Date of Issuance
July 25, 2025

Decision 25-07-041 July 24, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees. (U39E.)	Application 24-03-018

ORDER MODIFYING AND DENYING REHEARING OF DECISION 24-12-033

I. SUMMARY

This order addresses the applications for rehearing of Decision (D.) 24-12-033 (or Decision) filed by Pacific Gas and Electric Company (PG&E), Alliance for Nuclear Responsibility (A4NR), and San Luis Obispo Mothers for Peace (Mothers for Peace).[1] In the Decision, the Commission granted PG&E's application to recover Diablo Canyon power plant (DCPP) costs from September 1, 2023 through December 31, 2025 and conditionally approved PG&E's 2025 volumetric performance fee spending plan.

We have carefully considered all the arguments raised by PG&E, A4NR, and Mothers for Peace in their respective applications for rehearing and do not find grounds for granting rehearing, and so deny the applications, subject to the modifications, described below.

[1] Unless otherwise noted, citations to Commission decisions are to the official pdf versions, which are available on the Commission's website at: http://docs.cpuc.ca.gov/DecisionsSearchForm.aspx.

II. BACKGROUND

DCPP is owned and operated by PG&E. DCPP was slated for retirement at the expiration of its United States Nuclear Regulatory Commission (NRC) licenses, November 2, 2024 for Unit 1, and August 26, 2025 for Unit 2.

In September 2022, Governor Newsom signed into law Senate Bill (SB) 846, which allowed for the extension of operations at DCPP for up to five additional years, under specific conditions provided in the statute.

In enacting SB 846, the Legislature established how extended operations are to be funded and directed the Commission to review certain PG&E DCPP spending. As relevant here, SB 846:

1. Sets a fixed payment of $50 million/year for each unit, "[i]n lieu of a rate-based return on investment," subject to annual escalation, (Pub. Util. Code § 712.8(f)(6));[2]
2. Directs the Commission to "authorize [PG&E] to recover all reasonable costs and expenses necessary to operate Diablo Canyon Units 1 and 2 beyond the current expiration dates ... on a forecast basis in a new proceeding structured similarly to its annual Energy Resource Recovery Account [ERRA] forecast" (§ 712.8(h)(1)); and,
3. Specifies that only costs authorized by the Commission under section 712.8 shall be recovered from all load-serving entity (LSE) customers, unless explicitly provided otherwise. (§ 712.8(c)(4) & (l)(1).)

In D.23-12-036, the Commission established the broad parameters for the required ERRA-like cost application. Pursuant to D.23-12-036, on March 29, 2024, PG&E filed the *Application of the Pacific Gas & Electric Company (U39 E) to Recover in Customer Rates the Costs to Support Extended Operation of DCPP from September 1, 2023, through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees* (Application). PG&E filed an Amended Application on April 8, 2024.

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[2] Unless otherwise specified, all section references are to the Public Utilities Code.

The Commission's review of the DCPP cost forecast, just as it is in any ERRA forecast proceeding, is structurally accelerated. The Commission must make a determination on PG&E's application by the end of the year so that the approved forecast costs can begin to be recovered in rates for the following year.

Working within this timeframe, the Commission developed an extensive record. Thirteen parties participated in the proceeding. There were protests and replies filed in response to PG&E's application; PG&E and the parties presented testimony; the Commission held an evidentiary hearing; and the parties filed opening and reply briefs. (Decision at 6-8.)

On November 14, 2024, the Commission mailed a proposed decision, received opening and reply comments, and issued the Decision on December 20, 2024. The Decision authorizes a DCPP revenue requirement of $722.6 million for the forecast period, September 1, 2023 through December 31, 2025, a reduction from the $761 million requested by PG&E. The Decision also approves a joint proposal on the establishment of the DCPP non-bypassable charge, denies PG&E's proposal on allocating DCPP resource adequacy and greenhouse gas attributes, and conditionally approves PG&E's 2025 volumetric spending plan.

On January 17, 2025, A4NR and Mothers for Peace filed Applications for Rehearing of the Decision; and on January 21, 2025, PG&E filed an Application for Rehearing. On February 5, 2025, PG&E, Small Business Utility Advocates (SBUA), Energy Producers and Users Coalition (EPUC), and The Utility Reform Network (TURN) filed responses.

PG&E argues the Commission erred in denying its request to gross up the fixed-management fee to account for its associated tax liability. A4NR alleges legal error on the grounds that certain operations and maintenance expenses, nuclear fuel procurement costs, and employee retention costs should have been excluded as preparatory costs that must be funded through Department of Water Resource-administered loans; the amount approved for substitute capacity costs violates section 451 and Standard of Conduct No. 4; and the Commission's failure to make specific findings on cost effectiveness, reasonableness, and prudence violates section 451. Mothers for Peace argue that a contingency factor should have been included as an expense; the Commission erred in failing to make findings on cost effectiveness, prudence, and need; and that certain findings were not supported by substantial evidence.

III. DISCUSSION

A. The Decision Correctly Held that PG&E Is Not Entitled to Recover Tax Gross-ups on Fixed-Management Fees from Ratepayers.

The Decision rejected PG&E's proposal to collect a state and federal tax gross-up applied to the $100 million fixed-management fee established in section 712.8(f)(6). (Decision at 40-43, 81-83.) The tax gross-up would add 42.53% to the cost of the fixed-management fee, or $33.63 million for the 2024-2025 revenue requirement. (Decision at 41, 81; TURN Opening Brief at 2, 14.) If authorized for the entire period of extended operations, the cumulative tax gross-up on the fixed-management fee is forecasted at $231.8 million. (Decision at 41; TURN Response to PG&E's App. Rehg. at 1-2.)

The Decision reasoned that the fixed-management fee is not analogous to an income generating investment in capital expenditures and therefore would not require a tax gross-up. (Decision at 42.) It further explained that, pursuant to section 712.8(c)(4), the intent of the Legislature was "to prevent ratepayers from being charged for items not explicitly referenced in SB 846." (*Ibid.*) It further bolstered its conclusion by discussing the relevant precedent on this issue in D.23-12-036, which held section 712.8 prohibits costs outside those delineated in that section and provides the specific example of tax payments as excluded costs. (*Id.* at 42-43.) Based on this reasoning, the Decision concluded that, "any incremental tax liabilities on fixed management fees should be born exclusively by PG&E and its shareholders. PG&E is not authorized to recover any tax gross-up on the fixed management fee." (*Id.* at 43.)

PG&E's Application for Rehearing objects to the Decision's determination denying the tax gross-ups and makes three arguments to support its position: (1) PG&E

rejects the Commission's reasoning that the fixed-management fee is not analogous to an income-generating investment in capital expenditures; (2) PG&E argues the Decision is contrary to ratemaking principles and the legislative intent of section 712.8(h)(1); and (3) PG&E argues the Decision misinterprets section 712.8(c)(4) to exclude an income tax gross-up. As discussed below, PG&E's arguments are unpersuasive and do not demonstrate any legal error with respect to the Decision's denial of a tax gross-up on the fixed-management fee.

1. The Decision correctly determined the fixed-management fee should not be treated the same as an income-generating investment.

PG&E renews its prior argument that the fixed-management fee established in section 712.8(f)(6) should be treated analogously to the after-tax return in a General Rate Case (GRC) because it is intended to be "in lieu" of a traditional return, which creates a tax liability. (PG&E App. Rehg. at 8.) However, this argument remains unpersuasive and PG&E's rehearing application presents no compelling arguments or legal authority to revise the Decision's original determination.

Although PG&E takes issue with the Decision comparing the fixed-management fee to an expense, the Decision is not misguided in its analogy that the fixed-management fee is more like a ratepayer expense than a capital expenditure. (PG&E App. Rehg. at 5-8.) However, because the fee is not technically a ratepayer expense, this sentence may be confusing, and therefore, we strike that sentence from the Decision. This modification is for clarity and does not change the Decision's underlying analysis finding the fixed-management fee should not be treated the same as an income-generating investment.

