

1 DOCKET NO.: A.24-03-018
2 EXHIBIT NO.:
3 DATE:
4 WITNESS: John Geesman
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9 **BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

10 **PUBLIC VERSION**

11 **PREPARED TESTIMONY OF JOHN GEESMAN ON BEHALF OF THE**
12 **ALLIANCE FOR NUCLEAR RESPONSIBILITY (“A4NR”)**

13
14 Q01: Please state your name and business address for the record.

15 A01: My name is John Geesman, and my business address is: Dickson Geesman LLP, P.O. Box
16 177, Bodega, CA 94922.

17 Q02: Are your professional qualifications included in your testimony?

18 A02: Yes, my professional qualifications are contained in Appendix 1 to my testimony.

19 Q03: Was your testimony prepared by you or under your direction?

20 A03: Yes, it was.

21 Q04: Insofar as your testimony contains material that is factual in nature, do you believe it to
22 be correct?

1 A04: Yes, I do.

2 Q05: Insofar as your testimony contains matters of opinion or judgment, does it represent
3 your best judgment?

4 A05: Yes, it does.

5 Q06: Does this written submittal complete your prepared testimony and professional
6 qualifications?

7 A06: Yes, it does.

8 Q07: What is the purpose of your testimony?

9 A07: The purpose of my testimony is to provide evidence of why PG&E's Application in this
10 proceeding is unreasonable and imprudent, and why PG&E's envisioned extended operation of
11 the Diablo Canyon Nuclear Power Plant ("DCNPP") until 2029 (Unit 1) and 2030 (Unit 2) is
12 neither reasonable, prudent, nor cost-effective. My testimony is organized to address each of
13 the questions identified in the Assigned Commissioner's Scoping Memo and Ruling, begins with
14 an Introduction to establish factual context, and ends with a Conclusion containing my
15 preliminary observations about PG&E's ability to meet its burden of proof.

16 **I. INTRODUCTION: FACTUAL CONTEXT.**

17 The affordability maelstrom that envelops many recent Commission proceedings makes
18 it useful to reflect upon the striking perspective offered by the February 16, 2024 Reply
19 Comments of Southern California Edison Company ("SCE") in R.18-07-006:

1 The Joint Ratepayers recognize that the Commission has determined that
2 rate increases over the last few years have been driven, not by unchecked utility
3 spending, but instead by efforts associated with wildfire safety and California’s
4 clean energy and climate policy goals. [footnote omitted] Nevertheless, the Joint
5 Ratepayers contend that the Commission must moderate utility spending in
6 these areas and should even consider a one-year hiatus on the implementation
7 of any rate increases. [footnote omitted] Under cost-of-service ratemaking,
8 however, it would not be appropriate to arbitrarily moderate or pause all utility
9 spending. Instead, individual rate increase requests must continue to be
10 evaluated on their own merits and based on consideration of factors that go
11 beyond whether rates will increase, such as safety, reliability, resiliency, and
12 clean energy.

13 Additionally, moderating or pausing spending in the near term is not
14 necessarily the cheapest option or in the best interest of customers. California is
15 undergoing a remarkable evolution to achieve its decarbonization goals.
16 Supported by its residents, the legislature and other governmental leaders, the
17 State has taken major steps to reduce emissions and is committed to achieving
18 carbon neutrality by 2045 to reduce the threat of climate change. However,
19 meeting the State’s decarbonization requirements requires profound changes in
20 the electric sector to enable carbon reduction and facilitate customer adoption
21 of electrified solutions. These changes cannot wait. As Governor Newsom
22 emphasized in 2022: ‘Later is too late to act – lifestyles, places, and traditions are
23 being destroyed – and California is leading the world in our efforts to combat
24 climate change.’ [footnote omitted] Moreover, there are real costs to delay and
25 inaction. CARB’s 2022 Scoping Plan for Achieving Carbon Neutrality explains
26 these costs as follows:

27 Any delays in action or insufficient action are a threat to public
28 health and the environment. The impacts to our economy would
29 be devastating as well. While not specific to California, a 2022
30 report from Deloitte Economics Institute finds that failing to take
31 sufficient action to reduce emissions could result in economic
32 losses to the U.S. of more than \$14.5 trillion over the next 50
33 years. On a hopeful note, however, the report finds that if the
34 country invests now and in the coming years in a net-zero
35 economy, \$3 trillion could be added to the economy over the next
36 50 years...The lessons for California from these analyses are clear:
37 invest now or pay the price later. [footnote omitted]

38 This larger context is missing in the Joint Ratepayers’ insistence that the
39 Commission ‘tap the breaks’ [*sic*] on the pace of utility spending in support of
40 these important initiatives and must not be lost when assessing the affordability
41 of near-term investments and rate increases.

1 Finally, the larger context of the clean energy transition also means that
2 holistic assessments of electric affordability must move beyond exclusive focus
3 on near-term increases in electric bills. While enabling the clean energy
4 transition requires strategic near-term investments which will increase electric
5 bills, increased electrification can both create downward pressure on electric
6 rates over time (by spreading costs over a larger load) and ultimately reduce
7 customers’ overall energy costs (due to reduced gasoline consumption and gains
8 in energy efficiency). SCE’s share of wallet analysis in its 2025 GRC shows that
9 despite electric bills increasing due to electrification, by the early 2030s, the
10 average SCE household can expect to see a significant decrease (>10%) in total
11 energy bills. [footnote omitted] This context is important when assessing the
12 affordability of near-term investments in the electric system.¹

13 Does a massive financial rescue, propping up the aging DCNPP white elephant for
14 another five years, fit this vision? Changed conditions in California’s electrical markets since the
15 2022 enactment of SB 846, combined with the significant increase in projected costs of a five-
16 year extension of DCNPP, have upended the economic logic of viewing the extension as a
17 defensible “strategic near-term investment.” The May 2024 Joint Agency Reliability Planning
18 Assessment from the CPUC and CEC indicated that aggressive procurement, and successive
19 rounds of the Commission’s Integrated Resource Planning process, have greatly mitigated the
20 2025 – 2030 insufficient-generation concerns that motivated SB 846. The two agencies now
21 estimate 18,800 MW of net qualifying capacity of new resources will have come online
22 between 2020 and 2028 (more than 8,000 MW of that by year-end 2023), and announced, “The
23 results from the analyses agree that the proposed 2023 Preferred System Plan meets the
24 reliability standard through 2035. The CEC performed additional analysis around potential
25 import and supply shortfalls and concluded the state remains reliable even under extreme
26 scenarios.”² The post-SB 846 success of the Commission’s procurement orders in bringing new

¹ R.18-07-006, SCE Reply Comments, pp. 10 – 12.

² Joint Agency Reliability Planning Assessment, May 2024, pp. 2 – 4, attached hereto as Appendix 2. See also Governor Newsom’s April 25, 2024 announcement that California has increased battery storage capacity to 10,379

1 clean resources online has empirically overwhelmed any contribution attributable to DCNPP's
2 2,280 MW of net qualifying capacity during the 2024 – 2030 extended operations period.

3 As explained in 2022 by Hunter Stern, representing the International Brotherhood of
4 Electrical Workers Local 1245 (a party to the 2016 Joint Proposal to retire and replace DCNPP),
5 to the Assembly Utilities and Energy Committee then considering SB 846:

6 We were a sponsor to SB 1090 and we worked very hard to get that passed and
7 signed by Governor Brown in 2018. And yet, regrettably, the CPUC did not
8 approve resources to enact that agreement until last year. And it's put us in a
9 very bad position because we do honor, and will honor, the Joint Proposal but
10 we can't honor something where the other piece of the agreement has not been
11 achieved. And we stand ready, and support the Administration's position that
12 Diablo Canyon should close and decommission when that deal is achieved or
13 honored.³

14 The next day, Mr. Stern made a similar statement about GHG-free resources to the Senate
15 Energy, Utilities, and Communications Committee: "We stand ready to honor our commitment
16 and close the, have the plant closed, when we know that the resources are available."⁴

17 In the meantime, PG&E's recent media statements acknowledge that projected costs of
18 DCNPP extended operations have increased, while downplaying the new forecast as only \$8.3
19 billion⁵ rather than the larger amounts others have estimated. But PG&E's modeling projects

MW, up from 770 MW in 2019. <https://www.gov.ca.gov/2024/04/25/california-achieves-major-clean-energy-victory-10000-megawatts-of-battery-storage/> Newsom was quoted in the April 25, 2024 edition of *The Hill* as saying, "This is our biggest power source in California — significantly bigger than the last remaining nuclear plant in the state of California."

³ <https://www.assembly.ca.gov/media/assembly-utilities-energy-committee-20220826> at 1:51:12.

⁴ <https://www.senate.ca.gov/media/senate-energy-utilities-communications-committee-20220825?format=video> at 39:25.

⁵ See, e.g., <https://www.usnews.com/news/business/articles/2024-06-13/california-legislators-break-with-gov-newsom-over-loan-to-keep-states-last-nuclear-plant-running>; <https://www.msn.com/en-us/news/us/californians-warned-of-12-billion-nuclear-bill/ar-BB1odb8X>; <https://www.msn.com/en-us/money/news/critics-fear-pg-e-s-aging-diablo-canyon-power-plant-costs-may-be-twice-the-initial-estimates/ar-BB1ocolH>

1 a rate of electricity output that is 5.3% higher than the average experienced over the past five
2 years. It fails to account for the annual 15% cost-overrun safe harbor which SB 846 exempts
3 from Commission reasonableness review. It also assumes the revolving \$300 million Liquidated
4 Damages Account for replacement power purchases is never used, and instead returned intact
5 to ratepayers, despite SB 846’s explicit “acknowledgment of the greater risk of outages in an
6 older plant that the operator could be held liable for.”⁶ Adjusting for the 115% cost overrun
7 safe harbor, and adding the \$1.5 billion in government funds that subsidize the DCNPP
8 extension,⁷ results in a ratepayer/taxpayer cost burden of \$9.8 billion.

9 Assuming no additional increases in costs (a dubious indulgence of hope over
10 experience), and normalizing output to the five-year average, DCNPP electricity during
11 extended operations will cost \$114.53/MWh – a substantial increase above the \$75/MWh the
12 Governor’s Cabinet Secretary, Ana Matosantos, estimated to the Legislature in late August 2022
13 “for what this [SB 846] proposal will be.”⁸ For comparison, the Commission’s May 2024 Padilla
14 Report on the Renewable Portfolio Standard (“RPS”) identified the average cost of new RPS
15 contracts signed in 2023 at \$58/MWh, down from \$62/MWh for new contracts signed in 2022.⁹

16 Notwithstanding PG&E’s perennial disinformation campaign to describe DCNPP
17 electricity as low-cost, even the company projects CAISO market revenues that will fall short of
18 DCNPP costs by some \$3.7 billion during the extended operations period. This is a significant

⁶ Pub. Util. Code Sections 712.8(f)(5) and 712.8(f)(6).

⁷ PG&E Data Response A4NR_003-Q003, attached hereto as Appendix 3.

⁸ <https://www.assembly.ca.gov/media/assembly-utilities-energy-committee-20220826> at 3:01:08.

⁹ CPUC Padilla Report, May 2024, p. 22.

1 uptick from the more than \$2.1 billion in 2017 – 2021 cumulative above-market costs that
2 PG&E acknowledged in its Civil Nuclear Credit grant application.

3 The legislative history for SB 846 quotes the author, Senator Bill Dodd, as stating, “If
4 California is able to secure sufficient renewable energy and zero carbon resources without the
5 Diablo Canyon Power Plant being operational, there will not be any extension of Diablo beyond
6 the preexisting closure date.”¹⁰ Relying on a plant with significant above-market costs, whose
7 design compels operating 90% of the time, as a coherent response to transitory reliability
8 challenges that occur less than 10% of the time, has always required a sense of last resort
9 desperation – or indifference to economic considerations. Accordingly, PG&E’s justification for
10 extending DCNPP operations has shifted to the associated decarbonization benefits. But this
11 flag-waving also requires indifference to economic considerations. \$9.8 billion can buy nearly
12 twice the clean electricity at \$58/MWh that it can at \$114.53/MWh. Alternatively, a specified
13 volume of clean electricity can be purchased for about half less if the price is \$58/MWh than if
14 the price is \$114.53/MWh. The Commission’s “reasonable manager” standard precludes PG&E
15 from ignoring conspicuous opportunity costs; “least cost, best fit” remains a resource planning
16 mantra; and continued public support for California’s clean energy strategies requires sustained
17 demonstration of economically rational choices by decisionmakers.

