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DATE:
WITNESS: John Geesman

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

PUBLIC VERSION

PREPARED TESTIMONY OF JOHN GEESMAN
ON BEHALF OF THE ALLIANCE FOR NUCLEAR RESPONSIBILITY
("A4NR")

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I. Introduction

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

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

Q02: Are your professional qualifications included in your testimony?

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

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

A03: Yes, it was.

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

A04: Yes, I do.

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

A05: Yes, it does.

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

A06: Yes, it does.

Q07: What is the purpose of your testimony?

A07: The purpose of my testimony is to address issues 1.a, 2, 4, and 5 identified in the Assigned Commissioner's Scoping Memo and provide evidence of why PG&E's Application requires significant modification before it can be approved by the Commission.

PG&E's testimony pridefully notes that it has lowered the projection of Diablo Canyon's gross cost per megawatt-hour for 2027 to $73,[1] down from the $80 per MWh the company forecasted in October 2024. PG&E neglects to point out that it only expects to receive market revenues of $41 per MWh for the plant's output in 2027. Its October 2024 estimate anticipated 2027 market revenues of $59.86 per MWh.[2] The economic drag embedded in the plant's 2027 generation has grown from a projected $20.14 per MWh to $32 per MWh in the 18 months between forecasts! PG&E's attempt to whistle past the stranded asset graveyard should not divert attention from a stark economic scorecard midway through SB 846's six annual cost forecasts:

- Diablo Canyon continues to fail, by a very large margin, to recover its operating costs from the CAISO market revenues it receives for its electrical output. PG&E forecasts a $595 million deficit for 2027, bringing the cumulative shortfall since November 2024 to $1.7 billion. Ongoing operating deficits are a common hallmark of a financially stranded asset.
- The large chasm between operating costs and market revenues has been a longstanding problem for Diablo Canyon, and PG&E management determined in 2016 that the plant should close for economic reasons when NRC licenses expired in 2024 and 2025. PG&E's 2022 grant application to the U.S. Department of Energy tallied nearly $2.2 billion in above-market costs incurred during the five years from 2017 thru 2021.
- After D.25-06-049 corrected the Market Price Benchmark methodology for valuing system reliability capacity, PG&E's forecast for Diablo Canyon's cumulative capacity value during extended operations declined by more than 72%, from $5.9 billion[3] to $1.6 billion.[4] Even assuming this notional, non-cash benchmark could be monetized, these reduced capacity benefits are insufficient to offset the operating revenue shortfalls. In October 2024, PG&E projected a cumulative ***net financial benefit*** from Diablo Canyon's extended operation thru

[1] A.26-03-031, $750.559 million (PG&E Testimony, Table 1-1, line 14, Year 2027)/ 18.288 gigawatt hours (PG&E Testimony, p. 3-2, line 4).
[2] A.24-03-018, $1,093.6 million (PG&E October Update, Table 2-3, line 14)/ 18.268 gigawatt hours (A.26-03-031, PG&E Testimony, p. 1-1, footnote 2).
[3] A.24-03-018, PG&E October Update, Table 2-3, line 16.
[4] A.26-03-031, PG&E Testimony, Table 1-1, line 16, as corrected by PG&E April 24, 2026.

2030 of nearly $4.1 billion.[5] Now it calculates a cumulative ***net financial cost*** thru 2030 of $825.8 million.[6] And, based on historical performance since SB 846's enactment, only the gullible trust PG&E's numbers on Diablo Canyon.

- PG&E's $825.8 million estimated cumulative net cost does not include the subsidies received from state and federal taxpayers for the plant's extended operation thru 2030. Including the $1.4 billion forgivable loan authorized by SB 846, the $150 million in interest rate subsidies accrued to date,[7] and the $75 million in PG&E expense reimbursement authorized by AB 180 (2022), the cumulative net cost of Diablo Canyon extended operations would grow (using PG&E's assumptions) to ***$2.451 billion*** plus whatever interest rate subsidies accrue after March 2026.
- Although SB 846 was premised on the expectation that the $1.4 billion forgivable loan from the State General Fund would be fully reimbursed by a federal grant,[8] it now appears that the maximum amount of grant proceeds potentially available is limited to $741 million.[9] Under the terms of the PG&E loan, the anticipated ***$659 million shortfall*** is likely to be absorbed by General Fund.
- Despite repeated boasts that it has selflessly "answered the call" when California needed Diablo Canyon to continue operating, PG&E has been a less than trustworthy business partner for state government. Notwithstanding the Matosantos/Laird assurances about matching state and federal amounts, on the same day SB 846 was signed into law PG&E submitted a federal grant application for some ***$300 million less*** than the $1.4 billion state loan. Researchers at UC Santa Barbara have accused PG&E of inflating its grant application

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[5] A.24-03-018, PG&E October Update, Table 2-3, line 19.
[6] A.26-03-031, PG&E Testimony, Table 1-1, line 21, as corrected by PG&E April 24, 2026.
[7] This subsidy level was calculated by comparing the SB 846 loan's zero interest rate to the debt rate used to determine PG&E's Commission-authorized cost of capital for the October 2022 thru March 2026 period.
[8] At an August 26, 2022 Assembly hearing, the Governor's Cabinet Secretary, Ana Matosantos, spoke of "these federal funds that we believe will offset the entirety of the loan that we are proposing," https://www.assembly.ca.gov/media/assembly-utilities-energy-committee-20220826/video at 1:02:20. According to the written statement of Senator John Laird, publicly distributed as SB 846 was taken up on the floor of the State Senate on August 31, 2022, "The $1.4 billion loan expenditure will be matched with $1.4 billion in Federal revenue, which limits the requirement of any ratepayer or taxpayer money for that purpose." Unnumbered pdf p. 4, included in this testimony as Attachment A.
[9] Department of Water Resources SB 156 Report, February 1, 2026, p. 3.

by ***$359 million***,[10] while PG&E shrugs off the federal disallowance as merely "(d)ifferences" in statutory interpretation.[11]

- The sustained success of the Commission's multiple procurement orders has upended the 2022 reliability doom loop that precipitated SB 846. The most recent Joint Agency Reliability Planning Assessment 10-year projection states that 14,675 MW of new Net Qualifying Capacity will have come on line between 2023 and 2028,[12] notes an additional 6,000 MW recently ordered by D.26-02-057 for the 2029 – 2032 period,[13] and uses a probabilistic assessment of 2031 – 2036 conditions to conclude, "Planned retirement of the [Diablo Canyon] nuclear plant confirms the conclusion from previous reliability reports that California will continue to meet 0.1 LOLE reliability criteria through 2036 under the 2023 [Preferred System Plan]."[14]
- PG&E's A.26-03-031 filing estimates that SB 846's extended operations of Diablo Canyon through 2030 "are expected to reduce GHG emissions from natural gas generation and imported energy by 34.5 million metric tons."[15] Accepting this projection at face value, despite opaque assumptions about what generation is actually offset by Diablo Canyon's operation, the $2.625+ billion cost[16] of achieving it will exceed $76 per metric ton, some two-and-half times recent prices in the CARB Cap-and-Invest market.[17]

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[10] "The Economics of Diablo Canyon: Maximizing Pollution Reduction While Protecting California Ratepayers and Taxpayers," Leah C. Stokes, Arjun Krishnaswami and Madeline Ranalli, April 2026,

[11] PG&E PowerPoint presentation to Department of Water Resources, April 12, 2024, unnumbered pdf p. 9.

[12] 2026 First Quarterly Joint Reliability Planning Assessment, February 20, 2026, p. 23.

[13] *Id.,* p. 26.

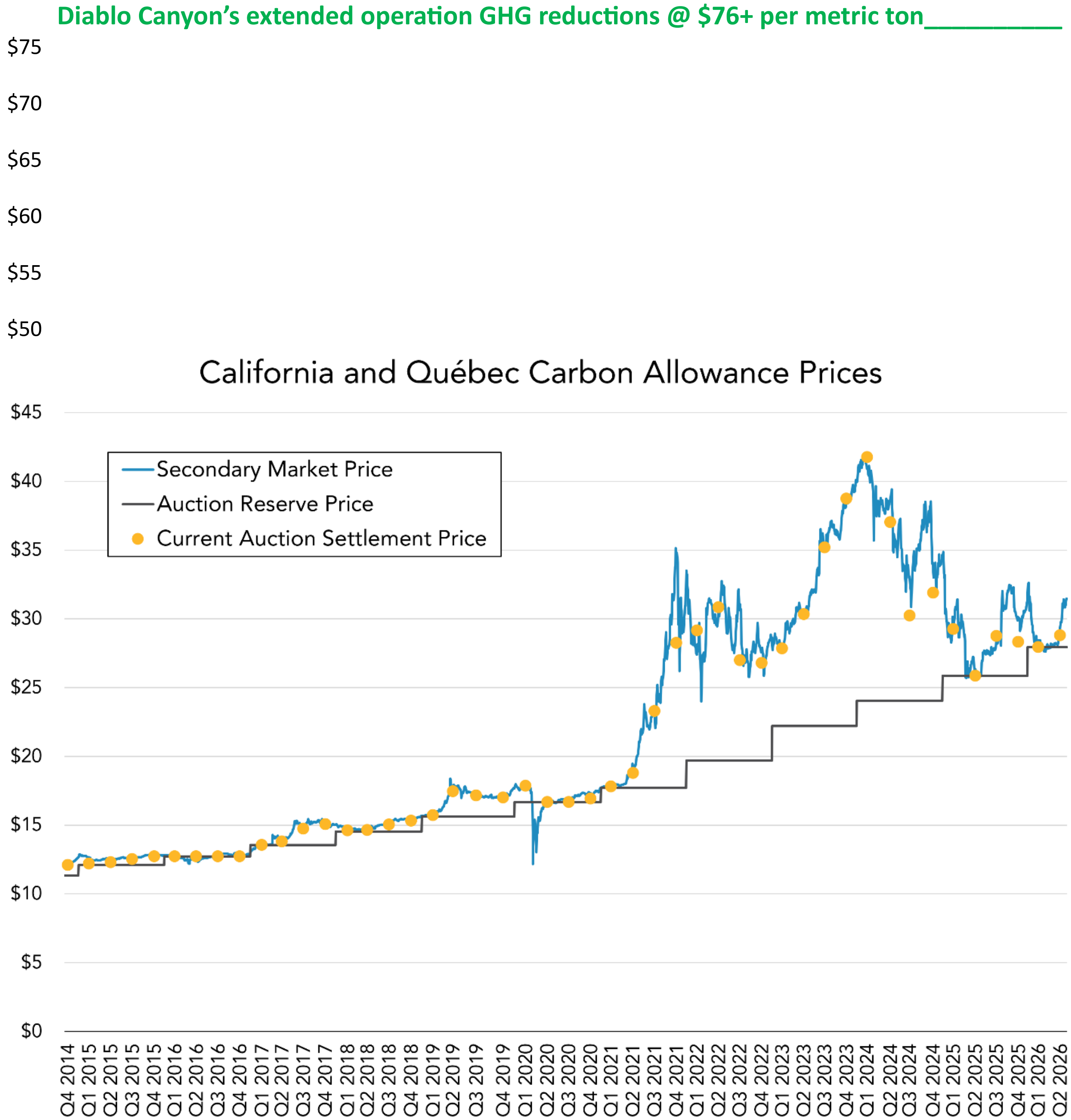
[14] *Id.,* pp. 47 – 48.

[15] A.26-03-031, PG&E Testimony, p. 1-2, lines 23 – 24.

[16] PG&E's projected $1.0 billion cumulative net cost thru 2030 + the $1.4 billion forgivable loan authorized by SB 846 + the $150 million in interest rate subsidies accrued to date + the $75 million in PG&E expense reimbursement authorized by AB 180 = $2.625 billion plus whatever interest rate subsidies accrue after March 2026.

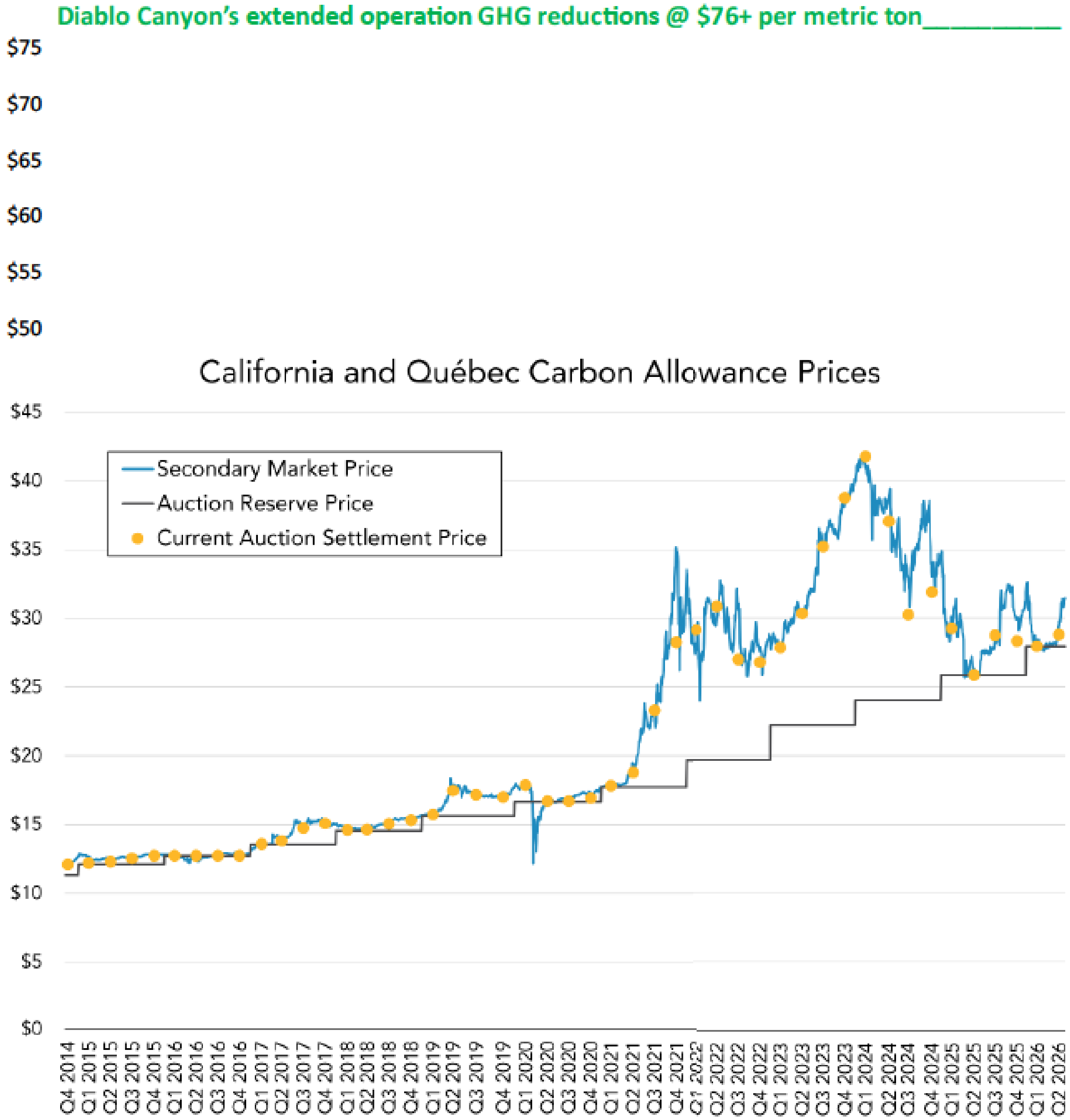
[17] CARB graph of historical carbon allowance prices accessed June 30, 2026 from https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/program-data/cap-and-trade-program-data-dashboard#Figure2.

Expensive Electricity = Very Expensive Offsets



Those whom PG&E has persuaded to believe that Diablo Canyon's above-market price of electricity can be justified as part of a coherent climate strategy should ponder why this $2.625+ billion surcharge doesn't buy considerably more than 34.5 million metric tons of reduced emissions.

Expensive Electricity = Very Expensive Offsets



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II. Scoping Issue 1.a: Reasonableness of O&M Costs

A4NR challenges the inclusion in the 2027 revenue requirement of four of the projects described in Chapter 2 of PG&E's Testimony. These include the three identified in Table 2-3 of the Testimony (feedwater heaters, $14.1 million in 2027; control room ventilation system condenser replacement, $11.5 million in 2027; and intake bar rack replacement, $0.4 million in 2027) as having been reclassified from DCTRMA to DCEOBA funding, as well as the vertical cask transporter warehouse, $63,000 in 2027. The three reclassified projects from Table 2-3 are discussed under Scoping Issue 3 at page 8 below.

Construction of the new 5,400 sq. ft. warehouse to house the Vertical Cask Transporter ("VCT") does not qualify for ratepayer funding because it is a required feature of the Aging Management Program for PG&E's renewed license of the Diablo Canyon Independent Spent Fuel Storage Installation ("ISFSI"). Pub. Util. Code section 712.8(c)(1)(C) specifies: "The commission shall not allow the recovery from ratepayers of costs incurred by the operator to prepare for, seek, or receive any extended license to operate by the United States Nuclear Regulatory Commission." As acknowledged by PG&E in its workpapers, "In the ISFSI License Renewal Application, PG&E ***committed*** to house the VCT in a sheltered environment to protect it from the elements."[18] (emphasis added) PG&E's April 30, 2024 Letter DIL-24-004 responding to a Nuclear Regulatory Commission request for additional information explained, "Element 2 of LRA Table A-6 and Section D.3 for the Cask Transportation System AMP are revised in Enclosure 2 to include sheltered long-term storage of the SSCs as a preventive action."[19]

In addition to the $63,000 forecast for 2027, PG&E's 2024 regulatory commitment to the Nuclear Regulatory Commission should have governed accounting treatment of the $25,000 recorded in 2025 and the $212,000 recorded in 2026 for the Vertical Cask Transporter warehouse.

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[18] PG&E WP 2-37.
[19] PG&E Letter DIL-24-004, Enclosure 1, pp. 2 of 17 and 3 of 17, included in this testimony as Attachment B.

III. Scoping Issue 2: Non-Bypassable Charge and Rate Proposals

Prior to Commission adoption, the Non-Bypassable Charge should be recalculated to reflect the $26.063 million in disallowances recommended by this testimony. The Commission should also clarify that a principal ramification of D.23-12-036's inclusion of the Non-Bypassable Charge in public purpose program rates will be that most residential customers will pay their assigned Diablo Canyon costs through the new fixed charge on their bills. The electric generation portion of rates has traditionally been treated as a variable cost allocated among customers based on their metered consumption. Characterizing Diablo Canyon costs for the majority of residential customers as fixed, irrespective of electricity usage, financially favors larger users over smaller ones. This preference may be consistent with a promotion of greater electrification, but its regressive nature should be acknowledged and, if possible, justified.

IV. Scoping Issue 4: Reclassifications from DCTRMA to DCEOBA

D.25-12-007 indicated that multiple intervenors, including A4NR, "raise legitimate concerns that PG&E may be recovering, in this application, overspending on DCPP transition and renewal costs in excess of the $1.4 billion DWR loan."[20] As the Commission noted, "the parties appropriately raise questions as to whether PG&E's reprioritization of transition and renewal funds might be improperly shifting those costs to the current application as funding for DCPP extended operations."[21] D.25-12-007 found it reasonable, in future Diablo Canyon cost recovery applications,

> to require PG&E to disclose whenever any transition and license renewal costs that were part of the amounts included in the TLRES are proposed for recovery in any future DCPP forecast proceedings for DCPP extended operations, along with explanations for why those costs were originally proposed as transition and license renewal costs and why those costs are now eligible for recovery for extended operations.[22]

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[20] D.25-12-007, p. 25.

[21] *Ibid.*

[22] *Id.* pp. 25 – 26. TLRES is an acronym for Transition and License Renewal Expenditure Summary, the title of the PG&E spreadsheet cited in D.25-12-007's Finding of Fact 20 and Conclusion of Law 5, and included in this testimony as Attachment C.

PG&E tracks loan-eligible costs in the Diablo Canyon Transition and Relicensing Memorandum Account ("DCTRMA") and records ratepayer-funded costs of extended operations in the Diablo Canyon Extended Operations Balancing Account ("DCEOBA"). Because the amount of the SB 846 loan is fixed at $1.4 billion, any increase above the costs forecast at the time SB 846 was enacted will create pressure to shift costs out of DCTRMA and into DCEOBA. The only permissible funding source under Pub. Util. Code section 712.8(c)(1)(C) for such overruns is "other nonratepayer funds available to the operator." But, under the calendar-driven allocation system approved in D.24-12-033, PG&E can easily avoid this remedy (and instead shift costs to ratepayers) by delaying the commencement or completion of a project.