The Decision explained the tax gross-up is generally only applied to the shareholder equity return on the rate base portion of the revenue requirement, but without this treatment, the shareholders would not actually achieve the authorized rate of return on rate base investment. (Decision at 42.) As TURN notes, "[u]nlike return on equity, which is tied to the amount of ratebased capital investment, the [fixed-management fee] is expressed as a specific dollar amount that is insensitive to the cost of plant operations. SB 846 prohibits PG&E from adding any Diablo Canyon costs to ratebase… and forecloses the potential for PG&E to earn an authorized rate of return tied to the amount of spending on Diablo Canyon." (TURN Response to PG&E's App. Rehg. at 2-3 (citing § 712.8(h)(1).)) Distilled down, TURN argues the fixed-management fee is fixed, unlike a regular return on equity, so Commission ratemaking policies on return on equity do not apply to this situation. (*Id.* at 3.) These distinctions are persuasive and sufficient to warrant different treatment from a traditional return on investment like the Commission would grant in a GRC where tax gross-ups are included. Moreover, as TURN's Response to PG&E's rehearing application points out, SB 846 created a new, novel, non-traditional ratemaking structure—therefore, the fixed-management fee is easily distinguished from a rate-based return on investment. (TURN Response to PG&E's App. Rehg. 1-4.) Because the fixed-management fee is a unique ratemaking mechanism specific to DCPP, the Decision does not disturb traditional ratemaking principles in typical GRCs by finding the fixed-management fee is not eligible for a tax gross-up.

PG&E also alleges the fixed-management fee "is the equivalent of the return component in routine utility ratemaking and subject to the gross up unless the Legislature has expressly specified that it should not be treated routinely like any other cost of service." (PG&E App. Rehg. at 5.) Addressing the latter half of this argument, PG&E unsuccessfully attempts to argue it is entitled to the tax gross-up because the Legislature didn't expressly restrict it. However, PG&E itself acknowledges that section 712.8(f)(6) is silent about "whether the fixed payment amounts are pre-tax or after-tax." (Decision at 41; PG&E App. Rehg. at 6.) As discussed below, the Decision properly concluded the Legislature's silence on taxes with respect to the fixed-management fee, when read in conjunction with section 712.8(c)(4), establishes the Legislature's intent to restrict ratepayers from being charged for costs outside those expressly included in SB 846. (Decision at 42.) As SBUA's Response to PG&E's Application for Rehearing aptly notes, "[i]f the state legislature wanted to pay for PG&E's taxes on its profit, it would have said so. . . . The fact that the Legislature did not expressly include tax obligations within the scope of allowable cost recovery underscores that PG&E, as a profit seeking entity, should bear the tax consequences of that profit." (SBUA Response at 4, 5.) We agree with this argument and the Decision's finding on this issue.

Based on the foregoing, the Decision properly found that the fixed-management fee should not be treated the same as an income-generating investment. On that basis, it correctly determined PG&E was not entitled to a tax gross-up on the fixed-management fee. Therefore PG&E's rehearing application fails to identify any legal error in the Decision's finding that the fixed management fee should not be given the same accounting treatment as an income-generating investment.

2. The Decision is consistent with the statute, the legislative intent of section 712.8, and Commission precedent

PG&E's rehearing application argues the Decision is not consistent with section 712.8. When interpreting the meaning of a statute, California courts follow a three-step approach to ascertain and effectuate the legislature's intent.

> First, [courts] look to the words of the statute itself, as the chosen language is the most reliable indicator of its intent. If the statutory language is clear and unambiguous, our task is at an end, for there is no need for judicial construction. When the plain meaning of the text does not resolve the question, we proceed to the second step and turn to maxims of construction and extrinsic aids, including legislative history materials. If ambiguity remains, we must cautiously take the third and final step and apply reason, practicality, and common sense to the language at hand.

(*Conservatorship of T.B.* (2024) 99 Cal.App.5th 1361, 1379 (cleaned up).) Courts may also "examine the context in which the [statutory] language appears, adopting the construction that best harmonizes the statute ... with related statutes." (*T.M. v. Super. Ct. of Contra Costa County* (2024) 104 Cal.App.5th 664, 680-81 (quoting *People v. Super. Ct. (Zamudio)* (2000) 23 Cal.4th 183, 192-93).)

a) The Decision is consistent with the plain meaning and legislative intent of section 712.8.

Turning to the first step in the legislative intent analysis, although PG&E argues section 712.8(h)(1) authorizes it to recover a tax gross-up, this argument is unsupported by the plain meaning of section 712.8. (PG&E App. Rehg. at 10-14). In evaluating this argument, we first turn to the language granting the fixed-management fee, which is found in section 712.8(f)(6)(A). Section 712.8(f)(6)(A) provides:

> **In lieu of** a rate-based return on investment and in acknowledgment of the greater risk of outages in an older plant that the operator could be held liable for, the commission shall authorize the operator to recover in rates **a fixed payment** of fifty million dollars ($50,000,000), in 2022 dollars, for each unit for each year of extended operations, subject to adjustment in subparagraphs (B) to (D), inclusive. **The amount of the fixed payment shall be adjusted annually by the commission using commission-approved escalation methodologies and adjustment factors.**

(Emphasis added.)

Nothing in this language grants PG&E a tax gross-up in addition to the fixed-management fee. Rather, this section expressly delineated recoverable costs only include "commission-approved escalation methodologies and adjustment factors" as annual adjustments—not a tax gross-up. As TURN notes, the statute states that the fixed-management fee is provided "in lieu of" a rate of return, indicating PG&E is not entitled to collect the fixed-management fee <u>in addition to</u> a "'rate based return on investment' as part of the SB 846 framework." (TURN Response to PG&E's App. Rehg. at 2). As this section does not include a tax gross-up on the fixed-management fee, the Decision was correct to find it was excluded under the general prohibition of section 712.8(c)(4) limiting customers' financial responsibility for the costs of extended operations to those authorized by section 712.8; such finding was not legal error.

Moreover, as discussed below, in D.23-12-036, the Commission previously interpreted this section and held "the general prohibition on cost recovery from ratepayers outlined in section 712.8(c)(4) is meant to apply to costs outside of those delineated in section 712.8…For example, such excluded costs could include the tax payments due on lump sum performance payments highlighted by TURN." (D.23-12-036 at 69-70; Decision at 42-43.) PG&E admits section 712.8 is silent on whether the fixed-management fee is after-tax. (PG&E App. Rehg. at 6.) Thus, as this cost was not explicitly delineated elsewhere in section 712.8, the general prohibition in section 712.8(c)(4) applies to the requested tax gross-up, as the Decision correctly determined.

Admitting section 712.8(f)(6) says nothing of a tax gross-up, PG&E's rehearing application instead relies on section 712.8(h)(1) to support its argument. That section states in full:

> The commission shall authorize the operator to recover all reasonable costs and expenses necessary to operate Diablo Canyon Units 1 and 2 beyond the current expiration dates, **including those in subdivisions (f) and (g)**, net of market revenues for those operations and any production tax credits of the operator, on a forecast basis in a new proceeding structured similarly to its annual Energy Resource Recovery Account forecast proceeding with a subsequent true-up to actual costs and market revenues for the prior calendar year via an expedited Tier 3 advice letter process, provided that there shall be no further review of the reasonableness of costs incurred if actual costs are below 115 percent of the forecasted costs. **All costs shall be recovered as an operating expense and shall not be eligible for inclusion in the operator's rate base**.

(Emphasis added.)

Section 712.8(h)(1) specifically refers to subdivision (f), which as discussed above, does not provide any support in its plain language that the Legislature intended to grant PG&E a tax gross-up in addition to the fixed-management fee. As TURN observes,

> the list of "reasonable costs" in Public Utilities Code §712.8(h)(1) specifically references costs identified "in subdivisions (f) and (g)" (which include the [fixed-management fee]) but does not contemplate the possibility that these costs could be adjusted upwards by the Commission to reflect shareholder tax liabilities. The referenced subdivisions mention federal production tax credits, so the legislature was aware of tax issues but chose not to include the additional tax gross-up for the [fixed-management fee]. So, PG&E's attempts to shoehorn the fixed management fee gross-up into this provision should be rejected.

(TURN Response to PG&E's App. Rehg. at 5.)

