STATE OF CALIFORNIA EDMUND Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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Ratesetting

TO PARTIES OF RECORD IN APPLICATION 16-03-006:

This is the proposed decision of Administrative Law Judge Darcie L. Houck. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's May 25, 2017 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.3(c)(4)(B).

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:jt2

Attachment

Decision **PROPOSED DECISION OF ALJ HOUCK (Mailed 4/20/2017)**

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

| | |
|---|---|
| Application of Pacific Gas and Electric Company in its 2015 Nuclear Decommissioning Cost Triennial Proceeding (U39E). | Application 16-03-006<br>(Filed March 1, 2016) |

# DECISION APPROVING DECOMMISSIONING COST ESTIMATE

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## DECISION APPROVING DECOMMISSIONING COST ESTIMATE


### Summary

This decision finds reasonable the 2017 Decommissioning Cost Estimate (DCE) and expenses for work completed submitted by Pacific Gas and Electric Company (PG&E or Applicant) in this proceeding with the adjustments set forth herein.[1] The Commission adjustments primarily concern the amounts requested in the DCE proposed for Diablo Canyon Power Units 1 and 2 (DCPP). The Commission finds the following amounts for Humboldt Bay Power Plant Unit 3 (HBPP) for deposit to the Nuclear Decommissioning Trust Fund (NDTF) reasonable: $62.924 million in annual revenue requirements for HBPP; 3) $4.493 million for HBPP Safe Long-Term Protective Storage (SAFSTOR) operation and maintenance (O&M) costs in 2017; 4) $4.475 million for HBPP SAFSTOR O&M costs in 2018; and 5) $3.885 million for HBPP SAFSTOR O&M in 2019. Accordingly, decommissioning cost collections from ratepayers may be increased as set forth herein.

This proceeding is closed.


### 1. Background

On March 1, 2016, Pacific Gas and Electric Company (PG&E) filed this application for review of its updated nuclear decommissioning cost studies and ratepayer contribution analyses in support of requests to fully fund the nuclear decommissioning master trusts to the level needed to decommission the Diablo Canyon Power Plant (DCPP) and Humboldt Bay Power Plant (HBPP). In

[1] The Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) is intended to ensure that the funds in the nuclear decommissioning trusts are sufficient to cover the decommissioning of nuclear facilities at the expiration of their operational life.

addition, funds for operations and maintenance (O&M) costs associated with the requirements of the HBPP non-operating license were also included. PG&E requested a determination by the Commission of the reasonableness of decommissioning projects at HBPP since the last Triennial proceeding.

Specifically, PG&E sought Commission authorization, effective January 1, 2017, for PG&E to collect an estimated $117.324 million in annual revenue requirements for contributions to the Qualified Diablo Canyon Nuclear Decommissioning Trusts for Units 1 and 2, and $62.924 million in annual revenue requirements for contributions to the Qualified HBPP Nuclear Decommissioning Trust.

In addition to revenue requirements for funding the decommissioning trusts, PG&E also sought approval of HBPP O&M revenue requirements[2] of $4.493 million for 2017, $4.475 million for 2018, and $3.885 million in annual revenue requirements for 2019 and thereafter. The total estimated 2017 CPUC-jurisdictional revenue requirement for nuclear decommissioning requested is $184.741 million, an increase of $77.308 million over PG&E's currently authorized decommissioning revenue requirement of $107.433 million.

PG&E requests findings of reasonableness for the following:[3]

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[2] When HBPP was permanently shut down in the mid-1980s, the Nuclear Regulatory Commission (NRC) changed the wording of HBPP's (10 CFR) Part 50 operating license to state that while it is still an operating license it is not a license to operate. At that time, the NRC did not have a separate license for storage of spent nuclear fuel (SNF). PG&E had chosen the SAFSTOR (safe storage) method for the plant's future decommissioning. The other two options for dealing with a permanently shut down plant were DECON (decontamination) and ENTOMB. The requested O&M is for the SAFSTOR program.

[3] PG&E Application at 2 filed March 1, 2016.

(1) PG&E's expenditures of $371 million for completed PG&E Self Perform and Plant System Removal decommissioning expenditures;

(2) Its efforts to retain and utilize sufficient qualified and experienced personnel to effectively, safely, and efficiently pursue physical decommissioning related activities; and

(3) The differences between forecast and recorded SAFSTOR O&M expenses for 2013 through 2015.

PG&E provided ten chapters of prepared testimony in support of its application and requested an effective date of January 1, 2017.

On March 9, 2016, Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) (collectively the Utilities) moved for consolidation of this proceeding with Application (A.) 16-03-004, (SCE and SDG&E's (NDCTP), as well as s A.15-01-014 and A.15-02-006 [2014 San Onofre Nuclear Generating Station (SONGS) 2&3 Reasonableness Review].

On March 17, 2016, the Commission preliminarily categorized this proceeding as ratesetting with hearings required in Resolution ALJ 176-3374.

Protests were filed by the Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN) on April 4, 2016. The Alliance for Nuclear Responsibility (A4NR) filed a motion for party status on April 8, 2016.

On May 10, 2016, the assigned Administrative Law Judge (ALJ) issued a ruling scheduling a prehearing conference (PHC) for all proceedings on June 13, 2016, requiring parties to meet and confer regarding the procedural schedule and scope of this proceeding, and to set forth any agreed-upon proposals in PHC statements. The ruling also granted A4NR's motions for party status and to late-file a response to PG&E's Application.

On June 6, 2016, SCE and SDG&E filed and served their joint PHC statement with an attached Meet and Confer Report (Report) from the parties to proceedings A.16-03-006 and A.16-03-004. The Report proposed consolidation of both applications (and consolidation with A.15-01-014 and A.15-02-006), with three separate phases. PG&E's application was proposed as the first phase of the consolidated proceedings, and would address only PG&E issues. The Report contained an agreed-upon list of issues for each phase and a proposed schedule. A limited number of disputed issues were also set forth in the Report.

On June 13, 2016, the assigned ALJ convened a PHC for this proceeding as well as SCE and SDG&E's NDCTP, A.16-03-004. The parties discussed whether this application had sufficient factual and legal overlap with the Joint Application submitted by SCE and SDG&E.

On July 15, 2017, the assigned Commissioner and assigned ALJ issued a joint scoping memo for this proceeding and determined that it would not be consolidated with A.16-03-004. The Scoping Memo affirmed the preliminary categorization of this proceeding as ratesetting with hearings required.

The Scoping memo found that the Report provided by the parties did not show a sufficient relationship between the facts or law to be applied in this application and the facts and law to be applied in the SONGS applications. Therefore, as authorized by Rule 7.4 of the Commission's Rules of Practice and Procedure, this application was not consolidated with A.16-03-004.

The assigned Commissioner found that the scope of the matter properly before the Commission was whether or not PG&E has met its burden of justifying the requested relief as set forth in Pub. Util. Code § 455[4] and that the resulting rates will be just and reasonable as required by Pub. Util. Code § 451.

Pursuant to Public Utilities Code Section 8326, PG&E, as the owner of the HBPP and DCPP, must prepare, submit, and periodically revise the DCE) for these plants:

> (a) Each electrical utility owning, in whole or in part, or operating a nuclear facility, located in California or elsewhere, shall provide a decommissioning cost estimate to the commission or the board for all nuclear facilities which shall include all of the following:
>
> (1) An estimate of costs of decommissioning.
>
> (2) A description of changes in regulation, technology, and economics affecting the estimate of costs.
>
> (3) A description of additions and deletions to nuclear facilities.
>
> (4) Upon request of the commission or the board, other information required by the Nuclear Regulatory Commission regarding decommissioning costs.
>
> (b) The decommissioning costs estimate study shall be periodically revised in accordance with procedures adopted by the commission or the board pursuant to Section 8327.

The Commission's directive to review PG&E's Decommissioning Cost Estimate is set forth in § 8327:

> The commission or the board shall review, in conjunction with each proceeding of the electrical utility held for the purpose of considering changes in electrical rates or charges, the decommissioning costs estimate for the electrical utility in order to ensure that the estimate takes account of the changes in the technology and regulation of decommissioning, the operating experience of each nuclear facility, and the changes in the general

[4] All statutory references are to the Public Utilities Code unless otherwise noted.

economy. The review shall specifically include all cost estimates, the basis for the cost estimates, and all assumptions about the remaining useful life of the nuclear facilities.

The burden of proof is on PG&E to demonstrate the reasonableness of the DCE and the resulting rate change requests. The standard of proof is that of a preponderance of evidence.

The parties submitted the following agreed-upon list of issues as being within the scope of this proceeding:

1. Whether the Commission should find that PG&E's estimated updated cost to decommission DCPP Units 1 and 2 of $3.7792 billion (2014$) is reasonable.
2. Whether the Commission should find that PG&E's estimated remaining cost to decommission HBPP of $531.3 million (2014$) (total estimated cost of $1.0548 billion) is reasonable.
3. Whether the Commission should find that PG&E's estimated forecast of $3.4 million of O&M expenses (SAFSTOR) for HBPP for 2017, $3.3 million for 2018, and $2.7 million for 2019 is reasonable.
4. Whether the Commission should find that the variances in actual versus forecast SAFSTOR expenses for the previous period are reasonable.
5. Whether the Commission should find that PG&E's estimated rate of return on equity of 7.7% and PG&E's estimated rate of return on fixed income of 3.6% are reasonable.
6. Whether the Commission should find that PG&E's trust contribution analyses for DCPP and HBPP are reasonable and in accordance with §§ 8321 through 8330.

7. Whether the Commission should authorize PG&E to collect in rates its proposed revenue requirements (adjusted as described in its Prepared Testimony).
8. Whether the Commission should find that PG&E has complied with prior Commission directives as described in its Prepared Testimony.
9. Other issues that may arise during discovery.