As noted by Finding of Fact 20 in D.25-12-007, which dealt with the forecast of 2026 costs, at the beginning of January 2025 PG&E had projected DCTRMA costs by year-end 2026 that would exceed the available SB 846 loan proceeds by $157 million. PG&E's financial witness, Brian Ketelsen, testified that PG&E had erased the projected DCTRMA overspend with "a reprioritization to ensure we got back down to the 1.4 billion."[23] When asked by the Administrative Law Judge who would pay if PG&E's transition costs exceed the SB 846 $1.4-billion loan amount, shareholders or someone else, Mr. Ketelsen explained:

> I do believe that those costs would be eligible for a future rate case. They are, you know, associated with -- potentially with project costs, reliability upgrade projects, that could be recovered in either case. We do expect that number to be very small if -- if at all.[24]

PG&E's Testimony in support of its forecast of 2027 costs proposes to convert the $26 million in project costs identified in Table 2-3 from their original characterization as transition costs, to be funded by the SB 846 loan, into extended operations costs, to be funded by ratepayers. Examination of the factual circumstances surrounding each of the three projects indicates that none of these cost reclassifications is reasonable.

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[23] A.25-03-015 Transcript (PG&E: Ketelsen), p. 21, lines 12 – 14.
[24] *Id.,* p. 41, lines 2 – 7.

A. Feedwater Heaters

Management of aging Diablo Canyon feedwater heaters has challenged PG&E since before the enactment of SB 846. Despite extensive tube-plugging in 2013, severe tube failure in Unit 2 Feedwater Heater 2-5B forced a shutdown of Unit 2 from October 15, 2021 to November 3, 2021 to mitigate potential turbine damage. PG&E calculated in A.22-02-015 that the forced outage cost ratepayers $28,070,513 for replacement power. Ultimately some 19% of the Feedwater Heater 2-5B tubes were plugged. PG&E told the February 21, 2022 meeting of the Diablo Canyon Independent Safety Committee ("DCISC") this still left considerable margin against an engineering limit of "less than 40% without impacting function or reliability."[25] PG&E also indicated that "replacement of the heat exchangers would be a very significant project and represents a project that if DCPP were seeking a license extension would have definitely been undertaken."[26] The DCISC found PG&E's Root Cause Evaluation of the Unit 2 outage, and the associated corrective actions, satisfactory.[27]

The DCISC's August 16, 2022 fact-finding visit to the plant learned that the corrective action testing of Unit 1 Feedwater heaters 1-3A, 1-4A. 1-4B, 1-4C, and 1-5C had found no adverse indications and that they had been determined to be in good condition.[28] Reporting on this fact-finding visit at the September 28, 2022 DCISC meeting, DCISC consultant Ferman Wardell confirmed that when PG&E had prepared its 2009 license extension application (withdrawn in 2018), "all the feedwater heaters were planned for replacement for twenty years of [additional] operation."[29]

At the DCISC's February 16, 2023 meeting, DCISC consultant Richard McWhorter reported that a fact-finding visit two weeks earlier had identified "a time element involved" with "major improvements to the plant or major purchases of spare equipment that may need to be made over the next few years." Citing feedwater heaters as an example, Mr McWhorter

[25] DCISC 32nd Annual Report, unnumbered pdf pp. 288 – 292, included in this testimony as Attachment D.
[26] *Id.,* unnumbered pdf pp. 291 – 292.
[27] DCISC 32nd Annual Report, unnumbered pdf pp. 451 – 453, included in this testimony as Attachment E.
[28] DCISC 33rd Annual Report, unnumbered pdf p. 467, included in this testimony as Attachment F.
[29] *Id.,* unnumbered pdf pp. 205 – 206, included in this testimony as Attachment G.

noted that time is required to complete an installation and that "the last opportunity to make major changes to the station, based on the five-year commitment from the state for extended operation, is during 2026-2027 which is the first refueling outage [for each Unit] following extended operation."[30] The DCISC's 33rd Annual Report provided greater detail of what the DCISC fact-finding team ("FFT") had been told in early 2023 by Allen Wilson, PG&E's Director of Projects at Diablo Canyon:

> Mr. Wilson provided the FFT with an update on plans for reviewing capital projects … Following the decision to extend operations under SB846, DCPP was now beginning a review of former and possibly new capital projects that would need to be implemented. He noted that there was currently no traditional authorization per se for additional capital expenditures as DCPP did not have any authority for capital projects to support operations beyond 2025 under its current general rate case authorized by the California Public Utilities Commission. Instead, DCPP was focused on applying for and receiving funds allocated by SB846 to the Department of Water Resources which could be used for plant improvements needed to maintain high plant reliability and nuclear safety through 2030.
>
> As DCPP neared the conclusion of its PMO++ initiative in a few months, Mr. Wilson stated that DCPP would begin a review of the PMO++ results along with lists of previously cancelled capital projects and supply chain issues for repair parts. The focus of those reviews would be to identify improvements that would result in immediate or short-term improvements in reliability. Historically most major capital projects took 18-24 months to design and one or two refueling cycles (18-36 months) to implement. Most such large projects would not be feasible or sufficiently beneficial for completion during the timeframe of a five-year extension of operations. Therefore, it was expected that DCPP would be generating a list of projects that would address spare parts availability or would improve reliability with a short implementation schedule. Examples included possible plans to purchase spare or refurbished large motors and/or improvements that could be implemented no later than refueling outages in the 2026-2027 timeframe. Lastly, he noted that any possible extension of operations beyond five years would appreciably change the number of capital projects that would be worthy of consideration.
>
> The FFT inquired about what would happen to the previously proposed and cancelled project to replace all of the plant's Feedwater Heaters. Mr. Wilson reported that although replacement of all Feedwater Heaters was not feasible

[30] *Id.,* unnumbered pdf pp. 303 – 304, included in this testimony as Attachment H.

> within the timeframes discussed above, he believed that some of the feedwater heaters could and would be replaced within those timeframes. Specifically, he believed that two to possibly four trains of the Feedwater Heaters which were the biggest threat to reliability could be replaced within the targeted 2026-2027 timeframe. This would be possible because of the extensive and recent industry experience with manufacturing and replacing similar equipment at other nuclear power plants.[31]

The DCISC's 34th Annual Report addressed PG&E's responses to Diablo Canyon's Equipment Reliability metrics having slipped to the second quartile of the industry's Equipment Performance Indicator:

> DCPP completed its responses to an initiative in ER [i.e., Equipment Reliability] from the Institute of Nuclear Power Operations (INPO) which was focused on improving the quality and reliability of parts procurement as well as incorporating cross-functional approaches to maintaining reliable equipment and in managing risk at the station.
>
> DCPP believed that its transition to extended operations required it to be more forward-looking in its future ER program. The change in direction from the planned cessation of power operations to an extension of operations left the station in a position of needing to perform many maintenance activities and initiate numerous upgrade projects to address obsolescence and/or implement new technologies at the station. The recently completed series of Refueling Outages, 1R24 [October 2023] and 2R24 [April 2024], allowed the station to catch up on maintenance activities and address needed inspections and minor improvements, and such would also be the case for the next series of Refueling Outages, 1R25 [April 2025] and 2R25 [October 2025] …
>
> Planning and implementing effective plant upgrades in the future 1R26 [October 2026] and 2R26 [April 2027] Refueling Outages would be critical to maintaining a high level of ER going forward into an extended operating period. Examples of projects to be completed in that timeframe that could have a positive impact on ER included replacements of the Main Feedwater Heaters …[32]

At the DCISC February 19, 2025 DCISC meeting, consultant Richard McWhorter summarized the discussion with PG&E that had taken place about feedwater heater replacements in the fact-finding visit to the plant the previous month:

[31] *Id.*, unnumbered pdf pp. 768 – 769, included in this testimony as Attachment I.
[32] DCISC 34th Annual Report, unnumbered pdf pp. 312 – 313, included in this testimony as Attachment J.

Mr. McWhorter reported replacement of the fourth and fifth point feedwater heaters is planned, representing three feedwater heaters for the fourth point and three feedwater heaters for the fifth point from each unit for a total of 12 feedwater heaters. He reported the replacements will be staged during outages 1R26 [October 2026] to 2R27 [October 2028] and the order will be determined primarily on the difficulties in getting the large and heavy feedwater heaters in and out of the Turbine Building which may require other feedwater heaters to be removed and then replaced.[33]

This was the first public mention by the DCISC of a possible modification to PG&E's early 2023 indication that two to possibly four trains of the Feedwater Heaters which were the biggest threat to reliability could be replaced within the targeted 2026-2027 timeframe**.** Later in the same DCISC meeting, Allen Wilson, identified as PG&E's Vice President of Engineering at Diablo Canyon, reported that the plant was in various phases (design, procurement, material fabrication) for safety and reliability focused on major projects, which for the PG&E designation of major projects included the replacements of the Unit 1 and Unit 2 high pressure turbines in 2025 "and feedwater heater contingency replacements in future outages."[34] As recounted in the DCISC's 35th Annual Report, Mr. Wilson elaborated:

In response to Consultant McWhorter's inquiry Mr. Wilson stated with reference to the feedwater heater replacement project that the feedwater heaters life-cycle windows are being reviewed to determine the need for their replacement and that replacing the individual feedwater heaters is contingent on that review and he commented there is a long lead time as fabrication of a feedwater heater can take up to three years to complete and all the feedwater heaters required will not be completed before the end of 2026 or the beginning of 2027. He observed there are issues involved with interference caused by removal of the feedwater heaters, of which there are 12 per unit, 24 in total, and the health of the feedwater heaters will be assessed and a decision made from the perspective of their replacement in view of the 2030 operational timeline.[35]

In December 2025, a tube leak in the Unit 1 feedwater heater 5-C forced Unit 1 offline for 44 hours while repairs to 27 tubes were conducted. The report of the January 2026 DCISC

[33] DCISC 35th Annual Report, unnumbered pdf p. 469, included in this testimony as Attachment K.
[34] *Id.,* unnumbered pdf p. 502, included in this testimony as Attachment L.
[35] *Id.,* unnumbered pdf p. 530, included in this testimony as Attachment M.

fact-finding visit evaluated the incident and its implications regarding feedwater heater replacement in considerable detail:

> On December 15, 2025, a high level alarm was received in the Control Room for Unit 1 Feedwater Heater 6C and upon inspection a large amount of drain water from Heater 5C was found to be draining to Heater 6C due to a tube leak in Heater 5C. Unit 1 power was reduced to 91 % and Heaters 5C and 6C were isolated. Mr. McWhorter reported plant operation could have continued in that configuration indefinitely, albeit at lower power production levels. However, to perform repair of a feedwater heaters the plant needs to be fully shut down to isolate the steam on the secondary side [footnote omitted] as extraction steam is coming from the turbine and the boundaries for safety purposes from that extraction steam are inadequate. DCPP management made the decision on December 16, 2025, to shut down Unit 1 and make repair immediately. Upon opening Heater 5C a number of tubes were found ruptured and several had indications and 27 tubes were repaired and the feedwater heaters returned to service in 44 hours with full power restored at 0900 on December 19, 2025.
>
> Mr. McWhorter reported the December 15, 2025, event was similar to a tube leak on Heater 5B in 2021 and the DCISC reviewed the Root Cause Evaluation (RCE) on that event at the February 2022 public meeting and reviewed in depth during the February 2022 fact finding. The RCE found the tubes failed due to stresses in areas around the drain cooler shroud, where the coldest water enters the lower section of the heaters and the water draining from the condensed steam accumulates together in that section creating a mixed steam-water flow which is very hard on the tubes and shrouds causing them to erode away and allowing some of the mixture to damage the tubes. Mr. McWhorter reported at the time of the 2022 event the plant was planning to close by 2025 and feedwater heater replacement was not considered as a corrective action. Eddy current testing [footnote omitted] was done for Heater SC during the spring 2025 refueling outage. There were also actions taken in 2022 to improve the operator's ability to diagnose and respond to these events and Mr. McWhorter reported those corrective actions were appropriate.
>
> A Cause Evaluation (CE) will be performed for the 2025 event which will focus on whether there is anything else necessary for the bridging strategy but Mr. McWhorter observed the long term solution is to replace the feedwater heaters as they are at the end of their service lives and little can be done with the issues affecting the shrouds and supports inside the tube bundles which are inaccessible for repair or individual replacement. DCPP has procured 12 new feedwater heaters for each unit which is sufficient to replace all the heaters in Stages 3 through 6. Mr. McWhorter reported the Stage 1 and 2 heaters are in

> better condition and are easy to access without the need to move equipment. For the procurement, 18 of the 24 are expected to be delivered in late 2026 and the remaining 6 in 2027. Mr. McWhorter reported plans for installing the new heaters are not clear at this time and depend upon plans for future operation and the potential for another failure of a heater. He displayed photos of the FFT touring the area and inspecting the feedwater heaters. In response to Dr. Peterson's observation Mr. McWhorter reported replacement of feedwater heaters is a complex evolution that requires preplanning, staffing, and equipment and likely cannot be done in one month's time and would require more than a 30-day planned outage with the feedwater heater replacement being on the critical path. He described some of the complications with the load path required for replacement of the heaters which are very long and quite heavy. In response to Dr. Peterson's query Mr. McWhorter confirmed the complications of the physical layout affects the removal and replacement of the feedwater heaters and it also depends upon which feedwater heater is to be replaced and as the bulk of some of the feedwater heaters is within the neck of the condenser this further complicates their removal and replacement.
>
> The FFT concluded the subsequent actions and shutdown after the December 15 feedwater heater failure were well managed by DCPP and the actions taken in 2021 in response to a similar event appear to have been effective. A cause evaluation for the 2025 event will be performed and DCPP is proceeding with acquiring 12 replacement heaters for each unit to be on site in late 2026 and early 2027, however no plan has yet been approved for installation of the replacement heaters.[36]

The draft minutes of the February 18, 2026 DCISC meeting report the following dialogue between DCISC members Peterson, Scarlat, and Meshkati and PG&E's Director of Strategic Projects, Al Bates:

> Mr. Bates reported 12 feedwater heaters per unit are reaching the end of their service lives and there is a contingency implementation project under another project director, Mr. Mark Sciacca, to replace the feed water heaters should a feedwater heater fall beyond normal repair. Low pressure feedwater heaters, 12 per unit, have been purchased and will arrive in mid-2027 and they will be installed if required on a contingent basis. Mr. Bates confirmed Dr. Peterson's observation that there are complicated issues of access due in part to the seismic bracing installed after the feedwater heaters were installed and

[36] Draft minutes of the February 18, 2026 DCISC Public Meeting, included in Agenda Packet for June 16 – 17, 2026 DCISC Public Meeting, unnumbered pdf pp. 84 – 85, included in this testimony as Attachment N. The minutes were formally accepted by the DCISC on June 17, 2026.

shoring will be needed on the decks to allow the feedwater heaters to roll across the deck and he described these as N-1 activities.

In response to Dr. Scarlat Mr. Bates stated the heaters are the size of two or three Volkswagen buses parked back-to-back and they will need to be rolled through narrow passages within the plant and various impediments to their passage will need to be temporarily removed. He stated the feedwater heaters generally have a 30-40 year lifespan and are not designed to be replaced. He stated the N-1 designation means the outage for their replacement is unknown. Mr. Bates stated the heater(s) being replaced would be removed prior to the outage. Mr. Bates observed use of the feedwater heaters provides higher efficiency and they are fairly complicated pieces of equipment. He remarked new computer codes will allow PG&E to design the feedwater heaters and they will be fabricated of new materials, more efficiently. Dr. Peterson observed by the increase in efficiency through new feedwater heaters this means getting more electricity on the grid and less waste heat into the ocean. Mr. Bates, responding to Dr. Scarlat, stated replacing the feedwater heaters is very costly and also disruptive and it takes a fairly long outage to do this work and the health of the operating heaters is being monitored closely including by eddy current testing on the tubes and by inspections conducted from the shell side.

Mr. Bates stated that if a tube breaks in a feedwater heater this caused the water level to go uncontrollably high which requires valving that heater out of service which in turn reduces thermal efficiency of the steam plant in a cascading fashion and one feed water heater affects the others as they are interdependent and loss of a feedwater heater means a loss in megawatts. He stated DCPP is managing the health of the feedwater heaters. In response to Dr. Scarlat, he stated the economics presently dictate that maintenance be performed rather than proactive replacement. He stated feedwater heater replacement planning is approximately an 18-month effort. In response to Dr. Scarlat, Mr. Bates stated that if the plant were to run for a full 20-year extension this plan would likely be different and it would be likely that all 12 replacement heaters would be needed and replacement would not be easy in any scenario as they cannot be simply cut out and replaced.

Dr. Peterson reported a DCISC FFT was on the site when the feedwater heater failed and precipitated shutdown and he remarked the heaters are very close to the end of life and since a propagating failure could cause catastrophic damage and this risk is mitigated if the feedwater heaters are replaced and he stated PG&E's strategy as described by Mr. Bates appears to be logical. Mr. Bates stated in order to install the feedwater heaters a longer than normal outage is required and this will increase the cost of the outage. Dr. Scarlat stated the use of the term "catastrophic" does not mean catastrophic for the public, but rather from an engineering perspective.

> Mr. Bates stated the scenario he fears is where a tube breaks inside a feedwater heater and the tube then thrashes around and damages other tubes and this happening cannot be determined from external observation. He concurred with Dr. Meshkati's comment that a feedwater heater failure does not necessarily have plant safety impacts, but rather on plant performance. Mr. Bates confirmed in response to Dr. Meshkati's observation that funding and approval for ordering and receiving replacement feedwater heaters has been received, but Mr. Bates said he did not know when a second phase concerning their installation was planned but he stated it is not scheduled before 2030.[37]

The DCISC minutes report the response of Tom Jones, PG&E's Senior Director at Diablo Canyon, to a public comment: "He stated that with a twenty year license and state-approved operating period DCPP would likely look uniformly at replacing all the feedwater heaters in one refueling outage and the way PG&E is approaching that project now is indicative of a short-term extended operational period."[38]

After further discussion, the DCISC adopted its Resolution 26-03 augmenting the recommendation from its 34th Annual Report to the Public Utilities Commission (i.e., "that the California Public Utilities Commission and all other necessary California state authorities support the funding of the plant upgrade projects recommended by DCPP"[39]) to specifically

> recommend to the CPUC that it and all other cognizant California state authorities support implementation of the Feedwater Heater replacement project at DCPP as soon as practically feasible. The DCISC believes that these replacements are important for the plant's operational performance by avoiding unnecessary plant shutdowns, forced outages, and startups in the future.[40]

The DCISC minutes record several comments from DCISC counsel Robert Rathie, stating that he would "work with Mr. Zizmor of the CPUC Energy Division on transmitting the Recommendation"[41] and indicating that the envisioned funding for the project would be from an allocation of volumetric performance fees:

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[37] *Id.,* unnumbered pdf pp. 75 – 76, included in this testimony as Attachment O.
[38] *Id.,* unnumbered pdf p. 78, included in this testimony as Attachment P.
[39] DCISC 34th Annual Report, unnumbered pdf p. 17.
[40] DCISC Resolution 26-03, transmitted by email February 26, 2026 to the Commission Energy Division.
[41] Draft minutes of the February 18, 2026 DCISC Public Meeting, included in Agenda Packet for June 16 – 17, 2026 DCISC Public Meeting, unnumbered pdf p. 90, included in this testimony as Attachment Q. The minutes were formally accepted by the DCISC on June 17, 2026.

Mr. Rathie stated that during the discussion on the January 2026 Fact Finding Report there were amendments made to the report and the report contained a recommendation to the CPUC expressing Committee support for the funding of the Feedwater Heater Replacement Project. He reported it was his understanding the funding for that project would be addressed in a CPUC proceeding concerning allocation of the volumetric performance fees which may have a component regarding funding for replacing the feedwater heaters and the matter would be open for comments through March 31, 2026. Mr. Rathie expressed his view that the Committee's Recommendation concerning the Feedwater Heater Replacement Project should be expeditiously transmitted to the CPUC Energy Division and not wait for the completion of the 36th Annual Report which, per past practice, incorporates and transmits the Committee's Recommendations to the CPUC and others. He stated that Resolution 2026-03 provides for approval of the Fact Finding Reports presented at this meeting and for the transmittal of the Committee's Recommendation on the Feedwater Heater Replacement Project to the CPUC Energy Division following this public meeting.

Dr. Gene Nelson of California for Nuclear Power was recognized and stated Californians for Green Nuclear Power approves and endorses the course of action described by Mr. Rathie.

Ms. Linda Seeley of Mothers for Peace was recognized. In response to Ms. Seeley's question Mr. Rathie replied it was his understanding that the CPUC proceeding, if it takes up the issue of the Feedwater Heater Replacement Project, would be in the nature of an allocation of volumetric performance fees not an increase in those fees.[42]

A4NR recommends disallowance of the request in PG&E's Testimony to include $14.1 million in the 2027 forecast of DCEOBA costs for six spare feedwater heaters[43] (in addition to the 18 spares expected for delivery by year-end 2026). As the PG&E Testimony makes clear, installation "will only occur in the event of feedwater heater failure that cannot be repaired using normal feedwater heater repair methods."[44] Being prepared for an emergent feedwater heater replacement might – as PG&E claims – "allow for reduced unplanned outage time and return to reliable operation,"[45] but PG&E will have 18 spares available for such contingencies

[42] *Id.*, unnumbered pdf p. 123, included in this testimony as Attachment R.
[43] PG&E Testimony, p. 2-15, lines 20 – 22.
[44] *Ibid.,* lines 13 – 14.
[45] *Ibid.,* lines 15 – 16.

and has acknowledged limitations on the number of replacements that can be performed in any refueling outage. PG&E's Testimony in no way alters the statements its representatives made to the February 18, 2026 DCISC meeting: they do not know when installation will be planned but it is not before 2030; and "with a twenty year license and state-approved operating period" PG&E would likely replace all of the feedwater heaters in a single refueling outage.[46] Under such circumstances, stockpiling an additional six feedwater heaters to address the contingency that more than 18 feedwater heaters will require replacement before 2030, and that more than 18 emergent replacements would be feasible under such conditions, is not a reasonable use of the DCEOBA Non-Bypassable Charge. If PG&E believes the "needed for Diablo Canyon" language or any other provision of Pub. Util. Code section 712.8(t)(1) provides it the authority to allocate $14.1 million of Volumetric Performance Fees to this purpose, it should amend its Testimony to propose doing so.