TURN also argues "the Commission may additionally find that the [fixed-management fee] tax gross up is not permissible under §712.8(h)(1) on the basis that these are not 'reasonable costs and expenses necessary to operate Diablo Canyon.' The [fixed-management fee] is not 'necessary to operate' the facility. The Commission's refusal to provide PG&E's requested [fixed-management fee] tax gross-up has no consequences for the safe and efficient operation of Diablo Canyon." (TURN Response to PG&E's App. Rehg. at 5-6.) Additionally, TURN notes that although the statute expressly references escalation of the fixed-management fee, it fails to similarly authorize PG&E to increase the fixed-management fee charge through a tax gross-up. (*Id*. at 3.) The Commission agrees with these arguments based on a reading of the plain language of the statute, which support the Decision's finding that PG&E is not entitled to the requested tax gross-up.

Turning to PG&E's argument that the Decision is inconsistent with the legislative intent of section 712.8, the Decision need not reach beyond an analysis of the plain meaning of the statute as the rehearing application does not identify ambiguity in the language of the applicable statute. However, even under the second or third steps of the legislative intent analysis, PG&E's rehearing application still fails to demonstrate legal error with respect to the Decision's denial of a tax gross-up on the fixed management fee.

Generally, PG&E's rehearing application argues the Decision misinterprets section 712.8(c)(4) to exclude tax gross-ups because this section is intended to prevent double recovery and does not apply to other provisions. (PG&E App. Rehg. at 10-14.) Specifically, PG&E argues that the absence of "an explicit reference to 'federal and state income taxes' in § 712.8(f)(6) does not mean that the Legislature intended to exclude those taxes from the broad and unqualified cost-recovery language in (h)(1), via an indirect inference under (c)(4)." (PG&E App. Rehg. at 13.) However, this argument is misplaced. While PG&E's rehearing application argues the Legislature intended to grant it a tax gross-up by implication in 712.8(h)(1), "[i]n construing a statute, [courts] do not insert words into it as this would 'violate the cardinal rule that courts may not add provisions to a statute.'" (*People ex rel. Gwinn v. Kothari* (2000) 83 Cal.App.4th 759, 768 (internal citations omitted).) Courts have "no power to rewrite the statute so as to make it conform to a presumed intention which is not expressed." (*City of Cotati v. Cashman* (2002) 29 Cal.4th 69, 75 (internal citations omitted).) Likewise, the Commission should not read an unexpressed legislative intent into its interpretation of the unambiguous statute.

Section 712.8(c)(4) explicitly states, "except as authorized by this section, customers or load-serving entities shall have no other financial responsibility for the costs of the extended operations of the Diablo Canyon powerplant." As the Decision explains, this provision demonstrates the Legislature's intent to prevent ratepayers from being charged for items not explicitly referenced in SB 846, not merely to prevent double recovery. (Decision at 42.) This language explicitly restricts the costs customers must bear for DCPP's extended operations to those that are expressly authorized by section 712.8. Again, nowhere does this section state PG&E is entitled to a tax gross-up on the fixed management fee. To read this unwritten additional cost into the statute that otherwise restricts customers' financial responsibility would be contrary to the cardinal rule of statutory interpretation not to add provisions to a statute or rewrite it based on an unexpressed intention of the legislature.

Furthermore, one canon of statutory construction provides that if exemptions are specified in a statute, then courts "may not imply additional exemptions unless there is a clear legislative intent to the contrary." (*Simmons v. Ghaderi* (2008) 44 Cal.4th 570, 583 (internal citations omitted).) EPUC argues "section 712.8(f)(6)(A) lists 'commission-approved escalation methodologies and adjustment factors' as annual adjustments, and under the canon of statutory construction of *expressio unius est exclusion alterious*, this list in presumed to be complete." (EPUC Response to PG&E's App. Rehg. at 7.) Under this canon, courts also presume "when language is included in one portion of a statute, its omission from a different portion addressing a similar subject suggests that the omission was purposeful and that the Legislature intended a different meaning." (*Dept. of Finance v. Com. on State Mandates* (2022) 85 Cal.App.5th 535, 568 (cleaned up).) Here, the statute clearly contemplates tax treatment and consequences because it mentions production tax credits in section 712.8(h)(1), but makes no mention of a tax gross-up on the fixed-management fee anywhere in section 712.8. Therefore, under this canon, this omission is presumed to be intentional and supports the Decision's finding that PG&E is not entitled to a tax gross-up on the fixed management fee.

As further support that the Legislature did not intend to include this additional cost recovery, TURN also points to

> [O]ther statutory provisions that expressly reference "after tax" values. For example, SB 901 (Dodd 2019) authorized the issuance of financing orders to recover the costs relating to a catastrophic wildfire and included a provision requiring that "the net after tax amounts" of any additional reimbursements received by the utility after the issuance of a financing order shall be credited to customers. A similar provision was included for financing orders relating to the regulatory asset created under PG&E's first bankruptcy.

(TURN Response to PG&E App. Rehg. at 3-4.) "Where the Legislature omits a particular provision in a later enactment related to the same subject matter, such deliberate omission indicates a different intention which may not be supplanted in the process of judicial construction." (*Cal. Pub. Records Research., Inc. v. County of Alameda* (2019) 37 Cal.App.5th 800, 810.) Accordingly, the Legislature understood how to affirmatively identify the relevant tax treatment for costs credited to or recovered from ratepayers and that it did not do so here is indicative that it did not intend to include them as part of PG&E's compensation. Courts will not read an unexpressed intent into the language of the statute and neither should the Commission. Accordingly, PG&E's argument to the contrary does not demonstrate legal error.

b) The Decision is consistent with prior Commission precedent

PG&E argues that Commission precedent dictates that the fixed-management fee should be treated analogously to the after-tax return in a GRC. (PG&E App. Rehg. at 8.) PG&E cites to D.84-05-036, D.96-10-037, and D.88-07-020 to support its argument (*Id.* at 9), but none of these prior decisions on tax gross-ups are analogous to the case here. As TURN notes, the fixed-management fee is a new incentive mechanism that is "fundamentally different from a rate of return and has never been subject to Commission review." (TURN Response to PG&E's App. Rehg. at 4.) TURN provides an illustrative example demonstrating that performance and management incentives—like the fixed-management fee—are not automatically granted tax gross-up treatment, even under traditional ratemaking. (TURN Response to PG&E's App. Rehg. at 3-4; TURN Opening Brief at 17-18.) In the Commission's Energy Efficiency Savings and Performance Incentives (D.13-09-023), where the Commission approved incentives that provided annual compensation to utility shareholders for successfully managing energy efficiency programs, the Commission did not authorize tax gross-ups on the incentive amounts awarded to PG&E, Southern California Edison Company (SCE), or San Diego Gas & Electric Company (SDG&E). This example shows that even in traditional ratemaking, the Commission does not authorize tax gross-ups as a default.

Looking to more recent precedent, as discussed in the Decision, in 2023, in Rulemaking 23-01-007, the Commission issued D.23-12-036, Decision Conditionally Approving Extended Operations at Diablo Canyon Nuclear Power Plant Pursuant to Senate Bill 846, which held:

> It is this decision's holding that the general prohibition on cost recovery from ratepayers outlined in section 712.8(c)(4) is meant to apply to costs outside of those delineated in section 712.8, as the prohibitionary language applies to "<u>other</u> financial responsibility for the costs of the extended operations of the Diablo Canyon powerplant" (emphasis added). For example, **such excluded costs could include the tax payments due on lump sum performance payments** highlighted by TURN.

(D.23-12-036 at 69-70 (emphasis added).) As TURN notes, PG&E did not challenge this holding in D.23-12-036, and is now foreclosed from doing so. (TURN Response to PG&E App. Rehg. at 6-7; *see also* § 1731(b)(1) (stating there is no cause of action in court arising out of a Commission decision unless the person filed a rehearing application within 30 days of decision's issuance).) Contrary to PG&E's attempt to dismiss the holding in D.23-12-036 as dicta, the Decision correctly interpreted this holding as relevant precedent in deciding to deny PG&E's request for a tax gross-up on the fixed-management fee. (PG&E App. Rehg. at 14; Decision at 42-43.)