18 **II. SCOPING MEMO ISSUES.**

19 ***1. Whether PG&E’s forecast cost of operations and requested revenue requirement of \$418***
20 ***million over the Record Period for DCP is reasonable, including the following forecasts and***

¹⁰ SB 846 Senate Third Reading, p.14.

1 *their underlying financial assumptions and calculations, subject to PG&E updating these*
 2 *forecasts in the Fall Update:*

3 *a. Operations and maintenance costs (including expenses, project costs, and statutory*
 4 *costs and fees, as well as associated escalations);*

5 PG&E’s Application for recovery of operations and maintenance costs during the 2023 –
 6 2025 Record Period disregards the restrictions established by Pub. Util. Code Section
 7 712.8(c)(1)(C) to protect “ratepayers of any load-serving entities” from costs of PG&E’s
 8 “preparation for extended operations.” The Legislature clearly expected these preparatory
 9 costs to be funded either from the \$1.4 billion forgivable loan to PG&E from the state General
 10 Fund or from “other nonratepayer funds available” to PG&E. Unsurprisingly, in light of the
 11 generous subsidies contained in SB 846, this statutory allocation of near-term cost-estimation
 12 risks placed the onus for forecast error on PG&E. In the face of material underestimates of
 13 these preparatory costs, the finite amount of the General Fund loan, and a limited ability or
 14 willingness to contribute “other nonratepayer funds,” PG&E instead seeks to shift these costs to
 15 ratepayers.

16 This testimony will address nuclear fuel procurement costs, by far the majority of the
 17 preparatory costs PG&E attempts to unlawfully shift, in response to Scoping Memo Issue 1.d.
 18 below. The other preparatory operations and maintenance costs during the 2023 – 2025
 19 Record Period which PG&E’s Application inappropriately assigns to ratepayers are estimated at
 20 \$65,227,000 in Table 3-1 of PG&E’s testimony:

21 **TABLE 3-1**
 22 **O&M EXPENSE**
 23 **(THOUSANDS OF NOMINAL DOLLARS)**
 24

Line No.	Cost Type	2023 Recorded	2024 Forecast	2025 Forecast	Total Period Forecast
2	Project Expense	–	2,197	63,030	65,227

1 PG&E’s testimony disaggregates these Project Expenses for the 2023 – 2025 Record Period in
 2 Tables 3-12 thru 3-19, with totals for the Record Period in thousands of nominal dollars as
 3 follows:

4 **SUMMARY OF O&M PROJECT EXPENSES FROM PG&E TABLES**

Table No.	Cost Type	2023 Recorded	2024 Forecast	2025 Forecast	Total Period Forecast
3-12	INSTRUMENT AND CONTROL SYSTEMS	--	691	21,307	21,998
3-13	INTAKE PUMPS, MOTORS AND EQUIP.	--	--	939	939
3-14	MAIN GENERATOR TURBINE	--	--	2,650	2,650
3-15	MOTOR COSTS	--	--	6,400	6,400
3-16	OTHER ELEC. EQUIP., CABLE, AND SYS	--	151	911	1,062
3-17	OTHER MECH. EQUIP. PIPING SYSTEMS	--	113	22,049	22,162
3-18	REACTOR VESSEL AND RAD. CONTROL	--	243	6,220	6,463
3-19	SECURITY INFRASTRUCTURE	--	--	1,554	1,554
	TOTALS	--	1,198	62,030	63,228

5 PG&E Workpapers p. WP 3-12 contains a similar (but not identical) tally of Project costs,
 6 and O&M Projects forecast to cost more than \$3 million are further described in PG&E
 7 Workpapers pp. WP 3-13 thru WP 3-34. However, summing the amounts attributed to 2023 –
 8 2025 Projects in the narrative of PG&E’s testimony produces a total of \$63.4 million. Unless
 9 subsequently clarified by PG&E, this testimony will assume that the \$65,227,000 identified in
 10 PG&E’s Table 3-1 is the amount of O&M Project Expense for which PG&E is seeking recovery
 11 from ratepayers.

12 In seeking to pass these \$65,227,000 in 2023 – 2025 costs onto ratepayers, PG&E makes
 13 only a halfhearted effort – and a quite arbitrary one, at that – to determine if the associated
 14 Projects should be characterized as “preparation for extended operations.” As PG&E’s
 15 testimony notes, “The projects included in this extended operations application have the bulk
 16 of the expense incurred after November 3, 2024. Projects with most of the expense prior to

1 November 2024 have been included in the Diablo Canyon Transition Memo Account and are
2 not part of this proceeding.”¹¹ PG&E acknowledged in a data response that the phrases “bulk
3 of the expense” and “most of the expense” were not meant to be precise delineations, and
4 indicated that no specific range of acceptable variance had been determined.¹² The anticipated
5 timing of the expense – not the preparatory purpose of the Project – appears to have played
6 the dominant role in PG&E’s determination of which costs are subject to the ratepayer
7 protections of Pub. Util. Code Section 712.8(c)(1)(C). But if the Legislature had intended its
8 safeguards to be so simplistically tied to the calendar, it would have stated that in SB 846.
9 Instead, the purpose of the expenditure was statutorily made determinative.

10 As PG&E has explained the 2023 – 2026 front-loading of the increases in its DCNPP
11 forecast engineering and capital costs since enactment of SB 846,

12 The second driver is the project identification and estimating work that was not
13 complete when PG&E submitted its May 19 [2023] testimony. Since then, costs
14 for engineering design efforts in readiness for the projects have increased. The
15 projects largely complete by 2028; however, the bulk of the expenditures are
16 incurred by the end of 2026 ... the project identification and planning efforts
17 were not complete at the time of submitting the May 19 [2023] testimony. It is
18 now apparent that these projects are needed earlier in extended operations to
19 ensure plant reliability through 2030.¹³

20 PG&E’s explanation makes clear that the \$65,227,000 in 2023 – 2025 Project costs in the
21 Application are “preparation for extended operations.” As such, Pub. Util. Code Section

¹¹ PG&E Testimony, pp. 3-2, line 20, thru 3-3, line 2.

¹² PG&E Data Response A4NR_001-Q019, attached hereto as Appendix 4.

¹³ PG&E Data Response A4NR_001-Q013, pp. 1 – 2, attached hereto as Appendix 5.

1 712.8(c)(1)(C) requires that they be funded from the General Fund loan or “other nonratepayer
2 funds.” The Commission should disallow their recovery from ratepayers.

3 ***b. Charges for the liquidated damages account pursuant to Pub. Util. Code section***
4 ***712.8(g);***

5 This testimony does not challenge these statutorily-mandated charges; or PG&E’s
6 statement that Pub. Util. Code Section 712.8)(i)(1) “provides no allowable uses of the liquidated
7 damages subaccount other than for reimbursement of replacement power costs when a unit is
8 out of service due to an unplanned outage where the reasonable manager standard has not
9 been met;”¹⁴ or PG&E’s stated expectation that, “if replacement power costs are recovered
10 through the Liquidated Damages Subaccount, it would be replenished with \$12.5 million per
11 month until it reaches a credit balance of \$300 million.”¹⁵ While quantitative specificity may be
12 unavoidably speculative, the Commission’s assessment of the reasonableness, prudence, and
13 cost-effectiveness of the 2024 – 2030 extended operations should weigh the credibility of
14 PG&E’s assumption that the Liquidated Damages Subaccount is never utilized. The six separate
15 forced outages suffered by Unit 2 between July 17, 2020 and November 3, 2021, a cumulative
16 149.2 days which PG&E estimated in A.22-02-015 resulted in \$178.6 million in replacement
17 power costs, were a precursor to SB 846’s creation of the Liquidated Damages Subaccount.

18 ***c. Resource Adequacy (RA) substitution capacity forecast costs;***

19 PG&E seeks recovery from ratepayers of forecast RA Substitution Capacity Costs of
20 \$78,129,900 for 2024 – 2025, as identified in Table 4-1 of PG&E’s testimony:

¹⁴ PG&E Data Response A4NR_001-Q033, attached hereto as Appendix 6.

¹⁵ PG&E Data Response A4NR_003-Q008, attached hereto as Appendix 7.

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TABLE 4-1
RA SUBSTITUTION CAPACITY COST FORECAST (2024 - 2025)

Line No.	Year	Total
1	2024	\$8,681,100
2	2025	\$69,448,800
3	Total	\$78,129,900

4 This testimony challenges the reasonableness of the methodology described in PG&E’s
5 testimony for estimating RA Substitution Capacity Costs.¹⁶ PG&E states that it “has chosen to
6 use the current 2024 Power Charge Indifference Adjustment (PCIA) system RA market price
7 benchmark” of \$15.23/kW-Month because “the Commission has not specified a specific market
8 reference price to use.”¹⁷ But PG&E’s confidential data response to CalCCA,¹⁸ when compared
9 to the 2024 – 2025 scheduled outage months specified in PG&E’s confidential workpapers,¹⁹
10 makes clear that the company actually estimates forward system RA prices for four out of five
11 of those months that are a fraction of the current \$15.23/kW-Month PCIA market price
12 benchmark:

13 **COMPARISON OF PG&E FORWARD PRICES WITH PCIA BENCHMARK**
14 **(In \$/kW-month)**

Scheduled Outage	Forward System RA Price	PCIA Price Benchmark
[REDACTED]	[REDACTED]	15.23
[REDACTED]	[REDACTED]	15.23
[REDACTED]	[REDACTED]	15.23
[REDACTED]	[REDACTED]	15.23
[REDACTED]	[REDACTED]	15.23

17

¹⁶ PG&E Testimony, p. 4-4.

¹⁷ *Id.*

¹⁸ PG&E **CONFIDENTIAL** Data Response CalCCA_001-Q020, attached hereto as **CONFIDENTIAL** Appendix 8.

¹⁹ PG&E **CONFIDENTIAL** Workpapers, pp. WP 4-2 – WP 4-4.

1 The significant difference in assumed RA Substitution Capacity Costs for the five months
 2 in the Record Period when PG&E has already planned outages – and conceivably could lock in
 3 substitution costs in the forward market – produce commensurate differences in amounts to be
 4 charged to ratepayers:

5 **COMPARISON OF RATEPAYER COSTS BASED ON ASSUMED PRICE**

6
7

Scheduled Outage	Forward System RA Price	PCIA Price Benchmark
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]
TOTALS	\$44,807,838	\$76,444,299

8
9 PG&E’s choice to use the current \$15.23/kW-Month PCIA market price benchmark
 10 instead of its own forward price estimates overstates its revenue requirement for system RA
 11 replacement capacity by \$31,636,461 in 2024 – 2025, more than 41%. This is unreasonable,
 12 and PG&E’s request should be reduced commensurately.

13 ***d. Operating expenses that would be amortized through 2030 (e.g., nuclear fuel***
 14 ***procurement);***

15 PG&E’s proposed amortization of certain fuel procurement expenses – yet not others –
 16 suffers from the same flouting of Pub. Util. Code Section 712.8(c)(1)(C) exhibited in the
 17 proposed recovery of Project expenses discussed previously. Without explanation for the
 18 distinction, PG&E has elected to charge fuel expenses for cycles 25 and 26 to its governmental

1 funding and to charge ratepayers for the amortized costs of cycle 27 and beyond.²⁰ But long
 2 lead times compelled PG&E to procure in advance all fuel and related services for the entire
 3 period of DCNPP’s extended operations. As PG&E disclosed in a data response, “enforceable
 4 commitments to procure each product or service were made on the contracts execution dates
 5 as follows:

Line No.	Product/Service	Contract Execution Date
1	Uranium Concentrates	8/17/2023
2	Uranium Concentrates	12/28/2023
3	Uranium Concentrates	12/6/2023
4	Uranium Concentrates	9/18/2023
5	Uranium Concentrates	11/15/2023
6	Conversion Services	11/15/2023
7	Enrichment Services	12/6/2023
8	Fabrication Services	9/18/2023 ²¹

7 PG&E’s testimony offers no basis for why the costs associated with cycle 27 and beyond
 8 are not eligible for funding from the \$1.4 billion forgivable General Fund loan authorized in
 9 2022 by SB 846, or the \$75 million General Fund appropriation in 2022 by AB 180 to establish
 10 the Reliability Reserve Reimbursement Agreement between PG&E and the Department of
 11 Water Resources (“DWR”). Nor does PG&E’s testimony make any attempt to explain why the
 12 costs associated with cycle 27 through the 2029 and 2030 DCNPP retirement dates should not
 13 be considered to have been incurred as “preparation for extended operations.” If PG&E
 14 chooses not to draw upon its available governmental funding for these fuel-related
 15 expenditures, then it is required by Pub. Util. Code Section 712.8(c)(1)(C) to pay them from

²⁰ PG&E Data Response A4NR_002-Q008, attached hereto as Appendix 9.