B. Control Room Ventilation System Condenser Replacement

The January 2021 DCISC fact-finding visit to Diablo Canyon performed a periodic review of the Control Room Ventilation System ("CRVS"), but no specific assessment appeared in the 32nd Annual Report. A similar review was conducted during the DCISC's July 2023 fact-finding, and the 34th Annual Report provided greater detail:

> Although formal system health monitoring was no longer required for the CRVS, the system was generally in good health with minor issues and problems. There were no significant failures of system equipment within the last two years. An issue discussed during the DCISC's last review concerning recurring air conditioning compressor trips had been resolved by changing the startup and shutdown sequences for the compressors. Similarly, actions taken to improve maintenance practices for isolation dampers have proven effective in resolving an issue with frequent damper shaft failures.
>
> Currently, the main issue affecting the CRVS was degradation of outdoor equipment due to corrosion, primarily on the air conditioning condensers. The

[46] *See* p. 17, lines 9 – 10 and 13 – 14 above.

> degradation of outdoor condensers was not planned for corrective action under the previous plan to cease power operations in 2025. However, with the possible extension of power operations, it was now expected that the outdoor condensers would be replaced in the near future. That replacement would probably occur as a part of a larger project for replacement of all HVAC systems at the station that still contained refrigerant R-22 ...
>
> Periodic testing is performed for the integrity of the Control Room ventilation envelope, which is a controlled HVAC atmosphere in the Control Room to protect operators from outside harmful gases or radioactivity. The envelope is periodically demonstrated by performing leakage testing using tracer gases. Such testing was done approximately every six years and was recently successfully completed in early 2023. No major issues were identified during the Control Room leakage testing.[47]

At the DCISC's September 13, 2023 public meeting, DCISC consultant Richard McWhorter's report on the July 2023 fact-finding results characterized the Control Room Ventilation System as being "in good health" despite "some issues with corrosion of outside components, particularly the condensers for the air conditioning system."[48] PG&E indicated in a December 21, 2023 written entry to its internal notification system that "the entire CRVS A/C refrigerant system will be replaced by an approved Project (PHIP 2023-S023-003), listed as a PMO++ Top Tier Priority item." [49] The September 12, 2023 writeup from the Gate 1 presentation identifies the consequences of project deferral as:

> Continued higher than expected maintenance to keep system tuned for reliable service and intermittent losses of individual component MR [i.e. NRC Maintenance Rule] required availability. Continued degradation of condenser units operating in salty humid environment. Increased maintenance frequencies as a result of continued degradation. It is very likely at the current rate of equipment degradation that there could be larger, consequential failure of CRVS A/C equipment if not replaced in the next few years or so (requiring extensive corrective maintenance, impacting Operations, and increasing the possibility of entering shutdown LCO [i.e., Limiting Condition for Operation] 3.0.3 per ECG [i.e., Equipment Control Guideline] 23.5). There will be an increasing cost for

[47] DCISC 34th Annual Report, unnumbered pdf p. 326, included in this testimony as Attachment S.
[48] *Id.*, unnumbered pdf p. 442, included in this testimony as Attachment T.
[49] PG&E data response DR_A4NR_002-Q007Atch01, p. 2 of 2, included in this testimony as Attachment U.

performing more preventative/corrective maintenance over time as the equipment continues to degrade.[50]

According to PG&E data responses, additional funding was sought in March 2024 through a Gate 1 budget trade in order "[redacted]."[51] The September 17, 2024 writeup for Gate 2 funding thru completion in Spring 2026 reiterated the Gate 1 presentation's recitation of the lengthy sequence of events underlying the need for prompt replacement of the CRVS condensers, summarizing:

> [redacted].[52]

Notwithstanding approval in September 2024 of the Gate 2 funding, the May 20, 2025 "reprioritization" of the CRVS condenser replacements approved by the Plant Health Prioritization Committee resulted in [redacted].[53] According to a PG&E data response, "A periodic meeting is held to evaluate any changes to the overall project portfolio and prioritization or adjust the current Long Term Financial Plan to align with station budgetary goals/targets. Reprioritization is evaluated on the

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[50] PG&E data response DR_A4NR_001-Q005Atch01, unnumbered pdf p. 2, included in this testimony as Attachment V. PG&E specified the September 12, 2023 date of this writeup in its data response DR_ A4NR_001-Q005.

[51] PG&E data response **DR_A4NR_001-Q005Atch02CONF**, included in this testimony as **CONFIDENTIAL Attachment W**.

[52] PG&E data response **DR_A4NR_001-Q005Atch03CONF**, unnumbered pdf p. 2, included in this testimony as **CONFIDENTIAL Attachment X**.

[53] PG&E data response **DR_A4NR_001-Q005Atch04CONF**, unnumbered pdf p. 1, lines 13 – 14, 43 – 44, included in this testimony as **CONFIDENTIAL Attachment Y**.

basis of plant risk, classification, resource availability, or current project status."[54] A subsequent PG&E data response added,

> This project was in the early scoping phase when previous forecasts were developed, including in the referenced [May 20, 2025] attachment, PG&E DR_A4NR_001-Q005Atch04CONF, and the forecast presented in the [January 6, 2025] TLRES. Through further planning — identifying design and installation vendors and timelines for procurement and delivery of equipment — it was determined that the completion date for the project would not occur before January 1, 2027.[55]

A4NR recommends disallowance of the request in PG&E's Testimony to reclassify the $11.505 million CRVS condensers replacement project from DCTRMA to DCEOBA, and include the entire amount (including $1.513 million in 2025 recorded costs and $1.887 million in 2026 forecast costs[56]) in the 2027 forecast of DCEOBA costs. A reasonable utility manager would have executed this PMO++ Top Tier Priority project with greater commitment, especially given the September 2023 foreboding that deferral would mean increasing the possibility of entering shutdown Limiting Condition for Operation 3.0.3 per Equipment Control Guideline 23.5. The March 2024 funding augmentation spoke of the need to begin implementation in 2025, and the September 2024 Gate 2 request was frank in admitting past failures to proactively address the degraded CRVS equipment. The January 2025 TLRES projection of a $157 million overspend for SB 846 loan-funded projects did not relieve PG&E of its Pub. Util. Code section 712.8(c)(10(C) obligation to use "other nonratepayer funds" for completion of the CRVS condensers replacement project. The May 2025 "reprioritization" exploited PG&E's completion date criterion for DCTRMA by making an unreasonable schedule adjustment to avoid the statutory requirement. Under such circumstances, shifting the funding obligation to ratepayers is not a reasonable use of the DCEOBA Non-Bypassable Charge. If PG&E believes the "needed for Diablo Canyon" language or any other provision of Pub. Util. Code section 712.8(t)(1) provides it the authority to allocate $11.505 million of Volumetric Performance Fees to this purpose, it should amend its Testimony to propose doing so.

[54] PG&E data response DR_A4NR_001-Q005, pp. 1 – 2, included in this testimony as Attachment Z.
[55] PG&E DR_A4NR_002-Q011, included in this testimony as Attachment Z1.
[56] PG&E WP 2-25.

C. Intake Bar Rack Replacement

The Intake Bar Racks, which are framed stainless-steel assemblies of vertical beams located at the mouth of the intake to block large debris (upstream of the finer-meshed traveling screens), are mentioned sparingly in the DCISC 32nd, 33rd, 34th, and 35th annual reports. At the June 20, 2024 DCISC public meeting PG&E's Senior Director of Engineering, Projects and Outages, Allen Wilson, included "Intake Structure bar rack replacements" in the projects list for the 2025 refueling outages, without further elaboration.[57] The August 2023 DCISC fact-finding visit to Diablo Canyon had been briefed on PG&E's plan to dredge the Intake Cove:

> Mr. Jackson [PG&E's Manager of Project Services and License Renewal at Diablo Canyon] reported that the area of concern was in the intake cove from its entrance from the Pacific Ocean to the intake bar racks and screens located at the Intake Structure. This area was originally designed to have an average (base) depth of 36 to 38 feet. Over the last nearly 40 years of operations, about 16 to 20 feet of sand had accumulated in that area, significantly reducing the depth and increasing the velocity of seawater being drawn into the intake bays. The higher amount of sand and increased velocity of seawater made it more difficult for divers to keep the intake racks and bays clear of debris.
>
> There was also a concern that the conditions made it more likely for kelp to be drawn into the intake and foul the racks or condensers. Kelp ingestion has the potential to cause the Circulating Water (CW) system to trip, which stops cooling of the steam turbine condensers and can result significant stress on plant systems, and possibly a turbine/reactor trip, due to inability to dump steam to the condensers. Concern about the potential to have the circulating water system trip due to kelp ingestion is the reason that the plant will reduce power during some winter storms. The FFT inquired about any possible effects of the silt upon the safety-related Auxiliary Saltwater (ASW) Pumps, and Mr. Jackson reported that the ASW pumps were not affected as the flow through their intake screens was much lower than for the CW pumps.
>
> Approximately two years ago, DCPP began the permitting process to allow for dredging and sand removal to correct the problem. The effort was later abandoned due to the possibly high costs and time involved in completing the project given the previously planned cessation of power operations in 2025. With the more recent initiative to extend power operations, efforts had been restarted to obtain the necessary permits and contractor services to perform the dredging.

[57] DCISC 34th Annual Report, unnumbered pdf p. 626, included in this testimony as Attachment Z2.

> It was currently believed that DCPP might be able to obtain a permit under an expedited process to allow dredging to begin as early as fall of 2023. It was expected that the dredging would take about 50 days and spoils would be disposed of at a permitted spoils disposal site in Morro Bay, CA. The FFT found that the plan was prudent, and the DCISC should continue to follow DCPP's efforts in this area.[58]

The December 2023 DCISC fact-finding visit was further briefed on PG&E's efforts to maintain the bar rack area, by Mark Sciacca, PG&E Director of Projects, and Trevor Rebel, PG&E Environmental Permitting Manager:

> Regarding maintenance of the Intake Cove using divers, Mr. Rebel reported that PG&E routinely used divers in the Intake Cove to keep the intake bar rack area clean of debris and sand. The cleaning was performed periodically and was necessary to ensure that the traveling screens did not degrade or plug and that the area was kept clear to allow the installation of the bar racks for maintenance if needed. The cleaning involved using fire hoses to spray the bar racks and the sand near the intakes, with the material then being carried into the travelling screen system which removes larger material, and the smaller material including the sand then traveling through the Circulating Water System. The sand was cleared away from the intakes out to whatever distance was necessary to create a gentle slope that would ensure the sand could not collapse on divers working near the intake. The FFT asked if moving the sand through the Circulating Water System was allowed by the environmental permit, and Mr. Rebel reported that it was not precluded by any conditions of the station's environmental permits. He also noted that the sand which was moved by the divers was sand which had been swept from the ocean into the cove and was not a part of the cove's original bottom surface. Also, he pointed out that if the sand were not moved by the divers, the sand would eventually accumulate to a point where it would be picked up and carried through the system anyway.[59]

PG&E subsequently reported to the NRC that the dredging project had been successfully completed in July 2024.[60] With no explanation beyond "[redacted]," the May 20, 2025 "[redacted]" meeting of the Plant Health Prioritization Committee reclassified the Intake Bar Rack replacements from DCTRMA to DCEOBA funding.[61] PG&E's Testimony characterizes the

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[58] *Id.*, unnumbered pdf p. 760, included in this testimony as Attachment Z3.
[59] *Id.*, unnumbered pdf p. 807, included in this testimony as Attachment Z4.
[60] https://www.nrc.gov/docs/ML2419/ML24199A063.pdf
[61] PG&E data response **DR_A4NR_001-Q005Atch04CONF**, unnumbered pdf p. 1, lines 41 – 42, included in this testimony as **CONFIDENTIAL Attachment Y**.

Intake Bar Rack replacements as "low priority" and explains the process that was used to make that determination:

> Due to resource availability, all projects were reviewed and reprioritized in June 2025 based on the project's ability to support the safety and reliability of DCPP. High priority projects were those that had the most impact to safety and reliability and would be completed before January 1, 2027, and lower priority projects were those that had less impact and would be completed after January 1, 2027. Through this reprioritization process, replacement of the intake bar racks was determined to be low priority and its completion was moved from 2026 to 2027. Therefore, when applying the approved accounting framework, costs are appropriately reclassified for recovery through the DCEOBA.[62]

A4NR recommends disallowance of the request in PG&E's Testimony to reclassify the $0.4 million Intake Bar Rack replacement project from DCTRMA to DCEOBA, and include that amount in the 2027 forecast of DCEOBA costs**.** The absence of any information in PG&E's Testimony or workpapers, beyond calling the present bar racks corroded, to justify the need for replacement prior to 2030 undercuts the reasonableness of including the project in the 2027 forecast of DCEOBA costs. The fact that the May 20, 2025 Plant Health Prioritization Committee "[redacted]" attributed to bar rack replacement an amount some 50% greater[63] than what is presented in the PG&E Testimony reinforces the impression that the project functions more as a budgetary reserve than as a plant priority. Under such circumstances, shifting the funding obligation to ratepayers is not a reasonable use of the DCEOBA Non-Bypassable Charge. If PG&E believes the "needed for Diablo Canyon" language or any other provision of Pub. Util. Code section 712.8(t)(1) provides it the authority to allocate $0.4 million of Volumetric Performance Fees to this purpose, it should amend its Testimony to propose doing so.

V. Scoping Issue 5: Satisfaction of Regulatory Requirements

The Commission's unwillingness to consider cost-effectiveness, imprudence, or both, in its prior two Diablo Canyon extended operations cost-forecasting proceedings has been a

[62] PG&E Testimony, p. 2-16, lines 16 – 25.

[63] PG&E data response **DR_A4NR_001-Q005Atch04CONF**, unnumbered pdf p. 1, lines 11 – 12 and 41 – 42, included in this testimony as **CONFIDENTIAL Attachment Y**.

disservice to ratepayers and an abdication of constitutional and statutory responsibilities. The Assigned Commissioner's Scoping Memo and Ruling for this proceeding adopts the same blinders, misreading D.23-12-036's Conclusion of Law 15 for the principle that such review "may be in ratepayers' best interest"[64] when the actual text instead states, "It is well within the Commission's authority, and in ratepayers' best interest, to continue to evaluate the prudence and cost-effectiveness of continued DCPP operations." The Scoping Memo and Ruling hints at the possibility that this proceeding might be rescoped, but then adds, "If cost-effectives is ultimately not scoped into this proceeding, the Commission may consider the cost effectiveness of DCPP in a future proceeding for this purpose, among others, in 2027."[65] A4NR urges the Commission to adopt, no later than its decision in this proceeding, an order for such an examination.

VI. Conclusion

A4NR recommends a reduction in the forecast 2027 revenue requirement contained in PG&E's Testimony to reflect disallowances for the unreasonableness of the following proposed project expenditures: vertical cask transporter warehouse, $.063 million; feedwater heaters, $14.1 million; control room ventilation system condenser replacement, $11.5 million; and intake bar rack replacement, $0.4 million. A4NR additionally recommends that the Commission adopt an order, by the time of its decision in this proceeding, to review the cost-effectiveness of Diablo Canyon's extended operation under SB 846.

[64] Assigned Commissioner's Scoping Memo and Ruling, p. 5.
[65] *Ibid.*

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 the lawyer 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.

Attachment A

SB 864 floor statement of Senator John Laird

- The $1.4 billion loan expenditure will be matched with $1.4 billion in federal revenue, which limits the requirement of any ratepayer or taxpayer money for that purpose. ByJanuary the eligibility of that money will be established, and thus will allow for a status check at that time on this issue.

- Money from the loan is prohibited from going to PG&E shareholders.

- The over $80 million in transition monies to entities in San Luis Obispo County will not have to be paid back, and the fund will be replenished when the plant actually does close.

- The Coastal Commission process will be sped up, but will not be overridden.

- Any need for seismic retrofit and deferred maintenance will be considered and implemented if there's an extension of the life of the plant.

- There is a continuation of the differential to workers that will incent them to stay to the end of the life of the plant.

- The acquisition and preservation of the twelve thousand acres of Diablo lands will be assured. And the extra monies over the current level of once-through-cooling mitigation fees will be applied to Diablo Canyon Lands. That language was inadvertently dropped from the bill, but the administration has agreed to fix this issue in January.

- And extremely important, this bill is the first step in a Marshall Plan for renewable energy – over $1.1 billion will be invested in green energy development in a plan overseen bythe Energy Commission.

There are still significant tasks that must be undertaken and questions to be answered if this measure passes tonight. We should hold hearings this fall – when we are not under the gun – to have an in depth look at the state's energy portfolio in the next decade. And beyond. And depending on the success of PG&E's application for federal dollars – we can re-visit this issue in January and decide whether to move forward. Also, the cost concerns raised by the solar industry for end users have been addressed, so they are no longer opposing this bill.

Based on this summary provided here, and – only doing what is necessary now, doing our best to protect taxpayers and ratepayers, assessing seismic safety and deferred maintenance issues, addressing the local concerns on a host of issues – and making a strong initial investment on a Marshall Plan for renewable energy, I will cast an aye vote for this measure. I know this vote will not please a number of my constituents, but I have made a good faith attempt to address the concerns that have been brought to me in this process – and will continue to do so going forward.

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Attachment B

PG&E Letter DIL-24-004, Enclosure 1

addressed in the LRA to help demonstrate, in this case, how the AMP will adequately manage deficiencies or degradations identified for SSCs important to safety, even when the inspection interval is extended beyond the specified inspection frequency for the AMP.

It is further noted that a staff review of the AMPs program elements did not identify license-specific criteria addressing this issue. AMPs need to demonstrate that inspection frequencies used for evaluating deficiencies or degradations accounts for any inspection interval allowance specified to be found acceptable (i.e., 1.25 times the specified AMP inspection interval). This is necessary to provide reasonable assurance that the intended function of SSC important to safety will be maintain even when the inspection interval allowance is exercised by the licensee.

<u>Regulatory Basis:</u>
This information is necessary to demonstrate compliance with Title 10 of the Code of Federal Regulations (10 CFR) Section 72.240(c).

PG&E Response to RAI A.4-3a:
Element 7 of License Renewal (LR) Application (LRA) Tables A-2, A-3, A-4, and A-5 (i.e., for each aging management program [AMP] that specifies up to 1.25 times the inspection interval) are revised in Enclosure 2 to clarify that if conditions are identified by the AMP inspections that do not meet AMP acceptance criteria, the evaluation via the Corrective Action Program will determine whether the intended function(s) will be maintained until the next allowable inspection of 1.25 times the inspection interval. Enclosure 2 also includes the above changes to each corresponding AMP summary in the proposed Updated Final Safety Analysis Report (UFSAR) Supplement in LRA Section D.3.

RAI A.6-1a: *Preventive Actions, Storage in Sheltered Environment*

<u>Information Needed:</u>
State the AMP's preventive action/criteria that is in place to demonstrate that the aging effects proposed not to be managed by the AMP per LRA Table 3-6 (e.g., changes in material properties) will be prevented from occurring. Update the preventive actions program element of the Cask Transportation System Aging Management Program, as necessary.

<u>Issue:</u>
In is response to RAI A.6-1, it is stated that the cask transportation system is shared between the Diablo Canyon ISFSI and Humboldt Bay ISFSI, and that the Diablo Canyon ISFSI Cask Transportation System AMP is consistent with the Humboldt Bay ISFSI Cask Transportation AMP and the associated aging management review (AMR) line items. However, the response does not provide sufficient technical basis to demonstrate that the aging effects/mechanisms considered not to require aging management per LRA Table 3-6 and is acceptable without crediting proper storage of the SSCs as a preventive action. The AMP needs to include this preventive action to demonstrate that proper actions are in place to prevent these aging effects from occurring.

As stated in LRA Table 3-6 notes, some components had aging effects (e.g., changes in material properties due to exposure to elevate temperatures or chemicals) that were not listed in the AMR tables for aging management because the cask transporter and its components is expected to be stored in a sheltered environment. In the LRA, the storage as a sheltered environment is credited to prevent these SSCs from being exposed to the aging mechanism *conducive to the aging effects, but without proper control for storage location movable equipment may be allowed to be stored in other locations where the aging effects may need to be considered as required for aging management. It is noted that previous staff evaluations considered wear as the only aging effect requiring management for these components because they are expected to be stored in an indoor environment with only brief outdoor exposure. Therefore, proper storage in a sheltered environment is a condition necessary to sustain this safety determination. The AMP considers this type of condition a preventive action. However, no such action for proper storage has been credited in the Diablo Canyon ISFSI AMP to provide reasonable assurance that this preventive action will be maintained for the period of extended operation.*

Regulatory Basis:
This information is necessary to demonstrate compliance with 10 CFR 72.240(c).