The Decision soundly concludes, "any incremental tax liabilities on fixed management fees should be [borne] exclusively by PG&E and its shareholders. PG&E is not authorized to recover any tax gross-up on the fixed management fee" based on Commission practice in GRCs, statutory intent, and the Commission's prior holding in D.23-12-036. (Decision at 43.) TURN and the other intervenors argue that it would be unreasonable, and excessively costly to ratepayers to further increase rates to cover PG&E's incremental tax liabilities related to the fixed-management fee, which should be the sole responsibility of shareholders. We agree with Intervenors' arguments on this issue and are unpersuaded by any of PG&E's arguments in its rehearing application that the Decision finding PG&E should not be permitted to collect a tax gross-up on the fixed-management fee was in error.

B. The Commission Applied the Correct Standard when It Reviewed PG&E's DCPP Application for Reasonableness.

The Commission reviewed PG&E's DCPP extended operations cost forecast application based on the requirement established by statute and D.23-12-036.

A4NR and Mothers for Peace argue for additional review criteria. A4NR alleges that the Commission committed legal error for failing to make findings on the "cost-effectiveness, reasonableness, and prudence of Diablo Canyon's extended operations." (A4NR App. Rehg. at 19.) Mothers for Peace present overlapping allegations, and in greater detail. Mothers for Peace argue that (1) issues of prudency, cost-effectiveness, and need are all material to the Decision's cost forecast review and are required by statute to be included; (2) the Commission failed to make findings on these issues; and (3) that this failure violates the requirement under section 1705 that Commission decisions "contain, separately stated, findings of fact and conclusions of law

... on all issues material to the order or decision." (Mothers for Peace App. Rehg. at 3-6; 11-12.)[3]

The Commission was not under a legal obligation to take up these additional review criteria, and thus A4NR and Mothers for Peace fail to show legal error. The Commission has the discretion to organize its proceedings as it sees fit and can consider issues of cost-effectiveness, prudency, and need in other proceedings. (*See* Cal. Const., art. XII, § 2 ("[s]ubject to statute and due process, the commission may establish its own procedures"); *San Pablo Bay Pipeline Co., LLC v. Public Utilities Com.* (2015) 243 Cal.App.4th 295, 313) (interpreting "the Commission's constitutional authority to 'establish its own procedures' to mean the Commission is authorized to employ unwritten procedures on a case-by-case basis provided that those procedures do not contradict a statute and are consistent with the requirements of due process").) As to section 1705, the Commission has discretion to determine which issues are material to its decisions. (*Clean Energy Fuels Corp. v. Public Utilities Com.* (2014) 227 Cal.App.4th 641, 659 ("[i]t is within the PUC's discretion to determine what factors are material to its decision based on the issues before it").)

Beginning with the statutory requirements, section 712.8(h)(1) authorizes the forecast review and directs the Commission to conduct a process "structured similarly to its annual Energy Resource Recovery Account [ERRA] forecast proceeding." (Pub. Util. Code § 712.8(h)(1).) In an ERRA proceeding, the Commission's review is focused on whether the applicant met its burden to show the reasonableness of its request by preponderance of evidence. (*See, e.g.,* Decision 14-07-006 (in an ERRA proceeding the applicant "has the burden of affirmatively establishing the reasonableness of all aspects of its request").) While cost-effectiveness can be a factor in the ERRA reasonableness

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[3] Mothers for Peace's argues there is a lack of substantial evidence to support the Commission's determinations that certain costs were reasonable, however these arguments are premised on the assertion discussed here that the Commission was required to make cost-effectiveness, need, and prudency findings in the Decision. (See Mothers for Peace App. Rehg. at 11-12.)

review, it specifically pertains to least-cost dispatch requirements (Decision 02-12-074 at 77), and must be coupled with an intelligible standard. (*See* Decision 06-01-007 at 4-6 (recognizing that cost-effectiveness can be an element of a procurement forecast reasonableness review, but absent an established cost-effectiveness standard by which to judge particular procurement decisions, it is not appropriate means by which to evaluate a least cost-dispatch process).)

Turning to D.23-12-036, the Commission established the requirements for PG&E's DCPP cost forecast application in this prior decision. The Commission approved PG&E's proposed "ERRA-like forecast" process, and required that PG&E:

> (a) provide detailed projections of all costs and revenues associated with DCPP extended operations, in a manner similar to PG&E's presentation in its GRC and ERRA Forecast proceedings; (b) quantify the impact of DCPP's extended operations on its common costs relative to the amount approved in its 2023 GRC; and (c) demonstrate it will not double count the common costs it proposes for recovery in its GRC and DCPP Extended Operations Cost Forecast applications.

(D.23-12-036 at 132-33, COL 54.)[4] The Commission was also clear on the determinations it would make, in addition to its usual ERRA-like review:

> The Diablo Canyon Extended Operations Cost Forecast proceeding should: (a) determine the allocation of costs and benefits of DCPP extended operations among the large electrical corporations' service areas; and (b) utilize a process that mirrors the [Cost Allocation Mechanism (CAM)] process to determine the price of the volumetric [Non-Bypassable Charge (NBC)] to be charged by each of the large electrical corporations.

[4] Commission decision findings of fact, conclusions of law, and ordering paragraphs are abbreviated in citations as FOF, COL, and OP, respectively.

(*Id.* at 133, COL 55.) Notably, the Commission did not commit to conducting a cost-effectiveness, prudency, and need analysis as part of its annual DCPP cost forecast review proceeding.

Mothers for Peace incorrectly argue that D.23-12-036, Conclusion of Law 15 promises a cost-effectiveness review in this forecast proceeding. (Mothers for Peace App. Rehg. at 4.) While Conclusion of Law 15 of D.23-12-036 states that, "[i]t is well within the Commission's authority, and in ratepayers' best interest, to continue to evaluate the prudence and cost-effectiveness of continued DCPP operations," D.23-12-036 does not commit the Commission to conducting this evaluation as part of the cost forecast proceeding. Nor would it make sense to do so. The accelerated timeframe of an ERRA-like cost forecast proceeding is unlikely to allow the time required to conduct a broader cost-effectiveness review.

Mothers for Peace cite Public Resources Code sections 25548(b), 25548(c), and 25548.3(c)(5)(C), and Public Utilities Code sections 712.8(q) and 712.8(r) to support its claim that the Commission was required to conduct a need assessment and prudency review in the subject forecast proceeding. (Mothers for Peace App. Rehg. at 6-9.) But none of these cited code sections direct the Commission to conduct this review as part of the cost forecast proceeding mandated under section 712.8(h)(1). On need, the Decision correctly concluded that a system reliability needs assessment, which would include a review of resources such as Diablo Canyon, are conducted in the Commission's Integrated Resource Planning proceeding and out of scope of the subject proceeding. (Decision at 12.)

As to the cost-effectiveness review required by Public Resources Code section 25548.3(c)(5)(C), like the need assessment, the Commission's determination will affect whether DCPP is able to continue to operate for the forecast period. A finding that the DCPP extended operations is not cost-effective, would result in the termination of a critical loan. (Pub. Resources Code § 25548.3(c)(5).) SB 846 does not obligate the Commission to take up this question in the forecast proceeding and the more appropriate venue would be the DCPP rulemaking, R.23-01-007.

A4NR grounds its contentions in section 1757, arguing that in order for the Commission to determine DCPP costs are just and reasonable under section 451, it must make findings supported by substantial evidence on cost-effectiveness, reasonableness, and prudence. (A4NR App. Rehg. At 19-20 (*citing* D.23-12-036 at 47 (discussing the factors included in a section 451 review).) While it is true cost-effectiveness and prudence are factors the Commission may consider in a section 451 reasonableness review, there is no affirmative requirement that the Commission make separate findings on each of these factors in every case in which it approves a rate. For instance, the most recent PG&E ERRA decision contains findings on reasonableness but not cost-effectiveness or prudence. (D.24-12-038 at 81, COLs 1-5 (concluding that the approved costs are reasonable without considering cost-effectiveness).)[5] Similarly, the Decision makes findings on reasonableness but does not separately assess cost-effectiveness and prudence. (*See* Decision at 81-83, COLs at 3, 9, 13, 17, & 18.)[6]

In sum, D.23-12-036 established the requirements for DCPP extended operations cost forecast applications and it did not mandate a cost effectiveness, need, or prudence review. To the extent Mothers for Peace and A4NR believe the extended operations cost forecast applications should include additional criteria for review, they should have challenged D.23-12-036 and are now foreclosed from doing so because the decision is final. (§ 1709 ("In all collateral actions or proceedings, the orders and decisions of the commission which have become final shall be conclusive"); *see also Order Modifying D.14-02-016 and Denying Rehearing of the Decision, as Modified*, D.14-06-053, pp. 13-15 (citing *Camp Meeker Water System, Inc. v. Public Utilities Com.* (1990), 51 Cal.3d 845, 852, fn. 3) (finding that section 1709 barred parties' attempts to relitigate the findings of a study relied upon in a prior, final Commission decision to show a procurement need).)