²¹ PG&E Data Response A4NR_004-Q003, attached hereto as Appendix 10.

1 “other nonratepayer funds.” The Commission is statutorily precluded from allowing recovery
2 from ratepayers of the \$ [REDACTED] amortization installment requested in PG&E’s Application.

3 This testimony also challenges PG&E’s plan to charge ratepayers in the SCE and SDG&E
4 service territories for amortization of supplemental employee retention costs incurred prior to
5 the commencement of extended operations of Unit 1 in November 2024 and Unit 2 in August
6 2025. Pub. Util. Code Section 712.8(f)(2) directed the modification of the existing employee
7 retention program “to incorporate 2024, 2025, and additional years of extended operations”
8 with Commission-approved costs “fully recovered in rates.” A table in D.23-12-036 sets out the
9 various costs established by Pub. Util. Code Section 712.8 “and their responsible payers,” and
10 for the modified employee retention program identifies the “payer” as: “Not specified in
11 subsection (f)(2), so presumed to be ratepayers of all LSEs subject to the Commission’s
12 jurisdiction ...”²²

13 PG&E began incurring costs for the modified program on September 1, 2023 and
14 intends to recover a \$18,952,960 2023 revenue requirement through amortization of the
15 associated balancing account. Charging ratepayers in the SCE and SDG&E service territories –
16 rather than those in the PG&E service territory – for DCNPP employee retention costs before
17 DCNPP electricity becomes available to them is inconsistent with Pub. Util. Code Section 451’s
18 requirement for just and reasonable rates. The allocation of these costs was not before the
19 Commission in R.23-01-007, and the inclusion of a stated presumption in a table in D.23-12-036
20 cannot fairly be said to dispose of the matter. PG&E should be directed to file a Tier 3 Advice
21 Letter that allocates the costs incurred for DCNPP employee retention prior to commencement

²² D.23-12-036, p. 67.

1 of extended operations exclusively to ratepayers within the PG&E service territory. Thereafter,
2 DCNPP employee retention costs should be apportioned between ratepayers of all jurisdictional
3 load-serving entities on the same basis as other operating costs that are subject to the
4 nonbypassable charge established by Pub. Util. Code Section 712.8(l)(1). Record Period
5 extended operations for Unit 1 is limited to 59 days in 2024 and 365 days in 2025, and for Unit
6 2 is limited to 127 days in 2025. Cost responsibility assigned to customers outside the PG&E
7 service territory must reflect that in order for the nonbypassable charge to be just and
8 reasonable.

9 ***e. PG&E’s proposal to mitigate Internal Revenue Code (IRC) Normalization violation***
10 ***concerns by allowing the additional recovery of the revenue requirement equivalent of the***
11 ***Accumulated Deferred Income Taxes (ADIT) (for the normalization depreciation book-tax***
12 ***difference) included in the Results of Operation (RO) model;***

13 This testimony takes no position on this issue at this time.

14 ***f. Federal and state income tax gross up of fixed management fees; and***

15 This testimony takes no position on this issue at this time.

16 ***g. Netting of California Independent System Operator revenues for the period from***
17 ***November 3, 2024, to December 31, 2025.***

18 Notwithstanding the concerns expressed above that PG&E’s modeling may overstate
19 DCNPP electricity output (and, consequently, CAISO revenues) during extended operations, this
20 testimony does not challenge the granular forecast for the near-term period from November 3,
21 2024, to December 31, 2025. The statistical reversion to mean phenomenon (e.g., to the
22 average electricity output over the past five years) is more likely to be experienced over the
23 longer time horizon of the extended operations period than in the 14-month Record Period for
24 this Application. It must be noted, however, that even the potentially overstated CAISO

1 revenues of \$812,991,000²³ will fall considerably short of the \$1,241,301,000 Record Period
2 costs forecast by PG&E²⁴: a burdensome above-market cost to be charged to ratepayers of
3 \$428,310,000.

4 **2. Whether the calculation of the non-bypassable charge and rate proposals by PG&E, SCE,**
5 **and SDG&E comply with D.23-12-036 and should be approved.**

6 This testimony takes no position on this issue at this time.

7 **3. Whether PG&E's proposal complies with the implementation of the methodology**
8 **established by D.23-12-036 for allocating the RA attributes and GHG-free energy associated**
9 **with DCP's extended operations.**

10 PG&E's proposal is an impermissible collateral attack on D.23-12-036's allocation of the
11 RA and GHG-free attributes associated with DCNPP extended operations. This topic was fully
12 litigated in R.23-01-007 Phase 1, Track 2. The provisions in Pub. Util. Code Section 712.8(q)
13 which PG&E's testimony invokes were addressed by SCE and CalCCA in their advocacy of a
14 uniform allocation mechanism across the PG&E, SCE, and SDG&E service territories. Quite
15 simply, PG&E previously had every opportunity to make its case that the RA and GHG-free
16 attributes allocation mechanism should tilt in favor of the PG&E service territory, but the
17 company was unsuccessful in the limited attempts that it made.

18 PG&E's R.23-01-007 Reply Brief acknowledged a recommendation by Cal Advocates that
19 the allocation of RA benefits take into account the higher volumetric fees to be paid within the
20 PG&E service territory, and expressed support for "consideration of revisions to an allocation

²³ PG&E Errata Testimony, p. 11-AtchA-1, Updated Table 11A-4, line 15.

²⁴ *Id.*, lines 13 + 17 + 20.

1 methodology consistent with Section 712.8(q) as part of Phase 2 of this proceeding.”²⁵ PG&E’s
2 Opening Comments on the R.23-01-007 Phase 1, Track 2 Proposed Decision (“PD”) were more
3 emphatic, arguing that the PD “erred by not considering the applicability of § 712.8(q), which
4 permits the CPUC to consider the higher cost to customers in PG&E’s service territory as part of
5 any attribute allocation,” and requesting the Commission “order that Phase 2 of this
6 proceeding – or specify another appropriate venue – consider adjustments to any allocations
7 given the increased costs borne by PG&E service territory customers.”²⁶

8 D.23-12-036 did not adopt PG&E’s (or Cal Advocates’) recommendation regarding the
9 allocation methodology for RA and GHG-free attributes. PG&E did not include the allocation
10 issue in its Application for Rehearing of R.23-01-007. While the increasingly unlikely outlook for
11 surplus DCNPP market revenues, to be credited to the PG&E service territory under Pub. Util.
12 Code Section 712.8(h)(3), may cause second-guessing by PG&E of the D.23-12-036 allocation
13 methodology, the proper means by which to raise these ostensibly “new” or “changed”
14 concerns is a Petition for Modification consistent with Rule 16.4. PG&E declined to answer a
15 data request to explain why, when it agreed to support SB 846, it had agreed to a higher
16 allocation of costs to the PG&E service territory.²⁷

17 **4. Whether PG&E’s proposed volumetric performance fees (VPFs)²⁸ pending plan for the**
18 **November 3, 2024 to December 31, 2025 period complies with Pub. Util. Code section**
19 **712.8(s)(1) requirements and should be approved.**

²⁵ R.23-01-007 Phase 1, Track 2, PG&E Reply Brief, p. 24.

²⁶ R.23-01-007 Phase 1, Track 2, Opening Comments on PD, pp. 11 – 12.

²⁷ PG&E Data Response A4NR_001-Q011, attached hereto as Appendix 11.

²⁸ Noting that PG&E’s receipt of the volumetric fees “is not contingent upon its performance,” D.24-05-068 suggested, “(t)hus, the Commission should, going forward, consider referring to the Section 712.8(f)(5) volumetric fees as ‘Section 712.8(f)(5) volumetric fees,’ or, simply, ‘volumetric fees.’ D.24-05-068, p. 7, footnote 11. To be

1 PG&E's proposed spending plan falls defiantly short of the requirement of Pub. Util.
2 Code Section 712.8(s)(1) that limits such spending to very specific circumstances: i.e., "to the
3 extent that it is not needed for Diablo Canyon." In a Record Period when PG&E's
4 \$1,241,301,000 cost forecast exceeds PG&E's \$812,991,000 revenue forecast by a whopping
5 \$428,310,000 (or 52.7% of revenues), PG&E's proposal to spend \$159,610,000²⁹ on projects
6 unrelated to DCNPP is a profound abuse of the "discretion" PG&E's testimony claims for the
7 company:

8 Finally, to the extent PG&E determines the expenditures for the above-described
9 categories is not needed, or that the VPFs should otherwise be spent on
10 operational costs of DCP, PG&E will use its discretion to apply the VPFs to
11 reduce DCP operational costs for all customers.³⁰

12

13 If the large deficit projected for this Record Period is insufficient to motivate PG&E to "reduce
14 DCP operational costs for all customers," what would it take? Should such indifference to the
15 electricity affordability issues chronicled regularly in the California media be described as, in
16 PG&E's words, "a balanced and pragmatic approach that endeavors to accommodate the
17 concerns and interests of a range of stakeholders while still advancing priority work"?³¹

18 In the implausible circumstance where this \$159,610,000 were considered to be "not
19 needed for Diablo Canyon," the restriction in PG&E's proposed spending plan to projects within
20 PG&E's service territory runs afoul of the "just and reasonable" requirement of Pub. Util. Code

consistent with the Assigned Commissioner's Scoping Memo and Ruling in this proceeding, this testimony uses the term, "VPFs."

²⁹ PG&E Testimony, p. 11-5, Table 11-4, line 10 + line 11.

³⁰ *Id.*, p. 9-15.

³¹ *Id.*, pp. 9-15 – 9-16.

1 Section 451. PG&E’s plan ignores the fact that 55% of the statewide VPFs (i.e., \$43,892,750)
2 will be collected from customers in the SCE and SDG&E service territories. What benefit will
3 these customers receive for their generous contributions to PG&E expenditures unrelated to
4 DCNPP? PG&E’s proposed spending plan would interpret Pub. Util. Code Section 712.8(s)(1) as
5 creating a surcharge on DCNPP output, paid by all jurisdictional ratepayers, to fund extraneous
6 expenditures that – by design – can benefit only an arbitrary subset of such ratepayers. The
7 only fair and equitable use of the VPFs in this Record Period, which should be apparent to
8 PG&E, is to “apply the VPFs to reduce DCPD operational costs for all customers.”

9 Notwithstanding the acknowledgment in PG&E’s testimony that it may, in its discretion,
10 apply the VPFs in just this fashion, on July 3, 2024 PG&E sought a writ of review of D.23-12-036
11 from the First Appellate District of the Court of Appeal to establish that the company cannot be
12 required to do so. The PG&E writ petition’s analysis of the phrase “to the extent it is not
13 needed for Diablo Canyon” is directly applicable to the Record Period facts presented by
14 PG&E’s testimony in this proceeding:

15 Moreover, even if this parenthetical phrase did speak in mandatory terms, the
16 Legislature would have well understood that the volumetric fees would not be
17 ‘needed’ to cover reasonable operating costs, because those costs were already
18 fully accounted for under subsection (h)(1). Put differently, the volumetric fee
19 compensation would only ever be ‘needed’ to account for some other categories
20 of costs associated with Diablo Canyon. [footnote omitted] Those other costs
21 could include, for example, potential ‘disallowances’ by the Commission of cost
22 recovery sought by PG&E above the 115% threshold (as disallowed costs would
23 not be recoverable under (h)(1)), or cost overruns for other categories of
24 expenses, such as transition costs or facility upgrades associated with extended
25 operations that may exceed the funds provided through the General Fund loan
26 or federal funding.³²

³² PG&E Petition for Writ of Review, pp. 52 – 53.