PG&E Response to RAI A.6-1a:
Element 2 of LRA Table A-6 and Section D.3 for the Cask Transportation System AMP are revised in Enclosure 2 to include sheltered long-term storage of the SSCs as a preventive action. As stated in LRA Table 3.1-2 and Section 3.6.3, these sheltered SSCs are temporarily exposed to an outdoor environment during maintenance and transport activities but are otherwise housed in a sheltered environment.

RAI E-3: *Please revise the Environmental Report (ER) to discuss the potential impacts to the California red-legged frog from incidental take.*

Discussion:
On September 21, 2023, PG&E submitted their response (ML23264A859) to the NRC's request for additional information (RAI) (ML23159A238). Figure 3.8-1 "Sensitive Wildlife Resources at Diablo Canyon Power Plant," in Appendix F, Environmental Report Supplement, of the ISFSI license renewal RAI response indicates that the California red-legged frog occurs at the Diablo Canyon Creek in close proximity to the ISFSI site. Section F3.8 in Appendix F, Environmental Report Supplement, references the Permit Application Package for the Diablo Canyon Power Plant Decommissioning Project with the County of San Luis Obispo (PG&E 2021). The permit application package cites the biological survey performed by Terra Verde, which indicates the presence of the California red-legged frog at the Diablo Canyon Creek. The biological survey concludes that impacts from the decommissioning project on the California red-legged frog would be low due to the low population observed.

Section 9 of the Endangered Species Act of 1973, as amended (ESA) prohibits any action that causes the "taking" of any listed species of endangered or threatened fish or wildlife. ESA Section 7(a)(2) requires that Federal agencies consult with the U.S. Fish and Wildlife Service (FWS) or National Marine Fisheries Service (NMFS) for any action the agency carries out, funds, or authorizes that may affect species listed as threatened or endangered under the ESA or any critical habitat designated for listed species.

Request:
Please provide an analysis of the potential impacts of the proposed ISFSI license renewal on the California red-legged frog and its habitat, including the potential for vehicles traveling to and from the ISFSI site to collide with frogs that may occur on roadways. Please also describe any other effects from the proposed action that the California red-legged frogs may experience during the ISFSI license renewal period. Describe any actions that PG&E has

Attachment C

Transition and License Renewal Expenditure Summary

Transition and License Renewal Expenditure Summary

	Grouping Description	2022-2023	2024	2025 - Q1	2025 - Q2	2025 - Q3	2025 - Q4	2026
1	**License Renewal**	$ 45,947	$ 46,678	$ 7,812	$ 12,379	$ 6,364	$ 14,047	$ 16,548
2	**Dry Cask Storage**	[redacted]						
3	**Upgrade Projects**	$ 44,992	$ 91,023	$ 41,660	$ 53,290	$ 23,815	$ 33,000	$ 49,770
4	**Programs**	$ 9,196	$ 25,679	$ 7,348	$ 7,860	$ 5,627	$ 7,012	$ 14,330
5	**Operational Enhancements**	$ 108,088	$ 149,067	$ 3,936	$ 5,372	$ 3,670	$ 3,198	$ 6,411
6	**Fuel**	[redacted]						
7	**Performance Based Disbursements**	$ 161,992	$ 117,046	$ 16,181	$ 4,780	$ -	$ -	$ -
	Total:	$ 465,823	$ 602,639	$ 122,424	$ 101,996	$ 49,821	$ 57,319	$ 87,059
	Cumulative Total:	$ 465,823	$ 1,068,462	$ 1,190,886	$ 1,292,883	$ 1,342,703	$ 1,400,022	$ 1,487,081

Outstanding Commitments (As of 12/11/24)
$ 248,852

Note: Figures are in Thousands $

Attachment D

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commitment as it demonstrates a strong commitment and a caring attitude toward the personnel who work at the plant and is a commitment companies rarely make. Mr. Guess stated that lines of business across PG&E have a very high regard for Nuclear Generation employees based upon the DCPP employees' high standards for work, for safety, and for procedure use and experience. He commented the success of the redeployment of DCPP employees within PG&E will take effort on behalf of the employees as well in order to match their job skills to available positions and he observed this effort will be a top priority at the station over the course of the next two years.

Consultant McWhorter observed that with the success of the Tier 1 and Tier 2 programs, a significant concern by the DCISC has been the turnover of personnel at the manager and above levels. He remarked this turnover appears to have occurred at a rate which was unanticipated and the manager and above group may represent one of the most vulnerable groups over the 2023 to 2025 timeframe. He inquired as to the organizational focus on ensuring management positions are adequately staffed. Mr. Guess replied that succession and development plans are in place for all DCPP management positions and succession planning candidates have been identified, or if a candidate for a management position has not been identified DCPP leadership is committed to remain engaged to develop same and he stated the conclusion of the Tier 2 portion of the Employee Retention Program represents a critical time. Mr. Guess stated it is his personal perception from talking with employees that there is a strong incentive amongst employees to remain at DCPP until generation operations are concluded.

The Chair thanked Mr. Guess for an excellent presentation.

Mr. Garcia stated Senior Director, DCPP Station Director, Mr. Dennis Petersen who presented to the Committee earlier in this public meeting would make the next informational presentation of an overview of the feedwater heater tube failure. Mr. Garcia reported Mr. Petersen would be assisted in his presentation by Mr. Matthew Birkel, DCPP Manager of Performance Improvement and Corrective Action, who served as the root cause team lead for the Unit 2 feedwater heater tube failure.

<u>Sequence of Events, Causes and Corrective Actions for Unit 2 Manual Trip on October 15, 2021, Due to Feedwater Heater High Water Level.</u>

Mr. Petersen reported the object of the failure he would discuss was Unit 2 feedwater heater 2-5B (FWH 2-5B) and the failure occurred due to the catastrophic failure of a number of heat exchanger tubes which was revealed on October 15, 2021, when the water level in the FWH 2-5B shell increased to the point where it could no longer be measured by visual indication. Mr. Petersen stated procedures required a manual trip of Unit 2 and the shutdown of the Unit 2 Main Turbine in response. In response to Dr. Peterson, Mr. Petersen confirmed the feedwater is at a higher pressure than the condensing steam on the shell side and therefore water flowed into the shell and created the high level, he described the situation as having the same fluid with differing energies and when a compromise existed in the boundary of the tubes this contributed to the uncontrolled rise in the water level.

Mr. Petersen reported the primary and secondary plant systems responded during shutdown as expected and a root cause was initiated by a team of experts to prevent recurrence. He described the root cause evaluation process as an industry accepted method of analysis. He reported the FWHs are very large metal-shell devices designed for high pressures which contain a large number of tubes and there are minimal ways to gain access to the FWH internals. Mr. Petersen stated that while DCPP was unable to identify the root cause, a probable cause was determined which he described as the highly likely but inconclusive cause based on information such as circumstantial evidence, non-verifiable evidence and a limited availability of facts and industry operating experience and cause evaluation techniques.

Mr. Petersen provided a schematic diagram showing the location of FWH 2-5-B as part of the Condensate System and he described the system components and the dynamic flow of water and the pressure at the various stages for the feedwater as it is then passed through 18 feedwater heaters to pre-heat the feedwater which then enters the steam generators. In response to Dr. Peterson's comment Mr. Petersen stated DCPP believes the October 15, 2021, event was triggered by a number of FWH tubes failing catastrophically intermittently over an indeterminate period of time. He reported there is evidence of a progression of failure which likely involved the active movement of vulnerable adjacent tubes and the creation of asymmetrical loads following the initial failure. He provided a schematic depiction of FWH 2-5 which he described as being responsible for the 13th stage of turbine energy extraction and reported when the tubes failed and agitation began and mechanical forces impacted the adjacent tubes the water volume added to the FWH shell became significant and not in control of the FWH level control system. Dr. Peterson remarked the load placed on the tubes is principally due to temperature and pressure but velocity contributes as well to the load and Mr. Petersen replied the most significant factor in the load experienced by the failed tubes was the velocity and higher pressure of the feedwater in the tubes which are made of alloy stainless steel.

Mr. Petersen reported there are three heat exchangers in each heat exchanger set, designated A, B and C, and accordingly FWH 2-5A and FWH 2-5C were closely examined for evidence of degradation or failure similar to that found in FWH 2-5B. Mr. Petersen confirmed, in response to Dr. Budnitz' observation that in failure mode condensate backs toward and can endanger the Main Turbine which rotates at 1,800 revolutions-per-minute. He reported the heat exchangers are located three levels below the Main Turbine and pipes lead down from the Main Turbine to the heat exchangers and it is critical that the Main Turbine be protected from damage and therefore standard industry guidance is to trip the reactor and place it in a safe condition and then to trip the Main Turbine and take the subsequent steps necessary to cool down the power plant and deal with the damage.

Mr. Petersen displayed an overview depiction of a feedwater heater and its internals and stated the feedwater heaters have a dimension of approximately 39 feet in length and approximately 5 feet in diameter. He described the heat exchanger's heat extraction function as to condense and cool steam by the condensate running through the feedwater heater tubes and for the heat exchanger to continually and incrementally increase the temperature of the water being fed to the steam generators. He indicated on the depiction the location of the tubes which failed in FWH 2-5B which he reported was identified through the use of a fiber optic camera as due to the compact structure of the internals of the heat exchangers there is no ability for a person to perform an inspection inside a heat exchanger. He described the operation of the heat exchanger drain cooler which he reported also serves as a baffle to cause the water to follow a tortuous path designed to extract as much heat out of the water as possible. In response to Dr. Peterson's question Mr. Petersen confirmed the water flows in from bottom and out through the top of the heat exchangers.

Mr. Petersen described the sequence of events on October 15, 2021 as follows:

- During 100% power operations an initial control room alarm indicated an issue with the Unit 2 Feedwater System.
- Per plant procedures Operations investigated the FWH level alarm for level control malfunctions and assessed for a FWH tube leak.
- During isolation activities FWH level rose high and out of sight and positive indication of FWH level was lost. After a failed attempt was made to isolate the inlet and outlet flows to feedwater heater this situation drove a procedurally required manual reactor trip to mitigate potential turbine damage.

Mr. Petersen displayed a cross-section of a feedwater heater tube bundle, which he described as a densely compacted arrangement of 690 tubes, which used a color coding to indicate to the Committee the tubes plugged, tubes tested using eddy-current[15] inspection technique with no concern identified, tubes tested with partial baffle indications, tubes tested and identified with full baffle indications identified, and tubes tested with shield plate indications identified. Mr. Petersen reported the testing revealed the existence of tube failure and the failure appeared related to where baffles were located in the drain cooler region. Areas were identified where the support for the tubes over their length appeared to have failed or to have eroded which due to the unsupported tube length allowed those tubes to vibrate and mechanically agitate other tubes and caused the tube failures. Seven tubes were found to have catastrophically failed in FWH 2-5B but there were some found with lesser damage. In response to Dr. Lam's query Mr. Petersen and Mr. Birkel reported the majority of FWH tubes plugged after the event were plugged for preventative reasons and approximately 19% of the total number of tubes have now been plugged. Mr. Petersen reported the feedwater heaters have been in service at DCPP since the plant was licensed. Following shutdown of Unit 2 DCPP performed dimple plugging and testing of the FWH 2-5B tubes using a rubber membrane to obtain indications of tube leakage as well as eddy-current testing and borescope inspection, and performed an extent of condition inspection for damage to FWH 2-5A and FWH 2-5C, located adjacent to FWH 2-5B, to identify any indication of failure.

Mr. Petersen displayed a depiction of the baffle plate configuration in the

FWH drain cooler region showing the location of the leaking tubes and reported the probable cause identified for the October 15, 2021, FWH 2-5B tube failure was excessive unsupported tube length caused by a break in the drain cooler shroud that led to high energy entering the region and caused fatigue fracture of the FWH tubes. In response to Dr. Peterson's inquiry Mr. Petersen and Mr. Birkel confirmed steam was distributed throughout the FHW shell, although the damaged tubes were located directly below the inlet from the drain in proximity to the drain cooler exit. In response to Dr. Peterson's observation Mr. Petersen confirmed some of the drain of energy involving FWH 2-5B affected FWH 2-4 but he stated he was unsure whether that was relevant to the failure mode as there is a shield plate protecting that area and there was no excessive erosion found due to the drain from FWH 2-4.

Mr. Petersen stated corrective actions to address and mitigate the probable cause include:

- With external peer support, determine which FWH(s) require additional inspections or preventative tube plugging and implement repair found to be necessary during upcoming unit outages (Unit 1 in April 2022 and Unit 1 in October 2022).
- Implement additional FWH system monitoring based on industry expertise and consultant guidance to identify a potential drain cooler shroud breach.
- For most vulnerable FWH(s) identified, implement additional monitoring to enhance early leak detection.

Dr. Budnitz remarked the DCISC will review the extent of condition FWH determinations during future fact finding. Dr. Budnitz reported that 40 years ago it was common for a nuclear power plant to trip approximately once each month and he stated he was impressed by the extent of the inquiry and technical examination by DCPP into this failure. Mr. Petersen stated DCPP in common with nuclear operators around the country wants to avoid any type of occurrence such as that with the FWH issue, as the safest condition for any plant is when it is operating in a stable, continuous power level which also minimizes impacts on plant operating crews. Mr. Petersen stated Unit 1 has not tripped for a long period of time which is likely equal or close to the best performance in the industry. Consultant McWhorter reported a copy of the Root Cause Evaluation for the FWH 2-5B event was included with the Committee's December 2021 document transmittal from PG&E.

Dr. Gene Nelson of California for Green Nuclear Power was recognized. Dr. Nelson inquired concerning the long-term implications of having feedwater heater tubes plugged, whether the number of tubes plugged would cause a greater load on the other heat exchangers, and at what point would the heat exchangers require replacement. He stated based upon his visits to DCPP he believed replacement of the heat exchangers would be a very significant undertaking. Mr. Petersen and Mr. Birkel reported the maximum tube plugging capacity engineering analysis for the feedwater heaters determined the maximum level is less than 40% without impacting function or reliability and therefore considerable margin exists after the tube plugging as a result of the October 15, 2021, event. Mr. Petersen confirmed that tube plugging does cause a higher flow through the adjacent heat exchangers and he confirmed that replacement of the heat exchangers would be a very significant project and represents a project that if DCPP were seeking a license extension would have definitely been undertaken.

The Chair thanked Mr. Petersen and Mr. Birkel for a very helpful presentation and he also thanked Mr. Garcia and the technicians from AGP Video for their support during this public meeting.

XIX ADJOURN EVENING MEETING

The Chair announced the Committee would convene in this room at 9:00 a.m. on the following morning and adjourned the evening meeting of the Committee at 7:00 p.m.

XX RECONVENE FOR MORNING MEETING

The February 16, 2022, public meeting of the Diablo Canyon Independent Safety Committee was called to order by its Chair, Dr. Robert J. Budnitz at 9:00 a.m. The Chair announced that due to the recent change in regulations by the San Luis Obispo County Health Officer face coverings were no longer required to be worn in the meeting room. Dr. Budnitz introduced himself and his colleagues on the Committee and he reviewed their respective appointments to the DCISC. He then introduced the Committee's Technical Consultants, the DCISC's Assistant Legal Counsel, and Mr. Hector Garcia who serves as the Chief Nuclear Officer's Support Manager and in that role serves as the principal liaison and facilitator for the DCISC. He then welcomed those persons attending in person and by Zoom Webinar and watching the proceedings on live streaming video.https://www.dcisc.org

XXI COMMITTEE MEMBER COMMENTS

There were no comments by Members of the Committee at this time.

XXII PUBLIC COMMENTS AND COMMUNICATION

The Chair reviewed the invitation to address remarks to the Committee on matters not on the agenda for this public meeting and invited any comments from members of the public who wished to address the Committee to do so now.

Dr. Gene Nelson legal assistant for the nonprofit group Californians for Green Nuclear Power was recognized. Dr. Nelson reported he has received information on some of the reaction in the local community to the San Luis Obispo County Board of Supervisors' decision to send a letter to the Governor expressing support for the continued operation of DCPP beyond 2025, which Dr. Nelson characterized as a very positive decision.

Mr. Eric Greening was recognized. Mr. Greening stated he attended the Board of Supervisors meeting referenced by Dr. Nelson when a presentation on a study was made by representatives of the Massachusetts Institute of Technology and Stanford University after which three members of the Board agreed to send the letter Dr. Nelson mentioned to Governor Newsom. Mr. Greening questioned that decision as he stated he was not sure what was expected of the Governor as there is an applicant [PG&E] applying for

Attachment E

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ground might have cleared after the motor heated up, operators conservatively declared the pump inoperable and initiated maintenance activities to replace the pump motor. The motor was successfully replaced and returned to service about three days later. The purpose of this meeting was to review the final Root Cause Evaluation (RCE).

The DCISC reviewed a copy of the final RCE Report, "Multiple Grounds on ASW Pp 1-1 Start," Revision 0. In the past, safety-related motors had been typically overhauled every three refueling outages, but this periodicity was extended to every four refueling outages in 2016. This extension was based on guidance from the Electric Power Research Institute that motor overhauls should occur on a ten-year (approximately four refueling outages) frequency. The ASW Pump motors were located indoors; however, their cubicles were provided unfiltered air directly from the outside near-ocean environment at the intake structure. The extended overhaul frequency provided an opportunity for increased buildup of mineral deposits inside the motor from the ocean air, and this potential environmental impact was not recognized or evaluated at the time of the periodic maintenance extension. In part, engineers reviewing the extension did not recognize that although the motor was physically located indoors, it was essentially subjected to an outdoor environment due to the forced flow of outside air directly into the motor's location. The RCE concluded that the primary root cause for the motor failure was this "unrecognized risk to ASW motor reliability with a motor heater failure given the operating environment and the potential for undetectable quantities of contamination."

To address the programmatic deficiency identified in the primary root cause, procedure ER1.ID1, "Equipment Reliability Process," was revised to add a requirement for a periodic review by select managers (conducted quarterly at a minimum) of new or updated preventative and corrective maintenance activities associated with critical equipment. This review was initiated to ensure equipment reliability challenges were mitigated by identifying possible unrecognized risks, ensuring correct work prioritizations, and ensuring robust monitoring was being implemented and tracked where appropriate. These periodic reviews were now being performed quarterly by managers from Maintenance, Operations, Engineering and Work Control.

The Root Cause Evaluation for a June 2021 Auxiliary Saltwater Pump 1-1 motor ground was comprehensive, and appropriate corrective actions were initiated to prevent recurrence.

<u>Feedwater Heater Tube Failure Root Cause Evaluation</u> (Volume II, Exhibit D.4, Section 3.5 and Exhibit D.6, Section 3.12)

The DCPP feedwater heaters are shell and tube heat exchangers which take low-grade (extraction) steam from the steam turbines to pre-heat feedwater prior to its entering the steam generators. This increases the thermal efficiency of the plant. Feedwater runs through the heat exchanger tubes to be heated from steam on the shell side. DCPP uses six cascading stages of preheat with spent steam sent to the condenser.

During startup from Outage 2R22 on October 15, 2021, FWH 2-5B was exhibiting indications of tube leakage. Power in Unit 2 was lowered to 90% to isolate the FWH to perform inspection and repair. The reactor was then manually tripped because of high FWH level. Significant tube failure of this nature significantly overwhelms the FWH drain system, requiring reactor shutdown to mitigate further damage.

A borescope examination showed a tube failure and other tube damage. Eddy Current Testing (ECT) showed the extent of condition, which was repaired. The unit was returned to power but shut down again due to additional tube leak indications. Further 100% ECT indicated additional repairs were needed, which were performed, and the unit was brought back up to power with extended FWH monitoring. The unit has operated satisfactorily since then.

A Root Cause Evaluation (RCE) team was established and completed its report in mid-December. The purpose of this January 2022 Fact-finding visit was to review the RCE, which was provided to the FFT prior to the meeting. The RCE determined the probable cause to be "Excessive unsupported tube lengths caused by a breach in the Drain Cooler shroud [which] led to fatigue fracture of the FWH tubes." (The RCE noted that a probable cause, rather than a root cause, was developed due to the limited accessibility of the FWH internals and availability of tube material evidence. Tube samples were not available for metallurgical analysis to confirm the failure mechanism.) Corrective actions included the following:

1. Determine which FWHs require additional inspections or preventive tube plugging and implement same
2. Implement additional FWH system monitoring to identify a potential Drain Cooler shroud breach on all 24 FWHs with an integral Drain Cooler
3. Identify additional leak detection monitoring in the most vulnerable FWHs and revise Operator Rounds to include additional FWH data points
4. Revise the Heat Exchanger Program to include assessment of unsupported tube lengths and to implement preventive tube plugging
5. Document reassessment of long-range plan for FWHs based on this RCE
6. Revise FWH Removal From and Return to Service to close the tube side inlet and outlet simultaneously when isolating for a leak

The RCE and corrective actions appeared satisfactory to the DCISC FFT. DCPP made a presentation on this event at the DCISC February 2022 Public Meeting.

DCPP experienced significant Feedwater Heater (FWH) tube failures in FWH 2-5B in mid-October 2021, which caused Unit 2 to be shut down twice to perform inspections and repairs. The unit has been operating normally with extended FWH monitoring since the final repairs were

made. The DCPP Root Cause Evaluation and planned corrective actions appeared satisfactory.