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[5] These reasonableness determinations are listed as Conclusions of Law.

[6] Here too, the findings are listed as Conclusions of Law, which is not itself legal error.

C. The Decision Properly Distinguishes Between Preparatory and Extended Operation Costs.

The Decision adopts PG&E's proposed methodology for distinguishing between preparatory costs that are to be funded by Department of Water Resources (DWR) or Department of Energy (DOE) Civil Nuclear Credit loans, and those costs required for extended operation that can be recovered from ratepayers. (Decision at 79, FOF 7.) The methodology provides that extended operations costs are "for projects not recovered by the NRC license renewal process or as a condition of license renewal and (1) that are expected to be placed in service on or after January 1, 2027 and/or (2) the project scoping, design, engineering, procurement and implementation efforts generally begin after the original Unit 1 license expiration of November 2, 2024." (Decision at 17-18 (quoting PG&E Opening Brief at 10).) The adoption of this methodology is reasonable and consistent with SB 846.

A4NR argues that the Decision's approval of project expenses totaling $65,227,000 violates section 712.8(c)(1)(C) because these expenses are preparatory and therefore should not be recoverable in rates. (A4NR App. Rehg. at 1-9.) The expenses are for projects that PG&E identified through its Preventative Maintenance Optimization Program ++ (PMO++), and that it describes as "necessary to support safe and reliable operation through 2029 and 2030." (PG&E Opening Brief at 10, 13.) A4NR claims that according to the plain meaning of the word "preparation," as defined in the Merriam-Webster Dictionary, these expenses qualify as preparatory under section 712.8(c)(1)(C). (A4NR App. Rehg. at 3.) Further, A4NR characterizes the adopted PG&E methodology as arbitrary and not grounded in the statute. (*Id.*)

A4NR argued for its interpretation in its opening and reply briefs, (A4NR Opening Brief at 11-12; A4NR Reply Brief at 4-6), the Commission considered the arguments, and in the Decision, declined to adopt A4NR's approach. (Decision at 15-18.).

First, the Decision correctly notes that the distinction between preparatory and extended operations costs is not clearly delineated in statute. Section 712.8(c)(1)(C) reads in relevant part, "[a]ctions taken by the operator pursuant to the commission's actions under this paragraph, including in preparation for extended operations, shall not be funded by ratepayers of any load-serving entities . . . ." (emphasis added). And section 712.8(h)(1) provides, "[t]he commission shall authorize the operator to recover all reasonable costs and expenses necessary to operate Diablo Canyon Units 1 and 2 beyond the current expiration dates ... ." What it means for a cost to be required for preparation for extended operation, versus necessary for the continued operation of DCPP, is not addressed by the statute. Faced with a need to clearly and predictably distinguish between these categories of project costs, the Commission adopted PG&E's framework.

In approving the framework, the Commission adopted a reasonable statutory interpretation that is consistent with the plain meaning of the statute and legislative intent. (*State Farm Mutual Automobile Ins. Co. v. Garamendi* (2004) 32 Cal.4th 1029, 1043 (affirming the principle that, in determining legislative intent, the inquiry begins with the legislative text).) While the text of the statute does not offer the precise boundary between preparatory and ongoing costs, it does speak to the intent of the Legislature, which is to ensure that those costs needed to prepare for relicensure are covered by loans, while those required for the operation of DCPP during the license extension period are recovered in rates.

The framework begins by categorizing all costs associated with the Nuclear Regulatory Commission (NRC) license renewal process, including costs for projects the completion of which are a condition of renewal, as preparatory. This makes sense as the request for the license extension is a predicate for continued operation, and thus squarely falls within the bounds of preparatory costs, as required by section 712.8(c)(1)(C).

As for extended operations costs, the framework identifies projects to be placed in service on or after January 1, 2027, and/or those that begin after Unit 1's license expiration on November 2, 2024, as non-preparatory. In other words, extended operations can be understood to have begun on November 24, 2024, after the first license expired, and thus, projects that begin after that date, or are placed into service well after that date, can be understood to be extended operation costs and subject to recovery in rates pursuant to section 712.8(h)(1).

Arguing against the adopted framework, A4NR alleges it is inconsistent with the statutory purpose in that it allows certain preparatory costs to be included in rates. (*See* A4NR App. Rehg. at 4.) A4NR quotes the Assembly Floor Analysis, which states that SB 846:

> Prohibits any funds needed by PG&E to prepare for any extended license from being paid for by ratepayers, and instead directs those costs to be covered by the DWR loan. Additionally prohibits the CPUC from increasing the costs to PG&E ratepayers for operations and maintenance of DCPP prior to the extension (2022-2025).

(Assembly Floor Analysis SB 846 Senate Third Reading, p. 4.) In distinguishing preparatory and ongoing costs, A4NR interprets the statute to "focus on the underlying purpose of the expenditure," which A4NR argues is inconsistent with "PG&E's calendar-driven taxonomy." (*Ibid.*) A4NR contrasts the PG&E framework with its own approach that relies on the Merriam-Webster Dictionary definition of "preparation," which reads, "the action or process of making something ready for use or service or of getting ready for some occasion, test, or duty." (A4NR App. Rehg. at 3, fn. 13.)

A4NR fails to demonstrate legal error. As discussed above, the adopted framework is consistent with the statute's text and purpose. Moreover, the framework is wholly consistent with A4NR's own evidence of purpose, and its textual reading. A4NR fails to demonstrate how the framework conflicts with the passage it provides from the Assembly Floor Analysis or its proffered dictionary definition. Contrary to A4NR's claim, the cited portion of the Assembly Floor Analysis does not clearly demonstrate a legislative purpose that preparatory and ongoing costs are distinguished by looking to the expenditure's purpose, and certainly not in a way that conflicts with the adopted framework. The cited passage identifies "funds needed by PG&E to prepare for any extended license" as preparatory, but leaves open the question of what it means to be "needed by PG&E to prepare." Looking at the purpose of the expenditure could be helpful, but still not dispositive, whereas hard date-based cutoffs can be used to determine need and purpose.

Finally, regarding PG&E's failure to satisfy the directive in D.22-12-005 to explain why it did not seek government funding for these project expenses (AFNR App. Rehg. at 8-9), the Decision requires that PG&E provide the necessary explanation in its next application. (Decision at 18-19, FoF 8.) To the extent the Decision deviates from a prior Commission decision, this is not legal error. The Commission is not bound by its past decisions. (D.95-11-031, 1995 Cal. PUC LEXIS 852 at *3 (citing *Postal Telegraph-Cable Company v. Railroad Commission of the State of California* (1925) 197 Cal. 426, 436).) Moreover, the Decision provides an appropriate remedy for any non-compliance in light of the Commission's finding that PG&E's request to recover operations and maintenance costs, which include the project costs, is reasonable. (*Id.* at 81, COL 3.) To disallow the recovery of these costs for the failure to offer a certain explanation would be disproportionate. (*See* § 2104.5 (stating that the Commission considers the "gravity of the violation" when determining the consequences of non-compliance).)

D. It Is Reasonable to Allow for the Recovery of Certain Nuclear Fuel Costs in Rates.

The Decision's approval of PG&E's 2025 nuclear fuel expense forecast is consistent with SB 846 as well as prior Commission decisions and resolutions. However, this Order does make one minor modification to clarify the source of lending for certain fuel costs.

A4NR challenges the approval, arguing that the Commission failed to explain why certain fuel expenses are funded by loans under section 712.8(c)(1)(C), and others are recoverable in rates. (A4NR App. Rehg. at 9-13.) Specifically, A4NR states the fuel expenses for cycles 25 and 26 were allocated to the loans, while the Decision allows the costs for cycles 27, 28, and 29 to be amortized and recovered from ratepayers without any clear reason given for this differing treatment. (*Id.* at 11.) A4NR further argues that the methodology for distinguishing preparatory costs from extended operation costs — discussed *supra* — does not support treating these fuel costs as recoverable in rates. (*Id.*).