The Report also set forth two issues where the parties were not in agreement whether or not the issues should be included in the scope of this proceeding. As set forth below, we need not address either issue as the proceeding was not consolidated with A.16-03-004, and PG&E has determined that it will not seek relicensing of Diablo Canyon.[5]

The assigned Commissioner found that the reasonableness of completed decommissioning projects at HBPP was to be included in the scope of this proceeding. The facts and law necessary for this determination are substantially identical to the facts and law underlying the other issues in this proceeding.

A second PHC was held on July 25, 2016 to discuss a revised schedule and scheduling of a technical workshop on site at the HBPP.

The assigned ALJ issued a ruling modifying the schedule for the proceeding on July 28, 2016 following the July 25, 2016 PHC. Pursuant to the procedural schedule adopted in the July 28, 2016 ruling, a HBPP Technical Workshop was held on site at the HBPP on August 9, 2016, and evidentiary

[5] PG&E has filed an application for approval of the retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, and recovery of associated costs through proposed ratemaking mechanisms, A.16-08-006. A.16-08-006 will address the Commission requirements for retirement of DCPP and implementation of the proposed Joint Settlement.

hearings were held on September 19 and 22, 2016. Pursuant to the schedule set out in the July 28, 2016 ruling and confirmed at the conclusion of hearings, opening briefs were submitted on October 14, 2016, and reply briefs were filed on October 31, 2016, by PG&E, ORA, TURN, and A4NR.

## 2. Standard of Review

PG&E bears the burden of proof in this proceeding to show, by a preponderance of the evidence, that the proposed cost estimates for completing decommissioning of DCPP and HBPP are reasonable.

The applicable standard of review for previously incurred costs for SAFSTOR and completed decommissioning projects, is whether the actual expenditures were reasonable and prudent.[6] Prudency of a particular management action depends on what the utility knew or should have known at the time that the managerial decision was made.[7] This is a ratesetting proceeding which means the estimated costs determined to be reasonable will be converted to a revenue requirement. The applicable standard of proof that PG&E must meet is that of a preponderance of the evidence.[8]

We consider the application based on these standards.

[6] D.14-02-082 at 18 citing to D.10-07-047 at 9.

[7] D.14-02-082 at 18 citing to D.10-07-047 at 54 Conclusion of Law 2.

[8] D.14-02-082 at 19 citing to D.12-11-051 at 9.

## 3. Humboldt Bay Power Plant Unit 3

### 3.1. PG&E's 2015 Nuclear Decommissioning Cost Triennial Proceedings Application

PG&E is decommissioning HBPP3[9] under the authority of the United States Nuclear Regulatory Commission (NRC) which requires assurance that minimum funding is available for decommissioning the site to a regulated level of decontamination. The Commission's authority includes determining whether PG&E's proposed cost estimates for decommissioning are reasonable, and whether actual decommissioning costs were reasonable and prudent. Reasonable costs may be captured in rates and added to the statutory nuclear decommissioning trust funds for approved expenditures. PG&E requests that the Commission make the following findings concerning decommissioning of HBPP:

- PG&E's estimated remaining cost to decommission HBPP of $531.3 million (2014$) (total estimated cost of $1,054.8 million) is reasonable and should be adopted.
- PG&E activities and associated costs of $371 million for completed HBPP decommissioning work were reasonable and prudently incurred.
- PG&E's forecast of $3.4 million of SAFSTOR O&M expenses for HBPP for 2017; $3.3 million for 2018; and $2.7 million for 2019 is reasonable and should be adopted.

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[9] HBPP was a 65 megawatt nuclear reactor that began commercial operation in August 1963. The plant was taken off line in July of 1976 for a refueling outage and to make seismic modifications. In 1979, a nuclear incident at Three-Mile Island occurred and as a result, the NRC mandated a comprehensive series of additional modifications that would have required additional significant investment, making restarting the plant uneconomic. PG&E Opening Brief at 25.

- The variances in actual versus forecast SAFSTOR expenses for the previous period are reasonable.
- PG&E's trust contribution analysis for HBPP is reasonable and in accordance with Sections 8321 through 8330 of the California Public Utilities Code.
- PG&E should be authorized to collect in rates commencing January 1, 2017 an annual revenue requirement of $62.924 million for funding the HBPP trust funds; and $4.493 million for funding HBPP SAFSTOR for year 2017, $4.475 million for HBPP SAFSTOR in 2018 and $3.885 million for HBPP SAFSTOR in 2019 (all as adjusted through Tier 2 Advice Letter (AL) after a final decision).
- PG&E has complied with prior Commission directives as to the decommissioning of HBPP.

### 3.2. Other Parties' Positions

#### 3.2.1. Office of Ratepayer Advocates

ORA does not oppose PG&E's updated HBPP DCE, 2017-2019 SAFSTOR O&M forecasts, 2013-2015 SAFSTOR O&M reasonableness, or the reasonableness of completed HBPP decommissioning projects.[10]

#### 3.2.2. The Utility Reform Network

TURN does not oppose approval of either the revised HBPP DCE or the expenditures proposed for reasonableness review.[11] TURNs expert witness, Bruce Lacey, stated in his testimony that the decommissioning effort at HBPP "is a unique effort due to design, siting, construction, fueling, and operation taking place during the early pioneering days of the commercial nuclear industry."[12]

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[10] ORA Opening Brief at 2.

[11] TURN Opening Brief at 7.

[12] Exh 33 (TURN/Lacey) at 13.

TURN also notes that "PG&E has made commendable progress in decommissioning HBPP, a unique challenge."[13]

TURN proposes that the Commission adopt the following directives related to HBPP for the next NDCTP.

- Consider decommissioning cost impact of PG&E's poor stewardship in preparation for and during delayed decommissioning (SAFSTOR) at Humboldt Bay;[14] and
- Future reporting to include clear accounting for additional costs beyond those required by the Nuclear Regulatory Commission

TURN raises concerns with what it characterizes as "PG&E's poor management of the site, and the decommissioning process, between 1976-2009."[15] TURN states that some of the increased decommissioning costs could have been avoided, and therefore a more comprehensive review in the next NDCTP regarding the extent to which PG&E's actions increased the decommissioning costs for HBPP is necessary.[16]

TURN states that this directive would provide two potential ratepayer benefits; 1) consideration of whether to disallow any excess HBPP decommissioning costs on the basis that PG&E's actions caused the increased costs; and 2) the assessment could be used to determine timing and development of standards for PG&E management of the decommissioning process at DCPP.[17]

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[13] Exh 33 (TURN/Lacey) at 13.

[14] TURN Opening Brief at 7-9.

[15] TURN Opening Brief at 8.

[16] TURN Opening Brief at 8; Exh 33 (TURN/Lacey) at 10.

[17] *Id.*, TURN Opening Brief at 8; Exh 33 (TURN/Lacey) at 10.

TURN also proposes that PG&E provide future reporting on HBPP progress in a manner that allocates total costs into three objectives: 1) license termination; 2) Spent Fuel Management; and 3) Site Restoration.[18] TURN argues that this reporting manner would "improve understanding the relative role of NRC, Spent Fuel Management (DOE), and state and local requirements in impacting decommissioning costs."[19] TURN would like the Commission to apply this proposed requirement to all future reporting on and cost estimates for HBPP.[20] TURN believes this manner of reporting will "help highlight the significant role and impact of state and local requirements that go beyond NRC standards" and "assist with assessing the reasonableness of decommissioning at both HBPP and other California nuclear facilities."[21]

#### 3.2.3. Alliance for Nuclear Responsibility

A4NR does not present any position on PG&E's request for the Commission to approve the revised HBPP DCE or the expenditures proposed for reasonableness review.

### 3.3. Discussion of 2015 Decommissioning Costs

PG&E's projected total cost for decommissioning HBPP is $1.0548 billion, including $523.5 million in expenditures to date.[22] PG&E's testimony includes a 2012 and 2016 HBPP Decommissioning Project Report Cost Comparison Table that provides a summary of broad cost categories for activities necessary to

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[18] TURN Opening Brief at 10.

[19] Exh 33 (TURN/Lacey) at 14.

[20] TURN Opening Brief at 10.

[21] TURN Opening Brief at 14; Exh 33 (TURN/Lacey) at 14.

[22] Exh 5 (PG&E/Sharp) at 4—12.

complete decommissioning as of 2016.[23] The estimated remaining amount for decommissioning of HBPP is approximately $531.3 million, including contingency.[24] PG&E also requests in its application a finding of reasonableness for expenditures of $371 million associated with the Self Perform/Plant Systems Removal Phase.[25]

### 3.3.1. Completed Decommissioning Expenditures

PG&E seeks reasonableness review of the expenses incurred for completed decommissioning projects since the 2012 NDCTP totaling $371 million. The appropriate standard of review for actual expenses is whether the costs are reasonable and prudent- assessing costs, activities and the decisions made to incur those costs. Such review should include comparison of actual costs to estimated costs in the most recently adopted estimate, cash flows and schedule. The Commission will also examine the reasons for cost differences (e.g., labor escalation, contractor bids), as well as examine the actual activities to determine if they are appropriate decommissioning activities (e.g. changed scope), and whether the utility prudently undertook them (e.g. decision-making process).[26]

#### 3.3.1.1. Background

The Commission monitors a utility's nuclear decommissioning costs and activities in three stages. During the triennial proceedings, cost estimates are reviewed for reasonableness ahead of performance of the work; actual

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[23] Exh 5 (PG&E/Sharp), Chapter 4, Attachment B, 2012 and 2016 Humboldt By Power Plant Unit 3 Decommissioning Project Report Costs Comparison Table.

[24] Exh5 (PG&E/Sharp) at 4-5.

[25] This $371 million is included in the $523.5 million in expenditures to date referenced above.

[26] D.14-02-024 at 43-44.

expenditures are reviewed after the fact to determine whether they are reasonable and prudent. When a utility undertakes actual decommissioning work, the Commission reviews periodic notices of progress as part of authorizing trust fund disbursements for costs included in the most previously approved cost estimate.

Pursuant to Commission approved procedures,[27] PG&E has annually submitted ALs requesting authorization to withdraw funds from its NDTF to fund specific decommissioning activities at HBPP. After specific projects are completed, PG&E brings them forth in the next NDCTP for the Commission to review and determine that the actual costs were reasonable and prudently incurred.