1 The \$65,227,000 in Projects and the \$ [REDACTED] fuel amortization installment
2 discussed earlier in this testimony are Record Period transition costs that “exceed the funds
3 provided through the General Fund loan or federal funding.” Together, they sum to a
4 materially greater amount than the \$159,610,000 in VPFs forecasted for the Record Period.
5 The Commission should direct PG&E to apply all of the Record Period VPFs to these otherwise
6 unfunded transition costs because even PG&E’s statutory construction would characterize them
7 as “needed for Diablo Canyon.”

8 ***5. Whether PG&E’s proposed modified regulatory process for PG&E to utilize a Tier 3 advice***
9 ***letter for reporting on the amount of VPF, how the funds were spent and a plan for prioritizing***
10 ***the uses of such funds pursuant to Pub. Util. Code sections 712.8(f)(5) and 712.8(s)(1), is***
11 ***reasonable and should be approved.***

12
13 This testimony takes no position on this issue at this time.

14 ***6. Whether PG&E’s testimony satisfies all the regulatory requirements set forth in D.23-12-***
15 ***036.***

16 Deficiencies in PG&E’s R.23-01-007 cost forecast caused D.23-12-036 to direct PG&E “to
17 produce a complete and transparent forecast of DCPD operations through 2030”³³ that
18 encompasses “any and all costs PG&E expects to be recovered from utility ratepayers for DCPD
19 extended operations.”³⁴ PG&E has responded with a forecast that is neither complete –
20 admitting in a data response that it has not calculated a revenue requirement for extended
21 operations in 2026 – 2030³⁵ -- nor transparent, especially in its treatment of post-2025
22 escalation factors for costs other than its Statutory Fees (which are cumulatively calculated to

³³ D.23-12-036, p. 58.

³⁴ *Id.*, Conclusion of Law 18.

³⁵ PG&E Data Response CalCCA_001-Q031, attached hereto as Appendix 12.

1 the fourth decimal point thru 2030³⁶). When asked to identify the applicable escalation
2 factor(s) and the calculated cumulative value of such factor(s) that was incorporated within
3 each annual entry in Table 2-3 of its testimony, PG&E indicated that it had not calculated
4 cumulative values, had not used escalation factors for Project costs, and provided only general
5 ranges for non-labor O&M expense.³⁷

6 PG&E combines the opaqueness of its post-2025 forecast with a piecemeal approach to
7 what it asks the Commission to approve. PG&E's Application limits its request for Commission
8 approval of "forecasts and their underlying financial assumptions and calculations" to the
9 November 3, 2024 thru December 31, 2025 Record Period, leaving 2026 – 2030 costs in a fog of
10 unaccountability despite the emphasis of D.23-12-036:

11 ... we find it in ratepayers' best interest to require PG&E to produce a more
12 comprehensive and transparent forecast of the costs associated with DCP
13 extended operations for Commission and party review, compared to what has
14 been presented to date in this proceeding ... An upfront, transparent forecast of
15 all anticipated DCP costs through 2030 is also expected to provide a more
16 comprehensive framework to aid parties and the Commission in determining
17 whether the costs included in PG&E's annual DCP Extended Operations Cost
18 Forecast applications are reasonable and prudent.³⁸

19
20 Allowing PG&E to radically shrink its burden of proof in this proceeding (i.e., to establish by a
21 preponderance of evidence, the reasonableness, prudence, and cost-effectiveness of extended
22 DCNPP operations over the full 2024 – 2030 period) would invite a continuing cycle of the
23 incomplete and misleading projections that D.23-12-036 sought to correct.

³⁶ PG&E Workpapers, p. WP 7-1, lines 24 and 36.

³⁷ PG&E Data Responses A4NR_003-Q004 and A4NR_004-Q004, attached hereto as Appendix 13.

³⁸ D.23-12-036, p. 59.

1 **III. CONCLUSION.**

2 D.23-12-036 states that government-funded transition costs “will not be considered
 3 ‘costs’ as part of any cost-effectiveness evaluation considered by the Commission” because
 4 they are “outside the Commission’s purview and general mandate to ensure just and
 5 reasonable rates.”³⁹ Focused only on those 2024 – 2030 extended operations costs which
 6 would be absorbed by ratepayers, DCNPP output would cost \$96.53/MWh. That is 1.66 times
 7 the cost of new RPS contracts signed in 2023, according to the Commission’s May 2024 Padilla
 8 Report. How will a DCNPP cost of \$96.53/MWh stack up against prices in the CAISO market?
 9 According to PG&E’s Workpapers for the forward power price derivation explained in Chapter 8
 10 of the PG&E testimony,⁴⁰ the applicable CAISO prices will fall considerably short of
 11 \$96.53/MWh in each year of the DCNPP extended operations period:

Year	Average of Monthly Average Price	Adjusted Price (DCNPP 0.93 weight)
2024		
2025		
2026		
2027		
2028		
2029		
2030		
Grand Total		

12
 13 While the cost-effectiveness of a baseload plant is probably best evaluated on the basis
 14 of these longer-term price averages, it should not go unnoted how seldom (according to PG&E’s

³⁹ *Id.*, p. 62.
⁴⁰ PG&E Workpapers, **CONFIDENTIAL** p. WP 8-3.

1 CAISO price data for the years 2021 – 2023) that a \$96.53/MWh plant would have been “in the
 2 money.” DCNPP, of course, is a “must-take” resource under the CAISO tariff and is
 3 consequently not subject to economic merit order dispatch. But the data compiled in PG&E’s
 4 Workpapers⁴¹ indicate that applicable prices in the CAISO market exceeded \$96.53/MWh in
 5 only 13.24% of the 26,280 hours comprising the three-year period:

Time Period	Total Number of Hours	Number of Hours When Price Exceeded \$114.53/MWh (and % of Hours)		Number of Hours When Price Exceeded \$96.53/MWh (and % of Hours)	
2021 Q1	2,160	53	(2.45%)	68	(3.15%)
2021 Q2	2,184	24	(1.10%)	40	(1.83%)
2021 Q3	2,208	100	(4.53%)	188	(8.51%)
2021 Q4	2,208	10	(0.45%)	58	(2.63%)
2022 Q1	2,160	1	(0.05%)	15	(0.69%)
2022 Q2	2,184	123	(5.63%)	295	(13.51%)
2022 Q3	2,208	335	(15.17%)	585	(26.49%)
2022 Q4	2,208	831	(37.64%)	1,039	(47.06%)
2023 Q1	2,160	733	(33.94%)	988	(45.74%)
2023 Q2	2,184	23	(1.05%)	78	(3.57%)
2023 Q3	2,208	55	(2.49%)	86	(3.89%)
2023 Q4	2,208	21	(0.95%)	39	(1.77%)
Cumulative Total	26,280	2,309	(8.79%)	3,479	(13.24%)

7
 8 PG&E faces a daunting burden to establish that a reasonable utility manager would
 9 consider encumbering ratepayers with the company’s estimated \$8.3 billion in costs for DCNPP
 10 extended operations (i.e., treating the \$1.5 billion taxpayer contribution as a sunk cost) to be a
 11 prudent course of action. The RA benefits come at an exorbitant annual price, since DCNPP’s
 12 above-market costs must be endured 24-7, year-round, to satisfy a need arising in only a small

⁴¹ *Id.*, pp. WP 8-8 – WP 8-605.

1 portion of the year’s 8,760 hours. PG&E’s testimony enlists the social cost of carbon as a
2 possible justification for this extravagance, but can’t disguise the fact that DCNPP GHG benefits
3 come at 1.66 times the average cost of new RPS contracts signed in 2023. Would the
4 reasonable manager choose to pay \$8.3 billion for the 34.44 million metric tons of emissions
5 reductions PG&E claims, or \$4.9 billion for the same benefit? Alternatively, if the \$8.3 billion
6 ratepayer commitment is irrevocable, would the reasonable manager prefer to purchase 34.44
7 million metric tons of reductions – or 57.32 million? Choices have consequences.

8 And PG&E’s financial valuation of the 34.44 million metric tons of emissions reductions
9 it claims for DCNPP extended operations is extremely sensitive to the discount rate selected.
10 This is immediately clear when examining all three of the social discount rates specified in the
11 2021 Senate Bill 100 Joint Agency Report cited in PG&E’s testimony. Table 2-11 in the PG&E
12 testimony contains calculations for the 2.5% and 3% discount rates used in the Joint Agency
13 Report, but omits the results from the 5% discount rate “(f)or purposes of brevity.”⁴² But what
14 PG&E estimates as a \$3.8 billion benefit using a 2.5% discount rate, and a \$2.6 billion benefit
15 with a 3% discount rate, shrinks to \$810 million at a 5% discount rate.⁴³ What discount rate
16 does PG&E use in its own capital allocation decisions? A PG&E data response stated that the
17 company “often” uses its after-tax weighted average cost of capital (currently 7.19%) for
18 internal planning purposes, but “typically” uses its weighted average cost of capital (currently
19 7.81%). Either of these higher rates – which PG&E presumably uses in evaluating decarbonizing

⁴² PG&E testimony, p. 2-19.

⁴³ PG&E Data Response A4NR_001-Q016, attached hereto as Appendix 14.

1 investment opportunities for electrification of company buildings and vehicles – would erode
2 PG&E’s financial valuation of DCNPP-related emissions reductions considerably.

3 While D.23-12-036 excludes the taxpayer contribution from the Commission’s cost-
4 effectiveness determination, two recently disclosed features of PG&E’s Civil Nuclear Credit are
5 likely to put upward pressure on ratepayer costs.⁴⁴ First is the partitioning of the \$1.1 billion
6 federal grant award into \$741 million of “Base Credits” to reimburse 2023 – 2026 costs, and
7 \$359 million in “Incremental Cost Credits” that only become available from the occurrence in
8 2024 – 2026 of “an Unscheduled Outage, an emergent operating condition, or a new
9 compliance requirement not reasonably foreseeable as of the [January 11, 2024] Execution
10 Date.”⁴⁵ According to a PowerPoint presentation provided by PG&E to DWR on April 12, 2024,
11 this bifurcation of the federal grant stemmed from “(d)ifferences” between DOE’s and PG&E’s
12 statutory interpretation and the computation of operating loss. By PG&E’s assessment, “In the
13 event there are new, additional, or unexpected costs beyond those currently forecast, there is
14 potential increase [*sic*] the Award Amount up to 1.1B.”⁴⁶

15 In light of PG&E’s proclivity in R.23-01-007 and this proceeding for finding “new,
16 additional, or unexpected costs beyond those currently forecast,” there seems little risk –
17 unless DOE withholds consent – of the \$359 million in Incremental Cost Credits being fully

⁴⁴ A March 13, 2024 letter from the Department of Finance to the Joint Legislative Budget Committee indicated that, because DWR is not a party to the January 14, 2024 Civil Nuclear Credit Award and Payment Agreement between PG&E and U.S. Department of Energy (“DOE”), it was not familiar with specific details. DWR’s representative emphasized in testimony that same day to Assembly Budget Subcommittee #4 that it was dependent upon public information about the agreement. <https://www.assembly.ca.gov/media/assembly-budget-subcommittee-no-4-climate-crisis-resources-energy-and-transportation-20240313> at 1:55:25.

⁴⁵ Civil Nuclear Credit Award and Payment Agreement between PG&E and DOE, p. 48.

⁴⁶ April 12, 2024 email from PG&E to DWR with unnumbered PowerPoint slides attached, obtained through Public Records Act request to DWR, and attached hereto as Appendix 15.