On its face, certain nuclear fuel expenses are clearly costs that would be deemed "necessary to operate Diablo Canyon Units 1 and 2 beyond the current expiration dates," and would thus be recoverable in the cost forecast proceeding under section 712.8(h)(1). The subject fuel cycles all concern refuelings that are scheduled for after the expiration of Units 1 and 2 license, with fuel cycle 27 beginning in the fall of 2026 for Unit 1, and the spring of 2027 for Unit 2. (Ex. PG&E-02 at 2-12, lines 25-26.) Fuel cycles 25 and 26, by contrast, are described by PG&E as covering "fuel needs through the end of the operating licenses ... ." (Ex. A4NR-01, Appx. 9 at 2.)

The Decision rightly notes that a prior Commission resolution contemplates that some fuel costs will be covered by the section 712.8(c)(1)(C) loans, while others will be recovered in rates. (Decision at 34-45; *citing* Res. E-5299 at 10, Finding 5.) A4NR's insistence that because some fuel costs can be covered by the loans, PG&E must seek loan funding for all fuel costs is inconsistent with the statute. The Public Resources Code section 25548.3(c)(3) lending authority provides for "fuel purchases," but limits the loan to those costs, "necessary to preserve the option of extending the Diablo Canyon powerplant or to extend the Diablo Canyon powerplant's operation to maintain electrical reliability." (Pub. Resources Code § 25548.3(c)(3).) In light of this limiting language, it is reasonable to conclude that fuel purchases for refuelings that will occur well into DCPP's extended operations, when PG&E can begin recovering costs under section 712.8(c)(1)(C), cannot be covered by the subject loans. As to PG&E's methodology for determining which **project** expenses are preparatory and which are ongoing, discussed *supra*, that methodology only applies to costs PG&E labeled as project costs, with fuel costs clearly delineated for separate treatment. (*See generally* Ex. PG&E-01-0E.)[7]

[7] A4NR points out that cycle 27 fuels costs would not necessarily be treated as ongoing costs under the project expense methodology. (*See* A4NR App. Rhrg. at 11.)

The Decision appropriately distinguishes fuel cycles 25 and 26 from cycles 27 and beyond by finding that these early cycles represent costs that, "are already attributed to the DWR Loan [which] are considered incremental as they were needed to pay for the extension of the existing fuel cycle ... ." (Decision at 79, FOF 15.) In other words, it was reasonable for PG&E to only seek loan funding for fuel cycles that were incremental to costs incurred before the expiration of the license because these costs were necessary to "preserve the option of extending" DCPP. (Pub. Resources Code § 25548.3(c)(3).) Similarly, an attempt to include cycles 25 and 26 in the subject application would violate section 712.8(c)(1)(C)'s prohibition on recovering in rates "costs incurred by the operator to prepare for, seek, or receive any extended license to operate by the United States Nuclear Regulatory Commission." (§ 712.8(c)(1)(C). Fuel cycles 27, 28, and 29, by contrast, provide refueling well into the extended operations period, in line with section 712.8(h)(1), which allows for ratepayer funding of costs needed to operate DCPP beyond the expiration of the licenses.

A4NR contests this distinction, arguing that the Decision mistakenly describes cycles 25 and 26 as funded by the DWR Loan, when in fact cycle 25 was included in the Reliability Reserve Reimbursement Agreement (RRRA), authorized under AB 180 and also administered by DWR. (*See* A4NR App. Rehg. at 11.) To the extent the Decision incorrectly described the loan treatment, the error is immaterial. The fact that cycles 25 and 26 were incremental to costs included in DWR loans is what is key to the determination and is uncontested. (Ex. A4NR-01, Appx. 9 at 1-2.) Even so, the Decision is modified to clarify the source of loan funding.

In the Decision, the Commission was tasked with determining the reasonableness of the fuel cost request. (Decision at 10-11.) A4NR does not contest the reasonableness of the fuel costs, or that fuel costs *can be* recovered under section 712.8(h)(1). A4NR's chief complaint is that the Decision does not provide a framework for determining whether fuel costs should be covered by loans or recovered in rates. (*See* A4NR App. Rehg. at 10-11.) But the absence of a framework is not legal error. Indeed, A4NR does not cite any legal standard or requirement that such a framework be given.

E. The Decision's Use of the RA MPB to Price Substitute Capacity Costs Does Not Constitute Legal Error.

The Decision approves PG&E's proposal to use the Commission-produced Resource Adequacy Market Price Benchmark (RA MPB) to value the substitute capacity needed to cover DCPP RA obligations during periods of outages and short-term curtailment. (Decision at 82, COL 11.) A4NR objects to this approval, arguing that the use of the RA MPB renders the resulting DCPP NBC unjust and unreasonable, in violation of section 451; and further, does not comply with PG&E's least-cost obligations under Standard of Conduct No. 4 (SOC 4). (A4NR App. Rehg. at 13-16.)

1. Use of the RA MPB in this 2023-25 Diablo Revenue Requirement Proceeding.

In the Commission's initial SB 846 decision, the Commission established that it is reasonable for PG&E to recover the costs associated with securing replacement capacity to cover periods of DCPP outage from all LSEs. (D.23-12-036 at 87.) Thus, when PG&E filed the instant underlying application for the 2023-25 DCPP revenue requirement, PG&E forecasted DCPP outages, including those outages required to meet refueling needs and conduct maintenance activities, and estimated the cost to secure substitute capacity. (Ex. PG&E-01-E at 4-2 - 4-5.) In line with its general practice, PG&E scheduled outages to occur outside of the peak summer months, such that they occur during shoulder periods when RA is less expensive. (Ex. PG&E-01-E-WP-C, Supporting Chapter 4.)[8] In calculating the cost to secure substitute capacity, PG&E used the RA MPB and stated it would secure the capacity from its Power Charge Indifference Adjustment (PCIA) portfolio. (Ex. PG&E-01-E at 4-4, lines 11-25; PG&E Opening Brief at 26-27.) PG&E explained it used the RA MPB because PCIA portfolio capacity is priced using the RA MPB in ERRA proceedings and a recent Commission decision found that the RA MPB may be used to value PCIA portfolio resources when those resources

[8] While the specific outage months are confidential, the fact that the planned outages will occur during off-peak periods was acknowledged in public filings.

are being used to supply substitute capacity. (PG&E Opening Brief at 26 (*citing* D.24-06-004 at 88, OP 15 (adopting 2025-27 Local Capacity obligations).)

PG&E's initial application, filed on March 29, 2024, relied on the RA MPB for 2024 forecasted system-capacity costs, the most recent available at that time, which priced system RA at $15.23/kW-month. (Ex. PG&E-08 at 2-5.)[9] PG&E used this price to estimate substitute capacity costs for the entire record period. (*Ibid.*) However, that calculation was known to be preliminary, and PG&E planned to provide an update to DCPP forecasted costs (the "Fall Update"), which would account for revised MPB values, among other updated values. (*Ibid.*) On October 4, 2024, the Commission's Energy Division published updated RA MPB prices, raising the 2024 RA price to $28.65/kW-month and the 2025 forecast price to $42.54/kW-month (hereinafter the "October 2024 RA MPB").[10] On October 11, 2024, PG&E filed its Fall Update, relying on the October 2024 RA MPB prices to, among other things, revise its forecasted substitute capacity costs from $78 million to $210 million. (Ex. PG&E-08 at 5.)

2. The bases for using the RA MPB

The Decision provides three reasons for approving the use of the RA MPB: (1) in Ordering Paragraph 15 of D.24-06-004 (adopting 2025-27 Local Capacity obligations), the Commission found that IOUs may use the RA MPB to value PCIA portfolio capacity used for CAM-eligible resource substitution costs; (2) using the RA MPB promotes transparency because the RA MPB is publicly available; and (3) using the RA MPB ensures consistency across Commission decisions, specifically the IOU ERRA

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[9] The same price was used for 2024 and 2025 capacity replacements.