#### 3.3.1.2. Discussion

PG&E presented $371 million in costs associated with completion of the Self Perform/Plant System Removal Phase work for HBPP in 2014 for reasonableness review. This work represents completion of a major phase of the HBPP decommissioning. Installation of site infrastructure and removal of systems and components made up the majority of the decommissioned work covered. This work included removal of large components with known high levels of radiation, and removal of contaminated systems under special engineering controls and requirements.[28] PG&E removed radiologically significant plant systems and remediated major sources of asbestos from the

[27] D.10-07-047 (2009 NDCTP) and D.14-02-024 (2012 NDCTCP).

[28] PG&E Opening Brief at 27-28.

building.[29] The $371 million presented for review includes the following completed work:[30]

- $131.1 million in General Staffing
- $39.5 million in Remainder of Plant Systems, Direct Labor and Liquid Radwaste Removal;
- $19.2 million in Remainder of Plant Systems, Tools & Equipment;
- $14.9 million in Site Infrastructure;
- $38.1 million in Specific Project Costs;
- $58.1 million in Waste Disposal Costs;
- $38.9 million in Small Value Contracts;
- $28.8 million in Spent Fuel Management; and
- $2.4 million in Common Site Support Caisson and Canals.

PG&E provides support for a finding that these expenditures are reasonable in its submitted testimony, as well as additional supporting documents that include the HBPP Complete Activities Report,[31] and the HBPP Decommissioning Pictorial Summary.[32] No party objects to the reasonableness of the expenditures presented in PG&E's application.

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[29] PG&E Opening Brief at 28; Exh 7 (PG&E/Sharp).

[30] Exh 5 (PG&E/Sharp); Exh 7 (PG&E/Shap); Exh 8 (PG&E/Sharp); Exh 9 (PG&E/Sharp).

[31] Exh 9 (PG&E/Sharp).

[32] Exh 8 (PG&E/Sharp) and Exh 5 (PG&E/Sharp) at: Attachment B 2012 and 2016 Humboldt Bay Power Plant Unit 3 Decommissioning Project Report Costs Comparison Table; Table 4-1 2012 NDCTP Cost Estimates.

#### 3.3.1.3. Future Review of Completed Decommissioning Projects

In Decision (D) 14-02-024 the Commission set forth orders pertaining to future review of completed decommissioning projects. The Decision states "We consider it necessary to protect ratepayers' interest going forward by establishing clear guidelines for what is expected of a utility which seeks to obtain review of disbursements and completed projects in the future."[33]

TURN requests that the Commission require additional future reporting requirements from PG&E for HBPP decommissioning that include a "clear accounting for additional costs beyond those required by the NRC. TURN requests future reporting of HBPP progress allocate total costs into three objectives; 1) license termination; 2) spent fuel management; and 3) site restoration.[34] TURN argues that such reporting will "improve understanding the relative role of the NRC, Spent Fuel Management (DOE), and state and local requirements impacting decommissioning costs."[35]

The Commission, in D.14-02-024, ordered PG&E to meet with the Commission's Energy Staff to develop a spreadsheet for requesting NDTF disbursements, and to submit the spreadsheet by Tier 1 AL and serve it on the service list for the NDCTP. D.14-02-024 required that the spreadsheet include:

- Identify whether the cost category is contract or self-perform work, and identify estimated costs in the 2012 Decommissioning Project Report,, adjusted to conform with the overall cost estimate adopted herein, by specific reference to the project and page numbers;

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[33] D.14-02-024 at 49.

[34] TURN Opening Brief at 10

[35] *Id.*; Exh 33 (TURN/Lacy) at 14.

- Self-performed work shall include subcategories, at a minimum, for staffing, tools and equipment, and contractors;
- For estimated costs adopted in prior NDCTP decisions for decommissioning projects not completed, PG&E shall identify the projects and aggregated expenditures; and
- Include a comparison of actual annual cash flow to PG&E's current estimated cash flow and of actual project schedule to the estimated schedule in the Post-Shutdown Decommissioning Activities Report.[36]

PG&E was required to track actual SAFSTOR expenses during the triennial period and report and explain any differences in PG&E's next NDCTP application.[37] PG&E was also required to maintain written records of key decisions about the cost, scope or timing of a major decommissioning project or activity at HBPP i.e., any decision that results in a variation from prior estimates by +/-10%, including the nature of the decision, who made the decision, factors considered, and whether and what alternatives were considered.[38] PG&E was ordered to provide testimony in its next triennial review that demonstrated it had made all reasonable efforts to retain and utilize sufficient qualified and experienced personnel to effectively, safely, and efficiently pursue any physical decommissioning related activities for the nuclear generation facilities under its control.[39]

The Commission finds that the guidelines and reporting requirements set forth in the "Future Review of Completed Decommissioning Projects" and

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[36] D.14-02-024 OP 2.

[37] D.14-02-024 OP 3.

[38] D.14-02-024 OP 4.

[39] D.14-02-024 OP 5.

ordering paragraphs 2, 3, 4, and 5 of D.14-02-024 are sufficient to ensure adequate and clear accounting of HBPP decommissioning activities, including costs beyond those required by the NRC. These detailed reports combined with the higher expectations of sufficient evidence to support expenditures have resulted in a detailed assessment of increased costs and performance. At this time we will require that PG&E continue to provide detailed reports and sufficient evidence to support expenditures consistent with the requirements set forth in D.14-02-024. We will not adopt TURN's recommendation regarding future reporting requirements. If concerns with the current reporting requirements arise, the Commission can revisit the guidelines and reporting requirements in a future NDCTP.

#### 3.3.2. Reasonableness of Proposed HBPP Decommissioning Cost Estimate

The decommissioning at HBPP is in the Civil Work Phase. Prior to 2012 PG&E began planning for a large Civil Works Contract that would conduct the balance of remaining decommissioning and demolition and final site restoration (FSR). The Commission previously found that PG&E had undertaken a reasonable process to solicit and evaluate bids for the general contractor of the Civil Works Contract. The Commission also previously found that PG&E had awarded the bid to an experienced contractor, the Civil Works Contractor (CWC).[40] The Civil Woks Contract was executed and the CWC has been on site since 2013. PG&E's remaining work to complete decommissioning includes

[40] D.14-02-024, Finding of Fact 6.

overseeing the CWC activities, cost control and accounting, disposal of wastes and management of spent nuclear fuel and GTTCC waste.[41]

The 2016 Decommissioning Project Report (DPR) for the HBPP, prepared by PG&E, sets forth the remaining activities, costs and schedule to complete HBPP decommissioning and license termination.[42] This report updates the prior HBPP Decommissioning Project Report 2012-2025 (2012 DPR) submitted in the 2012 NDCTP. The DPR incorporates site specific decommissioning tasks and additional scopes of work identified through the ongoing implementation of the HBPP decommissioning. The DPR includes changes resulting from the transition of PG&E self-perform work to work performed under the Civil Work Contract by CWC.[43]

PG&E estimates that the cost in 2014 dollars to complete HBPP decommissioning will be $531.3 million including contingency with a total estimated cost for decommissioning HBPP of $1.0548 billion.[44] This represents an increase of $76.9 million from the prior approved DCE in the 2012 NDCTP.[45]

No party opposes PG&E's updated forecast or change in estimate. The updated forecast and updated 2012 estimate is discussed further below.

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[41] PG&E Opening Brief at 29-30; Exh 5 (PG&E/Sharp) at 13 lines 16-22; also see Exh 5 (PG&E/Sharp) at 13, line 23 to 14, line 4; PG&E Opening Brief at 30.

[42] Exh 6 (PG&E/Sharp).

[43] Exh 5 at 4 lines 13-25 (PG&E/Sharp); PG&E Opening Brief at 30.

[44] Exh 1 (PG&E/Sharp) at 4; Exh 5 (PG&E/Sharp) at 4-5; Exh 6 (PG&E/Sharp); PG&E Opening Brief at footnote 140 PG&E notes that "because the 2016 DPR was prepared using costs incurred as December 31, 2014 this figure does not reflect $112.7 million in decommissioning expenses which were actually incurred in calendar year 2015."

[45] Exh 5 (PG&E/Sharp) at 4 line 26 to 5 line 3.

#### 3.3.2.1. Updated Forecast and Updated 2012 Estimates.

PG&E sets forth an updated forecast that includes changes in the work scope and updates to the 2012 DCE. The updated work scope includes: 1) extension of Department of Energy (DOE) pickup date; 2) Independent Spent Fuel Storage Installation (ISFSI) related projects; 3) site restoration; and 4) ISFSI FSR.[46]

<u>Change in Scope of Work</u>

In the 2012 NDCTP, PG&E assumed that DOE would commence SNF pickup in 2024 and that the HBPP site would be decommissioned and restored by 2025.[47] This estimate has been extended by four years to 2028 which would have the spent fuel picked up in years 2028 and 2029 with transfer of operations complete by 2029, and site restoration completed in 2030.[48] PG&E provides testimony stating that this change of scope increases the decommissioning cost estimate by $25.9 million (without contingency). The increased costs include $21.1 million for additional time that security personnel will be on site; $2 million for O&M; $1.1 million in NRC fees; $.9 million in engineering/specialty contracts; and $.8 million in infrastructure.[49] The assumptions and other issues related to Spent Fuel Management and DOE pick are discussed below.

ISFSI related projects account for an increase of $26.6 million ($33 million as approved) (without contingency) as reflected in the DPR.[50] This includes

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[46] Exh 5 at 14-24.

[47] Exh 5 at 15.

[48] Exh 5 at 14-15.

[49] Exh 5 (PG&E/Sharp) at 15.