1 harvested. The larger significance of this bifurcation of the federal grant lies in its *de facto*
2 incentivization of \$359 million in “new, additional, or unexpected costs beyond those currently
3 forecast” that can be attributed to the undemanding qualifier of “an emerging operating
4 condition.” With the cost overrun pump thus primed, is there any reason to think that the
5 resultant momentum will stop at \$359 million? Observers of PG&E’s past experience in
6 controlling costs are unlikely to doubt that the company will fully utilize the annual 115%-of-
7 forecast safe harbor created by SB 846 – perhaps out of a fiduciary duty to its shareholders to
8 not leave money on the table, if nothing else. But the tenacity with which PG&E’s court appeal
9 of D.23-12-036 disputes the Commission’s authority to apply VPFs to DCNPP operating costs
10 above the safe harbor threshold suggests the company has a much larger appetite than 115%.

11 A second newly disclosed feature of the Civil Nuclear Credit Award and Payment
12 Agreement between PG&E and DOE, with a significant potential impact on ratepayer cost
13 exposure, is the “poison pill” contained in Section 5.2(a). This provision enables DOE to
14 recapture all Credits awarded in the event that PG&E notifies the Nuclear Regulatory
15 Commission prior to January 1, 2027 of its intent to permanently cease operations at DCNPP.
16 Because the DOE grant is the primary source of repayment of the \$1.4 billion loan to PG&E
17 from the General Fund (and the only source, assuming no other federal funding, unless CAISO
18 market revenues in the final year of extended operations soar above PG&E’s current
19 projections), state officials may consider themselves fiscally “locked in” to DCNPP extended
20 operations through 2026 even if cumulative above-market costs to ratepayers exceed the \$1.1
21 billion expected from DOE.

1 Under the circumstances identified in this testimony, PG&E's ability to extract
2 government-funded transition costs from its burden of proving cost-effectiveness does not
3 significantly diminish the Sisyphean nature of its burden of proving DCNPP extended operations
4 to be a reasonable and prudent path to follow.⁴⁷

⁴⁷ Workpapers for this testimony are attached hereto as Appendix 16.

APPENDIX 1

Qualifications of John Geesman

QUALIFICATIONS OF JOHN GEESMAN

John L. Geesman is an attorney with the law firm, Dickson Geesman LLP, and a member in good standing of the California State Bar.

Mr. Geesman served as a member of the California Energy Commission from 2002 to 2008, and was the agency's Executive Director from 1979 to 1983. While a Commissioner, he chaired the Commission's Facilities Siting Committee during a period when nearly two dozen new power plants were approved for construction. Between his two tours at the Energy Commission, Mr. Geesman spent nineteen years as an investment banker focused on the U.S. bond markets and served as a financial advisor to municipal electric utilities throughout the western states.

Mr. Geesman has a long history of engagement with issues related to regulatory compliance, resource planning, environmental policy, financial management, and risk practices. This is demonstrated by his experience in numerous leadership capacities, including stints as:

- Co-Chair of the American Council on Renewable Energy;
- Chairman of the California Power Exchange;
- President of the Board of Directors of The Utility Reform Network (formerly known as Toward Utility Rate Normalization);
- Member of the Governing Board of the California Independent System Operator; and,
- Chairman of the California Managed Risk Medical Insurance Board.

Mr. Geesman has testified as an expert witness before the California Public Utilities Commission in many proceedings. He is a graduate of Yale College and the University of California Berkeley School of Law.

APPENDIX 2

Joint Agency Reliability Planning Assessment, May 2024,
pp. 2 – 4



Joint Agency Reliability Planning Assessment

Covering the Requirements of SB 846 (First Quarterly Report for 2024) and SB 1020 (Annual Report)

Gavin Newsom, Governor
May 2024 | CEC-200-2024-006

reliability into the future, as each progressive year sees increasingly divergent weather patterns from historical norms. Planning models and approaches need to be enhanced to account for greater weather variability. The state will benefit from updated planning strategies for bringing on new resources faster and at a larger scale while engaging more closely with communities on solutions that meet their needs.

- **Resource Scale:** Although the state is experiencing a boom in new project development, challenges remain to achieve the scale and diversity of resources necessary to accomplish the transition. New strategies are needed to increase demand flexibility. Moreover, as supply chain disruptions for solar and storage have the potential to continue, the state needs a more diverse portfolio of new resources to reduce the risk from unexpected project delays. However, alternative technologies are generally more expensive until they reach scale, which would benefit from incentives or cost-sharing strategies to achieve greater diversity in the near term.
- **Extreme Events:** Extreme heat events and wildfires remain a threat to grid reliability, and the state could look to existing programs such as the Strategic Reliability Reserve to expand the resources capable of managing or reducing net-peak demand reduction during extreme events. The Strategic Reliability Reserve was established in 2022 to provide additional generation and demand resources to be used in extreme events.

Demand Forecast

As directed in SB 846, this reliability analysis uses the most recently available Integrated Energy Policy Report (IEPR) forecast. For the analysis, staff used the 2023 IEPR Planning Forecast from the *2023 Integrated Energy Policy Report (2023 IEPR)*. The planning forecast is the forecast scenario that will be used by the CPUC for its Integrated Resource Planning (IRP) efforts. In the planning forecast, the annual managed sales for the California ISO region increases from 216,000 gigawatt-hours (GWh) in 2023 to 257,000 GWh in 2033. The 1-in-2 summer peak increases from 46,000 MW in 2023 to 54,000 MW in 2033. The primary drivers for the increase in electricity demand are transportation and building electrification.

Supply Forecast

California has an IRP process that was established by Senate Bill 350 (De León, 2015) for the load serving entities (LSEs) and the largest publicly owned utilities (POUs) to plan for mid- and long-term procurement of energy resources. Meeting increased load from economic and demographic growth and more extreme weather, replacing aging, retiring generation, and achieving greenhouse gas (GHG) reductions translates into an enormous level of procurement in the mid- and long term. Load serving entities and POU are procuring new energy resources to meet reliability and GHG reduction targets, but they are facing a variety of barriers, including permitting, financing, and supply chain issues. This report contains information on new supply resources for both CPUC-jurisdictional entities and publicly owned utilities.

As part of the CPUC IRP process, the CPUC adopts a Preferred System Plan (PSP) in the “planning track,” and then sets requirements for LSEs to plan toward that portfolio. The PSP is an optimal portfolio of resources for meeting state electric sector policy objectives at least cost to ratepayers. The IRP “procurement track” was initiated in 2019 to explore possible actions the CPUC could take to address potential reliability or other procurement needs. On February

15, 2024, the CPUC adopted a Decision on the 2023 Preferred System Plan and Transmission Planning Process portfolios, which – among other things - adopts an aggregated portfolio that reduces statewide yearly GHG emissions from the electric sector to 25 million metric tons by 2035. The decision provides an expected resource development portfolio for the California ISO to be utilized to plan transmission investments for their Transmission Planning Process. To date the CPUC has approved three decisions within its procurement track in the IRP rulemaking — D.19-11-016 covering the near term (ending in 2023) reliability, D.21-06-035 covering the midterm reliability, ending in 2028, and D.23-02-040 (supplemental midterm reliability) adding additional procurement to 2026 and 2027— ordering CPUC-jurisdictional load serving entities to procure a combined amount of 18,800 MW of net qualifying capacity of new electricity resources to come on-line between 2020 and 2028. The amount of new nameplate capacity identified in Preferred System Plans has also significantly increased year over year.

Publicly owned utilities are non-profit community owned utilities that provide electric service within their territories and are governed by locally elected governing boards. While many publicly owned utilities have used IRPs to guide their resource procurement for years, Senate Bill 350 established the requirement for the 16 largest POU's to adopt IRPs by January 1, 2019, and to submit those IRPs to the CEC for evaluation of consistency with Senate Bill 350 requirements, the state's GHG reduction targets, Renewables Portfolio Standard procurement requirements, and several other planning goals. The POU's filed IRPs in 2018-2019, and the CEC found they were consistent with Senate Bill 350 and other requirements. The publicly owned utilities are directed to update their IRPs every five years, and file and update with the CEC for a Senate Bill 350 consistency evaluation. The publicly owned utilities are currently in the process of filing IRP updates.

Tracking Project Development

The state has witnessed an extraordinary pace of new development in the past three years, with over 130 new clean energy projects coming on-line to serve load in the California ISO footprint during this time. Between 2020 and the end of 2023, the CPUC's IRP procurement orders and prior load serving entity procurement resulted in more than 15,000 MW of new nameplate energy resources, equivalent to more than 8,000 MW of new net qualifying capacity that can count toward resource adequacy capacity obligations.

There is a collaborative effort to track projects coming on-line to support reliability through the Tracking Energy Development Task Force. The task force is composed of the CEC, CPUC, California ISO, and the Governor's Office of Business and Economic Development (GO-Biz). The Tracking Energy Development Task Force reviews new energy projects critical for near-term reliability and provides support, as appropriate, for individual projects, identifies barriers, and coordinates actions across agencies to support all projects. The priority focus for the Tracking Energy Development Task Force has been near-term projects, defined as those that can come on-line in the next one to three years within California ISO territory. The Tracking Energy Development Task Force meets with developers to review projects under development and primarily works on interconnection and permitting delays. Through these coordination meetings with developers, the Tracking Energy Development Task Force has identified three key reasons for project delays: supply chain issues, interconnection delays, and permitting delays.

Reliability Assessments

The deterministic and probabilistic reliability assessment approaches used for this report looked at forecasted demand and supply for 2024–2034. Although SB 846 requires only considering the 5- and 10-year points, the CEC and CPUC included annual results for both analyses. The summer analysis for 2024 is preliminary and will be updated in the release of the SB 846 Second Quarterly Report by the end of June to capture relevant pre-summer conditions (e.g., hydroelectric updates). The analysis provides an overview of projects coming on-line in the near term (next 1–3 years) and describes barriers to new project development.

Near-Term Summer Reliability Assessment

The approach used for the near-term reliability assessment in this report is consistent with the previous deterministic Summer Stack Analysis included in past Senate Bill 846 Joint Reliability Quarterly reports, released in 2023. The analysis compares an hourly evaluation of anticipated supply against the projected hourly demand for the peak day of each month, July through September. The purpose of the stack analysis is to help understand the need for contingency resources under average and potentially extreme situations. Under a 17 percent reserve margin scenario, the CPUC's procurement orders and Preferred System Plan avoid reliability shortfalls well beyond the period covered by the current procurement orders. However, grid reliability risks will persist through 2030 under extreme heat, similar to the conditions experienced in 2020 and 2022. These risks are compounded by the risk of coincident wildfire impacting generation and/or electricity imports into California. Contingency resources may be necessary to avoid outages in these extreme events.

Mid- and Long-Term Probabilistic Reliability Assessment

CEC and CPUC both conducted probabilistic analyses for system reliability in the mid- and long-term planning horizons. While the analyses used different models and slight differences in methodologies, they used similar inputs and assumptions. These differences result in a more robust and complementary approach to evaluating the reliability of resource portfolios, potential risks, and system reliability for the entire state. The results from the analyses agree that the proposed 2023 Preferred System Plan meets the reliability standard through 2035. The CEC performed additional analysis around potential import and supply shortfalls and concluded the state remains reliable even under extreme scenarios.

Recommendations

The following recommendations are consistent with and built upon the efforts of the prior year. Updates to each recommendation are outlined:

- **Continue to Improve Situational Awareness:** The agencies should continue to track project development through the TED task force, as well as increase the transparency of transmission network upgrades and interconnection processes, through the Transmission Development Forum.
- **Improve Planning Assumptions:** The agencies should develop a common approach to better incorporate climate change into planning and evaluate whether changes to the planning reserve margin or other reliability metrics are warranted.

APPENDIX 3

PG&E Data Response A4NR_003-Q003

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_003-Q003		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_003-Q003		
Request Date:	May 28, 2024	Requester DR No.:	003
Date Sent:	June 11, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:	Conor Doyle	Requester:	John Geesman

QUESTION 003

PG&E’s response to TURN_001-Q006 indicated that costs paid from the \$75 million Reliability Reserve Funding Agreement with DWR are included in the DCTRMA costs in Chapter 2, Attachment A. Why do the entries for costs paid from DCTRMA on line 60 on page 2-ATCH-A-1 of PG&E’s testimony not sum to the full \$1.475 billion combined total of the Reliability Reserve Funding Agreement and the loan from DWR?