[10] Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2024-market-price-benchmarks-20241004.pdf. Then, on November 5, 2024, Energy Division revised down the values slightly to $26.26/kW-month and $40.31/kW-month, respectively. (Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2024-market-price-benchmarks-revised-20241105.pdf.)

proceedings, where the RA MPB is used to value PCIA portfolio capacity. (Decision at 32.)

Ordering Paragraph 15 of D.24-06-004 authorizes the use of the RA MPB here. In D.24-06-004, the Commission considered how to value capacity from an IOU's PCIA-eligible portfolio when it is used to provide substitute capacity to cover the RA obligations of CAM-eligible resources during outages. (D.24-06-004 at 66-68.) The Commission found the use of the RA MPB "to determine substitution capacity costs to be reasonable because it would minimize cost shifting between bundled customers and departing load." (*Id.* at 67.) This Commission precedent is on point given that DCPP is a CAM-like resource and PG&E proposes to use RA from its PCIA-eligible portfolio. (*See* D.23-12-036 at 133, COL 55 (directing Energy Division to use the CAM process to determine the allocation of RA benefits).)

Regarding transparency, the RA MPBs are one of the few publicly available measures of RA prices.[11] The alternative measure of RA pricing argued for by A4NR is PG&E's internal forward price curves, which are confidential. (*See* Ex. A4NR-01-C, Appx. 8 at 13.) The fact that the RA MPB is a public value is an appropriate Commission consideration when adopting a pricing methodology. (*See, e.g.*, D.99-07-018, 1999 Cal. PUC LEXIS 485, *21 (rejecting an IOU pilot in part because it failed to promote price transparency).)

Finally, the Commission has an interest in maintaining consistency across proceedings. In the parallel PG&E ERRA proceeding approving PG&E's 2025 forecasted revenue requirement, the Commission relied on the RA MPB, which represents a key input in the Commission-approved methodology for determining the

[11] Energy Division also produces a RA report, but these reports are not intended to provide current RA market pricing. For instance, the most recent RA report, published in May 2024, concerns the 2022 RA market, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2022-ra-report_05022024.pdf.

PCIA. (D.24-12-038 at 68, COL 1;[12] *see* D.18-10-019.) Had the Commission declined to use the RA MPB in the Decision, the Commission would have priced PG&E PCIA-eligible capacity differently in decisions voted out in the same month.

3. A4NR fails to prove legal error.

A4NR fails to prove legal error because its arguments against the use of the RA MPB constitute an impermissible collateral attack on D.24-06-004, lack the required specificity, and amount to an improper attempt to reweigh evidence and relitigate issues already decided.

A4NR challenges the Commission's reliance on D.24-06-004, arguing that D.24-06-004 does not require the use of the RA MPB — it states that IOUs "may use" the RA MPB, and seeks to distinguish D.24-06-004, highlighting that the Commission's rationale for using the RA MPB was to avoid cost shifting. (A4NR App. Rehg. at 15-16.) However, the "may use" language is sufficient, as it makes clear that the Commission previously determined that the RA MPB is a reasonable means by which to price substitute capacity. And while D.24-06-004 considered factors such as cost shifting that may not be as applicable here, such distinguishing features do not negate D.24-06-004's ultimate applicability, which very clearly concerns how to price an IOU's PCIA-eligible portfolio when it is used to provide substitute capacity for a CAM-like resource.

Ultimately, to challenge PG&E's use of the RA MPB is to challenge the Commission's determination in D.24-06-004 that the RA MPB is a reasonable method for pricing substitute capacity. Thus, A4NR's allegations regarding section 451 and SOC 4 violations amount to an impermissible collateral attack on D.24-06-004, foreclosed by section 1709's bar on collateral attacks of prior Commission decisions.

Even if D.24-06-004 were not determinative, A4NR's section 451 argument lacks the specificity required by section 1732. Applications for rehearing must

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[12] The Commission did, however, use the RA MPB values from the November 5, 2024 revisions, while in the subject Decision the Commission relies on the October 4, 2024 prices.

"set forth ***specifically*** the ground or grounds on which the applicant considers the decision or order to be unlawful." (§ 1732 (emphasis added).) The Commission's Rules of Practice and Procedure underscore the need for clarity: **"**Applications for rehearing shall set forth specifically the grounds on which the applicant considers the order or decision of the Commission to be unlawful or erroneous, and **must make specific references to the record or law**." (Cal. Code of Regs., tit. 20, § 16.1, subd. (c) (emphasis added).)

A4NR's only statement regarding section 451 in its discussion of the RA MPB reads, "whatever methodology the Commission chooses, Section 451 and Standard of Conduct No. 4 require that PG&E's 'forecast' be capped at the $44,807,838 amount at which the undisputed evidentiary record indicates RA substitution capacity could have been obtained." (A4NR App. Rehg. at 16.) This claim under section 451 is not supported by a legal standard or other references that would allow the Commission to evaluate whether the Decision commits legal error on these grounds.

Moreover, A4NR's arguments against the use of the RA MPB are an improper attempt to have the Commission reweigh the evidence on substitute capacity pricing. (D.17-08-033 at 7 ("a rehearing application is not a permissible vehicle to seek relitigation or reweighing of the evidence").) For instance, A4NR's claims under SOC 4 would have the Commission re-evaluate on rehearing the appropriate substitute capacity price, and cap total recovery at a level based on PG&E's forward price curves. (A4NR App. Rehg. at 16.) But in the underlying proceeding, the appropriate price for substitute capacity was extensively litigated, then evaluated in the Decision, which ultimately determined that the RA MPB was the appropriate pricing methodology. To reach a different result would require an impermissible reweighing of the evidence on substitute capacity pricing.

Finally, after the issuance of the Decision, the Commission opened a rulemaking to evaluate, among other things, the RA MPB methodology. (*Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Change Indifference Adjustment Policies and Processes* [R.25-02-005].) Such a rulemaking, and not an application for the rehearing, is the proper forum for the Commission to evaluate reforms to the RA MPB and to address any concerns regarding the prices it provides. Indeed, this rulemaking has already yielded a significant set of methodological revisions, which will be reflected in the Fall 2025 RA MPB. (D.25-06-049). These changes stand to directly impact the subject forecast period costs given that the Fall 2025 RA MPB will include a 2025 actual RA MPB price, and this price may be used to true-up the Decision's approved DCPP forecasted costs. (*See Assigned Commissioner's Scoping Memo and Ruling*, July 2, 2025 at 4 [R.25-03-015] (scoping in consideration of whether the MPB will be used to calculate DCPP true-up costs).)

F. It Is Correct to Exclude the Costs Associated with Contingencies that Are Overly Speculative.

The Decision found that, "it is reasonable for PG&E to exclude speculative costs in this application." (Decision at 23.) Mothers for Peace disagree and argue that this finding is undermined by three legal errors: (1) the Decision improperly placed the burden of proof for the inclusion of a contingency factor on Mothers for Peace; (2) the Decision uses an incorrect test to determine whether a contingency factor must be included; and (3) the finding is not supported by substantial evidence. (Mothers for Peace App. Rehg. at 2-3, 9-11.)

These arguments lack merit. Mothers for Peace do not provide legal support for the claim that a contingency factor must be considered, and as a result, these arguments fail to meet the requirements of section 1732 to specify, analyze, or explain how the Decision violates any legal authority or requirements. (§ 1732.)

There is no requirement that PG&E consider or propose a contingency factor in its forecasted DCPP extended operations application. The Decision arises out of the section 712.8(h)(1) requirement that the Commission authorize PG&E to "recover all reasonable costs and expenses necessary to operate" DCPP beyond the license expiration dates on a "forecast basis." (§ 712.8(h)(1).) D.23-12-036 implemented this section and described the information that must be included in PG&E's forecast application.

(D.23-12-036 at 60-61, 98-102.) D.23-12-036 does not include any mention of a contingency factor, nor is the consideration of a contingency factor in scope for the subject proceeding. (Decision at 10-11.)

As relevant here, the Commission was tasked with reviewing PG&E's proposed costs for reasonableness (Decision at 12), not determining if additional expenses could be expected, but were not included. Mothers for Peace fail to provide support for the existence of this latter obligation. Noting this failure is not an impermissible burden shift, as Mothers for Peace allege, instead it merely shows that Mothers for Peace have not identified a legal error.

