load. Second, the full D.23-11-069 authorized MWC 16 capital expenditure amounts for the transformer purchasing and scrapping lines must have been expended prior to recording any amounts under the MWC 16 transformer purchasing or transformer scrapping lines in the ratemaking mechanism. Third, 30 percent of the MWC 16 line item amounts used to satisfy the second condition must have been expended for the MWC 16 transformer purchase or transformer scrapping energization projects."

Workpaper Table C-3
Pacific Gas and Electric Company
New Business
Updated Forecast for Eligible MWC 16 Activities - MWC 16
(Thousands of Dollars)

		2024	2025	2026	Total	2024	2025	2026	Total	2024	2025	2026	Total
Line No.	Line Description	Informational	Updated Forecast (All MWC 16 Costs)			Informational	Updated Forecast (Ineligible MWC 16 Activities)			Informational	Updated Forecast (Eligible MWC 16 Activities)		
1	Residential Connects	$ 363,009	$ 1,041,729	$ 1,190,801	**$ 2,232,529**					$ 363,009	$ 1,041,729	$ 1,190,801	**$ 2,232,529**
2	Non-Residential Connects	$ 162,971	$ 528,026	$ 661,361	**$ 1,189,387**					$ 162,971	$ 528,026	$ 661,361	**$ 1,189,387**
3	PEV	$ 175,678	$ 525,595	$ 659,441	**$ 1,185,037**	$ 110,785	$ 343,934	$ 328,107	**$ 672,041**	$ 64,893	$ 181,662	$ 331,334	**$ 512,996**
4	Transformer Purchases	$ 275,865	$ 335,599	$ 374,653	**$ 710,252**	$ 65,450	$ 103,633	$ 128,880	**$ 232,513**	$ 210,415	$ 231,966	$ 245,772	**$ 477,738**
5	Transformer Scrapping	$ 7,770	$ 5,654	$ 5,744	**$ 11,398**	$ 1,590	$ -	$ -	**$ -**	$ 6,180	$ 5,654	$ 5,744	**$ 11,398**
6	AB50 Connects	$ 398,435	$ 271,258	$ 60,042	**$ 331,300**					$ 398,435	$ 271,258	$ 60,042	**$ 331,300**
7	**MWC 16 Total**	**$ 1,383,728**	**$ 2,707,861**	**$ 2,952,042**	**$ 5,659,903**	**$ 177,825**	**$ 447,567**	**$ 456,987**	**$ 904,554**	**$ 1,205,903**	**$ 2,260,294**	**$ 2,495,055**	**$ 4,755,348**

Assumptions and Details

Including 2024 as informational to lead into deriving 2025-2026 forecast and is not part of the Updated Forecast for Eligible MWC 16 Activities
Ineligible MWC 16 Activities:
(1) PEV NonRes (Rule 29)
(2) 70% of Transfomer Purchases above GRC Imputed amounts
(3) 70% of Transformer Scrapping above GRC Imputed amounts

Workpaper Table C-4
Pacific Gas and Electric Company
New Business
Capital Expenditure Request Forecast by Category Details - MWC 16

Line No.	Line Description	2024 Informational	2025 Updated Forecast (All MWC 16 Costs)	2026 Updated Forecast (All MWC 16 Costs)	Total	Assumptions	Notes	Reference
Table A: Costs Forecast ($000's)								
1	Residential Connects	$ 363,009	$ 1,041,729	$ 1,190,801	**$ 2,232,529**		2024 from WP 5: G10	2025 & 2026: [Line 9 x Line 15]/1,000
2	Non-Residential Connects	$ 162,971	$ 528,026	$ 661,361	**$ 1,189,387**		2024 from WP 5: G11	2025 & 2026: [Line 10 x Line 16]/1,000
3	PEV	$ 175,678	$ 525,595	$ 659,441	**$ 1,185,037**	(1)	2024 from WP 5: G12 + G13 + G24	2025 & 2026: ([Line 11 x Line 17]+[Line 12 x Line 18]+[Line 13 x Line 20]+[(WP 6: Line 20) x Line 21])/1,000
4	Transformer Purchases	$ 275,865	$ 335,599	$ 374,653	**$ 710,252**		2024 from WP 5: G27	2025 & 2026: [Line 54 + Line 55]
5	Transformer Scrapping	$ 7,770	$ 5,654	$ 5,744	**$ 11,398**	(2)	2024 from WP 5: G28	
6	AB50 Connects	$ 398,435	$ 271,258	$ 60,042	**$ 331,300**		2024 from WP 5: G21	2025 & 2026: ([Line 9 x Line 23] + [Line 10 x Line 24] + [Line 12 x Line 25])/1,000
7	**MWC 16 Total Costs**	**$ 1,383,728**	**$ 2,707,861**	**$ 2,952,042**	**$ 5,659,903**		Sum of Lines 1 - 6	
8	**SB-410 Eligible Costs**	**$ 1,205,903**	**$ 2,260,294**	**$ 2,495,055**	**$ 4,755,348**	(3)		
Table B: Average Unit Costs								
9	Residential Connects	$ 77,721	$ 106,888	$ 109,388		(4)	2024 from WP 5: [((G9 + G17)/1,000) / (H9 + H17)]	2025 & 2026 from WP 6: Line 26
10	Non-Residential Connects	$ 77,721	$ 106,888	$ 109,388		(4)	2024 from WP 5: [((G9 + G17)/1,000) / (H9 + H17)]	2025 & 2026 from WP 6: Line 26
11	PEV Res (Rule 15/16)	$ 127,698	$ 140,842	$ 142,933			2024 from WP 5: [(G12/1,000) / H12]	2025 & 2026 from WP 6: Line 17
12	PEV NonRes (Rule 15/16)	$ 190,716	$ 285,978	$ 290,391			2024 from WP 5: [((G13 + G20)/1,000) / (H13 + H20)]	2025 & 2026 from WP 6: Line 18
13	PEV NonRes (Rule 29)	$ 629,458	$ 872,217	$ 886,172			2024 from WP 5: [(G24/1,000) / H24]	2025 & 2026 from WP 6: Line 19
Table C: Units Forecast								
14	**Non-AB50 Connects**	**8,767**	**16,604**	**19,823**	**36,427**	(5)	Sum of Lines 15 - 19	
15	Residential Connects	5,727	9,746	10,886	**20,632**			
16	Non-Residential Connects	2,354	4,940	6,046	**10,986**			
17	PEV Res (Rule 15/16)	506	1,235	2,247	**3,482**			
18	PEV NonRes (Rule 15/16)	4	27	35	**62**			
19	PEV NonRes (Rule 29)	176	656	609	**1,265**	(6)		
20	DCFC	-	268	255	**523**			
21	L2	-	388	354	**742**			
22	**AB50 Connects**	**3,766**	**2,516**	**534**	**3,050**	(7)	Sum of Lines 23 - 25	
23	Residential Connects	2,076	1,182	216	**1,398**			
24	Non-Residential Connects	1,662	1,321	309	**1,630**			
25	PEV NonRes (Rule 15/16)	28	13	9	**22**			
26	**MWC 16 Total Units**	**12,533**	**19,120**	**20,357**	**39,477**			
27	**SB-410 Eligible Units**	**12,357**	**18,464**	**19,748**	**38,212**	(8)		
Table D: Units Forecast (Steady State vs Backlog)								
28	**Steady State**	**8,767**	**12,945**	**14,182**	**27,127**		Line 29 + Line 37	
29	**Non-AB50 Steady State Connects**	**8,767**	**12,411**	**13,648**	**26,059**		Sum of Lines 30 - 34	
30	Residential Connects	5,727	6,963	7,137	**14,100**			
31	Non-Residential Connects	2,354	3,769	3,863	**7,632**			
32	PEV Res (Rule 15/16)	506	1,012	2,024	**3,036**			
33	PEV NonRes (Rule 15/16)	4	11	15	**26**			
34	PEV NonRes (Rule 29)	176	656	609	**1,265**		Sum of Lines 35 - 36	
35	DCFC	-	268	255	**523**			
36	L2	-	388	354	**742**			
37	**AB50 Steady State Connects**	**-**	**534**	**534**	**1,068**		Sum of Lines 38 - 40	
38	Residential Connects	-	216	216	**432**			
39	Non-Residential Connects	-	309	309	**618**			
40	PEV Res (Rule 15/16)	-	9	9	**18**			
41	**Backlog**	**3,766**	**6,175**	**6,175**	**12,350**		Line 42 + Line 47	
42	**Non-AB50 Backlog Connects**	**-**	**4,193**	**6,175**	**10,368**		Sum of Lines 43 - 46	
43	Residential Connects	-	2,783	3,749	**6,532**			
44	Non-Residential Connects	-	1,171	2,183	**3,354**			
45	PEV Res (Rule 15/16)	-	223	223	**446**			
46	PEV NonRes (Rule 15/16)	-	16	20	**36**			
47	**AB50 Remaining Backlog Connects**	**3,766**	**1,982**	**-**	**1,982**		Sum of Lines 48 - 50	
48	Residential Connects	2,076	966	-	**966**			
49	Non-Residential Connects	1,662	1,012	-	**1,012**			
50	PEV Res (Rule 15/16)	28	4	-	**4**			
51	**MWC 16 Total Units**	**12,533**	**19,120**	**20,357**	**39,477**			
Table E: Forecast Transfomer Cost per New Business Job								
52	Backlog Units		6,175	6,175	**12,350**			
53	Average New Business Transformer Purchase Costs		$ 7,646	$ 7,768		(9)		WP 6: Line 21
54	Backlog Transformer Purchase Costs (000's)		$ 47,214	$ 47,970	**$ 95,184**		(Line 52 x Line 53)/1,000	
55	Transformer Purchases Forecast (000's)		$ 288,385	$ 326,683	**$ 615,068**	(10)		