<u>Emergency Diesel Generator System Follow-up Items</u> (Volume II, Exhibit D.5, Section 3.8)

The first issue that the DCISC inquired about was the status of the Cause Evaluation (CE) for a significant fuel oil leak that occurred on EDG 2-3 during a maintenance run in June 2021. The EDG was shut down and the leak was successfully repaired. Following the failure, the size of the leak was evaluated and found to have rendered the EDG unable to run for the duration of time needed in the accident analyses, and the failure was therefore classified as a Maintenance Rule Functional Failure and a Critical Equipment Clock Reset. The Cause Evaluation concluded that the probable cause of the leak was engine vibration along with thermal and pressure cycling during normal operation which resulted in the 1R "banjo bolt" torque working loose over time. The DCISC noted that an alternative cause could have been insufficient initial torquing of the bolt. The "banjo bolts" were fasteners that held fuel oil fittings called "banjo fittings" in place against the 18 fuel injection pumps on each EDG as shown below:

As corrective action for the issue, maintenance procedures were revised to add steps to regularly check the torque of the banjo bolts. Additionally, banjo bolts on the other EDGs were checked to ensure proper torquing. Across all of the remaining engines, approximately six bolts were found with slightly less than the required torque.

Following completion of the CE, additional investigations had been initiated primarily in response to a very high level of interest from NRC Resident and Regional Inspectors. Further investigations found some inconsistencies in the history of the types of material used in the banjo bolt gaskets.

The second issue was the failure of EDG 2-3 to achieve the required frequency of electrical output during a surveillance test on July 22, 2021. This failure was determined to be one that would prevent the EDG from performing its safety function during an accident, and Licensee Event Report 2021-01 for Unit 2 was submitted to the NRC to report the occurrence of this event to the NRC. It was noted in the report that the required overall safety functions were maintained by the other two Unit 2 EDGs which were not affected by the failure, and the EDG's frequency could have been adjusted manually to correct the issue if needed during an accident.

During a previous maintenance period for EDG 2-3 in June 2021, technicians performed tuning on the EDG governor to address minor load and frequency oscillations that had been noted during previous EDG tests. The governor tuning was successfully completed; however, post-maintenance testing did not include checking EDG output frequency during all modes of operation. Specifically, the frequency for isochronous mode operation was not checked following the governor

Attachment F

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For Unit 1 there are five additional FWHs that are similar to the affected Unit 2 units. They have been "Remote Field Tested" (similar to Eddy Current Testing), resulting in no adverse indications and were determined to be in good condition. There were some eroded baffle and baffle plates, which were not considered to be problematic. Unit 2 is believed to be in better condition than Unit 1, and this will be determined at each of the next refueling outages.

DCPP has developed a new preventable plugging strategy and plans to perform acoustic listening monitoring for flow noise which would indicate steam bubble collapse, which could mean unwanted forces on internal FWH components.

DCPP's follow-up actions to date and plans for future monitoring of Feedwater Heater internals appeared satisfactory.

Condensate Polisher Resin Issue (Volume II, Exhibit D.2, Section 3.10)

Electric generating station condensate must be maintained at a very high purity level to protect steam generators and turbines from corrosion. Removing contaminants is called "polishing." To remove contaminants from the condensate deep bed ion exchange condensate polishers are used and sometimes are preceded by a filter demineralizer or a fine particulate filtration system.

The DCPP condensate polishing system is comprised of seven mixed bed demineralizers. Either six or seven demineralizers are in service processing the full condensate flow (approximately 21,000 gpm) depending on whether any one of the demineralizers is in the regeneration mode or not. The demineralizer in the regeneration mode is taken out of service and is regenerated externally in order to minimize the possibility of introducing regenerant chemicals into the condensate and feedwater system. The external regeneration process for one demineralizer normally takes about 12 to 16 hours. Components of the condensate polishing system, including demineralizers, regenerators, and associated equipment, are located in the turbine building buttresses. The system is capable of either automatic or manual operation, and can be bypassed if necessary.

The condensate polishing system is designed to polish the full condensate flow during startup and normal plant operation. During startup, the system allows recirculation of condensate at approximately 5500 gpm (gallons per minute) through the condensate polishing demineralizers and feedwater heaters, returning it to the main condenser. This design provision allows a more complete cleanup of secondary water prior to system startup. The condensate polishing system monitors the secondary chemistry to protect the steam generator tubes which are a part of the reactor coolant pressure boundary from degradation during the course of their lifetimes.

The reason for the DCISC review here is an issue with the condensate polisher resin for which samples had been sent to the supplier. This had been reported in a Plant Health Committee meeting, which the DCISC observed. The resin had been

Attachment G

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refueling outage. Mr. Wardell reported the fuel was manufactured by Westinghouse and shipped to DCPP from South Carolina in long metal strongback containers, 20 feet long by 8 feet in diameter, each containing two fuel assemblies. The fuel assemblies are 14 feet long and approximately 1 foot by 1 foot square. The fuel is lifted and transported by crane to the new fuel vaults where a detailed inspection takes place. Following this inspection the fuel is lifted over the spent fuel pool and is transferred, via the spent fuel pool and the transfer canal, into Containment and then placed in the reactor vessel for a three-cycle operational lifetime. The FFT concluded the operation was performed professionally and carefully and Mr. Wardell displayed photos taken during the FFT visit. Dr. Peterson commented the surface dose rate on a fuel assembly was about 2.5 millirem per hour which drops off rapidly as one moves away from the assembly.

Ms. Sherry Lewis, a member of Mothers for Peace, was recognized. In response to Ms. Lewis inquiry Mr. Wardell reported that if the watertight integrity of the Intake Structure's rooms which contain the auxiliary saltwater pumps was compromised there would be water leakage into the room and the operation of the pumps could be affected and in accordance with Dr. Kadak's observation the DCISC will follow-up on the issue of watertight integrity of the Intake Structure rooms containing the auxiliary saltwater pumps. Dr. Peterson remarked the most important equipment to be protected from a tsunami are the emergency diesel generators which are located 85 feet above mean sea level and Dr. Peterson observed the auxiliary saltwater pumps are not essential to safe shutdown. Mr. Wardell observed that should the auxiliary saltwater pumps be lost the FLEX[9] Program capabilities provide a backup system.

Mr. John Geesman representing the Alliance for Nuclear Responsibility was recognized. Concerning the feedwater heater tube issue described by Mr. Wardell, Mr. Geesman inquired whether there was a material difference in time between the feedwater heaters current Green health status and the status of the feedwater heaters for extended operation. He remarked during the June 2022 DCISC public meeting DCPP Senior Director Mr. Dennis Petersen made the comment that replacement of the feedwater heaters would be a very significant project and represents a project that if DCPP were seeking a license extension would have definitely been undertaken. Mr. Geesman stated the failure of the feedwater heaters caused Unit 2 to shut down and to start up twice and there is a valid concern that such shutdowns and startups should be minimized for safety reasons. Mr. Geesman referred to Nuclear Energy Institute (NEI) Report 20-04 entitled "The Nexus Between Safety and Operational Performance" and its conclusion that "[w]hen changes in processes or equipment are made that result in improvements to equipment reliability or availability, the outcome has a positive impact on both safety and operational performance" and he inquired relative to the feedwater heater tubes what timeframe or time horizon would the Committee apply to the analysis as to whether something does or does not require replacement. Mr. Wardell stated he agreed that transients[10] should be avoided on any system whether it be primary or secondary but he remarked the plant is designed to handle these transients but the higher the equipment reliability the fewer transients will be experienced. Mr. Wardell recalled that when DCPP was preparing for the original license extension application, all the feedwater heaters were planned for replacement for twenty years of operation **but with the Joint Proposal it was determined the plant could operate satisfactorily to 2025 without replacing the feedwater heaters and he observed the lead time to obtain new feedwater heaters is lengthy, likely taking years. He observed this is an issue on which the plant will make a decision and the Committee will conduct a review**. Mr. Wardell reported feedwater heaters are designed with significant margin to account for tube plugging on account of tube failure. Mr. Geesman commented that it was his recollection the Unit 2 feedwater heaters have approximately 20% of their tubes plugged. Dr. Peterson remarked feedwater heaters are not safety significant in that the limits on the steam generators are associated with heat removal for safety-related purposes. Mr. Geesman commented that too many feedwater heaters shutdowns could result in a unit shutdown for an extended period and under SB 846 a substantial cost is placed on the taxpayers and the ratepayers and justified as liquidated damages as a result of continuing to run an aging power plant and in Mr. Geesman's view those parties should be protected against such costs. Mr. Geesman remarked the statutes enacted under SB 846 do not distinguish between safety-related and non-safety replated components and he suggested the DCISC should take a safety-oriented perspective as to both. Mr. Wardell commented the plant has and will be inspecting all the feedwater heaters to ensure their suitability for operation to 2025 but their operability beyond that date is an open question although an individual feedwater heater can be isolated from other feedwater heaters and the plant can continue to run albeit at lesser efficiency.

Dr. Budnitz observed that the confidence the plant can run effectively until 2025 needs to be based on something besides judgment and when the DCISC makes its inquiries it will ask about the operating experience in the industry for extended operation. Dr. Budnitz observed there are two possible extremes here, one that it creates a high degree of failure and another that there are a number of plants running for extended periods with no significant problems and this is a calculus that DCPP will need to engage in and the Committee will need to review. Dr. Budnitz stated extended operation of DCPP creates many similar lines of inquiry for which the Committee will need to come to an independent review about whether the judgments are acceptable but he reiterated it takes more than judgment, it takes data. Dr. Budnitz remarked the only accident of consequence in the United States occurred at the Three Mile Island Nuclear Generating Station in Pennsylvania and it began with a problem involving the failure of a polisher on the feedwater input and it is important to remember to be humble about things that don't look as if they're important because when they are combined with other factors they can contribute significantly to a problem. Mr. Geesman thanked Dr. Budnitz for his observation and remarked that at the February 2022 public meeting Dr. Budnitz expressed the view that the NRC should revisit its classification for safety and non-safety related systems and components which classification was developed in the 1970s. Dr. Budnitz replied there is a program under 10 CFR 50.69 for safety classification of system, structures and components which revisits the NRC's earlier classification and the 50.69 program was adopted a few years ago and is available to currently operating plants and he remarked that perhaps the 10 CFR 50.69 regulatory scheme could and should be used at least in part at DCPP. Mr. Geesman thanked Dr. Budnitz for this information and he commended the DCISC for the manner in which it conducts its public meetings.

Attachment H

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stated the Holtec canisters do not meet the requirements for inspection repair and that precursors to cracking were found, but the technology is not in place to actually find the cracks, measure their depth and direction and characterize the cracks. She added that the NRC has not evaluated the cold spray technique described by Ms. Walker. Ms. Gilmore remarked the NRC stated [a canister] could only stay within a transfer cask for approximately 224 days and in that case the fuel was not high burnup. She reported no one has requested an evaluation of any kind of overpack, a transport cask, or anything to be used for storage of what she described as thin-walled canisters and while they can be placed in transport casks there is a limit as to the time before they would overheat. Ms. Gilmore stated Holtec's planned procedure for its CIS [consolidated interim storage facility] in Texas in the event a canister is received that is leaking is to return the canister to the facility from whence it came, and the NRC appears to accept this procedure. She remarked in the event such a canister was placed within a spent fuel pool it would likely produce a steam flash and therefore the only other option is to use a hot cell facility, but such facilities no longer exist in the United States. She remarked there is no plan for when something goes wrong, and the NRC has stated in writing that once a crack begins it can grow through the wall in sixteen years.

Ms. Sheila Baker, a resident of Sonoma County, was recognized. Ms. Baker cited a statement from the Governors of New Mexico and Texas that their states will not become dumping grounds for the nation's spent nuclear fuel due to Congress' failure to identify a permanent disposal situation for commercial nuclear waste and she questioned what you do with the waste.

The Chair thanked the members of the public for their remarks.

XXX STAFF & CONSULTANT REPORTS & RECEIVE, APPROVE, AND AUTHORIZE TRANSMITTAL OF FACT FINDING REPORT TO PG&E

A. The Chair requested Consultant McWhorter to provide a report on the January 31-February 1, 2023, fact-finding visit to DCPP with Dr. Lam. Mr. McWhorter reviewed the topics discussed with PG&E during this visit as follows:

→ SB846 Requirements Regarding Deferred Maintenance – Consultant McWhorter reported the DCISC Fact-Finding Team (FFT) asked the DCPP representatives how PG&E intended to address the requirement for an independent consultant to catalog and evaluate deferred maintenance under the requirements of SB846. He remarked as addressed during this public meeting the PMO++ process is underway and following that process DCPP will obtain the services of a company or a university to independently and credibly review the PMO++ effort. He reported DCPP expects to retain these services late in the second quarter and to have completed the review by the fourth quarter of 2023. The FFT found this approach to be appropriate.

→ Plans for Reviewing and Restarting Capital Projects – Mr. McWhorter stated an issue with terminology exists concerning reviewing and restarting capital projects, which he described as a subset of the PMO++ process, in that the term "capital projects" in the strict financial definition sense no longer applies, but in context of extended operation these projects are the same physical type of projects as what are termed capital projects. The projects primarily involve major improvements to the plant or major purchases of spare equipment that may need to be made over the next few years and the review and decisions as to those projects will come after the completion of the PMO++ process and the addition of consideration of the availability of spare parts and the need for improvements to ensure reliability. Consultant McWhorter reported there is also a time element involved, in that time is required to design and procure equipment, as an example for the feedwater heaters, and time is required to complete an installation. He reported the last opportunity to make major changes to the station, based on the five-year commitment from the state for extended operation, is during 2026-2027 which is the first refueling outage following extended operation. There will also be a need to review the availability and the potential to procure spare parts, such as pump motors, for which procurement may have been deferred due to the expectation the plant would close in 2025. There is also a reliability factor to be considered for some projects or purchases as depending on the duration of operation some of those projects or purchases would not otherwise be performed or made. **Mr. McWhorter stated the FFT recommended the Committee should review the plant's conclusions concerning the restart of capital projects when it is complete, likely by or before the May 2023 fact finding**.

→ Meet with NRC Senior Resident Inspector – the FFT met with the NRC Senior Resident Inspector Mr. Mahdi Hayes to discuss the results of the PI&R Inspection. In response to the FFT's inquiry the Senior Resident reported the resident inspection team did not feel that the results of the PI&R Inspection were indicative of broader problems at the station and **Mr. McWhorter reported the Committee has plans to follow up on the PI&R Inspection during a future fact-finding.**

→ Engineering Department Update – Consultant McWhorter reported the work of the Engineering Department is ramping up quickly and in response a fourth group has been reactivated in the department, that group being the Design and Project Engineering Group. This group is responsible for the design and oversight of major projects. Prior to the adoption of SB846 the Engineering Department staff was planned to consist of 103 persons by the end of 2022, while currently the Department is planning to have a staff of approximately 130 persons and to reach 140 persons before the end of 2023. In response to Consultant Wardell's inquiry Mr. McWhorter stated those numbers do not include contractor personnel but it may be expected that DCPP will use a contractor engineer of record for some of the design engineering and also employ contract engineers for license renewal work including development of aging management plans. Mr. McWhorter reported Engineering Department staffing will likely be impacted by the conclusion of Tier 2 of the Employee Retention Program. He reported the Department's performance indicators, generated internally and externally, were all in Green status and showing steady or improving trends**. The FFT concluded the Engineering Department's performance is strong and the DCISC should review the Department's performance again in one year**.

→ Technical Review of New [Orano manufactured] Spent Fuel Storage System – the FFT led by Dr. Kadak reviewed the responses to questions posed by the Committee FFT

Attachment I

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safety were never affected by these reviews and continued to be performed.

The purpose and scope of the current Preventative Maintenance Optimization initiative designated as "PMO++," also referred to as "Equipment Long Range Plan Reviews," by DCPP was then discussed. The PMO++ initiative was previously reviewed by the DCISC in December 2022 (Reference 6.1). The PMO++ initiative uses a large group of individuals (about 30) from various departments (Engineering, Maintenance, Operations, Outage and Planning, Risk Management, etc.) to review all of the PMCRs processed since 2018 to determine what changes to PM activities were now needed to optimize equipment performance and reliability beyond 2025. Additionally, the team was reviewing all uncompleted CM activities from the same timeframe to determine if additional CM activities needed to be performed in light of extending operations through 2030. Together, the updated PM and CM activities would form an updated long-range maintenance plan for DCPP. The PMO++ initiative was planned to be completed by the end of the first quarter of 2023.

Mr. Wilson informed the FFT that after the PMO++ initiative is completed, DCPP plans to obtain the services of an independent entity to review the results of the process. DCPP has begun to search for an appropriate company or university that is both independent of PG&E and has trusted and credible expertise in the area of maintenance planning and risk management. The independent reviewer would be provided with both PM and CM information from before and after the PMO++ initiative along with the methodology used for the PMO++ review process. DCPP desires for the independent review to begin sometime in the second quarter of 2023. The FFT concluded that this approach appeared appropriate to meet the SB846 requirement and would aid in ensuring that maintenance activities continued to be effective in achieving the required equipment reliability through a period of extended operations. The DCISC should review the results of the independent review following its completion.

<u>Conclusions</u>: **DCPP plans to meet the SB846 requirement for a study by independent consultants to catalog and evaluate any deferred maintenance at DCPP through obtaining the services of an independent entity to review the results of its PMO++ initiative. The DCISC concluded that this approach appeared appropriate, and the DCISC should review the results of the study following its completion.**

<u>Recommendations</u>: **None.**

3.2 <u>Plans for Reviewing and Restarting Capital Projects</u>

The DCISC Fact-Finding Team met in-person with Allen Wilson, Director, Projects, for an update on DCPP's plans for reviewing and restarting capital projects in light of the possibility of extended operations as directed by SB846. The DCISC last reviewed this topic in December 2022 (Reference 6.1), when it concluded the following:

It appears that DCPP is appropriately beginning initiatives to review capital projects and review plant maintenance to support extended operation through 2030.

Mr. Wilson provided the FFT with an update on plans for reviewing capital projects that would be performed in addition to the PMO++ initiative discussed in Section 3.1. He noted that prior to the consideration of extended operations under SB846, there were only five capital projects approved for 2023 and the process for reviewing and approving those projects was discussed with the DCISC in May 2022 (Reference 6.2). Following the decision to extend operations under SB846, DCPP was now beginning a review of former and possibly new capital projects that would need to be implemented. He noted that there was currently no traditional authorization per se for additional capital expenditures as DCPP did not have any authority for capital projects to support operations beyond 2025 under its current general rate case authorized by the California Public Utilities Commission. Instead, DCPP was focused on applying for and receiving funds allocated by SB846 to the Department of Water Resources which could be used for plant improvements needed to maintain high plant reliability and nuclear safety through 2030.

As DCPP neared the conclusion of its PMO++ initiative in a few months, Mr. Wilson stated that DCPP would begin a review of the PMO++ results along with lists of previously cancelled capital projects and supply chain issues for repair parts. The focus of those reviews would be to identify improvements that would result in immediate or short-term improvements in reliability. Historically most major capital projects took 18-24 months to design and one or two refueling cycles (18-36 months) to implement. Most such large projects would not be feasible or sufficiently beneficial for completion during the timeframe of a five-year extension of operations. Therefore, it was expected that DCPP would be generating a list of projects that would address spare parts availability or would improve reliability with a short implementation schedule. Examples included possible plans to purchase spare or refurbished large motors and/or improvements that could be implemented no later than refueling outages in the 2026-2027 timeframe. Lastly, he noted that any possible extension of operations beyond five years would appreciably change the number of capital projects that would be worthy of consideration.

The FFT inquired about what would happen to the previously proposed and cancelled project to replace all of the plant's Feedwater Heaters. Mr. Wilson reported that although replacement of all Feedwater Heaters was not feasible within the timeframes discussed above, he believed that some of the feedwater heaters could and would be replaced within those timeframes. Specifically, he believed that two to possibly four trains of the Feedwater Heaters which were the biggest threat to reliability could be replaced within the targeted 2026-2027 timeframe. This would be possible because of the extensive and recent industry experience with manufacturing and replacing similar equipment at other nuclear power plants. The FFT also inquired about the timeframe for completing the

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34th Annual Report, Volume I, Section 4.13, Equipment Reliability

4.13 Equipment Reliability

4.13.1 Overview and Previous Activities

Aging-related degradation is the gradual degradation in the physical characteristics of a system, structure, or component (SSC) which occurs over time and use, and which could impair the ability to perform its design functions. The purpose of the Equipment Reliability Program is to ensure that the plant continues to operate safely and within its design and licensing bases throughout its life through the process of involving engineering, operation, and maintenance in activities to control age-related degradations or failures of SSCs to within acceptable limits.

During the previous reporting period, the DCISC reviewed the following topic related to Equipment Reliability at two Fact-finding Meetings:

- Equipment Reliability Update

The DCISC concluded the following during the previous reporting period:

DCPP's past secondary system equipment reliability issues appeared to be satisfactorily addressed with specific action plans and an excellence plan. Equipment Reliability performance improved substantially in 2021 and 2022, and its performance indicator improved to Green (Good).