[50] Exh 5 (PG&E/Sharp) at 15-18.

increased funding in the amounts of: $15 million in DOE litigation related support; $3.7 million in Engineering Services/Specialty Contracts; and $6.4 million in infrastructure. PG&E will need to seek an extension of the current HBPP ISFSI license for Special Nuclear Material as the current license will expire in 2025.[51] The license will need to be renewed due to the uncertainty as to the timeframe for DOE pick up of spent fuel. PG&E believes completion of the license renewal may take several years to complete. PG&E plans to submit an application to the NRC in 2018, with anticipated approval expected in 2021.[52] PG&E currently has two licenses for HBPP. One license is issued under 10 Code of Federal Regulations (CFR) § 50 for operation of the plant. The other is issued under 10 CFR § 72 for operation of the ISFSI and managing storage of spent nuclear fuel (SNF). After completion of decommissioning, PG&E will petition the NRC to terminate the 10 CFR § 50 license. The ISFSI related projects are discussed below in the SNF management section of this decision.[53]

PG&E proposes an increase in the costs for the HBPP FSR Plan by $21.7 million (without contingency) over the 2012 estimate. PG&E asserts this change is a result of discussions with the California Coastal Commission (CCC) and other state and local agencies.

> The areas impacted include additional building removal costs, storm water runoff-collection and treatment, restoration of additional wetlands, replacement and new additions to site fencing, more extensive Intake Canal modifications to support aquatic vegetation and bringing the site back to greenfield status.[54]

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51 Exh 5 (PG&E/Sharp) at 15.

52 Exh 5 (PG&E/Sharp) at 15.

53 Exh 5 (PG&E/Sharp) at15-17.

54 PG&E Opening Brief at 31; Ex. 5 (PG&E/Sharp) at 18-20.

PG&E estimates that the ISFSI FSR will cost significantly more than the $1.9 million assumed in the 2012 DPR. PG&E has presented a new estimate of $11.7 million (without contingency) for completion of the ISFSI FSR. The new estimate is a $9.8 million increase of the 2012 DPR estimate.[55]

Updates to 2012 Estimate

PG&E identifies a number of areas that include updated estimates. These areas include: 1) general staffing (estimated remaining costs of $44.5 million); 2) remainder of plant systems PG&E civil works support (estimated remaining costs for this category is $5.5 million- see 2016 DPR at Section 3.3.1.3); 3) other civil works [Facilities Demolition (estimated an additional $56 million to complete); Office Facility Demobilization and Demolition (estimated $1.6 million to complete); FSR (see discussion on SNF management below)]; 4) waste disposal (estimated cost to complete $34.8 million); 5) small value contracts (estimated remaining costs of $16.1 million); 6) caisson removal project (estimated $132.7 million to complete); 7) intake and discharge canal remediation (estimate $52.6 million, an increase of $1.3 million over the 2012 adopted estimate); 8) common site support caisson and canals (estimate to complete $2.2 million); and 9) engineering, procurement, construction (remaining work estimated cost is $10.3 million).[56]

The updated estimate from the 2012 forecast is supported by a preponderance of the evidence set out in the testimony provided by PG&E. The

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[55] PG&E Opening Brief at 32; Ex. 5 (PG&E/Sharp) at 23-24.

[56] Exh 5 at 24-45.

DPR for HBPP identifies remaining activities, costs and schedule to complete HBPP decommissioning.[57]

No party objects to the updated estimates for completion of decommissioning HBPP.

### 3.4. SAFSTOR

In 1988, PG&E placed HBPP into a custodial form of decommissioning, SAFSTOR where it is required to safely maintain and monitor the site until dismantled. Two issues are presented concerning the SAFSTOR requirements: 1) are PG&E's 2017 forecasts reasonable; and 2) is the difference between the estimated costs adopted in the 2012 NDCTP and actual SAFSTOR costs reasonable?

The NRC requires PG&E to maintain the radioactive material at HBPP, other than the SNF maintained in the ISFSI, in a SAFSTOR configuration. This condition will be maintained until the final dismantlement of the facility is accomplished. SAFSTOR operations and maintenance expenses include costs associated with activities required by the NRC to maintain HBPP in accordance with the terms of PG&E's current NRC non-operational Part 50 license. PG&E has incurred and recovered these expenses and will continue to incur such costs in the future.[58]

The SAFSTOR O&M expenses include the cost of maintenance and surveillance activities, environmental monitoring costs associated with collecting and analyzing samples in accordance with PG&E's NRC license requirements,

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[57] Exh 6 (PG&E/Sharp).

[58] Exh 10 (PG&E/Sharp) at 4.

routine and specific radiological surveys, training and qualifications of radiation technicians and professionals, instrument calibration and repair, routine reporting to NRC, and implementation of radiation safety programs. PG&E's current Part 50 license requires PG&E to comply with Environmental Protection Agency 40 CFR and Department of Transportation 49 CFR requirements. These requirements are separate and distinct from decommissioning activities and will continue until the Part 50 license is released by the NRC.[59] The Commission has previously acknowledged PG&E's SAFSTOR requirements, which extend to maintaining structures, systems, and components necessary to contain various contaminants during the decommissioning process.[60]

### 3.5. PG&E's Forecast of SAFSTOR Expenses

PG&E requests that the Commission adopt its 2017 forecast of $3.4 million of O&M expenses for HBPP. The year 2017 O&M expense forecast represents a decrease from the 2016 forecast ($4.9 million) that was adopted in the 2012 NDCTP. PG&E asserts that the decrease is a result of significant decommissioning progress that will be made in 2017 at HBPP. PG&E also requests that the Commission adopt its O&M expense forecasts of $3.3 million for 2018 and $2.7 million for 2019.[61]

In support of its request, PG&E provided a description of the proposed activities and costs, and its cost estimate methodology. No party disputes the reasonableness of PG&E's compliance cost estimates.

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[59] Exh 10 (PG&E/Sharp) at 4.

[60] D.14-02-024 at 53.

[61] Exh10 (PG&E/Sharp) at 3-5.

The Commission continues to expect a gradual decline in SAFSTOR expenses as HBPP proceeds through decommissioning. PG&E's testimony and work papers support the reasonableness of the cost estimates proposed in this proceeding for 2017, 2018 and 2019.[62]

### 3.6. Difference Between PG&E's Actual and Estimated SAFSTOR Expenses

In the 2012 NDCTP, the Commission adopted PG&E's uncontested forecast for 2014-2016 SAFSTOR O&M. PG&E was ordered to track its actual SAFSTOR expenses and make a "true-up" contribution to, or withdrawal from, the decommissioning trusts based on whether the amount collected in rates is greater or less than the expenses actually incurred. To the extent that contributions differ from estimates, PG&E was ordered to report on the differences in this NDCTP where the differences are subject to reasonableness review.

According to PG&E, SAFSTOR O&M costs exceeded the annual revenue requirement in 2013 by $1.192 million; in 2014 by $877 thousand; and 2015 by $532 thousand. The adopted revenue requirement forecast was $12.044 million for 2013; $10.301 million for 2014; and 10.180 million for 2015. PG&E asserts the forecasted under collection is due to a discrepancy in that the assumed forecast allocation of Administrative and General (A&G) to SAFSTOR activities was less than actually incurred.[63]

No party disputed that PG&E had sufficiently explained the variances from the estimated SAFSTOR costs in 2012 or improperly applied the true-up

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[62] Exh 10 (PG&E/Sharp) and Exh 11 (PG&E/Sharp); Exhs 9, 8, and 6 (PG&E/Sharp).

[63] Exh 10 (PG&E/Sharp) at 6.

method. PG&E incurs these expenses to meet the NRC's license requirements for containment of dangerous contaminants, even if actual costs exceed estimated costs. The Commission finds PG&E adequately explained the differences between the estimated and actual SAFSTOR O&M costs and finds the difference between the forecast and recorded SAFSTOR expenses reasonable.

## 4. Diablo Canyon Decommissioning Cost Estimate

PG&E's total cost estimate for decommissioning DCPP is $3.779 billion (2014$). The total estimate is approximately $1.493 billion (65%) more than the approved 2012 NDCTP cost estimate of $2.286 billion (2011$). We reduce PG&E's requested DCE by $1.358 billion to $2.421 billion[64] (2014$) as explained below.

PG&E retained TLG Services, Inc. (TLG) to prepare the DCE for DCPP. TLG has prepared the DCPP DCE for PG&E since 1987. It is undisputed that TLG is a recognized expert in nuclear decommissioning costs.

PG&E, in the previous NDCTP developed three decommissioning scenarios for DCPP: DECON,[65] SAFSTOR, and a 20-year license extension. The total costs were similar.[66] Although PG&E asserts that it is not necessary to

[64] This is an estimated amount. PG&E is directed to recalculate the 2017 DCE based on the adjustments set forth in this decision and submit the revised DCE to the Energy Division as a Tier 2 AL.

[65] Exh 3 (PG&E/Seymore) at 10 defines DECON as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations." PG&E cites to U.S. Code of Federal Regulations, Title 10, Parts 30,40, 50, 51, 70 and 72 "General Requirements for Decommissioning Nuclear Facilities", Nuclear Regulatory Commission, Federal Register Volume 53, Number 123 (at 24022, Column 3), June 27, 1988.

[66] D.14-12-082 at 84 citing to PG&E-24 work papers for chapter 2 (2012 Decommissioning Cost Analysis for DCPP at Executive Summary xvii).

choose a decommissioning method at this time, it used the DECON alternative as the basis for the DCPP DCE in this proceeding.[67]

PG&E provided prepared testimony and work papers setting forth its proposed DCE for DCPP. According to PG&E, a substantial share of the proposed increase is attributable to changes, recommended by the Independent Panel (Panel) of decommissioning experts hired in the 2009 NDCTP, its experiences decommissioning HBPP, and select examples of other decommissioning experiences outside of California. PG&E incorporated substantial cost increases in the areas of security, removal and disposal of all concrete on site, including the breakwater, and Utility and Decommissioning Oversight Contractor (DOC) costs. PG&E also assumes that it will need 10 years post operation to transfer SNF to dry casks, and includes a 25% contingency in its DCE.