ANSWER 003

The DCTRMA total on line 62 of Chapter 2, Attachment A does not sum to the \$1.475 billion combined total of the Reliability Reserve Funding Agreement and the loan from the DWR because \$300 million of the \$1.475 billion is for performance-based disbursements (PBD), which are not used to fund DCPP extended operations. Attachment A at line 62 includes ~\$59 million in spent fuel management transition costs, for which PG&E will submit a claim for reimbursement to U.S. Department of Energy (DOE). Based on the history of reimbursement to PG&E from DOE of spent fuel management costs, PG&E assumes the \$59 million will be reimbursed. The ~\$59 million reimbursement is not captured in Attachment A line 62. When accounting for the ~\$300 million in PBDs and the ~\$59 million in spent fuel management transition costs, the total sums to ~\$1.476 billion (\$1.235 billion (Attachment A line 62 total) + \$300 million (non-DCPP extended operations performance-based disbursements) = \$1.535 billion, \$1.535 billion less \$59 million (DOE reimbursement for spent fuel management transition costs = \$1.476 billion).

APPENDIX 4

PG&E Data Response A4NR_001-Q019

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_001-Q019		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_001-Q019		
Request Date:	April 5, 2024	Requester DR No.:	001
Date Sent:	April 19, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:	Brian Ketelsen	Requester:	John Geesman

QUESTION 019

Regarding the following statement found at pp. 3-2, line 20, thru 3-3, line 2,

“The projects included in this extended operations application have the bulk of the expense incurred after November 3, 2024. Projects with most of the expense prior to November 2024 have been included in the Diablo Canyon Transition Memo Account and are not part of this proceeding,”

- a. are “bulk of the expense” and “most of the expense” meant to be a precise demarcation?
- b. if the answer to (a) is affirmative, please specify the precise threshold PG&E consistently applied;
- c. if the answer to (a) is negative, please indicate the range of thresholds used by PG&E and provide an explanation for the amount of variance PG&E considered acceptable.

ANSWER 019

PG&E responds as follows:

- A. No. However, a breakdown of 2022-2030 costs by funding source (General Rate Case, Diablo Canyon Transition Memorandum Account, Diablo Canyon Extended Operations Balancing Account) is provided in Chapter 2 Attachment A.
- B. N/A
- C. A specific range of thresholds was not used. For most of DCP’s projects, the implementation phase of a project is the most cost intensive and incurs the “bulk of the expense”. There are some situations where engineering design is required, where project planning is necessary (identifying procedures, ordering materials, creating work orders) and project management is needed to ensure project readiness for implementation. These design and planning phases will incur costs earlier than the planned implementation and may be incurred prior to November 2024.

APPENDIX 5

PG&E Data Response A4NR_001-Q013

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_001-Q013		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_001-Q013		
Request Date:	April 5, 2024	Requester DR No.:	001
Date Sent:	April 19, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:	Conor Doyle	Requester:	John Geesman

QUESTION 013

Regarding Table 2-6 on p. 2-11 of PG&E’s testimony,

- a. please explain why the substantial majority of variance occurs in the 2023-2026 period;
- b. please explain the reasons for the comparatively large total increase in 2030;
- c. please quantify the cost effect on each outage of the “extended outage durations through 2025 and then significant reductions in duration beginning in 2026” described on lines 16 and 17 of p. 2-12;
- d. please estimate the change in capital costs on line 10 if operations extend past 2030;
- e. please quantify the effect of the changes in fuel cost assumptions described on lines 18 and 19 of p. 2-12.

ANSWER 013

- a. The variances in 2023 – 2026 are larger than in the later years for only a few of the line items:
 - i. Engineering: Incremental costs for engineering are primarily due to the following drivers: The first driver is the License Renewal (LR) application which completes by the end of 2026. Planning for LR was not complete when PG&E submitted initial 2023-2030 forecast costs in its May 19, 2023 testimony in Rulemaking R.23-01-007 (hereinafter May 19 testimony). Since submitting the May 19 testimony, costs for engineering inspections increased. The second driver is the project identification and estimating work that was not complete when PG&E submitted its May 19 testimony. Since then, costs for engineering design efforts in readiness for the projects have increased. The projects largely complete by 2028; however, the bulk of the expenditures are incurred by the end of 2026. The third driver is outage duration. Because of project implementation and additional preventive maintenance activities needed to extend operations, outage durations are longer in 2023 through 2025. As a result, engineering costs during those years have increased. Finally, headcount

- planning was not complete as of submitting the May 19 testimony and attrition in the later years was not well understood.
- ii. Capital: As mentioned in the Engineering drivers, the project identification and planning efforts were not complete at the time of submitting the May 19 testimony. It is now apparent that these projects are needed earlier in extended operations to ensure plant reliability through 2030.
 - iii. Outage: As mentioned in the Engineering drivers, outage durations for 2023 through 2025 are longer than in later years due to preventive maintenance, license renewal inspections and project implementation. As a result, outage costs for those years increased.
 - iv. Training: The need for additional trained operators was identified as a significant gap to address in order to support extended operations. Additional operations headcount and the significant investment of operator training to ensure they are well trained and adequately staffed for extended operations resulted in increased costs.
 - v. Fuel: Fuel procurement costs have experienced market volatility since SB 846 was passed in September 2022. This volatility in the markets was not anticipated in the forecasts presented in PG&E's May 19 testimony. Additionally, nuclear fuel costs recovered through the DCTRMA are presented on an as-spent basis. The amortized fuel costs presented for extended operations cycles 27 and on were forecast with awareness of volatility in the markets.
- b. The forecast for 2030 in PG&E's May 19 testimony assumed a DCPD Unit 2 retirement date of August 2030, however, CPUC Decision 23-12-036 established a Unit 2 retirement date of October 31, 2030. Additionally, the May 19 testimony assumed that the retirement of Unit 1 in 2029 would roughly reduce costs by 50%. However, that is not accurate as many functions require minimum staffing levels while Unit 2 remains in operation after 2029.
 - c. It is not possible to quantify the cost effect of extended outage durations. The costs are driven by work scope which varies with each outage.
 - d. No effort has been made to identify additional project expenditures necessary to extend operations beyond 2030.
 - e. An analysis of this type does not exist. The forecast in PG&E's May 19 testimony was developed from a trended EUCG reporting submittal of Nuclear Fuel costs that assumed costs would escalate at a constant percentage from a base year of 2021. This was the best information known at the time of preparing the overall forecast through 2030 for DCPD operations. The global price of uranium increased approximately 84.9% between the period of 5/2023 to 1/2024.¹

¹ International Monetary Fund, Global price of Uranium [PURANUSDM], retrieved from FRED, Federal Reserve Bank of St. Louis; <https://fred.stlouisfed.org/series/PURANUSDM>, March 27, 2024

APPENDIX 6

PG&E Data Response A4NR_001-Q033

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_001-Q033		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_001-Q033		
Request Date:	April 5, 2024	Requester DR No.:	001
Date Sent:	April 19, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:		Requester:	John Geesman

QUESTION 033

Please describe any allowable uses of the Liquidated Damages Subaccount other than for reimbursement of replacement power costs incurred by PG&E when a Diablo Canyon unit is out of service and the Commission determines that the reasonable manager standard has not been met.

ANSWER 033

PG&E objects to this question on grounds that it calls for a legal conclusion. Subject to and without waiving the objection, PG&E responds that Public Utilities Code section 712.8)(i)(1) provides no allowable uses of the liquidated damages subaccount other than for reimbursement of replacement power costs when a unit is out of service due to an unplanned outage where the reasonable manager standard has not been met.

APPENDIX 7

PG&E Data Response A4NR_003-Q008

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_003-Q008		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_003-Q008		
Request Date:	May 28, 2024	Requester DR No.:	003
Date Sent:	June 11, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:	Conor Doyle	Requester:	John Geesman

QUESTION 008

If the Liquidated Damages Subaccount is drawn upon after achieving a balance of \$300 million, does PG&E anticipate replenishing the subaccount to restore its balance to \$300million?

ANSWER 008

Yes. As described in Chapter 10 of PG&E's Prepared Testimony, page 10-3, if replacement power costs are recovered through the Liquidated Damages Subaccount, it would be replenished with \$12.5 million per month until it reaches a credit balance of \$300 million.¹

¹ Pub. Util. Code § 712.8(i)(2).

CONFIDENTIAL APPENDIX 8

PG&E **CONFIDENTIAL** Data Response CalCCA_001-Q020

The response to this data request contains Protected Materials that are confidential and protected under the Nondisclosure Agreement between CalCCA and PG&E

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	CalCCA_001-Q020		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_001-Q020CONF		
Request Date:	May 7, 2024	Requester DR No.:	001
Date Sent:	May 21, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:	Rhett Kikuyama	Requester:	Corey Cochran

QUESTION 020

Referring to PG&E's prepared testimony, pages 4-4 through 4-5: Please provide PG&E's expected market price for system RA capacity by month during the 2024 – 2025 forecast period in this proceeding.

ANSWER 020

The response to this data request contains Protected Materials that are confidential and protected under the Nondisclosure Agreement between CalCCA and PG&E

PG&E provides its confidential forward RA price curves (\$/kW-month) for 2024-2025 for system RA capacity.

Line No.	Month	2024	2025
1	Jan	-	
2	Feb	-	
3	Mar	-	
4	Apr	-	
5	May	-	
6	Jun	-	
7	Jul	-	
8	Aug	-	
9	Sep	-	
10	Oct	-	
11	Nov		
12	Dec		

APPENDIX 9

PG&E Data Response A4NR_002-Q008

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_002-Q008		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_002-Q008		
Request Date:	April 22, 2024	Requester DR No.:	002
Date Sent:	May 6, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:	Brian Ketelsen / Ryan Stanley	Requester:	John Geesman

QUESTION 008

PG&E’s testimony at p. 2-12, lines 18 – 19, states: “Fuel: Market prices during the transition, accounting changes, and cost recovery periods have changed since May 2023.” Please identify:

- (a) the amount by which PG&E’s estimates of fuel market prices during the transition have changed since May 2023;
- (b) each specific accounting change PG&E has made for fuel-related costs since May 2023;
- (c) the rationale for each specific accounting change identified in (b) above;
- (d) each specific change PG&E has made in in fuel-related cost recovery periods since May 2023; and
- (e) the rationale for each specific change in fuel-related cost recovery periods identified in (d) above.

ANSWER 008

PG&E responds as follows:

- A. An analysis of this type does not exist. The presentation of fuel costs in the May 2023 testimony was based on the CNC application which reported historical amortized fuel region costs with escalation assumptions identified in the submission.
- B. PG&E has made the following accounting changes for fuel-related costs since May 2023 compared to historical practices:
 - 1. Continue to amortize nuclear fuel expense for the final fuel cycle(s) through the end of the current license periods for Unit 1 and Unit 2;
 - 2. Expensed incremental fuel costs related to extending operating cycle 25 for Unit 1 and Unit 2 and recovering the costs from the Reliability Reserve Reimbursement Agreement (RRRA) with the California Department of Water Resources (DWR);

3. Expensed incremental fuel costs associated with cycle 26 for Unit 1 and Unit 2 and recovering the associated costs from the DWR loan agreement signed pursuant to SB 846; and,
 4. Deferred expenses for full fuel procurement and related costs for operating cycles 27 through the 2029 and 2030 license extension dates into a regulatory asset; these amounts will be amortized on a straight-line basis to be recovered from statewide customers between 2025-2030 with true-ups during each application.
- C. The rationale for these changes are as follows, in the same order as the response to subpart (b):
1. The overall cost of fuel needs through the end of the operating licenses ending in November 2024 (Unit 1) and August 2025 (Unit 2) should be fully recovered from PG&E customers through these license expiration dates. Prior to the state's decision to extend the license periods for Diablo's two units, these fuel costs were incurred to the benefit of these customers and were expected to be fully recovered through these time periods by these customers.
 2. Under AB 180 and the RRRRA, these fuel related costs are recoverable through governmental funds. As these amounts are recovered through governmental funding instead of from customers, these costs are immediately expensed and recorded separately from the balancing account mechanisms in the ERRRA proceedings or this application to ensure they are excluded from customer rates.
 3. An estimated cost for a full region's fuel cycle procurement for operating cycle 26 was anticipated to be recovered through the DWR loan. As these amounts are recovered through governmental funding instead of from customers, these costs are immediately expensed and recorded separately from the balancing account mechanisms in the ERRRA proceedings or this application to ensure they are excluded from customer rates.
 4. Recovery of future fuel cycles should be recovered from customers that are benefitting from the expected generation of Diablo Canyon's production. Under Accounting Standards Codification (ASC) 980, PG&E defers these costs for future amortization that will coincide with the recognition of revenue from customers as determined by this proceeding.
- D. Changes to recovery periods are also tied to the accounting changes and rationales provided in subparts (b) and (c) above. Here are the changes in recovery periods, the same order as the responses to (b) and (c) above:
1. No change to recovery of fuel expenses related to the originally planned cycles up to the end of the operating licenses ending in November 2024 (Unit 1) and August 2025 (Unit 2).
 2. Incremental fuel costs related to extending operating cycle 25 for Unit 1 and Unit 2 are recovered as incurred through the RRRRA as discussed above.
 3. Incremental fuel costs associated with cycle 26 for Unit 1 and Unit 2 are recovered as incurred through the DWR loan agreement.