4.13.2 Current Period Activities

During the current period, the DCISC reviewed Equipment Reliability (ER) programs at one Fact-finding Meeting. The following topic was reviewed:

- Equipment Reliability Program

Equipment Reliability Program (Volume II, Exhibit D.9, Section 3.2)

DCPP's Equipment Reliability (ER) metrics placed it in the second quartile in the industry's Equipment Performance Indicator. Unit 1's indicator was negatively affected by two events in the fall of 2023 associated with a manual trip during ramp down and a forced outage to repair a leaking Pressurizer Safety Valve. Unit

2's indicator was negatively affected by a reduction in power in the spring of 2023 caused by a biolab water line break. Despite those events, DCPP assessed that ER at the station had generally been good over the past two years but there was more that DCPP could do to improve ER in the future.

DCPP completed its responses to an initiative in ER from the Institute of Nuclear Power Operations (INPO) which was focused on improving the quality and reliability of parts procurement as well as incorporating cross-functional approaches to maintaining reliable equipment and in managing risk at the station.

DCPP believed that its transition to extended operations required it to be more forward-looking in its future ER program. The change in direction from the planned cessation of power operations to an extension of operations left the station in a position of needing to perform many maintenance activities and initiate numerous upgrade projects to address obsolescence and/or implement new technologies at the station. The recently completed series of Refueling Outages, 1R24 and 2R24, allowed the station to catch up on maintenance activities and address needed inspections and minor improvements, and such would also be the case for the next series of Refueling Outages, 1R25 and 2R25. During recent outages, the station had also taken advantages of opportunities to perform low complexity projects that would add to reliability such as High-Voltage Transformer refurbishments, Condenser Tube Sheet coatings, and Main Condenser internal lagging strap replacements.

Planning and implementing effective plant upgrades in the future 1R26 and 2R26 Refueling Outages would be critical to maintaining a high level of ER going forward into an extended operating period. Examples of projects to be completed in that timeframe that could have a positive impact on ER included replacements of the Main Feedwater Heaters, Annunciator Systems, and High-Pressure Turbines. DCPP desired to be proactive in implementing digital technologies but believed that caution was needed as digital technologies tended to drive up the level of complexity along with increased project implementation risks.

DCPP's Equipment Reliability program has been effective, and station reliability has improved over the last two years. With the transition to extended operations, the station is focusing on implementation of future equipment replacements and upgrades to maintain and improve reliability.

4.13.3 Conclusions and Recommendations

<u>Conclusions:</u> **DCPP's Equipment Reliability program has been effective, and station reliability has improved over the last two years. With the transition to extended operations, the station is focusing on implementation of future equipment replacements and upgrades to maintain and improve Equipment Reliability.**

Attachment K

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and other contributors and he observed these aspects can be used outside the event evaluation process to evaluate human performance events. Mr. McWhorter reported the goal of a RCE is to eliminate the possibility the event will ever recur while the goal of a CE is to make it very unlikely that the event will recur. Mr. McWhorter reported a list of questions is employed in making the Safety Culture Assessment required as part of a RCE which he described as a tool based on the NRC's safety culture characteristics. Consultant McWhorter reported that the FFT found some inconsistency in the results of the tools he described as there is not always a direct tie from the results of these tools to a corrective action. The FFT also identified a lack of trending across the organizational learning tools when they are part of the evaluation and he reported DCPP initiated a notification for that trending. He reported the FFT found the programs for RCEs and CEs were sound in their approaches, but the team identified possible weaknesses in how the insights gained from the organizational learning tools and safety culture assessments are captured and corrective actions initiated. **Mr. McWhorter reported the FFT had two recommendations for PG&E and one for the Committee including: for the Committee, to review organizational learning tools and safety culture assessments sections of all RCEs and CEs initiated within the past year during a future fact finding; and for PG&E, to (1) review the cause evaluate process and ensure deficiencies identified by those tools are being captured and tied to initiation of corrective actions; and (2) to ensure that trending is being performed across the organizational learning tools in the CE and RCE documents**.

→ Major Project Planning Update – Mr. McWhorter reported during the next refueling outages DCPP will be implementing many of the projects the DCISC has been following since the decision was made to consider extending operations and he described some of these including high voltage transformer improvements, traveling screen replacements, Unit 2 Main Generator inspections, and emergency diesel generator governor replacements. Mr. McWhorter reported the DCISC receives with its monthly documents a list of the status of currently active projects and he observed there is a transition beginning now with a large number of projects being filtered and scheduled for future implementation. He reported license renewal inspections and supporting activities were completed in the R24 refueling outages but some items were deferred with NRC approval to the R25 outages. Mr. McWhorter reported replacement of the fourth and fifth point feedwater heaters is planned, representing three feedwater heaters for the fourth point and three feedwater heaters for the fifth point from each unit for a total of 12 feedwater heaters. He reported the replacements will be staged during outages 1R26 to 2R27 and the order will be determined primarily on the difficulties in getting the large and heavy feedwater heaters in and out of the Turbine Building which may require other feedwater heaters to be removed and then replaced. Mr. McWhorter reported the annunciator system is also to be upgraded by replacement of the analog system with a digital system. The FFT found the planning for major projects was being effectively managed.

→ Emergency Preparedness Plan and Facilities Tour - Consultant McWhorter reported the tour provided an overview of how the Emergency Response Organization (ERO) is organized to staff its various facilities for different types of emergencies. The FFT

Attachment L

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→ The third and longest commitment period will run January 1, 2026 to December 31, 2028.

→ The fourth and final commitment period will cover January 1, 2029 through November 1, 2030, the day after Unit 2 is scheduled to go offline.

In response to Consultant McWhorter Mr. Jones reported the first payment under the current tranche is scheduled to be made in April 2025. He reported for the longer duration tranches payments will be made periodically.

Mr. Jones reported DCPP has been using the Employee Retention Program for almost a decade and it has proven to be very reliable and has provided accurate staffing forecasts by discipline and by numbers of employees.

Ms. Lopez then introduced Vice President of Engineering Mr. Allen Wilson. Ms. Lopez reported that Mr. Wilson has 14 years of experience with PG&E and has served in various responsible roles in the Engineering, Maintenance, Decommissioning and License Renewal organizations and most recently as Senior Director of Engineering, Projects and Outages. Prior to working for PG&E Mr. Wilson served as a reliability engineer with the United States Navy and Coast Guard and in various civilian engineering capacities and was responsible for creating and testing vessel maintenance and lifecycle management plans.

Mr. Wilson stated DCPP continues to make necessary project investments to ensure safe and reliable operations. The NRC continues to assess and reaffirm that Diablo Canyon is operating safely and is among the highest performing plants in the nation, additionally, the DCISC thoroughly evaluates activities at DCPP on a routine basis. He reported DCPP is in various phases (design, procurement, material fabrication) for safety and reliability focused on major projects, which for the PG&E designation of major projects includes the replacements of the Unit 1 and Unit 2 high pressure turbines in 2025 and feedwater heater contingency replacements in future outages.

Mr. Wilson reported that projects that do not fall into the major project category are primarily focused around obsolescence, reliability or modernization. He reported for 2025 these include replacing the digital rod position indication displays, the fuel transfer cart upgrades, tie line relay upgrades on Unit 1 for the 230kV and 500kV lines and for the 500kV line for Unit 2. He also identified the Pressurizer safety valve inlet restraint modification for Unit 1, removing the box restraint and replacing it with a strut which will resolve leakage. Also included is the removal of Capsule B from Unit 1 and the reactor pressure vessel inspection and Inservice Inspection including the inspection of welds as part of the Aging Management Program.

Ms. Lopez then introduced DCPP Director of Business and Technical Services Mr. Brian Ketelsen. She reported Mr. Ketelsen is responsible for financial management and forecasting at DCPP including implementation of the financial requirements of SB 846 and associated regulatory filings and DCPP extended operations cost recovery. Mr. Ketelsen joined the DCPP financial organization in 2011 and facilitated project approval control and in 2018 was designated as the Decommissioning Project Controls Manager. Mr.

Attachment M

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and affirm the safety of operations as does the DCISC. He remarked that for identified projects the process consists of three phases which include design, procurement, and material fabrication. He identified in this context the Unit 2 high-pressure turbine installation during 2R25 and the contingent replacement of the feedwater heaters, which for the feedwater heater project he reported is in the design and the beginning fabrication phase. Mr. Wilson provided a list that summarized projects for Unit 1 and Unit 2 and he observed a number of projects are planned on secondary side systems. Primary side projects are planned to deal with obsolescent items including the digital rod position indicator and the paper chart recorder. He reported projects for 2R25 are similar to those performed for 1R25 with the steam generator blowdown tank replacement being a project for Unit 2 that was not done during 1R25. Common unit projects include the biological lab system upgrades and the plant's air compressors along with refurbishing and relocating the spare high-voltage transformers.

In response to Consultant McWhorter's inquiry Mr. Wilson stated with reference to the feedwater heater replacement project that the feedwater heaters life-cycle windows are being reviewed to determine the need for their replacement and that replacing the individual feedwater heaters is contingent on that review and he commented there is a long lead time as fabrication of a feedwater heater can take up to three years to complete and all the feedwater heaters required will not be completed before the end of 2026 or the beginning of 2027. He observed there are issues involved with interference caused by removal of the feedwater heaters, of which there are 12 per unit, 24 in total, and the health of the feedwater heaters will be assessed and a decision made from the perspective of their replacement in view of the 2030 operational timeline. In response to Dr. Meshkati's question Mr. Wilson reported the Main Annunciator System for Unit 2 will be replaced during a future outage in 2026.

Dr. Gene Nelson of Californians for Green Nuclear Power was recognized. In response to Dr. Nelson question concerning a project involving the 10% steam dump controls and Dr. Nelson's observation that a Westinghouse four-loop pressurized water reactor with appropriate steam dump can be allowed to operate down to 15% of its rated power output or in idling mode, Mr. Wilson replied DCPP is not making any modifications in order to do any kind of idling or load following operations. The modification referred to by Dr. Nelson represented a deferred corrective action which will enable down power operation in order to be able to maintain the plant in hot standby condition separately from the capacity afforded by its 40% steam dump capability and the project was part of the PMO++ review process. In response to Dr. Budnitz' observation Mr. Wilson confirmed DCPP can continue to operate safely at any power level.

The Chair requested Mr. Rathie to make the next presentation. Mr. Rathie stated he would be assisted in this presentation by his colleague Mr. Willis Hon, a partner in the Nossaman LLP law firm who serves as special counsel to the Committee.

<u>Status of Governmental Agency Interactions, Response to the California Public Utilities Commission Pending Decision in R.23-01-0-07, Decision on Phase 2 Issues including Future Funding for Committee Activities and other Financial Matters, Regulatory and Administrative Matters including review of a Proposed Fourth Restatement of the</u>

Attachment N

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The FFT made a recommendation to the DCISC to schedule an observation of electronic procedure usage in the plant during the next fact finding visit which includes Dr. Peterson as the member conducting the fact finding visit [D12/15/25 FF – 3.14].

Dr. Gene Nelson of Californians for Green Nuclear Power was recognized. Dr. Nelson commented on the issue of stress corrosion cracking of the spent fuel canisters and observed this has been an issue concerning which Ms. Donna Gilmore has raised concerns for a number of years and Dr. Nelson stated in his opinion Ms. Gilmore's concerns were based upon a failure to understand that spent fuel is a dense ceramic-like solid, twice as dense as lead.

On a motion made by Dr. Scarlat, seconded by Dr. Meshkati, the December 15-16, 2025, Fact Finding Report was unanimously approved.

C. The Chair requested Consultant Mr. McWhorter to provide a report on the January 20-21, 2026, fact-finding visit with Dr. Meshkati. Mr. McWhorter reviewed the topics discussed with PG&E during the January 2026 visit as follows:

➢ Unit 1 Feedwater Heater Leak & Shutdown for Repair – Consultant McWhorter stated this topic was in follow up to the December 15, 2025, Fact Finding Report to receive more details on the feedwater heater leak which occurred on that date. The feedwater heaters are shell and tube heat exchanges that use extraction steam to preheat the condensate water. There are six stages with three parallel trains[15] in each. There is a total of 18 feedwater heaters per unit, with stage 1 being a part of the Feedwater System and stages 2 through 6 a part of the Condensate System, with condensate water flowing through the tubes with steam on the shell side. He displayed and described an illustration of the cascading operation, from Stage 6 to Stage 1 of the feedwater heaters.

On December 15, 2025, a high level alarm was received in the Control Room for Unit 1 Feedwater Heater 6C and upon inspection a large amount of drain water from Heater 5C was found to be draining to Heater 6C due to a tube leak in Heater 5C. Unit 1 power was reduced to 91% and Heaters 5C and 6C were isolated. Mr. McWhorter reported plant operation could have continued in that configuration indefinitely, albeit at lower power production levels. However, to perform repair of a feedwater heaters the plant needs to be fully shut down to isolate the steam on the secondary side[16] as extraction steam is coming from the turbine and the boundaries for safety purposes from that extraction steam are inadequate. DCPP management made the decision on December 16, 2025, to shut down Unit 1 and make repair immediately. Upon opening Heater 5C a number of tubes were found ruptured and several had indications and 27 tubes were repaired and the feedwater heaters returned to service in 44 hours with full power restored at 0900 on December 19, 2025.

[15] An equipment train is the sequential arrangement of machinery, units, or components used to produce a result or to process or move a product. It is often defined as a series of connected components.

[16] Primary and secondary side refer, respectively, to the Reactor Coolant System which is used to remove heat from the nuclear reactor (Primary side) and to the Main Steam and Feedwater Systems which provide cooling to the steam generators and generate and provide steam to the turbines (secondary side).

Mr. McWhorter reported the December 15, 2025, event was similar to a tube leak on Heater 5B in 2021 and the DCISC reviewed the Root Cause Evaluation (RCE) on that event at the February 2022 public meeting and reviewed in depth during the February 2022 fact finding. The RCE found the tubes failed due to stresses in areas around the drain cooler shroud, where the coldest water enters the lower section of the heaters and the water draining from the condensed steam accumulates together in that section creating a mixed steam-water flow which is very hard on the tubes and shrouds causing them to erode away and allowing some of the mixture to damage the tubes. Mr. McWhorter reported at the time of the 2022 event the plant was planning to close by 2025 and feedwater heater replacement was not considered as a corrective action. Eddy current testing[17] was done for Heater 5C during the spring 2025 refueling outage. There were also actions taken in 2022 to improve the operator's ability to diagnose and respond to these events and Mr. McWhorter reported those corrective actions were appropriate.

A Cause Evaluation (CE) will be performed for the 2025 event which will focus on whether there is anything else necessary for the bridging strategy but Mr. McWhorter observed the long term solution is to replace the feedwater heaters as they are at the end of their service lives and little can be done with the issues affecting the shrouds and supports inside the tube bundles which are inaccessible for repair or individual replacement. DCPP has procured 12 new feedwater heaters for each unit which is sufficient to replace all the heaters in Stages 3 through 6. Mr. McWhorter reported the Stage 1 and 2 heaters are in better condition and are easy to access without the need to move equipment. For the procurement, 18 of the 24 are expected to be delivered in late 2026 and the remaining 6 in 2027. Mr. McWhorter reported plans for installing the new heaters are not clear at this time and depend upon plans for future operation and the potential for another failure of a heater. He displayed photos of the FFT touring the area and inspecting the feedwater heaters. In response to Dr. Peterson's observation Mr. McWhorter reported replacement of feedwater heaters is a complex evolution that requires preplanning, staffing, and equipment and likely cannot be done in one month's time and would require more than a 30-day planned outage with the feedwater heater replacement being on the critical path. He described some of the complications with the load path required for replacement of the heaters which are very long and quite heavy. In response to Dr. Peterson's query Mr. McWhorter confirmed the complications of the physical layout affects the removal and replacement of the feedwater heaters and it also depends upon which feedwater heater is to be replaced and as the bulk of some of the feedwater heaters is within the neck of the condenser this further complicates their removal and replacement.

The FFT concluded the subsequent actions and shutdown after the December 15 feedwater heater failure were well managed by DCPP and the actions taken in 2021 in response to a similar event appear to have been effective. A cause evaluation for the 2025 event will be performed and DCPP is proceeding with acquiring 12 replacement heaters for each unit to be on site in late 2026 and early 2027, however no plan has yet been approved for installation of the replacement heaters.

[17] Eddy current testing (ECT) is a non-destructive testing (NDT) method that uses electromagnetic induction to detect surface and near-surface flaws in conductive materials. It is highly sensitive, fast, and requires minimal surface preparation, making it ideal for finding cracks, corrosion, and measuring coating thickness in industries like power generation.

Attachment O

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Circulating Water System. The water is delivered by the large (18"- 22") 40-year old piping and is also used to spray wash the traveling screens. The coatings of the pipes is aging and will be replaced with an alloy of stainless steel, impervious to the saltwater environment. He reported in response to Dr. Scarlat's question that the old piping was coated on the inside with a plastic core-type coating and on the outside hand-coated with a fibrous tar-like substance tape. Mr. Bates commented the piping is in close proximity to the circulating water pumps and the pumps must be protected from a saltwater leak.

➢ 230kV Replay Replacement – replacement of old electromechanical relates with digital relays.

➢ 500kV Tie-Line Relay Upgrade - replacement of old electromechanical relates with digital relays.

➢ Auxiliary Transformer 1-1 Radiator Replacement.

Mr. Bates reported 12 feedwater heaters per unit are reaching the end of their service lives and there is a contingency implementation project under another project director, Mr. Mark Sciacca, to replace the feedwater heaters should a feedwater heater fall beyond normal repair. Low pressure feedwater heaters, 12 per unit, have been purchased and will arrive in mid-2027 and they will be installed if required on a contingent basis. Mr. Bates confirmed Dr. Peterson's observation that there are complicated issues of access due in part to the seismic bracing installed after the feedwater heaters were installed and shoring will be needed on the decks to allow the feedwater heaters to roll across the deck and he described these as N-1 activities.

In response to Dr. Scarlat Mr. Bates stated the heaters are the size of two or three Volkswagen buses parked back-to-back and they will need to be rolled through narrow passages within the plant and various impediments to their passage will need to be temporarily removed. He stated the feedwater heaters generally have a 30-40 year lifespan and are not designed to be replaced. He stated the N-1 designation means the outage for their replacement is unknown. Mr. Bates stated the heater(s) being replaced would be removed prior to the outage. Mr. Bates observed use of the feedwater heaters provides higher efficiency and they are fairly complicated pieces of equipment. He remarked new computer codes will allow PG&E to design the feedwater heaters and they will be fabricated of new materials, more efficiently. Dr. Peterson observed by the increase in efficiency through new feedwater heaters this means getting more electricity on the grid and less waste heat into the ocean. Mr. Bates, responding to Dr. Scarlat, stated replacing the feedwater heaters is very costly and also disruptive and it takes a fairly long outage to do this work and the health of the operating heaters is being monitored closely including by eddy current testing on the tubes and by inspections conducted from the shell side.

Mr. Bates stated that if a tube breaks in a feedwater heater this caused the water level to go uncontrollably high which requires valving that heater out of service which in turn reduces thermal efficiency of the steam plant in a cascading fashion and one feedwater heater affects the others as they are interdependent and loss of a feedwater heater means a loss in megawatts. He stated DCPP is managing the health of the feedwater heaters. In response to Dr. Scarlat, he stated the economics presently dictate that maintenance be performed rather than proactive replacement. He stated feedwater heater replacement planning is approximately an 18-month effort. In response to Dr. Scarlat, Mr. Bates stated that if the plant were to run for a full 20-year extension this plan would likely be different and it would be likely that all 12 replacement heaters would be needed and replacement would not be easy in any scenario as they cannot be simply cut out and replaced.

Dr. Peterson reported a DCISC FFT was on the site when the feedwater heater failed and precipitated shutdown and he remarked the heaters are very close to the end of life and since a propagating failure could cause catastrophic damage and this risk is mitigated if the feedwater heaters are replaced and he stated PG&E's strategy as described by Mr. Bates appears to be logical. Mr. Bates stated in order to install the feedwater heaters a longer than normal outage is required and this will increase the cost of the outage. Dr. Scarlat stated the use of the term "catastrophic" does not mean catastrophic for the public, but rather from an engineering perspective.

Mr. Bates stated the scenario he fears is where a tube breaks inside a feedwater heater and the tube then thrashes around and damages other tubes and this happening cannot be determined from external observation. He concurred with Dr. Meshkati's comment that a feedwater heater failure does not necessarily have plant safety impacts, but rather on plant performance. Mr. Bates confirmed in response to Dr. Meshkati's observation that funding and approval for ordering and receiving replacement feedwater heaters has been received, but Mr. Bates said he did not know when a second phase concerning their installation was planned but he stated it is not scheduled before 2030.

In response to Dr. Meshkati's comment concerning the Main Annunciator System Replacement Project Mr. Bates confirmed the system replacement will occur for Unit 1 during 1R26 and during the outage Mr. Bates stated that although the Unit 1 and Unit 2 Control Rooms are adjacent and adjoining, he did not expect untoward disruption to the Unit 2 operators in the Control Room. He stated the system's presentation will be exactly the same for Unit 1 as for Unit 2 and the majority of the work will be done with both units operating by use of behind-the-scenes work to run cable. During the outage only the light boxes will be removed and the flat panels installed in that location. Dr. Meshkati stated his belief that there will be some disturbance by the work and Mr. Bates stated he did not envision untoward disruption to the Unit 2 operators and there are no plans to physically separate the Unit 1 and Unit 2 Control Rooms. A mock-up of the new Annunciator System will be built to demonstrate the changes and the installation and the work will be performed with the least amount of disturbance and he confirmed the Simulator facility will receive the entire new system. He confirmed Consultant McWhorter's statement concerning DCPP having benchmarked the Annunciator Replacement Project with other nuclear power plants with a common control room and Mr. Bates stated some of those plants have done the replacement online. Following 1R26 Unit 2 will have the same work done during 2R26.