Assumptions and Details

Including 2024 as informational to lead into deriving 2025-2026 forecast and is not part of the Updated Forecast for Eligible MWC 16 Activities
Including PEV Res (Rule29) for informational purposes only, not eligible per Existing D.24.-07-008
(1) PEV is the sum of PEV Res (Rule 15/16), PEV NonRes (Rule 15/16) & PEV NonRes (Rule 29)
(2) Transformer Scrapping Forecast: 2024 provided by PG&E's Sourcing Team and 2025-2026 are the approved GRC Imputed Amounts
(3) SB-410 Eligible Costs: excludes PEV Res (Rule 29), 70% Transformer Purchases above 2023 GRC Imputed Amount & 70% Transformer Scrapping above 2023 GRC Imputed Amount
(4) Residential and Non-Residentials Connects are combined to become Base Connects to differentiate core work from PEV
(5) Total Non-AB50 population as of August 2024 with COTD dates in 2024, 2025 or 2026
(6) PEV Res (Rule 29) Forecast: a combination DCFC and L2 chargers provided by PG&E's Clean Energy Transportation Team and current backlog (SB-410 Ineligible)
(7) AB50 population as of August 2024 -- includes of Residential Connects, Non-Residential Connects & PEV NonRes (Rule 15/16) ; excludes all PEV Res (Rule 15/16)
(8) SB-410 Eligble Units: excludes PEV Res (Rule 29)
(9) Historical Transformer Purchases Cost per New Business Unit
(10) Transformer Purchases Forecast for Steady State provided by PG&E's Sourcing team

Workpaper Table C-5
Pacific Gas and Electric Company
New Business
2024 Year-to-Date July Costs and 2024 August thru December Forecast - MWC 16

Line No.	Line Description	YTD July Budget Costs ($000's)	YTD July Units	Forecast (Aug - Dec) Forecasted Budget Costs ($000's)	Forecast (Aug - Dec) Forecasted Units	2024 Forecasted Budget Costs ($000's)	2024 Forecasted Units	Notes
Table A: Non AB50 Connects								
1	Base Connects	$ 154,230	4,148	$ 371,750	3,933	$ 525,980	8,081	[Line 2 + Line 3]
2	Residential Connects	$ 114,819	3,113	$ 248,190	2,614	$ 363,009	5,727	
3	Non-Residential Connects	$ 39,411	1,035	$ 123,560	1,319	$ 162,971	2,354	
4	PEV Res (Rule 15/16)	$ 31,417	221	$ 33,198	285	$ 64,615	506	
5	PEV NonRes (Rule 15/16)	$ 50	2	$ 228	2	$ 278	4	
6	**Non AB50 Population Total**	**$ 185,697**	**4,371**	**$ 405,176**	**4,220**	**$ 590,873**	**8,591**	Sum of Lines 2 - 5
Table B: AB50 Connects								
7	Base Connects	$ 284,557	2,705	$ 108,053	1,033	$ 392,610	3,738	[Line 8 + Line 9]
8	Residential Connects	$ 158,865	1,569	$ 62,211	507	$ 221,076	2,076	
9	Non-Residential Connects	$ 125,692	1,136	$ 45,842	526	$ 171,534	1,662	
10	PEV NonRes (Rule 15/16)	$ 3,923	21	$ 1,902	7	$ 5,825	28	
11	**AB50 Population Total**	**$ 288,480**	**2,726**	**$ 109,955**	**1,040**	**$ 398,435**	**3,766**	Sum of Lines 8 - 10
Table C: PEV NonRes (Rule 29)								
12	PEV NonRes (Rule 29)	$ 59,575	90	$ 51,209	86	$ 110,785	176	
Table D: Transformer Costs								
13	Transformer Purchases	$ 147,371		$ 128,494		$ 275,865		
14	Transformer Scrapping	$ 1,528		$ 6,242		$ 7,770		
Table E: Grand Total								
15	**MWC 16 Total**	**$ 682,652**	**7,187**	**$ 701,076**	**5,346**	**$ 1,383,728**	**12,533**	[Line 6 + Line 11 + Line 12 + Line 13 + Line 14]

Assumptions and Details

Including 2024 as informational to lead into deriving 2025-2026 forecast and is not part of the Updated Forecast for Eligible MWC 16 Activities

2024 End of Year forecast is based on (1) year-to-date July costs and (2) forecast August thru December 2024

Base Connects = Residential Connects + Non-Residential Connects

Workpaper Table C-6
Pacific Gas and Electric Company
New Business
2025 & 2026 Unit Cost Forecast Details - MWC 16

Line No.	Line Description	Budget Cost ($000's)	Units	Budget Cost per Unit	Assumptions	Notes	Reference
1	Base Connects	$ 972,075	12,361	$ 78,641		[Line 2 + Line 3] ; 2023 Year End + Q1 2024	
2	Residential Connects	$ 596,838	8,065	$ 74,003		2023 Year End + Q1 2024	
3	Non-Residential Connects	$ 375,238	4,296	$ 87,346		2023 Year End + Q1 2024	
4	PEV Res (Rule 15/16)	$ 31,956	238	$ 134,268		2023 Year End + Q1 2024	
5	PEV NonRes (Rule 15/16)	$ 13,732	50	$ 274,631		2023 Year End + Q1 2024	
6	PEV NonRes (Rule 29)	$ 64,952	77	$ 843,536		2023 Year End + Q1 2024	
7	New Business Transformer Puchases less Burden	$ 73,780	12,726	$ 7,395	(1)	2023 Year End + Q1 2024	

Line No.	Line Description	Since Inception Cost per Unit	% of Overall Cost by Construction Resource	Forecasted Budget Cost per Unit			
8	Internal Cost per Unit	$ 45,850	68%	$ 53,605	(2)	2023 Year End + Q1 2024	
9	Contract Cost per Unit	$ 137,299	204%	$ 160,520	(2)	2023 Year End + Q1 2024	
10	Overall Cost per Unit	$ 67,264		$ 78,641		2023 Year End + Q1 2024	

Line No.	Line Description	2025	2026			
		Forecast Cost per Unit				
11	Total Labor Hours required for Order Instituting Rulemaking (R.) 24-01-018	228,000	228,000	(3)		
12	Average Fully Burdened Hourly Rate for Project Management Staffing	$ 163	$ 163	(4)		
13	Total Additional Project Management Labor Cost (000's)	$ 37,092	$ 37,092			
14	Additional Project Management Labor Cost per Unit	$ 2,009	$ 1,878	(5)		

Line No.	Line Description	2025	2026			
		Forecast Cost per Unit				
15	Internal Base Connects Forecast Cost per Unit	$ 57,436	$ 58,192			
16	Contract Base Connects Forecast Cost per Unit	$ 167,987	$ 170,512			
17	PEV Res (Rule 15/16) Cost per Unit	$ 140,842	$ 142,933			
18	PEV NonRes (Rule 15/16) Cost per Unit	$ 285,978	$ 290,391			
19	PEV NonRes (Rule 29) Cost per Unit	$ 872,217	$ 886,172			
20	For Rule 29 - L2's only: PEV NonRes (Rule 15/16) Cost per Unit	$ 283,969	$ 288,512			
21	New Business Transformer Purchases Cost per Unit	$ 7,646	$ 7,768			
22	Forecasted Escalation Rate	3.4%	1.6%			S&P IHS Markit Q1 2024 Forecast

Line No.	Line Description	2025	2026			
		Forecast Units				
23	Internal Base Connects Forecast Units	9,500	9,500	(6)		
24	Contract Base Connects Forecast Units	7,689	7,957	(7)		
25	Total Base Connects Forecast Units	17,189	17,457			

Line No.	Line Description	2024	2025	2026			
		Forecast Cost per Unit	Forecast Budget Cost per Unit				
26	Base Connects Cost per Unit	$ 77,721	$ 106,888	$ 109,388			

Assumptions and Details

Including 2024 as informational to lead into deriving 2025-2026 forecast and is not part of the Updated Forecast for Eligible MWC 16 Activities

Base Connects = Residential Connects + Non-Residential Connects

(1) Total Transformer Purchases less Burden -- New Business portion only (%30). Applied 2025 PG&E Materials burden rate (~28%) to cost per unit

(2) Applied % of Overall Cost by Construction Resource to allocate Forecasted Budget Cost per Unit by Contruction Resource (Base Connects only)

(3) Projected total hours required to comply with energization timelines from the Order Instituting Rulemaking (R.) 24-01-018

(4) Average fully burdened hourly rate for Project Management Staffing in Service Planning and Design

(5) Forecasted cost per unit for additional Project Management Staffing

(6) Internal Construction crews are forecasted to complete a total of 9,500 units in both 2025 & 2026

(7) Any units over the Internal threshold will be executed by External Contract Construction resources

Workpaper Table C-7
Pacific Gas and Electric Company
New Business
Calculation of Gap Increase above GRC Imputed and Existing D.24-07-008 - MWC 16

Line No.	Line Description	Units 2025	Units 2026	Units Total	Unit Cost 2025	Unit Cost 2026	Costs in (000's) (Less Transformer Purchases and Scrapping) 2025	Costs in (000's) (Less Transformer Purchases and Scrapping) 2026	Costs in (000's) (Less Transformer Purchases and Scrapping) Total	Costs in (000's) (Including Transformer Purchases and Scrapping) 2025	Costs in (000's) (Including Transformer Purchases and Scrapping) 2026	Costs in (000's) (Including Transformer Purchases and Scrapping) Total	Notes
1	Updated Forecast for Eligible MWC 16 Activities	18,464	19,748	**38,212**	$ 109,547	$ 113,608	$ 2,022,674	$ 2,243,538	**$ 4,266,212**	$ 2,260,294	$ 2,495,055	**$ 4,755,348**	2025 Unit Cost: [(C9*1,000)/K9] 2026 Unit Cost: [(D9*1,000)/L9]
2	2023 GRC Imputed	6,117	6,117	**12,234**	$ 83,198	$ 84,529	$ 508,942	$ 517,045	**$ 1,025,987**	$ 702,148	$ 713,327	**$ 1,415,475**	2025 Unit Cost from WP 5: [(((C8 + C11 + C12)*1,000)/(D8 + D11 + D12)) * (1+D37) 2026 Unit Cost: [(G10) * (1+D37)]
3	Existing D.24-07-008 Caps (Incremental to 2023 GRC Imputed)	4,400	2,819	**7,220**	$ 83,198	$ 84,529	$ 366,096	$ 238,324	**$ 604,421**	$ 396,883	$ 279,650	**$ 676,533**	2025 Unit Cost from WP 5: [(((C8 + C11 + C12)*1,000)/(D8 + D11 + D12)) * (1+D37) 2026 Unit Cost: [(G10) * (1+D37)]
4	2023 GRC Imputed + Existing D.24-07-008 Caps	10,518	8,936	**19,454**	$ 83,198	$ 84,529	$ 875,038	$ 755,369	**$ 1,630,408**	$ 1,099,031	$ 992,977	**$ 2,092,008**	[Line 2 + Line3]
5	**Cap Increase Above GRC Imputed and Existing D.24-07-008 Caps**	**7,946**	**10,812**	**18,758**	**$ 144,422**	**$ 137,643**	**$ 1,147,635**	**$ 1,488,169**	**$ 2,635,804**	**$ 1,161,263**	**$ 1,502,078**	**$ 2,663,340**	[Line 1 - Line 4]

Assumptions and Details

Transformer Purchases and Scrapping are separate costs and not part the unit cost calculations.