### 4.1. Assumptions

In 2016, TLG generally applied the same methodology used in preparing the 2012 DCE, with some exceptions. The changes in assumptions made from the 2012 cost study integrated into the 2016 cost study are set forth below:[68]

- Extension of time for DOE pickup of SNF for cost estimate purposes assumes a 4-year delay, and that DOE will commence its SNF pick-up program in 2028 and begin picking up fuel from DCPP in 2035 with last pick up in 2061.
- PG&E assumes based on Executive Order D-62-02 that all decommissioned material, including demolished concrete, will need to be disposed of out-of-state.

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[67] Exh 2 (PG&E/Seymore) at 25-26.

[68] Exh 4 (PG&E/Sharp) throughout.

- Use of the most current information by reflecting, (1) the general effects of inflation and cost escalation over the three years since the 2012 study was prepared, and (2) experience from fieldwork in decommissioning;
- Development of new cost projections for Low Level Radioactive Waste (LLRW) disposal rate;
- Significant increase to the security work force;
- In prior NDCTPs TLG used the TLG model for Utility and DOC staffing. The TLG model incorporates industry-staffing averages from decommissioning projects across the U.S. to forecast staffing requirements during the decommissioning period. Here PG&E provided TLG with the number of staff required per year by position classification and the associated rate for each position classification;
- Contingency was estimated on a line item basis resulting in a composite contingency factor of 17.4% as determined by TLG which PG&E modified to reflect an overall contingency of 25% pro-rated on a line-by-line basis; and
- Estimated costs for ISFSI are included to accommodate SNF until off-site storage becomes available using an estimated 4 year delay in pick up by DOE.

PG&E provided a summary of the cost differences between the 2012 and 2016 DCE in its testimony.[69] Intervenors raise concern and object to increases proposed by PG&E in several categories. PG&E contends that failure to fund the proposed increased 2017 DCE would result in requiring future customers to pay for these costs.[70]

The parties' positions are discussed below.

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[69] Exh 2 (PG&E/Seymore) at 33-40, Tables 2-1 through 2-8.

[70] PG&E Opening Brief at 3.

### 4.2. Other Parties' Positions

#### 4.2.1. Office of Ratepayer Advocates

ORA argues that PG&E has not established a basis for the Commission to authorize the proposed increases in ratepayer funding for the DCPP DCE and associated trust contributions in accordance with §§ 8321 through 8330. ORA states that the evidence and arguments presented demonstrate that the Commission should reduce: 1) PG&E's proposed contingency factor to 17.4% as overall project contingency depends on contingency factors of work activities calculated on an item-by-item basis and 2) PG&E's 2017 DCE by $164.47 million in (2014$) until PG&E a) conducts a site-specific engineering and decommissioning study in preparation for decommissioning DCPP, and b) provides more information on the radiological content of breakwater material and it is determined whether or not the breakwater will be removed. ORA also asserts that when calculating PG&E's nuclear decommissioning revenue requirement, the Commission should use the most up-to-date trust fund balances.[71]

#### 4.2.2. The Utility Reform Network

TURN rejects PG&E's 2017 DCE which includes a series of adjustments totaling an increase of nearly $1.5 billion, and cumulatively produces a 65% increase when compared to the DCPP DCE adopted in the 2012 NDCTP and a 107% increase compared to the 2009 adopted DCE. TURN rejects most of

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[71] See ORA Opening Brief at 1-2. PG&E has agreed to use the December 31, 2016 year-end balance for purposes of calculating its nuclear decommissioning revenue requirement. See PG&E Opening Brief at 36-37.

PG&E's proposed adjustments on the grounds that PG&E has failed to adequately justify or explain the drivers behind the proposed cost increases.[72]

TURN disagrees with PG&E's assumptions and argues the following points. TURN asserts there is no basis for comparing decommissioning costs or experiences at HBPP to DCPP. TURN finds PG&E's 2017 DCE for DCPP out of proportion when compared with other comparable facilities. Bruce Lacy, TURN's expert witness found that "the Diablo Canyon Cost Study is a significant outlier from decommissioning costs studies for the U.S. population of similarly designed and operated commercial nuclear power plants."[73] TURN argues that PG&E has not met its burden of proof in demonstrating the reasonableness of the updated DCE for DCPP. Specific categories of concern raised by TURN include costs for: 1) security; 2) Utility and DOC; 3) large component removal; 4) removal of all onsite concrete as contaminated via "Rip and Ship"; and 5) assumption that all on-site debris must be sent out of state for disposal. TURN also raises concerns as to promptness of timing for decommissioning activities to occur at DCPP, and the cooling period for SNF.[74]

TURN recommends the following:

- The Commission should find that PG&E has not satisfied its burden of proof to justify a $344 million increase in total security costs at DCPP.

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[72] TURN Opening Brief at 15.

[73] TURN Opening Brief at 18 citing to Ex. 33 (TURN/Lacy) at 15.

[74] TURN also raises concerns with SNF management costs. Issues concerning SNF management are addressed in a separate section of this Decision.

- The Commission should find that PG&E has not satisfied its burden of proof to justify a $311 million increase in Utility and DOC staff costs at DCPP.
- The Commission should decline to approve a $492 million increase in large component removal costs based on an inadequate showing that higher staffing levels and a longer timeline are justified.[75]
- The Commission should reject PG&E's $312 million cost increase driven by the assumption that 100% of clean construction debris must be sent for disposal to an out-of-state landfill due to a 2002 Executive Order.
- The Commission should establish a presumption in favor of prompt decommissioning at DCPP. In the next NDCTP, PG&E should either commit to this approach or provide a detailed study explaining how delayed decommissioning would not result in the cost increases and surprises experienced at HBPP.
- The Commission should decline to approve PG&E's assumption that SNF cannot be transferred from wet storage to the onsite ISFSI for at least 10 years after plant shutdown. TURN recommends the use of a 7-year timeline that would reduce the cost estimate by $197 million. Alternatively, the Commission could adopt a different duration of less than 10 years.

TURN recommends a decrease of $1.358 billion (this does not include TURN's recommended adjustment of between 5-50% of incremental spent fuel management costs) for the DCPP DCE.

[75] TURN notes that approximately $298 million of the $492 million increase also appears as an increase in Utility and DOC staff costs. This means that if both recommendations are adopted it would result in a $505 million decrease to the overall cost estimate, not $803 million which would be the amount if both proposed reductions were merely added together.

#### 4.2.3. Alliance for Nuclear Responsibility

A4NR argues that PG&E has failed to meet its burden to prove the reasonableness of a 10-year post-shutdown SNF wet storage assumption. A4NR asserts that the Commission should include language in the decision for this proceeding that sends a clear message to PG&E that its forthcoming site-specific decommissioning plan for DCPP fully evaluates the costs, benefits, and feasibility of a pre-shutdown acceleration of dry cask loading of SNF. A4NR argues that, Section 3.2.3.1.3 of the proposed Settlement Agreement in A.15-09-001, PG&E's General Rate Case, and Section 5.4.1 of the Joint Proposal for Retirement of Diablo Canyon submitted in A.16-08-006 support this position to expedite dry cask loading.[76]

### 4.3. Discussion

PG&E requests that the Commission find reasonable its updated DCE of $3.77 billion (2014$) to decommission DCPP. The assumptions, methods and rational for the updated estimate is set forth in the 2016 TLG Diablo Canyon Units 1 and 2 Decommissioning Cost Study (2016 Cost Study).[77] TURN and ORA challenge the increase proposed by PG&E to its updated DCE. TURN and ORA argue that such major increases should not be approved in this NDCTP absent a more credible showing that the changed assumptions are reasonable and supported by substantial evidence, that the drivers of increases are transparent and fully documented, and that the utility has conducted some form of analysis in an effort to select least-cost options that satisfy applicable regulatory standards. PG&E in turn argues that the Commission must permit recovery in

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[76] Exh 31 (A4NR/Geeseman) at 1-4; A4NR Opening Brief.

[77] Exh 3 (PG&E/Seymore).

rates of reasonable decommissioning costs to ensure that the NDTFs are adequately funded now or future customers not PG&E shareholders will be responsible to pay any shortfalls.

#### 4.3.1. 2016 TLG DCPP Cost Study Update and Updated DCE

We find that TLG followed a reasonable approach to developing the 2016 DCPP cost study, which then utilized several specific inputs from PG&E in key areas that resulted in significant cost increases. The methodology used by TLG to develop the DCPP DCE conforms to NRC and DOE guidelines.[78] PG&E asserts that its additional inputs to TLG reflect a more rigorous review of its previous assumptions given the announcement that it plans to retire DCPP at the end of the current licenses.

TURN's arguments focus on the substantial overall increase in the DCPP DCE and that DCPP is conspicuous for the large increases during the last two NDCTP cycles, in comparison to other comparable nuclear facilities. PG&E's DCPP DCE is now $3.77 billion, approximately $1.49 billion more than the amount authorized for DCPP in PG&E's 2012 NDCTP.[79]

We agree with PG&E that a large increase in and of itself is not unreasonable, but the Commission must review the basis for changes and the evidence provided to support different assumptions. In reviewing these changes

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[78] Exh 2 (PG&E/Seymore) at 19; Exh 3 (PG&E/Seymore) 2016 DCPP Cost Study" at 12-13, and 50-51, Methodology, citing AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates,"] and the DOE "Decommissioning Handbook."

[79] See Exh 1 (PG&E/Sharp); Exh 2 (PG&E/Seymore); Exh 3 (PG&E/Sharp); Exh 4 (PG&E/Sharp); and Exh 33 (TURN/Lacy) at 17.

we keep in mind that PG&E has the burden of proving that its proposed DCE is reasonable.

TURN relied on the 2009 and 2012 DCPP cost studies as a basis for its calculations to reduce what it views as excessive cost increases by PG&E. Based primarily on comparison to costs for other facilities, and the contested SNF cooling periods as a major cost driver, TURN concludes that the DCPP DCE should be significantly reduced in a number of areas.