4. Recovery of future fuel cycles starting with cycle 27 through 2029 and 2030 are requested to be recovered straight line from 2025 through 2030.
- E. The rationale for these changes are as follows, in the same order as the response to (d):
1. Amounts recovered through the ERRA proceeding are intended to comply with the request in operating Units 1 and 2 through the end of the original operational licenses. This aligns with recovery from customers under PG&E's 2024 ERRA Forecast Proceeding for the original operation of Diablo Canyon prior to SB 846.
 2. Amounts recovered from governmental funds are expensed as incurred; for these amounts they were requested for reimbursement from DWR.
 3. Amounts recovered from governmental funds are expensed as incurred; for these amounts they were funded by the DWR Loan under SB 846.
 4. Amounts recovered from customers are subject to the outcome of this proceeding and will be amortized consistent with the final decision for cost recovery in customer rates.

APPENDIX 10

PG&E Data Response A4NR_004-Q003

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_004-Q003		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_004-Q003		
Request Date:	June 13, 2024	Requester DR No.:	004
Date Sent:	June 27, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:	Brian Ketelsen	Requester:	John Geesman

QUESTION 003

Regarding the “Nuclear Fuel As-Spent” forecast amounts identified for 2024-2030, for each annual amount, please identify:

- a) the date(s) that PG&E made an enforceable commitment to procure each product or service associated with this annual amount;
- b) how the final price of such product or service associated with this annual amount was (or is to be) established;
- c) any escalation factor that has been or will be applied to this annual amount; and
- d) PG&E’s quantification of the cumulative escalation reflected in each annual amount.

ANSWER 003

PG&E responds as follows:

- a) Nuclear Fuel As-Spent forecast enforceable commitments to procure each product or service were made on the contracts execution dates as follows:

Line No.	Product/Service	Contract Execution Date
1	Uranium Concentrates	8/17/2023
2	Uranium Concentrates	12/28/2023
3	Uranium Concentrates	12/6/2023
4	Uranium Concentrates	9/18/2023
5	Uranium Concentrates	11/15/2023
6	Conversion Services	11/15/2023
7	Enrichment Services	12/6/2023
8	Fabrication Services	9/18/2023

- b) Pricing for Uranium, Conversion, Enrichment, and Fabrication for the as-spent forecast amounts were established based on estimated reactor needs in

quantity at market price per unit or fixed price per unit depending on vendor and delivery terms at bid award.

- c) For forecast deliveries beyond 2023, a 3 percent standard escalation factor is applied to each delivery/invoice for contracts with fixed price escalation pricing terms and conditions. All other delivery/invoice values are in market based nominal dollars as per their contractual pricing terms and conditions.
- d) For the activities/contracts subject to cost escalation as provided in subpart c above, a standard 3 percent annual escalation factor is applied on a per delivery/invoice basis.

APPENDIX 11

PG&E Data Response A4NR_ 001-Q011

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_001-Q011		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_001-Q011		
Request Date:	April 5, 2024	Requester DR No.:	001
Date Sent:	April 19, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:		Requester:	John Geesman

QUESTION 011

When PG&E agreed to support SB 846, why did it agree to the higher allocation of costs to the PG&E service territory?

ANSWER 011

PG&E objects to this question on grounds that it is irrelevant and outside of the scope of this proceeding.

APPENDIX 12

PG&E Data Response CalCCA_001-Q031

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	CalCCA_001-Q031		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_CalCCA_001-Q031		
Request Date:	May 7, 2024	Requester DR No.:	001
Date Sent:	May 21, 2024	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Corey Cochran

QUESTION 031

Referring to PG&E’s prepared testimony, page 11-5, Table 11-4: Please provide the net revenue requirement forecast for years 2026-2030 including supporting workpapers.

ANSWER 031

PG&E objects to this request on the grounds that CalCCA’s request is outside the scope of PG&E’s request in this proceeding. In this proceeding, PG&E proposes to recover costs for the record period of September 1, 2023 to December 31, 2025. PG&E does not have a comparable net revenue requirement for the years of 2026 to 2030.

APPENDIX 13

PG&E Data Responses A4NR_003-Q004 and A4NR_004-Q004

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_003-Q004		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_003-Q004		
Request Date:	May 28, 2024	Requester DR No.:	003
Date Sent:	June 11, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:	Conor Doyle	Requester:	John Geesman

QUESTION 004

For each annual entry in Table 2-3 of PG&E’s testimony, please identify the applicable escalation factor(s) and the calculated cumulative value of such factor(s) that is incorporated within such annual entry.

ANSWER 004

PG&E has not calculated the cumulative value of the escalation factors applicable to its forecasts. Below are references to the location of the various escalation factors that are applied to forecasts presented in Table 2-3. Where escalation is applied to one of PG&E’s forecasts, it is referenced below.

DCPP Direct Costs (Ch.3) (excluding Nuclear Fuel)

- Projects – no escalation factors were used. Work scope is the basis for cost estimates.
- Expense O&M –
 - Labor: Labor rates utilized a 3.75% escalation factor effective for Bargaining Units on January 1 of each year and March 1 for Non-Bargaining Unit. Labor rates are applied to labor hours which is a function of permanent headcount, temporary hires during refueling outages, number of outages per year, and overtime estimates.
 - Employee related and miscellaneous expenses: 0% from 2023 onward.
 - Material expenses: 0% to 4% based on best judgment.
 - Contract expense: 0% to 6% based on best judgment with the vast majority of the escalation rates being 4% or less.
 - Other expense: 0% to 8% based on best judgment with the vast majority of the escalation rates being 4% or less.

Statutory Fees (Ch. 7)

Fixed Payment escalation rates are presented in Chapter 7, Section E.1.

Volumetric Performance Fee escalation rates are presented in Chapter 7, Section E.2.

Results of Operations Items

A&G escalation rates are presented in Chapter 2, Table 2-7.

Nuclear Generation-Related Benefits

Escalation rates for PG&E's Estimated Societal Benefits analysis (Table 2-11) are presented in workpapers for Chapter 2.

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_004-Q004		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_004-Q004		
Request Date:	June 13, 2024	Requester DR No.:	004
Date Sent:	June 27, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:	Conor Doyle	Requester:	John Geesman

QUESTION 004

Regarding the portion of PG&E’s response to A4NR_003-Q004 identified under “DCPP Direct Costs (Ch.3) (excluding Nuclear Fuel),” were the specified escalation rates applied to each year of the Period of Extended Operations, or were they instead applied only to the 2024-2025 record period addressed in Chapter 3?

ANSWER 004

The escalation rates noted in the response for Direct Costs were applied to each year of the Period of Extended Operations.

APPENDIX 14

PG&E Data Response A4NR_001-Q016

**PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2025 Forecast
Application 24-03-018
Data Response**

PG&E Data Request No.:	A4NR_001-Q016		
PG&E File Name:	DCPP-ExtendedOperations2025-Forecast_DR_A4NR_001-Q016		
Request Date:	April 5, 2024	Requester DR No.:	001
Date Sent:	April 19, 2024	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:	Rhett Kikuyama	Requester:	John Geesman

QUESTION 016

Regarding Table 2-11 on p. 2-20 of PG&E’s testimony,

- a. Please provide the societal benefits estimate identified in lines 1 thru 8 of Table 2-11 using the 5% discount rate mentioned at p. 2-19, line 8.
- b. What discount rate does PG&E commonly use in planning its capital investments?
- c. What discount rate does PG&E commonly use in CPUC proceedings to estimate ratepayer benefits?

ANSWER 016

PG&E responds as follows:

- a. PG&E estimates the societal benefits at approximately \$810.387 million (2023 dollars), at a 5 percent discount rate, using the social cost of carbon guidance published in California’s 2021 Senate Bill 100 Joint Agency Report.

Year	(A) Avoided CO ₂ (MMT)	(B) Social Cost of Carbon 5% Discount Rate (\$/MT)	(C) Estimated Societal Benefits at 5% Discount Rate (\$000)
2024	(0.59)	20.56	(12,197)
2025	(3.96)	21.24	(84,037)
2026	(6.91)	22.15	(153,152)
2027	(7.02)	23.13	(162,350)
2028	(6.66)	24.17	(161,031)
2029	(6.60)	25.24	(166,585)
2030	(2.70)	26.36	(71,035)
Total	(34.44)		(810,387)

- b. PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding. Subject to and without waiving that objection, PG&E responds that it typically uses a discount rate calculated as the weighted average cost of capital (WACC), based on the rates and capital

structure filed and adopted during CPUC proceedings. For internal planning purposes, the after-tax WACC is often used, which is calculated by including the additional step of adjusting down the weighted average cost of debt by the combined income tax rate (27.98 percent). This is because the interest payments are typically tax-deductible. The current WACC is based on the ACCAM trigger effective January 1, 2024, as outlined in the table below:¹

WEIGHTED AVERAGE COST OF CAPITAL (WACC) CALCULATION

Line No.	Category	Ratio	Cost	WACC		After-Tax WACC
1	Debt	47.5%	4.66	2.21	x (1-TR)	1.59
2	Preferred Stock	0.5%	5.52	0.03		0.03
3	Common Stock	52.0%	10.70	5.56		5.56
4		100.0%		7.81		7.19

Note: TR = Income Tax Rate = 27.9836%

- c. PG&E objects to this data request on the grounds that it is irrelevant, vague and overly broad, and outside the scope of this proceeding.

¹ Cost of Capital Formula Adjustment Mechanism Trigger for January 1, 2024; See PG&E Advice Letter 4813-G/7046-E.

APPENDIX 15

PG&E April 12, 2024 email of PowerPoint slides to DWR

From: [Krausse, Mark](#)
To: [Hou, Delphine@DWR](#); [Arechavaleta, Christian@DWR](#)
Subject: Fwd: Presentation
Date: Friday, April 12, 2024 3:54:55 PM
Attachments: [DOE Credit Award and Payment Agreement.pptx](#)

Classification: Confidential

FYI

From: Smith, Tyson (Law) <TRSN@pge.com>
Sent: Friday, April 12, 2024 3:37:54 PM
To: Krausse, Mark <MCKd@pge.com>
Subject: Presentation

Get [Outlook for iOS](#)

You can read about PG&E's data privacy practices at [PGE.com/privacy](https://www.pge.com/privacy).