Updated SB-410 Capital Expenditure Request excludes PEV Non Res (Rule 29). Units in 2025 & 2026 are based on Customer Demand by MATs. (Reference Assumption and Details in Workpaper Table 5)

Unit Costs for 2023 GRC Imputed and Exisiting D.24-07-008 Caps are derived based upon revised average unit costs used to develop the updated MWC 16 forecast. Does not account for additional contract resources.

Workpaper Table C-8
Pacific Gas and Electric Company
New Business
Updated Forecast for Eligible MWC 16 Activities Variance from Currently Available Funding - MWC 16

		2024	2025	2026	Total	2024	2025	2026	Total	2024	2025	2026	Total
Line No.	**Line Description**	**Informational**	**Currently Available Funding**			**Informational**	**Updated Forecast for Eligible MWC 16 Activities**			**Informational**	**Eligible Activites Variance to GRC Capacity Phase Proposed**		
Table A: Costs Forecast ($000's)													
1	Residential Connects	$ 435,670	$ 443,158	$ 467,280	**$ 910,438**	$ 363,009	$ 1,041,729	$ 1,190,801	**$ 2,232,529**	$ (72,661)	$ 598,570	$ 723,521	**$ 1,322,091**
2	Non-Residential Connects	$ 262,687	$ 278,614	$ 288,089	**$ 566,703**	$ 162,971	$ 528,026	$ 661,361	**$ 1,189,387**	$ (99,716)	$ 249,412	$ 373,272	**$ 622,684**
3	PEV	$ -	$ -	$ -	**$ -**	$ 64,893	$ 181,662	$ 331,334	**$ 512,996**	$ 64,893	$ 181,662	$ 331,334	**$ 512,996**
4	Transformer Purchases	$ 211,272	$ 217,802	$ 231,382	**$ 449,183**	$ 210,415	$ 231,966	$ 245,772	**$ 477,738**	$ (856)	$ 14,164	$ 14,391	**$ 28,555**
5	Transformer Scrapping	$ 5,597	$ 6,191	$ 6,226	**$ 12,417**	$ 6,180	$ 5,654	$ 5,744	**$ 11,398**	$ 583	$ (537)	$ (482)	**$ (1,019)**
6	AB50 Connects	$ 613,065	$ 153,266	$ -	**$ 153,266**	$ 398,435	$ 271,258	$ 60,042	**$ 331,300**	$ (214,630)	$ 117,992	$ 60,042	**$ 178,034**
7	**MWC 16 Total Costs**	**$ 1,528,290**	**$ 1,099,031**	**$ 992,977**	**$ 2,092,008**	**$ 1,205,903**	**$ 2,260,294**	**$ 2,495,055**	**$ 4,755,348**	**$ (322,387)**	**$ 1,161,263**	**$ 1,502,078**	**$ 2,663,340**
Table B: Units Forecast													
8	AB50 Backlog				**-**	3,766	2,516	534	**3,050**		2,516	534	**3,050**
9	NonAB50 Backlog				**-**	-	4,193	6,175	**10,368**		4,193	6,175	**10,368**
10	Steady State		10,518	8,936	**19,454**	8,591	11,755	13,039	**24,794**		1,237	4,103	**5,340**
11	**MWC 16 Total Units**		**10,518**	**8,936**	**19,454**	**12,357**	**18,464**	**19,748**	**38,212**		**7,946**	**10,812**	**18,758**
Table C: Unit Costs													
12	Total Budget Unit Cost		$ 83,194	$ 84,531	**$ 83,808**	$ 80,061	$ 109,547	$ 113,608					
13	Additional Contract Construction Resources						$ 26,353	$ 29,077					
14	Project Management Cost per unit						$ 2,009	$ 1,878					
15	Forecasted Escalation Rate per unit						$ 3,536	$ 5,376					
Table D: Eligible Activities Variance to GRC Capacity Phase Proposed													
16	Additional Steady State and Non AB50 units										$ 558,680	$ 770,700	**$ 1,329,380**
17	Additional Contract Construction Resources										$ 486,573	$ 574,220	**$ 1,060,793**
18	Transformer Purchases + Scrapping (Eligible portion)										$ 13,627	$ 13,909	**$ 27,536**
19	Project Management Costs										$ 37,092	$ 37,092	**$ 74,185**
20	Forecasted Escalation Rate										$ 65,290	$ 106,157	**$ 171,447**
21	**MWC 16 Total Costs**										**$ 1,161,263**	**$ 1,502,078**	**$ 2,663,340**
22	**Funding for Additional Units**										**$ 1,058,880**	**$ 1,358,828**	**$ 2,417,708**

Assumptions and Details

Including 2024 as informational to lead into deriving 2025-2026 forecast and is not part of the Updated Forecast for Eligible MWC 16 Activities

Total Budget Unit Cost = Residential Connects + Non-Residential Connects + PEV + AB50 Connects

GRC Capacity Phase did not address NonAB50 backlog and limited Steady State completion volumes to historic unit completions versus meeting demand, thus continuing a backlog

Updated request completes NonAB50 backlog by the end of 2026 and raises Steady State unit completions levels to meet demand

ATTACHMENT D

Attachment D Index
Pacific Gas and Electric Company
Distribution Capacity - MWCs 06 46

Table	Title	Description
MWCs 06 46 Workpaper Table D-1	Updated Forecast and Associated Units for Eligible Activities by Category - MWCs 06 46	Summary of updated forecasts by MWC for both Project Counts and Costs
MWCs 06 46 Workpaper Table D-2	Summary of Forecast to GRC Imputed and Existing D.24-07-008 by Category - MWCs 06 and 46	The walk from GRC Imputed and Existing D.24-07-008 to the New Cap
MWCs 06 46 Workpaper Table D-3	Capital Summary by Program Element (MAT Code)	Summary of Capital Expenditures by MAT Code using both Project Costs and Emergent Capital Expenditures
MWCs 06 46 Workpaper Table D-4	Revised Forecast Capital Expenditures by Project	Calculation details for Capital Expenditures for Projects for MWC 06 and 46
MWCs 06 46 Workpaper Table D-5	Emergent Energization Capital Expenditures	Calculation details for Emergent Energization Capital Expenditures for MAT 06H

MWCs 06 and 46 Workpaper Table D-1
Pacific Gas and Electric Company
Distribution Capacity
Updated Forecast and Associated Units for Eligible Activities by Category - MWCs 06 46
(Thousands of Nominal Dollars)[(1), (2), (3)]

		Projects			Cost		
Line No.	**Line Description**	**2025**	**2026**	**Total**	**2025**	**2026**	**Total**
1	**Updated Forecast for Eligible MWC 06 Activities**	123	265	388	$ 479,845	$ 503,771	**$ 983,616**
2	Current Available Funding (2023 GRC Imputed + D.24-07-008)[(4)]	81	186	267	$ 306,403	$ 282,246	**$ 588,649**
3	Cap Increase Above Current Available Funding (line 1 - line 2)	42	79	121	$ 173,442	$ 221,525	**$ 394,967**

		2025	2026	Total	2025	2026	Total
Line No.	**Line Description**						
8	**Updated Forecast for Eligible MWC 46 Activities**	19	38	57	$ 214,045	$ 165,590	**$ 379,635**
9	Current Available Funding (2023 GRC Imputed + D.24-07-008)[(4)]	17	32	49	$ 107,900	$ 301,618	**$ 409,518**
10	Cap Increase Above Current Available Funding (line 1 - line 2)	2	6	8	$ 106,145	$ (136,028)	**$ (29,883)**

Assumption and Details

(1) All costs are shown in Capital Expenditures in the year incurred.

(2) All costs in Nominal Dollars using 2024 costs and escalated based on Composite Labor and Non Labor Capital Escalation Rates from S&P IHS Markit Q1 2024 Forecast. Escalation Rates for Electric Distribution are 3.40% for 2025 and 1.60% for 2026.

(3) All amounts shown are for eligible MAT codes only.

(4) Project counts forecasted for Lines 2 and 9 ("Current Available Funding") correspond to the distribution plan published in PG&E's 20

MWCs 06 and 46 Workpaper Table D-2
Pacific Gas and Electric Company
Distribution Capacity
Summary of Forecast to GRC Imputed and Existing D.24-07-008 by Category - MWCs 06 46
(Thousands of Nominal Dollars)(1), (2), (3)

Line No.	Line Description	Capacity (MWC 06) Updated Forecast (ECNBIMA or Threshold E 2024	2025	2026	Total	2023 GRC Imputed 2024	2025	2026	Total
1	06A-Feeder Projs Assoc with Substation Work	$ 50,236	$ 59,059	$ 44,105	**$ 153,400**	$ 10,965	$ 11,277	$ 11,456	**$ 33,698**
2	06B-Overloaded Transformers	$ 10,722	$ 11,321	$ 11,730	**$ 33,773**	$ 8,902	$ 9,155	$ 9,301	**$ 27,358**
3	06D-Circuit Reinforcement-Distribution Planning (DP) Managed	$ 1,964	$ 109	$ 5,217	**$ 7,290**	$ 4,882	$ 5,021	$ 5,101	**$ 15,004**
4	06E-Circuit Reinforcement-Project Services (PS) Managed	$ 28,154	$ 44,437	$ 109,838	**$ 182,429**	$ 26,137	$ 26,880	$ 27,308	**$ 80,325**
5	06H - New Business Related Capacity Increase	$ 160,184	$ 364,919	$ 332,882	**$ 857,985**	$ 78,294	$ 80,521	$ 81,803	**$ 240,618**
7	**MWC 06 Total**	**$ 251,261**	**$ 479,845**	**$ 503,771**	**$ 1,234,876**	**$ 129,180**	**$ 132,854**	**$ 134,969**	**$ 397,003**