The Commission shares TURN's concern that clear calculations justifying the large increases associated with the changes which ratepayers are asked to fund have not been provided for many categories. We acknowledge that the DCE are not meant to be the final decommissioning plans, and are developed as an initial step in determining ratepayer-funded utility contributions. We do, however, expect the studies supporting the estimates to use unit cost factors and to be a high level estimate that evolves over time. The Commission cannot exercise its reasonable review of the DCE if we are unable to examine the cost estimates through the triennial proceedings to see what changed and why.

In D.14-12-082, we directed SCE and SDG&E to coordinate with Energy Division and intervenors to develop a revised Common Summary Format to increase the amount of summary information available for review in the NDCTP. Here we also direct PG&E to work with Energy Division and interested intervenors to see how presentation of revised data in the 2018 NDCTP can more clearly identify changed assumptions, the basis for making the changes in approach or activities, and how the associated costs were developed for inclusion in the revised DCE for DCPP decommissioning.

#### 4.3.1.1. Security Costs

PG&E proposes to double the total security costs from the previously adopted estimate of $343 million to $687 million.[80] PG&E states that security during the decommissioning period would begin at plant shut down in 2024 and 2025. PG&E attributes the increase in security costs to NRC requirements concerning "establishment and maintenance of a physical protection system capable of the protection of special nuclear material at fixed sites to protect against acts of radiological sabotage and to prevent the theft or diversion of special nuclear material."[81] In direct testimony, PG&E does not provide reference to any specific NRC authority that would require such an increase in the costs for onsite security during the decommissioning of DCPP. A similar increase was declined in the 2012 NDCTP as PG&E had failed to satisfy its burden of proof. The current estimate, as noted in TURN's Opening Brief includes a significantly larger increase in security costs than sought by PG&E in the 2012 NDCTP.[82]

TURN argues that "[d]espite the Commission's admonitions in the 2012 NDCTP, PG&E provides little additional evidence in this proceeding to justify the massive increase in security costs."[83] PG&E does not provide "detailed justifications with clear calculations showing the exact basis for the increase between the adopted 2012 estimate and the 2016 estimate."[84] PG&E offers no

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[80] Exh 2 at 2-29.

[81] PG&E Opening Brief at 6 citing to Exh 4 (PG&E/Sharp) at 5, lines 12-20.

[82] TURN Opening Brief at 25.

[83] TURN Opening Brief at 26.

[84] TURN Opening Brief at 26.

specific basis for the substantial increase and references only a few modest adjustments that do not appear to support a doubling of total costs.[85]

In its rebuttal testimony PG&E asserts that it "has provided 'clear-calculations' as to how it determined security costs. PG&E also asserts that it conducted "a from-the-ground" up analysis of DCPP security needs. PG&E also continues to assert that the increase here is required by the NRC.[86]

We agree with TURN that PG&E has not made a sufficient showing to justify the increases in security requested. TURN's expert witness, Mr. Lacy, stated during evidentiary hearings that the doubling of costs proposed by PG&E "does not comport with my general level of understanding of what's going on with security requirements in the industry."[87] Mr. Lacy also testified that NRC security requirements tend to decrease as decommissioning progresses and PG&E did not provide sufficient support for the assumptions presented concerning the proposed security cost increase.[88] PG&E did not meet its burden of proof as to this increase. PG&E's testimony shows that, the site-specific security cost data was developed by PG&E and "independently verified by" PG&E management.[89] PG&E's witness stated that "security, labor rates and equipment and material costs, and specific security levels identified for various

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85 TURN Opening Brief at 26.

86 PG&E Reply Brief at 6-8.

87 Reporter's Transcript (RT) Vol. 2 at 243.

88 RT Vol 2 at 243-44.

89 Exh 4 (PG&E/Sharp) at 3-5; Exh 2 (PG&E/Seymore) at 10-11.

phases of the project integrated with the decommissioning schedule" were provided by PG&E.[90]

As stated in D.14-12-082, we questioned to what extent it is reasonable to rely on PG&E's security personnel to estimate future costs for themselves without review. Here the only "independent review" was conducted by PG&E's own management. We agree with TURN that it is concerning that there was not a reasonableness review by TLG or some outside independent entity.

As in the 2012 NDCTP, the current estimate seems to be primarily additional workforce estimated as needed between 2025 and 2041. Again, we reiterate that it is not reasonable to recover costs from ratepayers for unsupported costs to be expended long into the future, even if labeled "security." Our disallowance of unsupported costs has no impact on current security at DCPP.

Therefore, the Commission finds it reasonable to reduce PG&E' estimated security costs by $344 million. DCPP is an operating facility and PG&E will again be provided an opportunity, should it choose, to return in 2018 to offer additional evidence to sufficiently support its estimates of necessary future security personnel. PG&E is encouraged to confer with Energy Division Staff and other parties in the proceeding as to what level of information would be sufficient to allow for a proper reasonableness review of security costs for the 2018 NDCTP.

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[90] Exh 2 (PG&E/Seymore) at 10.

#### 4.3.1.2. Utility and DOC Costs and Large Component Removal Costs

PG&E proposes to increase its estimated cost of Utility and DOC staff from $562 million (2012 NDCTP estimate) to $873 million.[91] TURN asserts that PG&E has not met its burden of proof to justify a $311 million increase in this category. We agree with TURN that PG&E needs to provide more information in order to meet its burden, as PG&E has failed to provide supporting documentation that would allow the Commission to understand the basis for the proposed increase in these categories.

PG&E cites a number of changes that increase the previously adopted 2012 DCE that include higher staffing levels for reactor vessel segmentation and large component removal, greater staff needs during wet fuel storage, and some reductions in staffing due to a shorter wet fuel storage duration.[92] PG&E's witness could not explain the "increase in the number of personnel" made at the direction of PG&E. PG&E's witness stated that PG&E increased its personnel based on experiences at Humboldt Bay" and "PG&E's understanding of the information received from the Zion experience."[93]

In the 2012 Cost Study TLG used a model that incorporated industry-staffing averages from decommissioning projects across the United States to forecast staffing requirements for decommissioning DCPP. For the 2015 NDCTP PG&E, based on its own decommissioning experience at HBPP and its

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[91] Exh 2 (PG&E) at 2-29, Table 2-1.

[92] Exh 2 at 2-6 and 2-7.

[93] RT Vol. 1 at 45.

understanding of the experience for segmenting the Zion Nuclear Station (Zion)[94] reactor vessels, provided TLG with the number of staff required per year by position classification and the associated rate for each position, as well as extended the time needed to complete work.[95] PG&E argues that based on its experience at HBPP and the experience at Zion the 2017 proposed estimate better reflects the decommissioning costs in these categories for DCPP than the estimates set forth in the 2012 NDCTP.[96]

TURN argues that the Braidwood Generating Station (Braidwood) and Bryon Generating Station (Bryon) better reflect the potential decommissioning for DCPP then HBPP or Zion.[97] TURN's expert witness testifies that his recommendation would be to take the average of the large component removal cost estimates and subtract this number from the large component removal cost estimates PG&E has presented for DCPP plus 10% assumed difference in labor costs.[98]

PG&E counters TURN's argument by stating TURN's witness ignores the specific cost components and assumptions contained in the DCE when comparing Braidwood and Bryon to DCPP. PG&E argues that TLG is a nationally known specialist in the field of developing nuclear decommissioning

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[94] Zion Nuclear Station is a nuclear facility in Illinois that was decommissioned since the 2012 NDCTP. Exh 4 (PG&E/Sharp) at 3-8.

[95] Exh 4 (PG&E/Sharp) at 8; Exh 2 (PG&E/Seymore) at 12-13; and Exh 3 (PG&E/Seymore) at 49 and 70; RT Vol. 1 at 53-54.

[96] Exh 2 (PG&E/Sharp) at 8; Exh 2 (PG&E/Seymore) at 12-13;; Exh 15 (PG&E/Rebuttal Testimony/Seymore) at 4-7.

[97] Exh 33 (TURN/Lacy) at 22-23.

[98] Exh 33 (TURN/Lacy) at 22-23.

cost estimates. PG&E also argues that it provided significant input regarding DCPP specific matters, and that Mr. Lacy ignores several DCPP specific factors.[99]

However, despite PG&E's recognition of TLG as a nationally known specialist in the field of developing nuclear decommissioning cost estimates, it appears that PG&E directed the substantial increase in this area not TLG. PG&E's witness, Mr. Seymore of TLG testifies that the large increase in DOC was done at the direction of PG&E. Mr. Seymore states "at PG&E direction the duration of this phase was increased from an average of 20 months used in the 2012 estimate to an average of 39 months in the 2016 TLG cost Study." PG&E on the one hand argues that TURN disregards the nationally known expert TLG in dismissing these increased cost estimates, but on the other hand PG&E appears to disregard TLG's opinion and has directed its consultant to substitute PG&E's independent assessment as to the necessary staffing and time needed in this category.[100]

PG&E also argues that its experience at HBPP and the information it has regarding the Zion facility represent a more accurate comparison for estimating decommissioning costs at DCPP. However, in other portions of its testimony PG&E argues that DCPP cannot be compared to HBPP. TURN's witness, Mr. Lacy testifies that little information is known regarding the actual situation at Zion.[101] This premise is confirmed by PG&E's own witness (Mr. Seymore).[102]

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[99] Exh 15 (PG&E/Rebuttal Testimony/Sharp) at 15-16.

[100] Exh 4 (PG&E/Sharp) at 12; Exh 2 (PG&E/Seymore) at 12-13; Exh 15 (PG&E#/Rebuttal/Seymore) at 4-7.

[101] Exh 33 (TURN/Lacy) at 22-26; RT Vol 2 at 209-210.

[102] RT Vol 1 at 101.