U.S. Department of Energy Civil Nuclear Credit Program

Credit Award and Payment Agreement



6/3/2024



State Policy Direction on Diablo Canyon Extension

- Heading into 2022, all Diablo Canyon work was focused on safe operations until end of licenses in 2024 and 2025, followed by prompt decommissioning
- On September 2, 2022, SB 846 was signed into law allowing continued operations at DCPD through no later than 2030
 - Identifies reliability need due to retiring resources and delays in new procurement
 - Sets new policy direction, requires certain technical/safety reviews, provides funding, and establishes timelines for state agency actions
 - Includes provisions for assessing and monitoring progress earlier towards replacement resources
 - Conditioned on authorization of continued operation by U.S. Nuclear Regulatory Commission and eligibility for DOE Civil Nuclear Credit Program
- Shift in policy requires unprecedented set of activities in limited window of time as compared to typical license extension



State Agency Activities in Support of SB 846

- California Department of Water Resources
 - Executed loan agreement with PG&E
 - Completed two semi-annual true-up reviews to date
- California Energy Commission
 - Performed Analysis of Need to Support Reliability
 - Completed Operations Assessment Report
 - Prepared Cost Comparison Report
- California State Lands Commission
 - Extended State Lands Commission lease to be co-extensive with retirement dates
- California Public Utilities Commission
 - Invalidated original retirement dates
 - Conditionally set new retirement dates of October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2)



PG&E Activities in Support of SB 846

- **Diablo Canyon Operations**

- PG&E pivoted to developing plans for NRC relicensing activities, fuel procurement, and hiring qualified workforce
- PG&E performed Seismic Assessment, with independent reviewers
- PG&E commissioned Independent Study on Deferred Maintenance

- **U.S. Nuclear Regulatory Commission**

- PG&E obtained exemption from NRC to permit operations past current expiration dates pending completion of license renewal application
- PG&E submitted license renewal application in November 2023

- **U.S. Department of Energy**

- PG&E filed Civil Nuclear Credit program application on September 2, 2022
- Conditional award announced in November 2022
- Final Credit Award and Payment Agreement executed January 11, 2024



Overview of Civil Nuclear Credit Program

- DOE's Civil Nuclear Credit Program is part of Infrastructure Investment and Jobs Act (IIJA)
 - Available for reactor scheduled to cease operations by September 30, 2026, due to economic factors
 - Award amount tied to demonstration of "operating loss" over 4-year Award Period (2023-2026)
- DOE modified CNC Program guidance and extended application deadlines at State's request
 - PG&E filed application the day after passage of SB 846 seeking up to ~\$1.1B in credits
 - On November 21, 2022, DOE announced the conditional selection of DCPD for first round of funding
- Parties negotiated Credit Award and Payment Agreement ("CAPA") over the next year
 - CAPA sets forth the terms and reporting structure for award of credits for up to \$1.1B to support extended operations
 - > DOE's computation results in Base Credits totaling ~\$741 million
 - > Potential up to \$1.1B, including available Incremental Credits
 - > Funds used to repay the Department of Water Resources ("DWR") loan, along with excess market revenues

6

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CAPA Provisions – Structure / Organization

Structure

- Article 1 – Definitions
- Article 2 – Operation of the Nuclear Reactor; Credits
- Requires PG&E to operate in accordance with prudent industry practice and provide advance notice of scheduled outages and prompt notice of unscheduled outages.
- Article 3 – Reports; Required Notices by Owner/Operator
- Article 4 – Representations and Warranties
- Article 5 – Term; Events of Default; Defaults, Remedies; Suspension
- Article 6 – Conditions Precedent to Final Award
- Article 7 – Miscellaneous

Key Documents

- Exhibit E – PG&E Officer Certificate for Execution
- Attachment 1 – Credit Award Amounts
- Schedule 2.1 – Scheduled Outage Information
- Schedule 3.2(c) – Davis-Bacon Wage/Contract Information
- Schedule 4.11 – Financial Projections; Calculation of Operating Loss and Credit Amount
- Schedule 4.12 – Information re Prohibited Person Interim Agreement with U.S. Dept. of Interior
- Community Benefits Plan

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CAPA Provisions – Timing and Reporting

- CAPA sets forth annual filings after each Award Year, which DOE will audit before issuing the award
 - 2023 Annual Report (submitted)
 - 2023 Audit Certificate (submitted)
- Initial funding/payments tied to end of Award Year in which each unit entered extended operations
 - For Unit 1 (enters extended ops in Nov 2024)
 - > First payment in 2025, for Award Years 2023 and 2024
 - > Second payment in 2026, for Award Year 2025
 - > Third payment in 2027, for Award Year 2026
 - For Unit 2 (enters extended ops in Aug 2025)
 - > First payment in 2026, for Award Years 2023, 2024, and 2025
 - > Second payment in 2027, for Award Year 2026
- CAPA provides for “recapture” if one or more units shut down prior to end of Award Period
 - Amount recaptured depends on when shutdown occurs and reasons for shutdown

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Community Benefits Plan

- Required PG&E to develop and implement a Community Benefits Plan
 - Community and Labor Engagement
 - Investing in Job Quality and Workforce Continuity
 - Diversity, Equity, Inclusion, and Accessibility
 - Justice40 Initiative
- CAPA provides ongoing reporting requirements at regular intervals
 - PG&E must submit an Annual Report:
 - > Data on variety of topics, including environmental impact (e.g., avoided emissions), reliability impacts, and market impacts (i.e., customer savings from reduced electricity and capacity costs) during the Award Year
 - > Annual Assessment of the Community Benefits Plan
 - Quarterly reporting is required for the Community Benefits Plan



Key Issues

- Calculation of Credit Award Amounts
 - CAPA award of Base Credit Amounts
 - > Annual award is the “operating loss”, calculated as Costs in excess of Revenue, if no loss, no award
 - > PG&E sought \$1.1B based on its proposed methodology and calculation of operating loss
 - > DOE approach based on its interpretation of statute; results in lower base credit award amount
 - Differences:
 - > DOE includes all ratemaking processes, including GRC and future DCPD cost recovery proceedings, in its calculations
 - > PG&E approach had focused on costs not covered by ratemaking mechanisms (i.e., only those costs addressed by the DWR loan)
 - > Results in an award cadence that is front-loaded
 - In the event there are new, additional, or unexpected costs beyond those currently forecast, there is potential increase the Award Amount up to \$1.1B
 - Where available, PG&E will seek Incremental Credit Amounts throughout the term of the CAPA; award of Incremental Credits subject to DOE discretion



Key Issues

- Davis-Bacon Act (DBA) Applicability

- IJA requires "laborers and mechanics" performing certain work on projects funded through the award program be "paid wages at rates not less than those prevailing on similar projects [...] in accordance with [the DBA]"
 - > 1931 law that applies to contractors/subs working on federally funded or assisted contracts
 - > Requires laborers and mechanics performing construction, alteration, or repair work be paid prevailing wage for the locality and requires weekly reporting to the Department of Labor
- DOE requires "certification" process
 - > PG&E, contractors, and subcontractors must execute Statements of Compliance at regular intervals
 - > Certify that the covered employees were paid at least prevailing wage
 - > If PG&E or any contractor/subcontractor was not in compliance, the CAPA includes a process to retroactively adjust pay to come in compliance



Key Issues

- U.S. Uranium Best Efforts
 - CAPA requires PG&E to use “best efforts” to source uranium from the U.S.
 - Obligations may increase cost of fuel purchases
- U.S. Manufacturing Best Efforts
 - CAPA requires “best efforts” to maximize U.S.-manufactured content:
 - > Acquired or used in reactor facilities and components,
 - > Taking into account availability, cost, technical performance, reliability, efficiency, warranty coverage and related commercial terms for 2023-2026
 - PG&E has established a standard/protocol for complying with U.S. manufacturing best efforts
 - Obligations may increase cost of equipment purchases



Extensive Reporting and Notification Obligations

- 2023 Annual Report (submitted)
- 2023 Audit Certificate (submitted)
- Ongoing Notification Requirements
 - Event reporting
 - Outages
 - NRC milestone reporting
 - DWR milestone reporting (e.g., semi-annual true-ups)
 - CPUC proceeding milestones

APPENDIX 16

A4NR Workpapers

A4NR WORKPAPERS

1. page 6, lines 1 – 2: “a rate of electricity output that is 5.31% higher than the average experienced over the past five years.”

YEAR	GWh	Source of Information
2019 (24 reactor months)	[REDACTED]	PG&E Civil Nuclear Credit Application
2020 (24 reactor months)	[REDACTED]	PG&E 2024 Report to DOE
2021 (24 reactor months)	[REDACTED]	PG&E 2024 Report to DOE
2022 (24 reactor months)	[REDACTED]	PG&E Revised Chapter 4 Workpapers
2023 (24 reactor months)	[REDACTED]	PG&E Revised Chapter 4 Workpapers
2024 (24 reactor months)	[REDACTED]	PG&E Revised Chapter 4 Workpapers
2025 (24 reactor months)	[REDACTED]	PG&E Revised Chapter 4 Workpapers
2026 (24 reactor months)	[REDACTED]	PG&E Revised Chapter 4 Workpapers
2027 (24 reactor months)	[REDACTED]	PG&E Revised Chapter 4 Workpapers
2028 (24 reactor months)	[REDACTED]	PG&E Revised Chapter 4 Workpapers
2029 (22 reactor months)	[REDACTED] ([REDACTED] annualized)	PG&E Revised Chapter 4 Workpapers
2030 (10 reactor months)	[REDACTED] ([REDACTED] annualized)	PG&E Revised Chapter 4 Workpapers

2019 – 2023 average: 16,865.14 GWh

2024 – 2030 average: 17,760.72 GWh (or 105.31% of 2019 – 2023 average)

2. page 6, line 8: “results in a ratepayer/taxpayer cost burden of \$9.8 billion.”

YEAR	PEO Costs identified on Line 86 of PG&E Revised Chapter 2 ATCH-A Workpapers	15% Cost Overrun Safe Harbor (plus increase to following year’s baseline)
2023	[REDACTED]	[REDACTED]
2024	[REDACTED]	[REDACTED]
2025	[REDACTED]	[REDACTED]
2026	[REDACTED]	[REDACTED]
2027	[REDACTED]	[REDACTED]
2028	[REDACTED]	[REDACTED]
2029	[REDACTED]	[REDACTED]
2030	[REDACTED]	[REDACTED]
TOTAL	\$ 7,014,732,056	\$ 1,219,530,385

$\$7,014,732,056 + \$1,219,530,385 = \$8,234,262,441$

$\$8,234,262,441 + \$1,535,000,000 = \$9,769,262,441$

3. page 6, lines 10 - 11: “DCNPP electricity during extended operations will cost \$114.53/MWh ...”

YEAR	PEO GWh Forecast	Source of Information
2024		PG&E Revised Chapter 4 Workpapers
2025		PG&E Revised Chapter 4 Workpapers
2026		PG&E Revised Chapter 4 Workpapers
2027		PG&E Revised Chapter 4 Workpapers
2028		PG&E Revised Chapter 4 Workpapers
2029		PG&E Revised Chapter 4 Workpapers
2030		PG&E Revised Chapter 4 Workpapers

TOTAL: 90,085.53 GWh
 $\times .9469$
 NORMALIZED TOTAL 85,301.99 GWh

$\$9,769,262,441 \div 85,301.99 \text{ GWh} = \$114.53/\text{MWh}$

4. page 6, lines 17 – 18: “even the company projects CAISO market revenues that will fall short of DCNPP costs by some \$ 3.7 billion during the extended operations period.”

YEAR	Market Revenues Forecast (\$)	Source of Information
2024	113,090,259	PG&E Revised Chapter 2 ATCH-A Workpapers
2025	699,901,093	PG&E Revised Chapter 2 ATCH-A Workpapers
2026	1,250,820,940	PG&E Revised Chapter 2 ATCH-A Workpapers
2027	1,234,182,191	PG&E Revised Chapter 2 ATCH-A Workpapers
2028	1,139,149,191	PG&E Revised Chapter 2 ATCH-A Workpapers
2029	1,167,917,814	PG&E Revised Chapter 2 ATCH-A Workpapers
2030	448,027,518	PG&E Revised Chapter 2 ATCH-A Workpapers

TOTAL \$6,053,089,006

$\$9,769,262,441 - \$6,053,089,006 = \$3,716,173,435$

5. page 23, lines 5 – 6: “Focused only on those 2024 – 2030 extended operations costs which would be absorbed by ratepayers, DCNPP output would cost \$96.53/MWh.”

$\$9,769,262,441 - \$1,535,000,000 = \$8,234,262,441$
 $\$8,234,262,441 \div 85,301.99 \text{ GWh} = \$96.53/\text{MWh}$

6. page 25, line 5: “... or \$4.9 billion for the same benefit?”

$\$58/\text{MWh} \times 85,301.99 \text{ GWh} = \$4,947,515,420$

7. page 25, lines 6 – 7: “... would the reasonable manager purchase 34.44 million metric tons of reductions – or 57.32 million?”

$96.53 \div 58 = 1.6643$

$1.6643 \times 34.44 \text{ million} = 57.32 \text{ million}$