Line No.	Line Description	D.24-07-008 Incremental Funding(5) 2024	2025	2026	Total	Currently Availble Funding (2023 GRC Imputed + D.24-07-008 In 2024	2025	2026	Total
1	06A-Feeder Projs Assoc with Substation Work	$ 33,075	$ 38,150	$ (1,787)	**$ 69,438**	$ 44,040	$ 49,427	$ 9,669	**$ 103,136**
2	06B-Overloaded Transformers	$ 1,820	$ 2,166	$ 2,429	**$ 6,415**	$ 10,722	$ 11,321	$ 11,730	**$ 33,773**
3	06D-Circuit Reinforcement-Distribution Planning (DP) Managed	$ (4,725)	$ (4,448)	$ (5,101)	**$ (14,274)**	$ 157	$ 573	$ -	**$ 730**
4	06E-Circuit Reinforcement-Project Services (PS) Managed	$ (15,505)	$ 8,040	$ (9,587)	**$ (17,052)**	$ 10,632	$ 34,920	$ 17,721	**$ 63,273**
5	06H - New Business Related Capacity Increase	$ 73,302	$ 129,641	$ 161,323	**$ 364,266**	$ 151,596	$ 210,162	$ 243,126	**$ 604,884**
7	**MWC 06 Total**	**$ 87,967**	**$ 173,549**	**$ 147,277**	**$ 408,793**	**$ 217,147**	**$ 306,403**	**$ 282,246**	**$ 805,796**

Line No.	Line Description	Cap Increase Above Currently Available Funding(7) 2024	2025	2026	Total	New Cap(8) 2024	2025	2026	Total
1	06A-Feeder Projs Assoc with Substation Work	$ 6,196	$ 9,632	$ 34,436	**$ 50,264**	$ 39,271	$ 47,782	$ 32,649	**$ 119,702**
2	06B-Overloaded Transformers	$ -	$ -	$ -	**$ -**	$ 1,820	$ 2,166	$ 2,429	**$ 6,415**
3	06D-Circuit Reinforcement-Distribution Planning (DP) Managed	$ 1,807	$ (464)	$ 5,217	**$ 6,560**	$ -	$ -	$ 116	**$ 116**
4	06E-Circuit Reinforcement-Project Services (PS) Managed	$ 17,522	$ 9,517	$ 92,117	**$ 119,156**	$ 2,017	$ 17,557	$ 82,530	**$ 102,104**
5	06H - New Business Related Capacity Increase	$ 8,588	$ 154,757	$ 89,756	**$ 253,101**	$ 81,890	$ 284,398	$ 251,079	**$ 617,367**
7	**MWC 06 Total**	**$ 34,114**	**$ 173,442**	**$ 221,525**	**$ 429,080**	**$ 124,998**	**$ 351,903**	**$ 368,802**	**$ 845,704**

Line No.	Line Description	Capacity (MWC 46) Updated Forecast (ECNBIMA or Threshold E 2024	2025	2026	Total	2023 GRC Imputed 2024	2025	2026	Total
8	46A - Normal Capacity Deficiencies	$ 19,619	$ 29,452	$ 22,521	**$ 71,593**	$ 17,149	$ 17,637	$ 17,918	**$ 52,704**
9	46H - New Business Related Capacity (Includes Emergent Work)	$ 69,618	$ 184,593	$ 143,068	**$ 397,279**	$ 45,059	$ 46,340	$ 47,077	**$ 138,476**
10	46N - Land Purchases and New Distribution Substations	$ -	$ -	$ -	**$ -**	$ -	$ -	$ -	**$ -**
11	**MWC 46 Total**	**$ 89,238**	**$ 214,045**	**$ 165,590**	**$ 468,872**	**$ 62,208**	**$ 63,977**	**$ 64,995**	**$ 191,180**

Line No.	Line Description	D.24-07-008 Incremental Funding(5) 2024	2025	2026	Total	Currently Availble Funding (2023 GRC Imputed + D.24-07-008 Incremental Funding)(6) 2024	2025	2026	Total
8	46A - Normal Capacity Deficiencies	$ (6,680)	$ 9,087	$ 12,550	**$ 14,957**	$ 10,469	$ 26,724	$ 30,468	**$ 67,661**
9	46H - New Business Related Capacity (Includes Emergent Work)	$ (31,385)	$ 34,836	$ 224,073	**$ 227,524**	$ 13,674	$ 81,176	$ 271,150	**$ 366,000**
10	46N - Land Purchases and New Distribution Substations	$ 2,392	$ -	$ -	**$ 2,392**	$ 2,392	$ -	$ -	**$ 2,392**
11	**MWC 46 Total**	**$ (35,673)**	**$ 43,923**	**$ 236,623**	**$ 244,873**	**$ 26,535**	**$ 107,900**	**$ 301,618**	**$ 436,053**

Line No.	Line Description	Cap Increase Above Currently Available Funding(7) 2024	2025	2026	Total	New Cap(8) 2024	2025	2026	Total
8	46A - Normal Capacity Deficiencies	$ 9,150	$ 2,728	$ (7,947)	**$ 3,932**	$ 2,470	$ 11,815	$ 4,603	**$ 18,889**
9	46H - New Business Related Capacity (Includes Emergent Work)	$ 55,944	$ 103,417	$ (128,082)	**$ 31,279**	$ 24,559	$ 138,253	$ 95,991	**$ 258,803**
10	46N - Land Purchases and New Distribution Substations	$ (2,392)	$ -	$ -	**$ (2,392)**	$ -	$ -	$ -	**$ -**
11	**MWC 46 Total**	**$ 62,703**	**$ 106,145**	**$ (136,028)**	**$ 32,819**	**$ 27,030**	**$ 150,068**	**$ 100,595**	**$ 277,692**

Assumption and Details

(1) All costs are shown in Capital Expenditures in the year incurred.
(2) All costs in Nominal Dollars using 2024 costs and escalated based on Composite Labor and Non Labor Capital Escalation Rates from S&P IHS Markit Q1 2024 Forecast. Escalation Rates for Electric Distribution are 3.40% for 2025 and 1.60% for 2026.
(3) All amounts shown are for eligible MAT codes only.
(4) "Capacity Updated Forecast (ECNBIMA or Threshold Eligible Activities)" equals the field "Capacity Updated Forecast (ECNBIMA or Threshold Eligible Activities)" in MWCs 06 46 Workpaper Table D-3.
(5) D.24-07-008 Incremental Funding amounts taken from Appendix A of D.24-07-008.
(6) "Currently Availble Funding (2023 GRC Imputed + D.24-07-008 Incremental Funding)" amounts are per Appendix A of D.24-07-008 and equal the sum of 2023 GRC Imputed and D.24-07-008 Incremental Funding amounts.
(7) "Cap Increase Above Currently Available Funding" equals the difference between "Capacity Updated Forecast (ECNBIMA or Threshold Eligible Activities)" and "Currently Availble Funding (2023 GRC Imputed + D.24-07-008 Incremental Funding)".
(8) "New Cap" amounts are equal to "Capacity Updated Forecast (ECNBIMA or Threshold Eligible Activities)" minus the "2023 GRC Imputed" amount, except that the "New Cap" amount is set to zero where this difference is less than zero, as negative values do not reflect a reduction in available capital (D.24-07-008, p. 54).

MWCs 06 and 46 Workpaper Table D-3
Pacific Gas and Electric Company
Capital Summary by Program Element (MAT Code)
(Thousands of Nominal Dollars) (1), (2)

Line No.	MAT Code	MWC 06														
		Capacity (MWC 06) Updated Forecast (All Activities)(6), (7), (8), (9)			Activities Eligible for 2023 GRC Imputed Threshold but not ECNBIMA(12)			2023 GRC Imputed(13)			Capacity (MWC 06) Updated Forecast (ECNBIMA or Threshold Eligible Activities)(14),(15)			Capacity Updated Project Completions (ECNBIMA Eligible Activities)(3)		
		2024 Forecast(5)	2025 Forecast	2026 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2024 Count	2025 Count	2026 Count(4)
1	06A-Feeder Projs Assoc with Substation Work	$ 50,236	$ 59,059	$ 44,105	$ 10,329	$ 7,749	$ 5,835	$ 10,965	$ 11,277	$ 11,456	$ 50,236	$ 59,059	$ 44,105	9	12	10
2	06B-Overloaded Transformers(10)	$ 10,722	$ 11,321	$ 11,730	$ -	$ -	$ -	$ 8,902	$ 9,155	$ 9,301	$ 10,722	$ 11,321	$ 11,730	0	0	0
3	06D-Circuit Reinforcement- Distribution Planning (DP) Managed	$ 1,964	$ 109	$ 5,217	$ -	$ -	$ 63	$ 4,882	$ 5,021	$ 5,101	$ 1,964	$ 109	$ 5,217	5	1	50
4	06E-Circuit Reinforcement- Project Services (PS) Managed	$ 28,154	$ 44,437	$ 109,838	$ -	$ 431	$ 2,916	$ 26,137	$ 26,880	$ 27,308	$ 28,154	$ 44,437	$ 109,838	13	34	99
5	06H - New Business Related Capacity Increase(11)	$ 160,184	$ 364,919	$ 332,882	$ 383	$ 160	$ 8,390	$ 78,294	$ 80,521	$ 81,803	$ 160,184	$ 364,919	$ 332,882	40	76	106
6	**MWC 06 Total(16)**	**$ 251,261**	**$ 479,845**	**$ 503,771**	**$ 10,712**	**$ 8,340**	**$ 17,204**	**$ 129,180**	**$ 132,854**	**$ 134,969**	**$ 251,261**	**$ 479,845**	**$ 503,771**	**67**	**123**	**265**

Line No.	MAT Code	MWC 46														
		Capacity (MWC 46) Updated Forecast (All Activities)(6), (7), (8), (9)			Activities Eligible for 2023 GRC Imputed Threshold but not ECNBIMA(12)			2023 GRC Imputed(13)			Capacity (MWC 46) Updated Forecast (ECNBIMA or Threshold Eligible Activities)(14),(15)			Capacity Updated Project Completions (ECNBIMA Eligible Activities)(3)		
		2024 Forecast(5)	2025 Forecast	2026 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2024 Count	2025 Count	2026 Count(4)
7	46A - Normal Capacity Deficiencies	$ 19,619	$ 29,452	$ 32,264	$ 335	$ 10,206	$ 27,661	$ 17,149	$ 17,637	$ 17,918	$ 19,619	$ 29,452	$ 22,521	6	5	6
8	46H - New Business Related Capacity (Includes Emergent Work)	$ 69,618	$ 197,601	$ 218,730	$ 15,941	$ 59,348	$ 122,738	$ 45,059	$ 46,340	$ 47,077	$ 69,618	$ 184,593	$ 143,068	12	14	32
9	46N - Land Purchases and New Distribution Substations	$ 3,720	$ -	$ -	$ 3,720	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0	0	0
10	**MWC 46 Total(16)**	**$ 92,958**	**$ 227,053**	**$ 250,994**	**$ 19,997**	**$ 69,554**	**$ 150,399**	**$ 62,208**	**$ 63,977**	**$ 64,995**	**$ 89,238**	**$ 214,045**	**$ 165,590**	**18**	**19**	**38**

(1) All costs are shown in Capital Expenditures in the year incurred.