PG&E does not provide specific calculations to support this increase in cost, nor does it provide substantial evidence to support its premise that experience with HBPP or the information known about Zion decommissioning activities represents a reasonable comparison for staffing and large component removal estimated decommissioning costs for DCPP.[103]

Therefore we find that PG&E has failed to meet its burden of proof in demonstrating the reasonableness of a $311 million increase for Utility and DOC staff costs, or an increase in estimated costs of $492 million for large component removal. There is an overlap of staffing costs between the Utility and DOC and the large component removal of $298 million. Therefore PG&E's DCE is reduced by a total of $505 million for both of these categories.[104]

#### 4.3.1.3. Removal of All Onsite Concrete

PG&E assumed in the 2012 NDCTP that decommissioned waste not subject to NRC regulation would be removed and disposed of at a California landfill.[105] This assumption was challenged and resulted in a reduction of PG&E's DCE for this category as set forth in D.14-12-082. PG&E states that as a result of this outcome it "undertook a thorough review of its assumption."[106] In

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[103] The basis of PG&E's argument here is heads we win, tails you lose- where PG&E seeks an increase in the DCE it references its experiences at HBPP and comparison to one other unique decommissioning situation; where other parties seek to reduce the DCE through reference to HBPP and comparison of other facilities PG&E argues there is no comparison. However, the cost estimate comparisons raised by other parties to support their arguments are more convincing as these examples are based on industry standards and practices rather than one or two unique decommissioning situations where PG&E has not identified any specific common unique facts with DCPP.

[104] Supra note 75.

[105] *See* Exh 4 (PG&E/Sharp) at 5-6.

[106] PG&E Opening Brief at 13-14.

the course of its review PG&E identified Executive Order D-62-02 (Executive Order). PG&E argues that the Executive Order, issued in 2002, and subsequent Abatement Order issued by the State Water Resources Control Board (Water Board) has a major impact on its previous assumption of in-state-disposal of decommissioned material at DCPP. PG&E raises the Executive Order as authority for the first time in this NDCTP.

PG&E argues that until the Department of Health Services/Public Health Department (the Department) promulgates regulations in accordance with the Executive Order there is a moratorium on disposal of all decommissioned materials into Class III landfills and California licensed sites. PG&E takes the position that the moratorium remains in effect until the Department takes formal action to promulgate regulations for the disposal of "decommissioned materials" in California.[107]

TURN argues that PG&E is taking an extreme position on interpretation of the Executive Order, contrary to the language of the Executive Order, the veto message that led to the Executive Order, and the text of Senate Bill (SB) 1970.[108]

PG&E proposes an increase of more than $312 million for out-of-state waste disposal of all decommissioned material, relying solely on the Executive Order and a review of its lease with the California State Lands Commission. PG&E concludes that there would be a significant risk and uncertainty with

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[107] PG&E Opening Brief at 13-17.

[108] SB 1970 (2002) "Radiation Safety Act of 2002, Proposed Health and Safety Code § 115301(f). This bill would have imposed severe restrictions on the disposal of hazardous waste in California. The bill was vetoed by Governor Gray Davis who then issued the Executive Order that limited the moratorium on "disposal of decommissioned materials above background levels in public landfills (Class III) and unclassified waste management facilities." Exh 34 at 75, Governor's Veto message re SB 1970.

assuming that it could dispose of concrete from DCPP in in-state landfills. PG&E acknowledges that the Executive Order and Abatement Order "lack clarity" as to the scope and intent of the moratorium and allowance for disposal of decommissioned material. PG&E asserts there is a risk that it may be required to remove the material from an in-state land fill as a result of the California Environmental Quality Act (CEQA) review and rulemaking directed in the Executive Order. PG&E's only example of such a removal is an out-of-state matter involving the Federal Environmental Protection Agency. This example only demonstrates that there may be a risk regarding removal at any facility whether out of state or in-state.[109]

TURN argues that the ambiguity of the Executive Order relied on by PG&E (for the first time over a decade after the order was adopted) does not exist. TURN points out that the moratorium defines decommissioned materials as "radioactive materials in excess of local background levels."[110] The Executive Order and subsequent Abatement Order apply only to material with some radioactive content above local background levels. PG&E provides no basis for application of the Executive Order to materials that are clean, lack contamination, and do not have detectable radioactivity above background levels.[111]

PG&E has permitted "thousands of cubic yards" of soil and concrete rubble to be used onsite for fill at HBPP. PG&E testifies that the reuse at HBPP is

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[109] PG&E Opening Brief at 13-14; Exh 2 (PG&E/Seymore) at 7, 8, and 14; Exh 4 (PG&E/Sharp) at 5; Exh 15 (PG&E/Rebuttal-Salmon) at 25-31.

[110] Exh 15 at 3-3.

[111] TURN Opening Brief at 26 citing D.14-12-082; Ex 33 at 23-25; RT Vol 2 at 215-222.

consistent with the Executive Order. PG&E witness James Salmon testified that, "On-site reuse of soil and concrete was not restricted by the Executive Order. The radiological reuse criteria for soil are established by the NRC." Mr. Salmon also testified that PG&E has a Voluntary Clean-Up Agreement with the state Department of Toxic Substances Control (DTSC). Mr. Salmon testified that this agreement "provides for reuse and/or disposal of soils excavated onsite at HBPP."[112] Despite this testimony Mr. Salmon concludes that the regulatory uncertainty of a 2002 Executive Order requires PG&E to take a 'conservative' position regarding disposal of decommissioned material at DCPP.[113] This conservative position results in a significant increase to the cost estimate for this category as all materials, including clean soil and rubble, would be removed and transported out-of-state for disposal.

PG&E applies this same theory to disposal of the breakwater concrete. It is PG&E's position that the breakwater concrete will require removal and disposal would fall under the Executive Order requiring transportation to an out-of-state landfill for disposal.[114]

ORA argues that PG&E's request for additional funds to remove the DCPP breakwater is premature and should be denied. ORA asserts that there is time to assess the impacts of removing the breakwater through a CEQA review, and that the breakwater may not be required to be removed. Such a review will allow the Commission, PG&E, and stakeholders to assess the impacts of different approaches to decommissioning DCPP, including whether to remove the

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[112] Exh 15 (PG&E Rebuttal Testimony) at 30.

[113] Exh 15 (PG&E Rebuttal Testimony) at 30-31.

[114] PG&E Opening Brief at 16-17.

breakwater concrete. ORA also argues that stakeholders in the DCPP decommissioning process may benefit from information presented in the State Lands Commission environmental review of disposition of SONGS 1 and the current environmental review of disposition of SONGS 2 and 3.[115]

ORA and TURN both assert without more evidence concerning PG&E's position on the Executive Order, it would be premature to grant PG&E's requested increase in decommissioning costs. We agree with TURN and ORA that PG&E has adopted an "extreme" interpretation of the Executive Order without providing substantial evidence to support its position. Despite PG&E's testimony as to reuse of materials at HBPP and no example of an entity being prevented from disposal or reuse of similar debris in-state PG&E asks us to increase costs to ratepayers by roughly $312 million. PG&E also fails to address any consideration of leaving the breakwater in place.

PG&E is directed to consult with the Department, the Water Board, the CCC, the State Lands Commission, and DTSC as to the how the Executive Order may impact decommissioning efforts at DCPP. PG&E is also directed to conduct a more detailed assessment of options to minimize costs for removal of decommissioned material at DCPP, including the potential for the breakwater to remain onsite and intact.[116] PG&E is directed to include the status and results of such consultations and assessment in testimony for the next NDCTP.

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115 ORA Opening Brief at 6-9.

116 These issues should be included within the site-specific decommissioning study to be prepared in A.16-08-006, and the CEQA analysis that will be required for decommissioning of DCPP. We agree with ORA that assessment of these issues will assist us in assessing decommissioning costs going forward.

PG&E's proposed increase in this category is premature, without further support for its interpretation of the Executive Order and a more detailed assessment of other options for removal of decommissioned material, including whether the breakwater should remain in place. We therefore deny the proposed increase of $312 million for removal of decommissioned material at this time. PG&E may revisit its cost estimate in the next NDCTP consistent with this Decision.

#### 4.3.2. Contingency

In the 2012 NDCTP the Commission found that a reasonable contingency amount is significantly tied to the stage of decommissioning and the activities projected, including the particular site-specific challenges. The Commission found that the reasonable contingency factor may vary between nuclear plants and at different stages of decommissioning. D.14-12-082 states that :

> the utilities have established that 25% may be reasonable for SONGS 2 and 3, DCPP, and PV, as projected in the prior NDCTP, because….Phase I activities had not yet commenced, and the utilities had not undertaken the more detailed site-specific cost analysis…[117]

PG&E has filed A.16-08-006 seeking approval for the retirement of DCPP Units 1 and 2 at the end of the licensing period. PG&E will be preparing a site specific study and cost analysis for DCPP as part of this proceeding. PG&E relies heavily on the testimony and treatment of SONGS in its arguments for a 25% contingency in its DCE, a presumption that the 25% contingency factor is Commission policy. As we move into the next stage of NDCTPs and the site specific study is completed, PG&E is expected to provide more specific details

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[117] D.14-12-082 at 38.

regarding costs that will allow us to better assess the reasonableness of the assumed contingency rate.

Although we find that PG&E has supported its position to maintain a 25% contingency for purposes of this NDCTP, we do not accept PG&E's premise that a 25% contingency is Commission policy. As stated in the 2012 NDCTP decision:

> The Commission finds the reasonableness of a contingency amount is significantly related to the stage of decommissioning and the activities projected, including particular site-specific challenges. Consequently, the reasonable contingency factor may vary between nuclear plants and at different stages of decommissioning.[118]

Therefore PG&E should not rely on SONGS contingency factor as a premise for maintaining a 25% contingency factor going forward.

Although we reject ORA's request for a reduction in the contingency at this time we will carefully consider ORA's recommendation of adopting a reduction of overall project contingency estimates from the current level to account for less uncertainty over time and greater industry experience in future NDCTPs.

#### 4.3.3. DCPP Spent Nuclear Fuel Transfer to Dry Cask Storage

The parties raise two issues specific to the transfer of SNF from wet storage to the onsite ISFSI. The first issue raised by TURN concerns the number of years necessary to move fuel from the wet storage to the ISFSI. The second issue raised by A4NR concerns assessment of accelerating dry cask loading of SNF pre-shutdown.