Mr. Bates displayed and discussed photos of the equipment and components he described during his presentation.

Ms. Corral introduced Director of Business and Technical Services Mr. Bryan Ketelsen to continue the PG&E presentations. She reported Mr. Ketelsen is responsible for financial

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lesser component based on operational duration. He stated components are typically designed for a 40-year operable lifespan. He stated there is an ongoing CPUC proceeding and oversight by the Department of Water Resources related to the five-year extended operation period. He stated that with a twenty year license and state-approved operating period DCPP would likely look uniformly at replacing all the feedwater heaters in one refueling outage and the way PG&E is approaching that project now is indicative of a short-term extended operational period. Dr. Scarlat commended PG&E for its proactive position regarding the five-year horizon while planning in parallel for other outcomes and she stated it is unfair to blame PG&E for being dishonest when in their efforts they are going above and beyond in supporting safety.

Dr. Nelson of California for Green Nuclear Power stated his opinion that an example of this proactive conservative approach was replacement of the steam generators in 2008-2009.

Dr. Scarlat commented on the hazards created by a nuclear power plant and the need to manage those hazards responsibly and she remarked this pertains to safe operation of the plant. She stated it was important not to mix a safety conversation with the desire to shut down the plant on the premise that nuclear power is not a hazard society wishes to manage. She stated such a mixed discussion is counterproductive to safety. She observed the job of the DCISC is to understand if the plant is being run safely, it is not to decide whether the plant should run for five or for twenty years.

XI CONSULTANT REPORT & RECEIVE, APPROVE, AND AUTHORIZE TRANSMITTAL OF A FACT FINDING REPORT TO PG&E

B. The Chair requested Consultant Ms. Lisa Darden to provide a report on the December 15-16, 2025, fact-finding visit conducted with Dr. Peterson. She reviewed the topics discussed with PG&E during the December 15-16 2025 visit as follows:

➢ Maintenance Department Performance – Consultant Darden reported 2025 was a year which imposed a huge workload on the Maintenance Department with two refueling outages and many projects including 5 EDG work packages. All required extensive preplanning and preparation as well as the need to manage everyday preventative maintenance work. Ms. Darden reported DCPP hired supplemental temporary staff for one-year contracts with selected skillsets to assist the Maintenance Department.

Ms. Darden stated the Unit 1 and Unit 2 High Pressure Turbine Rotor and Stator Replacement Projects represented major projects during the respective refueling outages for the Maintenance Department. She stated the work was performed first on Unti 1 and was not part of the critical path but became part of the critical path when cracks were found in the casing and the lessons learned were applied during subsequent work on Unit 2 when the work was part of the critical path from the commencement of the Unit 2 outage.

Ms. Darden reported DCPP employs the 12-week "T-week" readiness review used widely in the nuclear industry for its rotating routine maintenance work schedules, e.g., T-6 meaning there are six weeks prior to execution of the work. She reported all the metrics were Green with the

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➢ Station Update – Mr. McWhorter reported there was nothing learned which was new from the presentation during the morning session

➢ Meet with NRC Resident Inspectors – Mr. McWhorter reported in the discussion with the Resident Inspectors the FFT commented and the inspectors agreed that the Unit 1 feedwater heater leak was well managed by the Operations staff.

➢ Safety-Security Interface – In response to Dr. Scarlat's observation about the role of Security in FLEX guidelines Mr. McWhorter stated he believes this is addressed in the fundamental design of the FLEX Program as to where resources would be drawn. Dr. Peterson stated FLEX is a good example of a strong synergy between security and safety as the same capabilities apply to a variety of initiating events.

➢ Quality Verification (QV) Program – Consultant McWhorter reported Mr. Chris Newport has been appointed Acting QV Director and he commented QV produces the Nuclear Quality Digest each month, a document with a good summary of QV's findings.

Consultant McWhorter reported concerning the Recommendation to the CPUC regarding funding for the Feedwater Heater Replacement Project that replacement of the feedwater heaters sooner rather than later although not a safety concern was a prudent action to avoid plant shutdowns and startups and Mr. McWhorter stated in his opinion there will be another failure of a feedwater heater in the next four or five years. Dr. Meshkati stated and Drs. Scarlat and Peterson agreed that concerning this matter the responsibility to safely manage the plant should be decoupled from the question about its future operation. Dr. Meshkati remarked the wording of the recommendation was carefully considered and the prior feedwater heater problem in 2021 and the prior recommendation made to the CPUC in the 34th Annual Report were also considered. Dr. Peterson remarked the feedwater heaters are in such a degraded state that they will continue to cause problems to plant reliability with more incidents and although the plant may continue to run there will likely be forced outages as a result. Mr. Rathie commented he would work with Mr. Zizmor of the CPUC Energy Division on transmitting the Recommendation. [On February 26, 2026, the Committee Recommendation concerning the Feedwater Heater Replacement Project was sent by email to the CPUC Energy Division.]

Dr. Gene Nelson of Californians for Green Nuclear Power was recognized. Dr. Nelson stated he supported the recommendation to the CPUC concerning the feedwater heaters and as an amateur radio operator he was very aware of problems with interoperability of radios.

In response to a query from Consultant Kadak Mr. McWhorter confirmed that root cause evaluations and cause evaluations both look at extent of condition.

Mr. McWhorter requested approval of the Fact Finding Report with the changes to the recommendations discussed concerning the Boric Acid Corrosion Program and revisiting common cause evaluations, and on a motion made by Dr. Peterson, seconded by Dr. Scarlat, the January 21-22, 2026, Fact Finding Report was unanimously approved with Dr. Scarlat stating her approval included the Use of Common Cause Evaluation in the Corrective Action Program as

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On a motion by Dr. Peterson, seconded by Dr. Scarlat, a motion was introduced and passed unanimously to accept PG&E's Response as supplemented to the DCISC's 35th Annual Report and to adopt Resolution 2026-04 regarding the next steps in the process of the review conducted by the SRT.

Mr. Rathie stated that during the discussion on the January 2026 Fact Finding Report there were amendments made to the report and the report contained a recommendation to the CPUC expressing Committee support for the funding of the Feedwater Heater Replacement Project. He reported it was his understanding the funding for that project would be addressed in a CPUC proceeding concerning allocation of the volumetric performance fees which may have a component regarding funding for replacing the feedwater heaters and the matter would be open for comments through March 31, 2026. Mr. Rathie expressed his view that the Committee's Recommendation concerning the Feedwater Heater Replacement Project should be expeditiously transmitted to the CPUC Energy Division and not wait for the completion of the 36th Annual Report which, per past practice, incorporates and transmits the Committee's Recommendations to the CPUC and others. He stated that Resolution 2026-03 provides for approval of the Fact Finding Reports presented at this meeting and for the transmittal of the Committee's Recommendation on the Feedwater Heater Replacement Project to the CPUC Energy Division following this public meeting.

Dr. Gene Nelson of California for Nuclear Power was recognized and stated Californians for Green Nuclear Power approves and endorses the course of action described by Mr. Rathie.

Ms. Linda Seeley of Mothers for Peace was recognized. In response to Ms. Seeley's question Mr. Rathie replied it was his understanding that the CPUC proceeding, if it takes up the issue of the Feedwater Heater Replacement Project, would be in the nature of an allocation of volumetric performance fees not an increase in those fees.

Mr. Robert Sarvey was recognized. Mr. Sarvey stated he was concerned that PG&E has convinced the CPUC that the DCISC made no Recommendations in its 34th Annual Report. He stated the DCISC Recommendations are important as any recommended upgrades need to be evaluated by the CPUC in terms of the collective costs of the project and a determination made as to cost effectiveness. [There were two Recommendations made to PG&E and one Recommendation made to the CPUC in the DCISC's 34th Annual Report and the Report was transmitted to the CPUC by Federal Express on December 30, 2024.]

On a motion by Dr. Meshkati, seconded by Dr. Scarlat, Resolution 2026-03 was unanimously adopted.

Mr. Rathie reported concerning financial matters and stated the Committee in 2026 is under a new baseline funding methodology, based upon an average of Committee expenditures for 2023, 2024 and 2025, that has produced a significant increase in Committee funding over the previous allocations. This new method will continue for future calendar year funding. Mr. Rathie cautioned the Committee would still be well advised to operate within its means each year and in response to Dr. Scarlat's query he stated that should the Committee overspend its funding allocation in any year, under the new methodology that amount is recovered in the next

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independent trains of fans, dampers, heaters, and air conditioning for each unit that serve a common Control Room. The CRPS is composed of one train of pressurization fans and filters for each unit. These systems are interconnected mechanically and operationally and are intended to be operational during all plant operating modes. The CRHVAC and CRPS operate in one of the following modes:

Mode 1	Normal mode
Mode 2	Smoke removal mode to remove smoke in the Control Room
Mode 3	Recirculation with 100% air recirculation and 27% passing through High Efficiency Particulate Air (HEPA) filtration
Mode 4	Pressurization to counteract the detected presence of radiation at the Control Room air intake or in response to a Containment Isolation signal

Although formal system health monitoring was no longer required for the CRVS, the system was generally in good health with minor issues and problems. There were no significant failures of system equipment within the last two years. An issue discussed during the DCISC's last review concerning recurring air conditioning compressor trips had been resolved by changing the startup and shutdown sequences for the compressors. Similarly, actions taken to improve maintenance practices for isolation dampers have proven effective in resolving an issue with frequent damper shaft failures.

Currently, the main issue affecting the CRVS was degradation of outdoor equipment due to corrosion, primarily on the air conditioning condensers. The degradation of outdoor condensers was not planned for corrective action under the previous plan to cease power operations in 2025. However, with the possible extension of power operations, it was now expected that the outdoor condensers would be replaced in the near future. That replacement would probably occur as a part of a larger project for replacement of all HVAC systems at the station that still contained refrigerant R-22 (see Section 3.9.2.c below).

Periodic testing is performed for the integrity of the Control Room ventilation envelope, which is a controlled HVAC atmosphere in the Control Room to protect operators from outside harmful gases or radioactivity. The envelope is periodically demonstrated by performing leakage testing using tracer gases. Such testing was done approximately every six years and was recently successfully completed in early 2023. No major issues were identified during the Control Room leakage testing.

The ABVS consists of fans, dampers, ducting, and filters whose function is to supply, heat and/or cool, filter, and discharge air for the Auxiliary Building. The ABVS provides cooling and/or heating for both personnel and equipment, including several components of the Engineered Safety Feature System. The ABVS consists of two supply fan units with roughing filters and two discharge fan/filter units with roughing, HEPA filters, and charcoal filters, along with extensive ducting

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these two systems are both safety-related, with the Control Room Ventilation System providing air filtering, heat and cooling, as well as protection for operators through pressurization of the Control Room to prevent in-leakage in an accident involving release of radiation. The Auxiliary Building Ventilation System provides ventilation and cooling to safety-related equipment in that building and can filter the atmosphere in the Auxiliary Building in the event of a release of radiation. He reported both systems are in good health, which represents an improvement for the Auxiliary Building system, with the Control Room system having some issues with corrosion of outside components, particularly the condensers for the air conditioning system. Mr. McWhorter reported plans are to replace all systems at the plant containing the refrigerant R22. He reported the Control Room in-leakage test was recently completed with no major issues identified. The Auxiliary Building Ventilation System has in the past experienced issues with dampers which resulted in several NRC Maintenance Rule functional failures and a corrective action plan was developed and the system has now been returned to (a)(2) status under the Maintenance Rule.[3] Flow balance and charcoal and HEPA filter testing has also been completed satisfactorily and Mr. McWhorter reported both systems are in good health and performing well.

→ Inservice Inspection (ISI) Program – the FFT inquired as to current status of compliance with American Society of Mechanical Engineers (ASME) Section 11 Code which requires inspections and tests of pressure vessels and piping. During a typical refueling outage, 35-45 welds are tested using non-destructive examination and a large number of pressure tests are performed, as well as system walkdowns. Mr. McWhorter reported DCPP is in a fourth inspection interval and has commenced its third inspection period within that interval. He reported the ASME Section 11 Code is organized around 10-year intervals with each interval containing three inspection periods of typically three years each, intended to cover two scheduled refueling outages. DCPP is approaching its Unit 1 and Unit 2 R24 outages which are within the first part of the third inspection period and all inspections are being regularly scheduled as required by extended operations and no inspections were overdue due to the previous plan to cease operation in 2024 [Unit 1] and in 2025 [Unit 2]. Mr. McWhorter reported no exemptions are needed to meet the ASME Section 11 Code requirements. He reported during the twenty-fourth refueling outage for Unit 1 (1R24) standard ISI Program inspections are planned as well as inspections required for license renewal for tanks and piping and he reported DCPP has been able to secure a sufficient number of contractors to support these efforts. The FFT concluded the ISI Program is well planned and implemented.

→ Large Transformers- Consultant McWhorter described this as a routine review of the 14 large transformers at the site, with 6 transformers dedicated to each of the two nuclear units and 2 transformers which are shared by the units. He reported in general all are in good health, but there have been minor oil leaks and some issues with corrosion due to the salt air environment which given extended operation are now planned to be addressed in the 1R24 and 2R24 and the 1R25 and 2R25 refueling outages, focusing during each outage on 3 transformers serving the respective units and to do power factor testing on all transformers. He reported a slight upper trend of ethane in the gas analysis for Transformer 1-C will continue to be monitored. Mr. McWhorter

Attachment U

PG&E data response DR_A4NR_002-Q007Atch01

U-0

Notification: **51140794** Type: **DN** Work Type: **EVAL RMOD**

Description: **RMOD request Condenser Coil**

Order:

Funct. Loc: **DC-0-85** **U0 SYS 85 WAREHOUSE SPARE PARTS**

Reported By: [redacted] Rpt By Work Ctr: **SMT**

Contact Info: Created On: **12 Jan 22 17:30**

Planner Group:

Main Wrk Ctr: **EDM-PRJ** Mechanical Projects

PROBLEM DESCRIPTION

01/12/2022 17:30:21 PST [redacted]

Stock Code D949044, COIL CONDENSER W/CU FINS CONN UNIT 2, is obsolete with no replacement option.
MNFR = Trane

Procurement requested Trane provide a replacement option but they would not bid.
Therefore, engineering needs to specify a replacement, including technical and quality requirements and associated dedication activities.
Please note that Trane is not on the QSL. Please reference RPE H-7315 and drawing 663239-59.

This condenser coil is used on the following FLOC's:
DC-2-23-M-HX-CR37/CR38
This is for Unit 2 only as per SAPN 51038368.

Maintenance has requested that a replacement is procured due to recent issues on CR37. Please reference SAPN 51128183.

Event Date **12 Jan 22** Station Sig.: **5 Other**

Notif Required By **31 Dec 23** DN 5 Priority: **4 - Track**

Reference Notification:

U-0	Notification: **51140794** Type: **DN** Work Type: **EVAL RMOD** Description: **RMOD request Condenser Coil** Order:

No immediate work order demand exists for this condenser coil. This request is for stock.
01/12/2022 17:32:57 PST [redacted]

Assigning the SAPN to system engineering to evaluate the obsolescence.
01/13/2022 14:00:09 PST [redacted]
.
The issue/event documented on this notification was reviewed by the Notification Review Team (NRT) and determined to be the indicated significance level per OM4.ID14. If additional information is discovered that would affect the significance level determination, create a NRT Re-review task by clicking on the "NRT Re-review" button in the Action Box.
.
07/11/2022 09:09:22 PST [redacted]

The due date of this SAPN is being extended to 08/15/22, due to competing priorities and limited resources.
12/21/2023 08:43:41 PST [redacted]

This request is no longer needed since the entire CRVS A/C refrigerant loop will be replaced by an approved Project (PHIP 2023-S023-003), listed as a PMO++ Top Tier Priority item. A replacement coil will not be pursued in the interim due to the need for customization to fit within the existing housing and match original design performance. This would require a design change and extensive vendor input/cost.

STATUS DETAILS

System Status: **NOCO ATCO**

User Status: **20** **APPV** Approved

SFMR Shift Foreman Reviewed

Attachment V

PG&E data response DR_A4NR_001-Q005Atch01

PMO++ Item 136 - CRVS A/C Equipment Replacement

2023-S023-003

GATE 1

Block 1

Status:	Initiated
System:	023 - Ventilation and Air Conditioning (HVAC)
Classification:	Discretionary
Input Source:	Obsolescence
Unit:	1 and 2
Design:	Major

Block 2

Issue Owner:	[redacted]
Issue Sponsor:	[redacted]
Issue SAPN:	50944868
ROM:	250,000
Priority Matrix Score:	45

Block 4

Problem Statement

Control Room A/C System has a long history of reliability issues including failure of the standby unit to start on demand. Much of the Control Room A/C System equipment are heavily corroded/degraded due to both its age and being located outdoors and, thus, constantly exposed to harsh outdoor moist/salty air. The following issues are created because of the continuing degraded condition of the Control Room A/C System equipment:1) Condensers are vulnerable due to exposure to outdoor air; moisture and salt effect on carbon Steel. 2) Capacity control dampers, condenser housing, and supports are rusted and require extensive repair.3) The condensers require extensive maintenance (and EFIN work) due to the units having seen significant degradation and being heavily corroded.4) The A/C system is sized to meet accident conditions which requires 1 train (unit) of Control Room A/C System to cool the entire Control Room envelope. Therefore, this A/C system runs at around 50% of its maximum cooling capacity during normal plant operation. Not a desirable operating condition. If the A/C system had the ability to downward adjust its cooling capacity during normal operation, this would improve operational efficiency for the system.5) Replacement parts for the A/C system are typically difficult to procure because many of the parts are now obsolete due to their age.6) Resolution of Control Room A/C system equipment issues may sometimes require adding R-22 refrigerant. R-22 refrigerant is banned from sale in California and the existing R-22 refrigerant available onsite at DCPP is depleting. With the decision to extend the operations of DCPP, there is now not likely to be sufficient R-22 refrigerant inventory to last until the end of DCPP operations.7) At the current rate of equipment degradation, there is an ever-increasing likelihood of having multiple equipment failures occurring around the same time. At least 1 Control Room A/C unit (total between both Units' CRVS) is required to function in order to meet Control Room ambient temperature requirements per ECG 23.5. A loss of 2 Control Room A/C units within the same Unit's CRVS requires alternate cooling measures be implemented (per OP H-10:IV) in order to achieve adequate Control Room cooling . Alternate cooling per OP H-10:IV is provided by staging/operating portable fans (and/or opening doors). If no Control Room A/C units are available and functional, then ECG 23.5 is entered and the plant must immediately commence shutdown actions per LCO 3.0.3.