(2) All costs in Nominal Dollars using 2024 costs and escalated based on Composite Labor and Non Labor Capital Escalation Rates from S&P IHS Markit Q1 2024 Forecast. Escalation Rates for Electric Distribution are 3.40% for 2025 and 1.60% for 2026.

(3) Project completions is the count of all projects listed in Workpaper Table Capacity-02 by the year placed in operation.

(4) Higher project counts in 2026 include small projects heavily concentrated in the Central Valley on circuits that are often long and far apart, making it especially difficult to maintain voltage during increased loading. These projects can be completed in 1 year or less and have an average cost of ~$200k, as they are typically smaller and require less scope. For example, many of these projects require just the installation of a single voltage regulator to resolve a modeled voltage issue.

(5) 2024 Revised Forecast based on Actuals through 6/30/24 and forecasted costs for the remainder of the year based on financial work plan.

(6) Revised Forecast is the sum of the Capital Expenditure (in nominal dollars) for all project costs identified in MWCs 06 46 Workpaper Table D-4 plus Emergent Energization Work (MWCs 06 46 Workpapers Table D-5).

(7) Revised Forecast reflects an updated Distribution Plan from a new Distribution Planning cycle. Revised forecast supersedes the previous forecasts provided in testimony and data requests that were created in October 2023. Individual project plans may be adjusted to reflect forecast changes, new customer requests, unanticipated cancellations, postponements, etc.

(8) Updates to the Revised Forecast include additional customer applications for service have been received and are now creating additional growth; use of the 2022 CEC IEPR forecast versus the 2021 CEC IEPR forecast for system level load and DER growth; and projects and transfers that were completed in 2023 now show as complete and their impacts are modeled in the plan.

(9) The Updates to the Revised Forecast include the identification of new grid needs and projects, as well as the cancellation and delay of other projects as part of the annual Distribution Planning Process.

(10) Revised Forecast for MAT 06B is unchanged from PG&E's Base Scenario used in D.24-07-008. No project counts are shown for MAT 06B.

(11) Eligible Emergent Energization Capital Expenditures for MAT 06H for 2025 and 2026 equal Line 11 and Line 12 of MWCs 06 46 Workpaper Table D-5. Emergent work for MWC 46 is not included because it is unlikely to be completed by January 1, 2027. Emergent Energization Capital Expenditures are to start n

(12) "Activities Eligible for 2023 GRC Imputed Threshold but not ECNBIMA" includes Capital Expenditures incurred for projects placed in service before January 1, 2024 or placed in service after January 1, 2027; MAT 46N expenditures because all 46N expenditures involve new substations that are expected to be

(13) 2023 GRC Imputed corresponds PG&E's 2023 GRC imputed adopted amounts (D.23-11-069).

(14) "Capacity Updated Forecast (ECNBIMA or Threshold Eligible Activities)" equals the "Capacity Updated Forecast" if the "Activities Eligible for 2023 GRC Imputed Threshold but not ECNBIMA" does not exceed the 2023 GRC Imputed amount. However, if the "Activities Eligible for 2023 GRC Imputed Threshold

(15) "Capacity Updated Forecast (ECNBIMA or Threshold Eligible Activities)" does not include any projects proposed to address supply-side deficiencies or issues caused by distributed generation.

(16) The MWC 06 Total and the MWC 46 Totals are for the eligible MAT codes only.

MWCs 06 and 46 Workpaper Table D-4
Pacific Gas and Electric Company
Revised Forecast Capital Expenditures by Project[(1),(5),(6),(7),(8),(9)]
(Thousands of Nominal Dollars)[(2)]

(1) All Projects with eligible MAT Codes (06A, 06D, 06E, 06H, 46A, 46H, and 46N) and Capital Expenditures in 2024, 2025, or 2026 are included. All costs are shown in Capital Expenditures in the year incurred. Total project costs may include capital expenditures in years outside of 2024-2026 that are not shown.
(2) All costs in Nominal Dollars using 2024 costs and escalated based on Composite Labor and Non Labor Capital Escalation Rates from S&P IHS Markit Q1 2024 Forecast. Escalation Rates for Electric Distribution are 3.40% for 2025 and 1.60% for 2026.
(3) Operation Year is the year project is expected to be placed in service. There may be Capital expenditures in years other than the Operation Year given the multi-year nature of the projects, including close out work after the project is placed in-service.
(4) 2024 Forecast based on Actuals through 6/30/24 and forecasted costs for the remainder of the year based on financial work plan.
(5) Project list does not include emergent capital expenditure for MAT 06H. Capital Expenditure for emergent work is based on MWCs 06 46 Workpaper Table 4 for MAT 06H. Emergent work for MWC 46 is not included because it is unlikely to be completed by January 1, 2027.

(6) Revised Forecast reflects an updated Distribution Plan from a new Distribution Planning cycle. Revised forecast supersedes the previous forecasts provided in testimony and data requests that were created in October 2023. Individual project plans will be adjusted to reflect forecast changes, new customer requests, unanticipated cancellations, postponements, etc.

(7) Updates to the Revised Forecast include additional customer applications for service have been received and are now creating additional growth; use of the 2022 CEC IEPR forecast versus the 2021 CEC IEPR forecast for system level load and DER growth; and projects and transfers that were completed in 2023 now show as complete and their impacts are modeled in the plan.
(8) The Updates to the Revised Forecast include the identification of new grid needs and projects, as well as the cancellation and delay of other projects as part of the annual Distribution Planning Process.
(9) Individual project plans may be adjusted to reflect forecast changes, new customer requests, unanticipated cancellations, postponements, etc.
(10) Nearest City is the nearest city (geographically) to the Substation associated with the project.