PG&E's forecast accounts for costs it reasonably believes it will incur, including costs associated with "known unknowns," such as outage and vendor delays. (PG&E Reply Brief at 7.) Mothers for Peace argue for more, stating that a "contingency factor is warranted if it is for a risk that is foreseeable to a prudent manager;" and that there are risks foreseeable to a prudent manager not included. (Mothers for Peace App. Rehg. at 2.) But, as PG&E explains, the actual risks Mothers for Peace identify include plant features subject to Nuclear Regulatory Commission (NRC) and Diablo Canyon Independent Safety Committee (DCISC) review or coastal development permits. Until one of the risks manifests, and PG&E is directed or advised to incur a given cost to mitigate such risks, it is not reasonable to include costs associated with these risks in the current forecast. When or if these costs arise, they will be recoverable. As the Decision rightly concludes, "[i]n the event the DCISC or NRC provides new recommendations that may affect PG&E's cost forecast, then the Commission may consider the new or updated information, as appropriate, in this proceeding or a future proceeding." (Decision at 23 (*quoting* E-Mail Ruling Granting Pacific Gas and Electric Company's Motion to Strike Testimony, August 15, 2024, at 3).)

G. The Decision Appropriately Follows D.23-12-036 in Allocating Employee Retention Costs Across All LSEs.

The Decision approves PG&E's request to recover from all ratepayers $128.5 million in employee retention costs incurred during the record period, September

1, 2023 through December 31, 2024. (Decision at 21-22, COL 4.) A4NR contests the approval, arguing it is inequitable and discriminatory to impose DCPP costs from a period that precedes extended operations on SCE and SDG&E customers, because during that time these customers were not receiving the benefits of the DCPP extension. (A4NR App. Rehg. at 16-18.) However, the Commission already decided this cost allocation question in D.23-12-036 and determined that employee retentions costs are recoverable from all ratepayers. (D.23-12-036 at 67.) In light of this prior determination, A4NR's argument is rejected as an impermissible attempt to relitigate an issue that the Commission previously decided. (§ 1709.)

Section 712.8(f)(2) is clear that DCPP employee retention costs are "fully recoverable in rates." (§ 712.8(f)(2).) But the statute generally does not specify whether the costs listed for recovery in section 712.8, including 712.8(f)(2), are to be recovered from all ratepayers or just PG&E customers. Section 712.8(c)(4) limits ratepayer DCPP financial responsibility to only those costs authorized by section 712.8, while section 712.8(l)(1) states in the affirmative that, "[a]ny costs the commission authorizes the operator to recover in rates under this section shall be recovered on a fully nonbypassable basis from customers of all load-serving entities subject to the commission's jurisdiction, as determined by the commission, except as otherwise provided in this section." (Pub. Util. Code, §§ 712.8(c)(4) & 712.8(l)(1).)

Given the need to determine which costs can be recovered from all ratepayers, in D.23-12-036, the Commission reviewed the statutorily authorized cost categories and created a table specifying from which customers the costs can be recovered. (D.23-12-036 at 67-69.) Regarding employee retention costs under section 712.8(f)(2), the Commission found that the statute does not specify the ratepayers from which these costs can be recovered, and thus it is "presumed to be ratepayers of all LSEs subject to the Commission's jurisdiction — via an NBC — per subsection (l)(1)." (D.23-12-036 at 67.)

A4NR tries to overcome this clear Commission precedent, arguing that "the snippet of language in the table would not qualify as a 'conclusive presumption'" under the Evidence Code; that it is instead a rebuttable presumption, which A4NR overcame in its testimony, shifting the burden back to PG&E, which it did not meet. (A4NR App. Rehg. at 18.) A4NR further asserts that reading this language to suggest that retention costs can be recovered from all ratepayers before they begin to receive the benefits from DCPP is in tension with Conclusion of Law 34 of D.23-12-036, which describes the receipt of benefits as "a matter of equity" for those who pay the DCPP costs. (*Ibid.* (*citing* D.23-12-036 at 130, COL 34).) Finally, A4NR argues that the Decision's treatment of retention costs violates sections 451, 453(a), and 453(c). (*Id.* at 17-18.)

The Decision cites page 67 of D.23-12-036, where the table entry on employee retention costs can be found, for the proposition that the subject costs are recoverable from all ratepayers. (Decision at 21-22, fn.56.) In doing so, the Commission reasonably interpreted D.23-12-036 to support the finding that these retention costs can be included in the DC NBC. Regarding Conclusion of Law 34 of D.23-12-036, it does not directly speak to the question at issue here. It affirms the principle that the customers who pay for DCPP should also be entitled to a share of the benefits, which is not in dispute. Ultimately, to the extent A4NR's argument constitutes a disagreement with how the Commission interpreted one of its prior decisions, A4NR's argument fails. The Commission is afforded considerable deference when it is interpreting its own decisions. (*The Utility Reform Network v. Public Utilities Com.* (2014) 223 Cal.App.4th 945, 958 ("[t]he Commission's interpretation of its own rules and regulations is entitled to consideration and respect by the courts") (cleaned up).) A4NR's overemphasis on the Commission's use of "presumed" is a red herring. All entries in the table on pages 67-69 of D.23-12-036 use the word "presumed" when the statute does not state directly whether the given cost can be recovered from all ratepayers. It should not be read to suggest the Commission's determinations here are rebuttable.

Given that this matter was decided in D.23-12-036, the Commission need not consider A4N4's arguments under sections 451, 453(a), and 453(c). (*See* Pub. Util. Code, § 1709; *Anchor Lighting v. Southern California Edison Co.* (2006) 142 Cal.App.4th 541, 549 (finding that appellant's arguments that contest a separate

Commission decision were barred as collateral attacks, citing with approval the Commission's same determination under section 1709).)

IV. CONCLUSION

The Decision should be modified to make clarifications, as set forth in the ordering paragraphs below. As modified, the applications for rehearing should be denied as the applicants fail to show legal error.

THEREFORE, IT IS ORDERED that:

1. Decision (D.) 24-12-033 is modified as follows with additions in underline and deletions in strikethrough:

a. Page 35 is modified to state:

> Upon review, the Commission finds PG&E's request to recover nuclear fuel costs reasonable and in alignment with the relevant statute. We note that the costs that are already attributed to the <u>loans administered by</u> DWR ~~Loan~~ are considered incremental as they were needed to pay for the extension of the existing fuel cycle, whereas the nuclear fuel costs sought herein are outside of the transition window and part of ongoing operations during the extension and are necessary for the operation of the plant. This treatment aligns with the Commission's historical treatment of nuclear fuel costs where these costs were recovered annually in rates through the ERRA Forecast proceeding.

b. Pages 41-42 are modified to state:

> The Commission notes that typically in a GRC the use of a Net-to-Gross (NTG) multiplier is allowed to "gross up" net revenues which are after income taxes, to become gross revenues before income taxes. This is generally only applied to the shareholder equity return on rate base portion of the revenue requirement (the debt portion is not included, because the interest expense is tax-deductible). Without this treatment, the utility shareholders would not actually achieve the authorized rate of return on rate base investment, because income taxes would otherwise reduce some of that return. That is, the NTG multiplier adds more money into the revenue requirement to pay the income taxes on the shareholder's return on the investment in rate base. However,

the management fee is not the same as an authorized return on rate base and the~~. The~~ Commission has no reason to think the management fee is akin to an income generating investment in capital expenditures. ~~It is more akin to an expense (which is deducted from taxable income), not a return on investment (which generates taxable income). Hence, there is no reason to allow a "gross up" on a fixed management fee.~~

c. Pages 79-80, Finding of Fact 15, is modified to state:

Costs that are already attributed to the loans administered by DWR ~~Loan~~ are considered incremental as they were needed to pay for the extension of the existing fuel cycle, whereas the nuclear fuel costs sought herein are outside of the transition window and part of ongoing operations during the extension and are necessary for the operation of the plant.

2. As modified, the applications for rehearing of D.24-12-033 are denied.

3. Application 24-03-018 is closed.

This order is effective today.

Dated July 24, 2025 at San Francisco, California.

ALICE REYNOLDS
President
DARCIE L. HOUCK
JOHN REYNOLDS
KAREN DOUGLAS
MATTHEW BAKER
Commissioners