Background

This is a request for future work to support continued operation of the plant.Relevant FLOCs:DC-1-23-M-BC-CP-35DC-1-23-E-MTR-CP-35DC-1-23-M-HX-C35DC-1-23-M-HX-CR35DC-1-23-P-V-VAC-1-505DC-1-23-P-V-VAC-1-506DC-1-23-P-V-VAC-1-507DC-1-23-I-SV-SV-5019DC-1-23-I-I-PI-5048DC-1-23-I-I-PI-5073DC-1-23-I-I-PI-5077DC-1-23-I-I-PI-5081DC-1-23-I-V-1-23P-50ADC-1-23-I-V-1-23P-50BDC-1-23-M-BC-CP-36DC-1-23-E-MTR-CP-36DC-1-23-M-HX-C36DC-1-23-M-HX-CR36DC-1-23-P-V-VAC-1-502DC-1-23-P-V-VAC-1-503DC-1-23-P-V-VAC-1-504DC-1-23-I-SV-SV-5021DC-1-23-I-I-PI-5049DC-1-23-I-I-PI-5075DC-1-23-I-I-PI-5079DC-1-23-I-I-PI-5083DC-1-23-I-V-1-23P-49ADC-1-23-I-V-1-23P-49BDC-2-23-M-BC-CP-37DC-2-23-E-MTR-CP-37DC-2-23-M-HX-C37DC-2-23-M-HX-CR37DC-2-23-P-V-VAC-2-505DC-2-23-P-V-VAC-2-506DC-2-23-P-V-VAC-2-507DC-2-23-I-SV-SV-5020DC-2-23-I-I-PI-5052DC-2-23-I-I-PI-5072DC-2-23-I-I-PI-5076DC-2-23-I-I-PI-5080DC-2-23-I-V-2-23P-60ADC-2-23-I-V-2-23P-60BDC-2-23-M-BC-CP-38DC-2-23-E-MTR-CP-38DC-2-23-M-HX-C38DC-2-23-M-HX-CR38DC-2-23-P-V-VAC-2-502DC-2-23-P-V-VAC-2-503DC-2-23-P-V-VAC-2-504DC-2-23-I-SV-SV-5022DC-2-23-I-I-PI-5053DC-2-23-I-I-PI-5074DC-2-23-I-I-PI-5078DC-2-23-I-I-PI-5082DC-2-23-I-V-2-23P-59ADC-2-23-I-V-2-23P-59B

Over the years, long-term degradation has caused numerous issues on the CRVS A/C equipment. A search in SAP yielded the results below:SAPN 50036380 - CR-38 CORRODED HOUSINGSAPN 50199526 - corrosion of Condenser cr-38SAPN 50275121 - CP-38 LeakingSAPN 50305607 - CR-37 CorrosionSAPN 50316918 - U2 CP-38 has an oil leakSAPN 50319431 - CP-38 oil leakSAPN 50322431 - CRVS CP-36 low oil levelSAPN 50406721 - Corrosion on CR37 condenserSAPN 50414338 - Minor fitting leak at PI-5080 for CP-37SAPN 50443094 - U2 PI5082 for CP 38 has an oil leakSAPN 50464945 - Glycerine Leaking from PI-5078SAPN 50496508 - PI 5076 discharge pressure gauge leakingSAPN 50503563 - CR38 fan housing is degradedSAPN 50504853 - CR36 had degraded door

PMO++ Item 136 - CRVS A/C Equipment Replacement

2023-S023-003

hingeSAPN 50518935 - Corros. on CR38 Mounting (Unit 2)SAPN 50519813 - Corrosion on base HVAC Condenser CR37SAPN 50519823 - Corrosion on actuators/tubing HVAC CR37SAPN 50569294 - Replace HVAC CR37 Copper TubingSAPN 50607514 - Replace CR37 filter assemblySAPN 50624807 - CR-35 Diverter actuator leaking freonSAPN 50637884 - CR-36 Filter Bank Access Door degradedSAPN 50637885 - CR-36 Filter Frames coating is degradedSAPN 50637911 - CR-36 FLEXIBLE BOOT DAMAGESAPN CR36 housing replacementSAPN 50665229 - CR-36 Damper Leaking FluidSAPN 50681229 - Degraded Coatings CR-38SAPN 50692083 - Minor Oil Leak on CP-35SAPN 50711019 - CP-38 has a leak on condenser coilSAPN 50861534 - Leak on CP-38 Expansion TankSAPN 50862378 - Refrigerant piping leak at receiver tankSAPN 50910229 - CP-36 small oil leak at motorSAPN 50933584 - CP-38 Refrigerant LeakSAPN 50935056 - Corrosion metal loss @ CR-38 Fan HousingSAPN 50935653 - Corrosion on CR-37SAPN 50946362 - Request new PM to monitor CR37SAPN 50946397 - small refrigerant leak at motor j-boxSAPN 50949587 - CR35 oil leak found at sight glass.SAPN 50970639 - Replace CP 37 compressor unitSAPN 50970808 - CR37 replace dryer cartridgeSAPN 50974337 - sheet metal degraded on CR36SAPN 50979145 - CP -36 MAIN CONTACT EROSIONSAPN 50979146 - CP- 36 MOTOR J BOX REFIGERANT OIL LEAKSAPN 50979147 - SMALL REFIGERANT LEAK AT CP-36 VALVESAPN 50983953 - Repair or Replace VAC-2-502SAPN 50983954 - Repairor Replace VAC-2-503SAPN 50983955 - Repairor Replace VAC-2-504SAPN 50983956 - Repair/Replace Filter Dryer HousingSAPN 50983957 - Repair/Replace Pressure Relief ValveSAPN 50985646 - Replace CP 38 compressor unitSAPN 50990143 - Replace CR35 filter boxSAPN 50993927 - Replace CR38 condenser coilSAPN 50994828 - D955449 Refurbish and RTSSAPN 50999515 - CREH Self-Assessment DeficiencySAPN 51038309 - CR-38 corroded parts need fabricatedSAPN 51040543 - CR-36 damper actuator leaking oilSAPN 51048581 - CP-36 liquid line solenoid valve leakbySAPN 51070045 - 2-SV-5020 RebuildSAPN 51072348 - Cr-37 fan hatch hinges degradedSAPN 51072904 - CR37 Fan Hatch Door & Frame DegradedSAPN 51073679 - Oil Leak at CP-36SAPN 51092878 - CP-36 Leak Rate Tracking EV2.DC6SAPN 51118226 - Cr-36 condenser damper bladeSAPN 51118346 - Replace CR-36 condenser coilsSAPN 51118868 - Degraded bypass damper on CR-36SAPN 51114659 - Refrigerant leak identified on CR-36SAPN 51121514 - Degraded component CP37AX at CP-37SAPN 51128183 - CR-37 condenser refrigerant leakSAPN 51133202 - CR-38 Refrigerant leak at Filter/DryerSAPN 51144201 - CR-38 has through wall refrigerant leakSAPN 51150089 - CP-37 potential leakSAPN 51151119 - Document Refrigerant Leak on CP-36SAPN 51182972 - Hole in flexible boot on CR37SAPN 51182973 - corrosion on fan housing CR-37SAPN 51183292 - discharge valve found leaking VAC-2-506SAPN 51192728 - CR-36 Housing and dampers degradingThe CRVS A/C equipment is in various states of degradation that have resulted in a considerable increase in corrective maintenance scope and frequency over the years. The station has not over time proactively addressed these now long-standing air conditioning equipment issues prior to reaching their present degraded state. Much of the CRVS A/C equipment is nearly 40 years old and is located in environmentally harsh conditions. Additionally, because of the age of the equipment, many of the parts are now obsolete, making the ever-increasing need to replace parts very difficult. Also, there are refrigerant leaks that occur to varying degrees on CRVS A/C equipment, creating potentially environmental and regulatory challenges. The increased frequency and scope of all CRVS A/C issues challenges Maintenance craft in keeping up with routine preventative maintenance.Additionally, due to the diminshing supply of onsite R-22 refrigerant (and the inability to procure new R-22 refrigerant), a new/replacement refrigerant for R-22 refrigerant systems (such as the CRVS A/C system) will be procured. The replacement CRVS A/C equipment will need to be compatible with the new/replacement refrigerant. This is a general issue for all A/C systems onsite that use R-22 refrigerant and a study is being performed per a separate PHIP (ref. SAPN 51192937) to determine a suitable replacement refrigerant.

Consequence of Deferral

Continued higher than expected maintenance to keep system tuned for reliable service and intermittent losses of individual component MR required availability. Continued degradation of condenser units operating in salty humid environment. Increased maintenance frequencies as a result of continued degradation. It is very likely at the current rate of equipment degradation that there could be larger, consequential failure of CRVS A/C equipment if not replaced in the next few years or so (requiring extensive corrective maintenance, impacting Operations, and increasing the possibility of entering shutdown LCO 3.0.3 per ECG 23.5). There will be an increasing cost for performing more preventative/corrective maintenance over time as the equipment continues to degrade.

Bridging Strategy

Keep current system functional through continued preventative maintenance until equipment replacements have been made.If a component within a Control Room A/C subtrain fails, there exists multiple RPEs to reverse engineer parts (8*5093, 8*5159, 8*5292, and 8*6070).If 1 Control Room A/C subtrain in each Unit's CRVS is lost (due to the ever-increasing heavy corrosion/degradation of the A/C equipment), there would not be any operability impacts, since there is 1 redundant A/C subtrains within each Unit's CRVS. However, a loss of 2 Control Room A/C units within the same Unit's CRVS would require alternate cooling measures be implemented (per OP H-10:IV) in order to achieve adequate Control Room cooling. Alternate cooling per OP H-10:IV is provided by staging/operating portable fans (and/or opening doors).

PMO++ Item 136 - CRVS A/C Equipment Replacement

2023-S023-003

Block 5

Proposed Solution

The entire air-conditioning refrigerant loop with its associated equipment/piping is proposed to be replaced in both Unit's CRVS, utilizing a new commericially available refrigerant, as follows:1) Replace condenser room air intake filter racks to reduce moisture/salt in the condenser rooms. 2) Replace air-cooled condenser units (CR35, 36, 37, and 38), complete with:- stainless steel housing and dampers in order to withstand the outdoor salt laden air.- Condenser fans to have direct drive sealed VFD motors to improve operating life and reliability (fan belts eliminated).3) Replace compressors (CP-35, -36, -37, and -38).4) Replace evaporator coils (C35, 36, 37, 38).5) Replace refrigerant piping (including miscellaneous parts like valves, instrument tubing, pressure indicators, filter dryer, and strainer).6) Specify that the CRVS A/C system has the ability to control its cooling capacity during normal operation in order to improve operational efficiency.The project is seeking Gate 1 funding of $250K for design change scoping, including vendor equipment options review and selection. Once scoping effort is complete and vendor quote is finalized, PHPC Gate 2 presentation will be prepared for entire project effort.

Alternatives Considered

1) Do not implement any of the proposed scope of work. Continue operating the CRVS A/S System as-is. This is not recommended. This is zero project cost, but minimizes the potential safety, efficiency, and reliability improvements for the CRVS A/C equipment. Note that there will still be an increasing cost for preventative/corrective maintenance over time as the equipment continues to degrade.2) Reduce the work scope by only implementing some of the proposed scope of work. This is not recommended. This is a lower project cost, but does not maximize much-needed improvements to the safety, efficiency, and reliability of the CRVS A/C System. Note that there will still be an increasing cost for preventative/corrective maintenance over time as the equipment continues to degrade.

Block 8

Basis for Decision

Approvals Required:

1. Scope of selected alternatives considered/approved
2. Schedule considered/recommended - aligns with LROP
3. Cost considered/acknowledged
4. Determining Major Projects (Strat proj)

Attachment W

PG&E data response

DR_A4NR_001-Q005Atch02CONF

CONFIDENTIAL

Attachment X

PG&E data response

DR_A4NR_001-Q005Atch03CONF

CONFIDENTIAL

Attachment Y

PG&E data response

DR_A4NR_001-Q005Atch04CONF

CONFIDENTIAL

Attachment Z

PG&E data response DR_A4NR_001-Q005

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2027 Forecast
Application 26-03-031
Data Response

PG&E Data Request No.:	A4NR_001-Q005
PG&E File Name:	DCPP-ExtendedOperations2027Forecast_DR_A4NR_001-Q005
Request Date:	May 4, 2026
Requester DR No.:	001
Requesting Party:	Alliance for Nuclear Responsibility
Requester:	John Geesman
Date Sent:	June 2, 2026
PG&E Witness(es):	Brian Ketelsen – Diablo Canyon Power Plant

QUESTION 005

Please provide copies of all written communications about the Unit 1 and Unit 2 CRVS condensers used by or originated by the Diablo Canyon Plant Health Prioritization Committee between September 2, 2022 and the filing of A.26-03-031.

ANSWER 005

See the following attachments:

1. See Attachment 1 from September 12, 2023, which includes Gate 1 presentations requesting acceptance of a path forward and authorization to proceed with project scoping (filename, "*DCPP-ExtendedOperations2027-Forecast_DR_A4NR_001-Q005Atch01.pdf*").
2. See Confidential Attachment 2 from March 19, 2024, which contains confidential commercially sensitive vendor financial information (filename, "*DCPP-ExtendedOperations2027-Forecast_DR_A4NR_001-Q005Atch02CONF.pdf*"). This attachment provides Gate 1 Budget Trade presentation to realign currently approved funding between units and to request additional funding to complete scoping.
3. See Confidential Attachment 3 from September 17, 2024, which contains confidential commercially sensitive vendor financial information (filename, "*DCPP-ExtendedOperations2027-Forecast_DR_A4NR_001-Q005Atch03CONF.pdf*"). This attachment provides Gate 2 presentations requesting approval of scope, schedule, cost, and authorization to complete engineering design and implementation, as necessary.
4. See Confidential Attachment 4 from May 20, 2025, which includes projects reprioritization information (filename, "*DCPP-ExtendedOperations2027-Forecast_DR_A4NR_001-Q005Atch04CONF.pdf*"). A periodic meeting is held to evaluate any changes to the overall project portfolio and prioritization or adjust the current Long Term Financial Plan to align with station budgetary goals/targets.

Reprioritization is evaluated on the basis of plant risk, classification, resource availability, or current project status.

Personal employee information such as names and contact details has been redacted from these attachments pursuant to PG&E's confidentiality policy on employee-specific data.

Presentations of transition costs recovered through the Diablo Canyon Transition and Relicensing Memorandum Account in these attachments are redacted as they are out of scope for this proceeding.

Attachment Z1

PG&E data response DR_A4NR_001-Q005

PACIFIC GAS AND ELECTRIC COMPANY
DCPP Extended Operations 2027 Forecast
Application 26-03-031
Data Response

PG&E Data Request No.:	A4NR_002-Q011
PG&E File Name:	DCPP-ExtendedOperations2027Forecast_DR_A4NR_002-Q011
Request Date:	June 10, 2026
Requester DR No.:	002
Requesting Party:	Alliance for Nuclear Responsibility
Requester:	John Geesman
Date Sent:	June 24, 2026
PG&E Witness(es):	Brian Ketelsen – Diablo Canyon Power Plant

QUESTION 011

Regarding PG&E DR_A4NR_001-Q005Atch03CONF,

a) when was this document created?

b) please explain PG&E's rationale for the deferrals in the Unit 1 and Unit 2 CRVS projects noted on lines 43 and 44 on red-numbered p. 4.

ANSWER 011

PG&E observes that the document in reference in this question is incorrect and that the correct reference document is PG&E DR_A4NR_001-Q005Atch04CONF. PG&E responds as follows:

a) This document was developed over a three-month period leading up to the 05/20/2025 Plant Health Prioritization Committee (PHPC) meeting.

b) The Control Room Ventilation System (CRVS) Condenser Replacement project replaces the Control Room A/C system which has encountered reliability issues, including failure of the standby unit to start on demand. This project was in the early scoping phase when previous forecasts were developed, including in the referenced attachment, PG&E DR_A4NR_001-Q005Atch04CONF, and the forecast presented in the TLRES. Through further planning — identifying design and installation vendors and timelines for procurement and delivery of equipment — it was determined that the completion date for the project would not occur before January 1, 2027.

Attachment Z2

DCISC 34th Annual Report p. 626

Institute (NEI) requirements and measurements were taken for the High Pressure Turbine Replacement Project.

→ High Voltage Transformer Reliability Investments – main bank startup and auxiliary transformers made leak tight and power factor testing performed to assess health along with inspection of the internals to inform a long-term reliability or life-cycle management plan.

→ Main Condenser Seawater Expansion Joint Replacement – to improve reliability.

→ Main Condenser Steam Side Strap Project - to improve reliability.

→ Traveling Screen Frame Replacements - due to long-term effects of corrosion and the cost of repair.

→ Condensate Booster Pump Pedestal & Motor replacement – to improve reliability and reduce vibration on the motors.

→ Control Room Chart Recorder Replacements – upgraded to digital to provide better trending and to require less maintenance, performed as a cost-effective project for efficiency.

During his discussion of the 2R24 projects Mr. Wilson confirmed Dr. Budnitz' observation that the projects he described were also done for Unit 1 in 1R24. Dr. Peterson observed and Mr. Wilson agreed that one reason Unit 2 outages generally go well is due to the lessons learned from prior work done on Unit 1. Mr. Wilson observed there was more work done in 2R24 than in 1R24 because of lessons learned and efficiencies achieved from the experience with Unit 1.

Concerning upcoming 2024 daily and 2025 refueling outage projects Mr. Wilson reported 2024 projects to be performed online are focused on secondary plant reliability and critical spare parts inventory. Projects include Intake Cove dredging, improvements to the high voltage transformer spares, critical motor and pump procurement, Intake Structure upgrades, air compressor replacements, and HVAC studies to reduce the use of CFC gas. He reported 2025 refueling outage projects will continue to focus on secondary plant reliability, obsolescence upgrades, and required in-service inspections. The project list includes digital rod position indication display replacements, fuel transfer cart upgrades, traveling screen replacements, Intake Structure bar rack replacements, chart recorder upgrades, and reactor vessel inspections.

In response to Consultant McWhorter's inquiry concerning the Intake Cove Dredging Project Mr. Wilson reported mobilization has started, including staging tugboats and dredge barges, but the project schedule was deferred due to inclement weather, high swells and high wind. He reported sand will begin to be removed during the next week and will be continuous for a duration expected to take 24 days and to conclude in the middle or the end of July 2024. He reported the dredging spoils, approximately 60,000 cubic yards consisting mainly of sand, will be deposited in a location south of Morro Bay, California, which should assist in regenerating sandy beaches in the vicinity. In response

Attachment Z3

DCISC 34th Annual Report p. 760

Recommendations: **None.**

3.13 Intake Cove Sediment Issues

The DCISC Fact-finding Team met with Allen Wilson, Director of Projects, and Michael Jackson, Manager of Project Services and License Renewal, for an update on the status and impacts of sediment accumulation at the DCPP Intake Cove. This was the DCISC's first review of this issue.

During its reviews of equipment long-range planning and maintenance earlier in 2023, the DCISC became aware of an issue with intake cove sediment, and the FFT requested a briefing on the problem and its proposed solution. Mr. Jackson reported that the area of concern was in the intake cove from its entrance from the Pacific Ocean to the intake bar racks and screens located at the Intake Structure. This area was originally designed to have an average (base) depth of 36 to 38 feet. Over the last nearly 40 years of operations, about 16 to 20 feet of sand had accumulated in that area, significantly reducing the depth and increasing the velocity of seawater being drawn into the intake bays. The higher amount of sand and increased velocity of seawater made it more difficult for divers to keep the intake racks and bays clear of debris.

There was also a concern that the conditions made it more likely for kelp to be drawn into the intake and foul the racks or condensers. Kelp ingestion has the potential to cause the Circulating Water (CW) system to trip, which stops cooling of the steam turbine condensers and can result significant stress on plant systems, and possibly a turbine/reactor trip, due to inability to dump steam to the condensers. Concern about the potential to have the circulating water system trip due to kelp ingestion is the reason that the plant will reduce power during some winter storms. The FFT inquired about any possible effects of the silt upon the safety-related Auxiliary Saltwater (ASW) Pumps, and Mr. Jackson reported that the ASW pumps were not affected as the flow through their intake screens was much lower than for the CW pumps.

Approximately two years ago, DCPP began the permitting process to allow for dredging and sand removal to correct the problem. The effort was later abandoned due to the possibly high costs and time involved in completing the project given the previously planned cessation of power operations in 2025. With the more recent initiative to extend power operations, efforts had been restarted to obtain the necessary permits and contractor services to perform the dredging. It was currently believed that DCPP might be able to obtain a permit under an expedited process to allow dredging to begin as early as fall of 2023. It was expected that the dredging would take about 50 days and spoils would be disposed of at a permitted spoils disposal site in Morro Bay, CA. The FFT found that the plan was prudent, and the DCISC should continue to follow DCPP's efforts in this area.

Conclusions: **DCPP's plans to pursue dredging of the intake cove are**

Attachment Z4

DCISC 34th Annual Report p. 807

Regarding maintenance of the Intake Cove using divers, Mr. Rebel reported that PG&E routinely used divers in the Intake Cove to keep the intake bar rack area clean of debris and sand. The cleaning was performed periodically and was necessary to ensure that the traveling screens did not degrade or plug and that the area was kept clear to allow the installation of the bar racks for maintenance if needed. The cleaning involved using fire hoses to spray the bar racks and the sand near the intakes, with the material then being carried into the travelling screen system which removes larger material, and the smaller material including the sand then traveling through the Circulating Water System. The sand was cleared away from the intakes out to whatever distance was necessary to create a gentle slope that would ensure the sand could not collapse on divers working near the intake. The FFT asked if moving the sand through the Circulating Water System was allowed by the environmental permit, and Mr. Rebel reported that it was not precluded by any conditions of the station's environmental permits. He also noted that the sand which was moved by the divers was sand which had been swept from the ocean into the cove and was not a part of the cove's original bottom surface. Also, he pointed out that if the sand were not moved by the divers, the sand would eventually accumulate to a point where it would be picked up and carried through the system anyway.

The FFT then informed PG&E of the A4NR email and provided PG&E with copies of the two documents. The individuals present in the meeting were not aware of any similar concerns expressed by any plant employees in the past. The PG&E personnel suggested and the FFT agreed that the documents should be entered into the station's Employee Concerns Program (ECP) to receive a detailed investigation and evaluation similar to that which would be normally done had the documents been received anonymously from a plant employee. PG&E agreed to provide an update on its investigation at the DCISC's next Fact-Finding Meeting in January 2024.

Based on the information provided by PG&E, the FFT concluded that there were no nuclear safety concerns stemming from the alleged improprieties sent to the DCISC by A4NR. The FFT found that the Intake Cove dredging project was on track for completion in the Spring of 2024 and had not been inappropriately deferred. Additionally, maintenance activities using divers in the Intake Cove were appropriate and not precluded by the station's environmental permits. The FFT did not find any reluctance on PG&E's part to discuss the matters. Based on past reviews of the ECP and other matters, the FFT was not immediately concerned about possible threats of retaliation to employees at the station who raised concerns. The documents received from A4NR were referred to the station's ECP for further investigation, and the DCISC should follow up on the investigation results during its January 2024 meetings.

<u>Conclusions</u>: The DCISC reviewed documents received from the Alliance for Nuclear Responsibility regarding alleged improprieties in managing dredging and maintenance of DCPP's Intake Cove, and the DCISC