Line No.	Division	Region	Project Description	Nearest City[(10)]	Substation	Planning Order (PO)	MWC	MAT	Operation Year[(3)]	2024 Forecast[(4)]	2025 Forecast	2025 Forecast (Escalated)	2026 Forecast	2026 Forecast (Escalated)	Comments
1	East Bay	Bay Area	San Pablo: Install San Pablo 1104 feeder	San Pablo	San Pablo	5796279	46	46H	2025	$ 294	$ 1,475	$ 1,525	$ 25	$ 26	
2	Fresno	Central Valley	Coalinga #1 - Replace Bank 2, add feeder	Coalinga	Coalinga No. 1	5796871	46	46H	2026	$ 901	$ 11,190	$ 11,570	$ 5,405	$ 5,678	
3	Kern	Central Valley	Tupman Sub - Install 2 feeders on Bank 2	Tupman	Tupman	5800041	46	46H	2025	$ 257	$ 1,886	$ 1,950	$ 304	$ 319	
4	Kern	Central Valley	San Bernard - Install Bank 2	Lamont	San Bernard	5796538	46	46A	2025	$ 2,115	$ 1,556	$ 1,609	$ 10	$ 11	
5	Los Padres	South Bay & Central Coast	Reconductor Cholame 1101	Cholame	Cholame	5808798	46	46H	2025	$ 2	$ 450	$ 465	$ -	$ -	
6	North Bay	North Coast	Calistoga - Install Bank 2 and Install 1103 new feeder	Calistoga	Calistoga	5791138	46	46H	2025	$ 1,418	$ 8,145	$ 8,422	$ 29	$ 30	
7	Peninsula	Bay Area	R1 INSTALL NEW BAIR1101 CIRCUIT	Redwood City	Bair	5809054	46	46H	2025	$ 184	$ 1,186	$ 1,226	$ -	$ -	
8	Sacramento	North Valley & Sierra	Vaca Dixon - Install New Feeder	Vacaville	Vaca Dixon	5803458	46	46H	2025	$ 417	$ 3,438	$ 3,555	$ 27	$ 28	
9	San Francisco	Bay Area	Install New Feeder Martin (SF H) 1117 Ph 1 Demolition & Conversion	San Francisco	Martin (SF H)	5789638	46	46H	2025	$ 1,471	$ 850	$ 879	$ 5	$ 5	
10	Sonoma	North Coast	Monroe - Install two new 21kV feeders	Santa Rosa	Monroe	5801267	46	46H	2025	$ 71	$ 2,040	$ 2,109	$ -	$ -	
11	Stockton	Central Valley	Vierra - Install new 1704 on existing breaker	Lathrop	Vierra	5790020	46	46H	2025	$ 2	$ 850	$ 879	$ -	$ -	
12	Stockton	Central Valley	Purchase land for new Glass Fab substation	Tracy	Carbona	5550539	46	46N	2027	$ 22	$ -	$ -	$ -	$ -	46N for substation in-service past 1/1/27
13	Sierra	North Valley & Sierra	Momentum Substation - Land Purchase	Roseville	Momentum	5800805	46	46N	2024	$ 198	$ -	$ -	$ -	$ -	46N for substation in-service past 1/1/27
14	Yosemite	Central Valley	Storey - Replace Bank 1 and install two feeders	Madera	Storey	5796823	46	46H	2026	$ 816	$ 11,485	$ 11,875	$ 2,439	$ 2,562	
15	San Francisco	Bay Area	Martin (SF H) 1113 - Install New Feeder	San Francisco	Martin (SF H)	5810932	46	46H	2026	$ 0	$ 560	$ 579	$ 840	$ 882	
16	Central Coast	South Bay & Central Coast	Boronda Sub - Replace Bus and Control Building	Salinas	Boronda	5804780	46	46A	2026	$ 226	$ 633	$ 655	$ 199	$ 209	
17	Central Coast	South Bay & Central Coast	Green Valley - Install Bank 4	Watsonville	Green Valley	5796728	46	46H	2026	$ 2,548	$ 6,255	$ 6,468	$ 1,060	$ 1,114	
18	De Anza	South Bay & Central Coast	Wolfe Install 1 New Circuit 1111	Cupertino	Wolfe	5790914	46	46H	2026	$ 0	$ 495	$ 512	$ 1,200	$ 1,261	
19	Diablo	Bay Area	Willow Pass - Replace Bank 1	Concord	Willow Pass	5790245	46	46A	2026	$ 2,416	$ 4,816	$ 4,980	$ 730	$ 767	
20	East Bay	Bay Area	Oakland J: Install New Circuit Feeder Oakland J1113	Oakland	Oakland J	5801180	46	46H	2026	$ -	$ 560	$ 579	$ 840	$ 882	
21	East Bay	Bay Area	Oakland J: Oakland J1152 Circuit Extension	Oakland	Oakland J	5802982	46	46H	2025	$ -	$ 295	$ 305	$ -	$ -	
22	Fresno	Central Valley	Kearney - Replace Bk 3 and install 1115	Fresno	Kearney	5807760	46	46H	2026	$ -	$ 6,050	$ 6,256	$ 4,330	$ 4,549	
23	Fresno	Central Valley	Add feeder at McMullin	Caruthers	McMullin	5807925	46	46H	2026	$ 1	$ 560	$ 579	$ 840	$ 882	
24	Fresno	Central Valley	Airways - Install Bank 3 and Switchgear 3, and Airways 1109 and Airways 1110 Feeders	Clovis	Airways	5796868	46	46A	2026	$ 2,648	$ 2,060	$ 2,130	$ 830	$ 872	
25	Humboldt	North Coast	Willits - Replace Bank 1 with 30MVA	Willits	Willits	5802679	46	46H	2026	$ 163	$ 2,550	$ 2,637	$ 6,630	$ 6,965	
26	Humboldt	North Coast	Potter Valley - Replace Bank 1 and install feeder in conjunction with hydro replacement	Potter Valley	Potter Valley	5797279	46	46H	2026	$ 253	$ 6,520	$ 6,742	$ 6,580	$ 6,913	
27	Kern	Central Valley	Old River - Install 1106 Feeder	Old River	Old River	5807800	46	46A	2026	$ 73	$ 560	$ 579	$ 840	$ 882	
28	Kern	Central Valley	Install Shafter 1110	Shafter	Shafter	5806241	46	46A	2026	$ 74	$ 560	$ 579	$ 840	$ 882	
29	Kern	Central Valley	Install Charca 1101	Wasco	Charca	5809480	46	46A	2026	$ 61	$ 560	$ 579	$ 840	$ 882	
30	Kern	Central Valley	Replace Tejon Bank 1 and Install Tejon 1104	Tejon	Tejon	5807799	46	46H	2026	$ 16	$ 3,060	$ 3,164	$ 4,080	$ 4,286	
31	Kern	Central Valley	7th Standard - Install Bank 2 and two 21 kV feeders	Shafter	7th Standard	5800042	46	46H	2026	$ 175	$ 7,750	$ 8,014	$ 1,200	$ 1,261	
32	Kern	Central Valley	Wheeler Ridge - Install Bank 6	Bakersfield	Wheeler Ridge	5800039	46	46H	2027	$ 1,700	$ 2,490	$ 2,575	$ 3,591	$ 3,773	
33	Los Padres	South Bay & Central Coast	San Miguel Sub - Install 30 MVA Bank	San Miguel	San Miguel	5794990	46	46A	2025	$ 2,386	$ 6,055	$ 6,261	$ 48	$ 50	
34	Peninsula	Bay Area	Belle Haven - Replace Bank 4 w/ 30MVA and Inst BH 1109 & 1110 Fdrs	Menlo Park	Belle Haven	5791141	46	46H	2027	$ 3,232	$ 4,795	$ 4,958	$ 781	$ 820	
35	Sacramento	North Valley & Sierra	Add 1 new feeder at West Sacramento	West Sacramento	West Sacramento	5806180	46	46H	2026	$ 0	$ 800	$ 827	$ 1,320	$ 1,387	
36	Sacramento	North Valley & Sierra	Peabody - Replace Bank 3 and add feeder	Fairfield	Peabody	5802685	46	46H	2026	$ 270	$ 6,013	$ 6,217	$ 3,159	$ 3,319	
37	Sacramento	North Valley & Sierra	PEABODY BK 3 - INSTALL CB 2114	Fairfield	Peabody	5809482	46	46H	2026	$ 245	$ 959	$ 992	$ 1,549	$ 1,627	
38	Sacramento	North Valley & Sierra	PEABODY BK 3 - REPLACE CB 2300	Fairfield	Peabody	5808761	46	46H	2026	$ 219	$ 934	$ 966	$ 1,507	$ 1,583	
39	San Francisco	Bay Area	Potrero A1106 Recable inside Sub	San Francisco	Potrero (SF A)	5797246	46	46A	2025	$ 0	$ 155	$ 160	$ -	$ -	
40	San Jose	South Bay & Central Coast	Llagas Sub - Replace Bus at Bank 3 and finsh 2108 install	Gilroy	Llagas	5800982	46	46H	2026	$ 96	$ 828	$ 856	$ 1,673	$ 1,758	
41	Sonoma	North Coast	Fulton - Replace Bank 5	Fulton	Fulton	5799443	46	46H	2026	$ 1,525	$ 5,819	$ 6,017	$ 10,034	$ 10,541	
42	Stockton	Central Valley	Ripon - Install new 17kV feeder	Ripon	Ripon	5790021	46	46H	2026	$ -	$ 379	$ 392	$ 2,149	$ 2,258	
43	Stockton	Central Valley	Weber - Replace Bank 3 and install 1117	Stockton	Weber	5800420	46	46H	2025	$ 3,133	$ 5,180	$ 5,356	$ -	$ -	
44	Stockton	Central Valley	Weber - Replace Bank 4 and Install 1118	Stockton	Weber	5806218	46	46H	2026	$ 377	$ 6,522	$ 6,744	$ 4,832	$ 5,076	
45	Stockton	Central Valley	Banta - Replace Bank 1	Tracy	Banta	5792892	46	46H	2027	$ 3,344	$ 9,364	$ 9,682	$ 9,208	$ 9,673	
46	Yosemite	Central Valley	Oro Loma - Replace 1106 bus conductor	Dos Palos	Oro Loma	-	46	46A	2025	$ -	$ 1,200	$ 1,241	$ 15	$ 16	
47	Yosemite	Central Valley	Ortiga - Install New Bank & 2 Feeders	Los Banos	Ortiga	5796818	46	46H	2026	$ 304	$ 6,191	$ 6,401	$ 2,874	$ 3,019	
48	Yosemite	Central Valley	Panoche - Install Bank 4	Mendota	Panoche	5800037	46	46H	2026	$ 2,584	$ 4,170	$ 4,312	$ 2,560	$ 2,689	
49	Yosemite	Central Valley	El Capitan - New Bank and Feeder	Merced	El Capitan	-	46	46H	2028	$ -	$ -	$ -	$ 3,240	$ 3,404	
50	Yosemite	Central Valley	Borden - Replace Bank and Install New1102 Feeder	Madera	Borden	-	46	46A	2028	$ -	$ -	$ -	$ 2,070	$ 2,175	
51	Central Coast	South Bay & Central Coast	Chualar Substation - build new substation	Salinas	Chualar	5796900	46	46H	2027	$ 1	$ 1,300	$ 1,344	$ 3,250	$ 3,414	
52	De Anza	South Bay & Central Coast	Los Gatos Sub - Repl Bk 1 and Bk 2	Los Gatos	Los Gatos	5806547	46	46H	2027	$ -	$ 4,160	$ 4,301	$ 7,380	$ 7,753	
53	De Anza	South Bay & Central Coast	Britton - Replace Bank 1 and Bank 3 and install a new feeder	Sunnyvale	Britton	5809931	46	46H	2027	$ -	$ 2,910	$ 3,009	$ 3,880	$ 4,076	
54	Fresno	Central Valley	Camden - Install 1106 and 1107 feeders to offload Camden 1103 and Hardwick Bank 1	Riverdale	Camden	5808818	46	46H	2026	$ -	$ 1,120	$ 1,158	$ 1,680	$ 1,765	
55	Fresno	Central Valley	New Feeder Lemoore 1106 on Bank 1	Lemoore	Lemoore	-	46	46H	2027	$ -	$ -	$ -	$ 560	$ 588	
56	Fresno	Central Valley	New West Fresno 1113 and 1114 Feeders	Fresno	West Fresno	-	46	46H	2027	$ -	$ -	$ -	$ 1,120	$ 1,177	
57	Fresno	Central Valley	Tulare Lake Increased Capacity	Kettleman	Tulare Lake	-	46	46A	2028	$ -	$ -	$ -	$ 3,910	$ 4,108	
58	Fresno	Central Valley	Biola new bank	Biola	Biola	-	46	46A	2028	$ -	$ -	$ -	$ 3,240	$ 3,404	
59	Fresno	Central Valley	Giffen Sub - Install Bank 2 and new feeder	San Joaquin	Giffen	5796869	46	46H	2027	$ -	$ 1,200	$ 1,241	$ 2,063	$ 2,167	
60	Fresno	Central Valley	Dinuba - Install New Feeder 1107 (formerly Reedley Sub - Install Reedley 1114 feeder)	Reedley	Reedley	5805321	46	46A	2027	$ -	$ -	$ -	$ 560	$ 588	
61	Humboldt	North Coast	Carlotta - Replace Bank 1	Carlotta	Carlotta	-	46	46H	2027	$ -	$ 3,670	$ 3,795	$ 2,560	$ 2,689	
62	Humboldt	North Coast	Fruitland - Replace Bank 1 with 12MVA bank	Myers Flat	Fruitland	5797202	46	46H	2029	$ 2	$ 1,200	$ 1,241	$ 3,000	$ 3,152	
63	Kern	Central Valley	Goose Lake - Install Two 12 kV Feeders	Wasco	Goose Lake	5809478	46	46H	2026	$ -	$ 1,120	$ 1,158	$ 1,680	$ 1,765	
64	Kern	Central Valley	Midway - Replace Bank 8 and inst 3 feeders	Buttonwillow	Midway	5800038	46	46H	2026	$ 2,564	$ 6,891	$ 7,125	$ 666	$ 700	

65	Los Padres	South Bay & Central Coast	Foothill - Replace Bank 1	San Luis Obispo	Foothill	5809939	46	46H	2027	$ -	$ 4,170	$ 4,312	$ 5,560	$ 5,841	
66	Los Padres	South Bay & Central Coast	Templeton Bank 2 Replacement	Templeton	Templeton	5807983	46	46A	2027	$ 0	$ 2,250	$ 2,327	$ 2,250	$ 2,364	
67	Los Padres	South Bay & Central Coast	Fairway - Replace Bank 1 and Install new 1102 feeder	Santa Maria	Fairway	5809981	46	46H	2027	$ -	$ 3,570	$ 3,691	$ 4,760	$ 5,001	
68	Mission	Bay Area	NEWARK:INSTALL BANK 23 AND FEEDERS	Newark	Newark	5809199	46	46H	2028	$ -	$ -	$ -	$ 240	$ 252	
69	Peninsula	Bay Area	Sneath Lane:Install Sneath Lane 1108 at Bank 2	San Bruno	Sneath Lane	5800425	46	46H	2026	$ -	$ 45	$ 47	$ 255	$ 268	
70	Peninsula	Bay Area	Millbrae Sub: Install Bank 2 and Millbrae 1109 & 1110 Fdrs	Millbrae	Millbrae	5800302	46	46H	2026	$ 61	$ 1,350	$ 1,396	$ 12,450	$ 13,079	
71	San Francisco	Bay Area	Potrero Sub - Install New Bank 5 and feeder	San Francisco	Potrero (SF A)	5804783	46	46H	2027	$ 4,249	$ 3,750	$ 3,878	$ 8,639	$ 9,076	
72	Sierra	North Valley & Sierra	Momentum Sustation Phase 1 - Install Bk 1 and three 21kV feeders	Roseville	Momentum	5807358	46	46H	2027	$ 2,858	$ 5,240	$ 5,418	$ 6,060	$ 6,366	
73	San Jose	South Bay & Central Coast	Mc Kee Sub - Replace McKee Bank 1, Install new 1102 feeder	San Jose	Mc Kee	5800321	46	46A	2027	$ -	$ 2,800	$ 2,895	$ 2,800	$ 2,942	
74	San Jose	South Bay & Central Coast	Milpitas - Replace Bank 2 and install a new feeder	Milpitas	Milpitas	5809929	46	46H	2028	$ -	$ -	$ -	$ 2,490	$ 2,616	
75	San Jose	South Bay & Central Coast	Evergreen - Replace Bank 2	San Jose	Evergreen	5809930	46	46H	2027	$ -	$ 2,508	$ 2,593	$ 3,302	$ 3,469	
76	Sonoma	North Coast	Bellevue - Install new 12kV feeder	Santa Rosa	Bellevue	-	46	46A	2027	$ -	$ -	$ -	$ 250	$ 263	
77	Stockton	Central Valley	Corral - Install new 1104 Feeder	Bellota	Corral	-	46	46A	2027	$ -	$ -	$ -	$ 560	$ 588	
78	Yosemite	Central Valley	Storey - Replace Bank 2 and install two new feeders	Madera	Storey	-	46	46H	2027	$ -	$ 920	$ 951	$ 2,300	$ 2,416	
79	Yosemite	Central Valley	Gustine - New Bank and Feeder	Gustine	Gustine	-	46	46H	2028	$ -	$ -	$ -	$ 3,240	$ 3,404	
80	De Anza	South Bay & Central Coast	Ames - Install Ames 1103	Mountain View	Ames	5809043	46	46H	2027	$ -	$ -	$ -	$ 560	$ 588	
81	Humboldt	North Coast	Garberville - Ph 1 Replace Substation disconnects, recond line, Ph 2 replace 12kV bus	Garberville	Garberville	5809044	46	46H	2024	$ 72	$ 430	$ 445	$ 811	$ 852	
82	Kern	Central Valley	Columbus new feeders (formerly Magunden)	Bakersfield	Columbus	-	46	46H	2027	$ -	$ -	$ -	$ 1,120	$ 1,177	
83	Fresno	Central Valley	Replace Coppermine Bank 1 with 45 MVA Bank	Clovis	Coppermine	-	46	46H	2028	$ -	$ -	$ -	$ 2,250	$ 2,364	
84	Los Padres	South Bay & Central Coast	Buellton - Replace Bank 1 with 45MVA Bank and add new 1103 feeder	Buellton	Buellton	5804725	46	46A	2027	$ 0	$ 2,820	$ 2,916	$ 2,820	$ 2,963	
85	Peninsula	Bay Area	Woodside Sub - Add new feeder	Woodside	Woodside	5552422	46	46H	2026	$ 0	$ 560	$ 579	$ 840	$ 882	
86	Peninsula	Bay Area	RAVENSWOOD SUB:INSTALL RAVENSWOOD 21 KV DISTRIBUTION BANKS AND FEEDERS	Menlo Park	Ravenswood	5799745	46	46H	2028	$ 8	$ 340	$ 352	$ 1,569	$ 1,648	
87	San Jose	South Bay & Central Coast	Morgan Hill Repl Bk 2 and Inst New 2107 Circuit	Morgan Hill	Morgan Hill	5806520	46	46H	2028	$ -	$ 1,000	$ 1,034	$ 2,170	$ 2,280	
88	Sonoma	North Coast	Cloverdale - Install Bank 2, 1104	Cloverdale	Cloverdale	5810018	46	46H	2028	$ -	$ -	$ -	$ 4,320	$ 4,538	
89	Sonoma	North Coast	Rincon - Install Feeder 1105	Santa Rosa	Rincon	5797280	46	46A	2027	$ -	$ -	$ -	$ 1,200	$ 1,261	
90	Stockton	Central Valley	Vierra - Install new bank 3 and 2 new feeders	Lathrop	Vierra	5796821	46	46H	2028	$ 3	$ 1,000	$ 1,034	$ 3,660	$ 3,845	
91	Stockton	Central Valley	French Camp - Replace Bank 1 and install new feeder	Stockton	French Camp	5796819	46	46A	2028	$ 1	$ 1,000	$ 1,034	$ 2,170	$ 2,280	
92	Yosemite	Central Valley	Hammonds - Replace Bank 1 and add new feeder	Fresno	Hammonds	5796822	46	46A	2028	$ -	$ 1,000	$ 1,034	$ 2,250	$ 2,364	
93	Central Coast	South Bay & Central Coast	Gabilan - Install Bank 2	Salinas	Gabilan	5796872	46	46H	2028	$ -	$ -	$ -	$ 3,660	$ 3,845	
94	Stockton	Central Valley	Terminous - Install Bank 2 and 2 feeders	Lodi	Terminous	5802179	46	46H	2028	$ -	$ -	$ -	$ 3,660	$ 3,845	
95	Central Coast	South Bay & Central Coast	Camp Evers - Install 2102 Feeder	Scotts Valley	Camp Evers	-	46	46H	2027	$ -	$ -	$ -	$ 560	$ 588	
96	Fresno	Central Valley	Install Tulare Lake 1105 feeder on Tulare Lake Bank 1	Kettleman	Tulare Lake	-	46	46H	2027	$ -	$ 560	$ 579	$ 840	$ 882	
97	Sacramento	North Valley & Sierra	Williams New BK and Two 12-kV Feeders	Williams	Williams	-	46	46H	2028	$ -	$ -	$ -	$ 3,750	$ 3,940	
98	San Francisco	Bay Area	Martin New H1116 feeder for 1 Quarry Rd	San Francisco	Martin (SF H)	-	46	46H	2026	$ -	$ 1,500	$ 1,551	$ 1,500	$ 1,576	
99	Yosemite	Central Valley	French Camp - Replace Bank 2	Stockton	French Camp	-	46	46A	2028	$ -	$ -	$ -	$ 2,250	$ 2,364	
100	North Valley	North Valley & Sierra	Orland B Replace Bk1	Orland	Orland B	-	46	46H	2028	$ -	$ 250	$ 259	$ 2,000	$ 2,101	
101	De Anza	South Bay & Central Coast	Dixon Landing: Replace Bank 2	Milpitas	Dixon Landing	-	46	46H	2029	$ -		$ -	$ 2,490	$ 2,616	
102	Central Coast	South Bay & Central Coast	Industrial Acres - 12kV Switchgear	Salinas	Industrial Acres	5811307	46	46H	2026	$ -	$ 3,000	$ 3,102	$ 3,000	$ 3,152	
103	East Bay	Bay Area	NEW OAKLAND D 1135 FEEDER	Oakland	Oakland D	5807551	46	46H	2026	$ -	$ 25	$ 26	$ 1,000	$ 1,051	
104	San Jose	South Bay & Central Coast	San Jose Station A Rebuild	San Jose	San Jose A	5811202	46	46H	2028	$ -	$ 3,000	$ 3,102	$ 7,000	$ 7,354	
105	Fresno	Central Valley	RAINBOW 1106 COBBLESTONE CAPACITY SELF-F	Sanger	Rainbow	5810525	06	06H	2025	$ 766	$ 1	$ 1	$ -	$ -	
106	Peninsula	Bay Area	Woodside 1101, Reconductor OL 6C near LR 8974	Woodside	Woodside	5502947	06	06E	2025	$ 174	$ 66	$ 68	$ -	$ -	

MWCs 06 and 46 Workpaper Table D-5
Pacific Gas and Electric Company
Emergent Energization Capital Expenditures
(Thousands of Nominal Dollars)

Line No.	Year	Estimated Emergent Energization Costs	Assumptions	Reference
1	2021	$ 213,504	(1)	
2	2022	$ 237,071	(1)	
3	2023	$ 103,391	(1),(2)	
4	Total Emergent Energization Project Costs	$ 553,967		Line 4 equals Line 1 + Line 2 + Line 3
5	Total Number of Years	3		Line 5 equals Count of Line 1, Line 2, and Line 3
6	Average Annual Emergent Energization Project Costs	$ 184,656		Line 6 equals Line 4 / Line 5
7	Years of Eligible Emergent Energization Costs	0.5	(3)	Line 7 equals Half of a year (1/1/2025 to 7/1/2025)
8	Total Eligible Emergent Energization Costs	$ 92,328	(4)	Line 8 equals Line 6 x Line 7
9	2025 Eligible Emergent Energization Capital Expenditure (Unescalated)	$ 46,164	(5)	Line 9 equals Line 8 / 2
10	2026 Eligible Emergent Energization Capital Expenditure (Unescalated)	$ 46,164	(5)	Line 10 equals Line 8 / 2
11	**2025 Eligible Emergent Energization Capital Expenditure**	**$ 47,733**	(6)	Line 11 equals Line 9 x 1.034
12	**2026 Eligible Emergent Energization Capital Expenditure**	**$ 48,497**	(6)	Line 12 equals (Line 10 x 1.034) x 1.016

(1) Emergent Energization Costs exclusively includes new MAT 06H work identified between January 2021 and December 2023 . Costs are shown for the Year in which the Project is identified.

(2) Line 3: 2023 Estimated Emergent Energization Costs are preliminary and have not yet been vetted by Project Managers for all projects. Data from 2021 and 2022 has been included as that data has been more fully vetted and thus gives a more accurate indication of estimated emergent costs.

(3) Line 7: Years of Eligible Emergent Energization Costs assumes only projects that are identified between 1/1/25 and 7/1/25 (half a year) will be able to be completed by 1/1/27 and therefore be eligible for inclusion in the Memorandum Account. This assumes a Timeline of ~1.5 years for MAT 06H work, if funding is fully authorized.

(4) Line 8: Total Eligible Emergent Energization Costs equals Years of Emergent Work (0.5 years or 6 months) times the Average Annual Emergent Work Costs.

(5) 2025 and 2026 Eligible Emergent Energization Capital Expenditures are based on the Total Eligible Emergent Energization Costs split equally between 2025 and 2026 assuming work begins upon project identification in 2025 and continues into 2026 through being placed into service.

(6) All costs in Nominal Dollars with Average Monthly Emergent Work Costs set to 2024 and escalated based on Composite Labor and Non Labor Capital Escalation Rates from S&P IHS Markit Q1 2024 Forecast. Escalation Rates for Electric Distribution are 3.40% for 2025 and 1.60% for 2026.

ATTACHMENT E

Attachment E - Index

Pacific Gas and Electric Company

Work at the Request of Others - MWC 10

Table	Description
E-1	Updated energization-related MWC 10 unit and dollar forecast and requested new cost caps
E-2	High level summary of 2023 GRC funding, D.24-07-008 funding, and updated forecast for MWC 10 ECNBIMA eligible activites
E-3	Updated energization-related MWC 10 unit and dollar forecast, using units from Table E-4
E-4	Updated energization-related MWC 10 unit forecast, using unit relationship from Table E-5
E-5	Determination of historical relationship between energization-related MWC 10 units and MWC 16 units

MWC 10 Workpaper Table E-1
Pacific Gas and Electric Company
Work at the Request of Others
Updated Energization-Related MWC 10 Forecast and Requested New Cost Caps
(Thousands of Dollars)

		2025	2026	Total	2025	2026	Total
Line No.	Line Description	Units			Dollars		
1	Updated Forecast for Eligible MWC 10 Activities	660	594	1254	$ 95,538	$ 87,360	$ 182,898
2	2023 GRC Imputed	247	247	494	$ 35,699	$ 36,267	$ 71,966
3	D.24-07-008 Incremental Funding	30	40	70	$ 4,349	$ 5,848	$ 10,198
4	Current Available Funding (line 2 + line 3)	277	287	564	$ 40,048	$ 42,116	$ 82,164
5	Proposed Cap Increase Above Current Available Funding (line 1 - line 4)	383	307	690	$ 55,490	$ 45,245	$ 100,734

Assumptions and Details
(1) Units for Line 2 and 3 were derived by dividing the dollars by the associated unit cost in MWC 10 Workpaper Table E-3 Line 8

MWC 10 Workpaper Table E-2
Pacific Gas and Electric Company
Work at the Request of Others
Summary of Forecast and Eligibility for GRC Imputed and SB-410 Final Decision D.24-07-008 - MWC 10
(Thousands of Dollars)

		2024	2025	2026	Total
Line No.	Line Description	Informational	Updated Forecast (ECNBIMA Eligible Activities)		
1	MWC 10 - Energization Total	$71,257	$95,538	$87,360	$254,156

		2024	2025	2026	Total
Line No.	Line Description	Informational	2023 GRC Imputed		
1	MWC 10 - Energization Total	$ 34,711	$ 35,699	$ 36,267	$ 106,678

		2024	2025	2026	Total
Line No.	Line Description	Informational	D.24-07-008 Incremental Funding		
1	MWC 10 - Energization Total	$77,601	$4,349	$5,848	$87,798

		2024	2025	2026	Total
Line No.	Line Description	Informational	Current Available Funding		
1	MWC 10 - Energization Total	$ 112,312	$ 40,048	$ 42,116	$ 194,476

		2024	2025	2026	Total
Line No.	Line Description	Informational	Proposed Cap Increase Above Current Available Funding		
1	MWC 10 - Energization Total	$ (41,055)	$ 55,490	$ 45,245	$ 59,680

		2024	2025	2026	Total
Line No.	Line Description	Informational	New Cap		
1	MWC 10 - Energization Total	$ 36,546	$ 59,839	$ 51,093	$147,478

Assumptions and Details
(1) 2023 GRC Imputed MWC 10 Energization values are determined by applying a 24% factor as described in D.24-07-008
(2) See MWC 10 Workpaper Table E-3 for detailed WRO Energization-Related forecast

MWC 10 Workpaper Table E-3
Pacific Gas and Electric Company
Work at the Request of Others
Updated Energization Related Forecast - MWC 10
(Thousands of Dollars)

Line No.	Line Description	2021	2022	2023	2024	2025	2026	Notes
		Actual			Forecast			
1	Work Request by Others (WRO) Energization Units Total	365	246	243	509	660	594	From GRC-2023-PhI_DR_TURN_001-Q001Atch03 Table 3, updated 2023 - 2026 numbers due to revised 2023 actuals and updated 2024-2026 unit forecast from MWC 10 Workpaper Table E-4
2	WRO Energization Units - Non-Residential	181	110	108	239	310	279	Line 1 * 47% (from 2021-2023 historical completions)
3	WRO Energization Units - Residential	184	136	135	270	350	315	Line 1 * 53% (from 2021-2023 historical completions)
4	WRO Energization Units - PEV	0	0	0	0	0	0	Line 1 * 0% (from 2021-2023 historical completions)
5	WRO Energization Unit Cost - Non-Residential	$ 132	$ 169	$ 151	$ 152	$ 158	$ 160	2024 assumes 2024 YTD unit costs. 2025 and 2026 are escalated according to the S&P IHS Markit Q1 2024 Forecast
6	WRO Energization Unit Cost - Residential	$ 128	$ 108	$ 176	$ 129	$ 133	$ 135	2024 assumes 2024 YTD unit costs. 2025 and 2026 are escalated according to the S&P IHS Markit Q1 2024 Forecast
7	WRO Energization Unit Cost - PEV							
8	WRO Energization Total Unit Cost				$ 140	$ 145	$ 147	Line 9 / Line 1
9	WRO Energization Cost	$ 47,359	$ 33,293	$ 40,045	$ 71,257	$ 95,538	$ 87,360	Forecast = Line 10 + Line 11 + Line 12
10	WRO Energization Cost - Non-Residential	$ 23,839	$ 18,540	$ 16,273	$ 36,477	$ 48,906	$ 44,720	Forecast = Line 2 * Line 5
11	WRO Energization Cost - Residential	$ 23,519	$ 14,753	$ 23,772	$ 34,781	$ 46,632	$ 42,640	Forecast = Line 3 * Line 6
12	WRO Energization Cost - PEV	$ -	$ -	$ -	$ -	$ -	$ -	Forecast = Line 4 * Line 7
13	WRO Energization 2023 GRC Imputed Cost			$ 33,236	$ 34,711	$ 35,699	$ 36,267	See Decision 24-07-008 Appendix A
14	WRO Energization Cost Above 2023 GRC Imputed			$ 6,808	$ 36,546	$ 59,839	$ 51,093	Line 9 - Line 13

MWC 10 Workpaper Table E-4
Pacific Gas and Electric Company
Work at the Request of Others
Updated Energization Related Unit Forecast - MWC 10

Line No.	Line Description	2024	2025	2026	Notes
1	New Business Units (excluding AB50)	8767	16598	19815	New Business Forecast (excluding AB50)
2	WRO Energization-Related Units (excluding AB50)	263	498	594	PG&E estimates on average 3% of New Business jobs have a WRO component (see MWC 10 Workpaper Table 4). This is not applied to the AB50 population.
3	WRO Energization-Related AB50 Units	246	162		PG&E determined there were 552 AB50 Work Request by Others orders established prior to 1/31/2023 that were remaining at the start of 2024. Assumed 80% attainment of initial WRO population in 2024. Assumed 72 cancellations per year.
4	WRO Energization-Related Units Total	509	660	594	Ln 2 + Ln 3

MWC 10 Workpaper Table E-5

Pacific Gas and Electric Company

Work at the Request of Others

Historical Energization-Related MWC 10 and 16 Unit Completions

Line No.	Line Description	2022	2023	Total	Notes
1	MWC 16 Unit Completions	7907	9580	17487	MWC 16 unit completions by year
2	Eligible MWC 10 Unit Completions	246	243	489	MWC 10 energization-related unit completions by year
3	Eligible MWC 10 % Unit Completions	3%	3%	3%	Line 2 / Line 3