[118] D.14-12-082 at 38.

#### 4.3.3.1. Spent Nuclear Fuel Cooling Periods

In the 2012 NDCTP the Commission found that PG&E's assumption of a 12-year wet cooling period after plant shut-down was reasonable.[119] PG&E now proposes to reduce this 12-year period to 10 years. PG&E also commits to evaluate further options for expediting the transfer of SNF post shutdown in the site specific DCPP cost for the next NDCTP. PG&E asserts that it does not believe it can transfer all SNF to dry storage in less than 10 years after decommissioning commences.[120]

TURN argues that PG&E's 10-year assumption is "overly conservative, unrealistic, and outside the industry norm."[121] TURN urges the Commission to "direct PG&E to explore all possible strategies to realize the cost savings resulting from a shorter timeline to" terminate wet pool operations.[122] Both PG&E and TURN agree that there is a $65 million per year savings for reducing the amount of time SNF is in wet storage before transfer to dry storage.[123] TURN recommends reducing PG&E's cost estimate by $197 million to reflect a 7-year cooling period for transfer of SNF to dry casks.[124]

PG&E asserts it does not believe that transfer of SNF from wet pools to dry casks could occur in less than 10 years.[125] However, it does not provide more than general statements regarding meeting its NRC licensing requirements

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[119] D.14-12-082, Conclusion of Law (COL) 6.

[120] PG&E Opening Brief at 8-9; Exh 4 (PG&E/Sharp) at 10.

[121] TURN Opening Brief at 45.

[122] TURN Opening Brief at 45.

[123] Exh 2(PG&E/Seymore) at 40, Table 2-8; RT Vol. 2 at 245.

[124] Exh 33 (TURN/Lacy) at 26; RT Vol. 2 at 244-5.

[125] Exh 4 (PG&E/Sharp) at 8-10.

concerning the amount of heat that can be stored in the canisters.[126] When asked to provide known other plants with similar fuel types in a data response to TURN, PG&E provided the names of six nuclear facilities. TURN provides evidence that the latest TLG cost estimates assume 5-5.5 years for the transfer of SNF from wet pools to dry cask storage for these facilities.[127] We also note that SONGS and Palo Verde use a 6-year timeline for transfer of SNF from wet pools to dry cask storage.[128]

PG&E, in the Joint Proposal submitted in A.16-08-006, has committed to developing "a plan to expedite post-shut-down transfer of spent fuel as promptly as is technically feasible using the transfer schedules implemented at San Onofre Nuclear Generating Station as a benchmark."[129] PG&E did not provide the Joint Proposal submitted in A.16-08-006 to TLG and this commitment to benchmark the SONGS comparison was not included in the DCE for this NDCTP.[130]

PG&E's witness, Mr. Seymore, testified that PG&E is committed to look at the potential to advance the transfer of SNF to a shorter date, and that he expects "there is a chance for some reduction."[131] PG&E states that any evaluation for accelerating the timeline for dry cask loading should be addressed in the next

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[126] PG&E does not cite to any specific NRC regulation or licensing requirement, or any specific technical limitation that supports this assertion.

[127] Exh 18 (TURN Cross Examination) at 18 and 21.

[128] Exh 18 (TURN Cross Examination) at 18 and 21; RT Vol 137-39.

[129] Exh 18, at 24 (Joint Proposal submitted by PG&E in A.16-08-006).

[130] RT Vol 1 at 104-105.

[131] Vol 1 at 104-105.

NDCTP.[132] TURN argues that PG&E's commitment to benchmark its transfer schedule for dry cask loading with that proposed at SONGS constitutes changed circumstances since filing of the application. This combined with considering the industry standard being roughly half the time for dry cask loading assumed by PG&E warrant a reexamination of our previous findings. In D.14-12-082 the Commission found it reasonable to allow for a 12-year period. However, the evidence presented here shows that a 12-year period is not needed to transfer the SNF. PG&E argues for a 10-year period, SONGS now estimates a 6-year period,[133] facilities comparable to DCPP have a 5-5.5 year transfer period,[134] and TURN recommends a 7-year period to transfer the SNF to dry casks, based on its understanding of industry practice.[135]

PG&E's 10-year time period to dry cask load seems to be an outlier resulting in significant costs to ratepayers that can be reduced. We understand there may be additional costs associated with an expedited transfer; however transferring the fuel from the wet pools to dry casks sooner rather than later provides not only economic benefits, but safety benefits. PG&E should examine all opportunities to reduce this time period.

We find there is sufficient evidence to reduce the time period for transferring SNF from wet pools to dry casks no later than 7 years after shut-down. PG&E will have an opportunity to present additional evidence as to

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[132] Exh 15 (PG&E/Rebuttal Testimony) at 15.

[133] Exh 18 (TURN Cross Examination) at 16.

[134] RT Vol 1 at 74-75.

[135] Exh 4 (PG&E/Sharp) at 8-10; Ex 18 (TURN/Cross Examination); TURN Opening Brief at 45-48.

the time period needed for transferring SNF in the next NDCTP. PG&E is directed to diligently work to safely reduce the timeframe for transferring SNF from wet pool to dry cask storage consistent with NRC requirements and this decision as well as provide an updated timeline in the next NDCTP.

#### 4.3.3.2. Assessment of Dry Cask Loading Pre-Shutdown of DCPP

A4NR requests that PG&E fully evaluate the costs, benefits, and feasibility of a pre-shutdown acceleration of dry cask loading of SNF in the site-specific decommissioning plan for DCPP that will be prepared consistent with Section 5.4.1 of the Joint Proposal for the Retirement of Diablo Canyon (Joint Proposal) submitted for review in A.16-08-006. PG&E argues that this request is outside the scope of the proceeding. PG&E states that the NDCTP is not the forum for addressing operational issues at DCPP, its purpose is to review decommissioning cost estimates to determine if the estimates contain reasonable decommissioning assumptions.

We agree that the NDCTP is not the forum for allocating funds or determining operational issues at DCPP. However, an assessment of the costs, benefits, and feasibility of a pre-shutdown acceleration of dry cask loading of SNF would provide information to assist the Commission in determining the reasonableness of future decommissioning cost estimates. We see no prejudice to the applicant in directing that pre-shutdown acceleration of dry cask loading be considered in the site specific study. In fact PG&E testified that it:

> has taken steps to accelerate its transfer of spent fuel from wet to dry storage during Diablo Canyon's operational period. In accordance with the 2014 GRC Final Decision, PG&E has submitted its plan for transferring spent fuel to dry storage during the operational period has also been reflected in the 2017 NDCTP base assumptions to reflect the updated number of spent fuel assemblies PG&E

> anticipates will remain in the spent fuel pool at the start of the decommissioning period.[136]

We therefore direct PG&E to provide testimony that includes updated and specific information regarding its plans for and the feasibility of pre-shutdown acceleration of dry cask loading and how these plans impact the DCE assumptions in the next NDCTP.

## 5. Spent Nuclear Fuel Management Costs

The Parties raise a number of issues concerning the decommissioning cost estimate as to SNF management costs. The two primary issues raised are whether it is reasonable to 1) assume that DOE will begin accepting SNF in dry cask storage for long-term storage in 2028; and 2) assume that the DOE litigation settlement payments will be sufficient to cover SNF management costs and continue to be made until pick up by DOE at some indefinite date in the future.[137]

### 5.1. DOE Acceptance of SNF

In the 2012 NDCTP the utilities proposed to extend the assumed date for DOE pick-up of SNF by the same amount of time that had passed between 2009 and 2012 NDCTP filings. This assumption was for a pick-up date of 2024. The Commission found in Phase 2 of the 2012 NDCTP that "the record provided for no support for any particular date other than 2024."[138] The Commission therefore concluded that "It is reasonable to assume for cost estimation purposes

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[136] Exh 4 (PG&E/Sharp) at 10.

[137] A third SNF management issue concerns the timing for transfer of SNF from wet pool storage to dry cask storage. This issue pertains only to DCPP and is discussed in section 4 above.

[138] D.14-12-082 at 23.

that DOE will not begin to accept SNF for long-term storage prior to 2024."[139] DOE has not provided any substantive information since the last NDCTP decision was issued. PG&E therefore believes it is reasonable to assume another 4-year delay in commencement of DOE SNF pick-up.[140] PG&E testifies that it is reasonable to assume commencement of the DOE pick-up program for SNF of 2028 for cost purposes with SNF pick up beginning in 2029 for HBPP and 2035 for DCPP.[141]

We again find there is little more than speculation in the record to support a projected date for DOE to begin accepting SNF for long-term storage. Many technical, political, and administrative decisions beyond the Commission's authority will drive the development of any interim or long-term storage of SNF. We agree that 2028 is optimistic, and the actual implementation of a permanent geologic repository will be impacted by many considerations outside this proceeding.

However, the sooner the utilities can safely transfer SNF to DOE control the better. The longer the transfer to DOE is delayed, the higher the transfer and storage costs for SNF. The record provides no support for any particular date other than 2028 for initiation of the DOE SNF transfer program. Even if we are skeptical of a near-term political solution, we need to have an assumption to make cost estimates in this NDCTP. It is reasonable to assume that DOE will not begin to accept SNF for long term storage prior to 2028.

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139 D.13-12-082 at COL 5.

140 Exh 4 (PG&E/Sharp) at 5.

141 Exh 4 (PG&E/Sharp) at 5.

### 5.2. DOE Litigation Proceedings

As a requirement of its license, PG&E is required to enter a standard SNF disposal agreement with the DOE. The agreement states that DOE will begin accepting SNF to transport to a permanent repository in 1998. No permanent repository has been established to date. PG&E filed two lawsuits, one for HBPP and one for DCPP, to recover on site SNF costs through 2004.[142] A second round of lawsuits was filed by PG&E to recover costs from 2005 through 2010 for on-site SNF storage.[143] PG&E reached an agreement to settle the litigation with DOE on September 5, 2012 for both rounds of litigation.[144]

The settlement resulted in DOE making payments to PG&E for past damages and use of an annual administrative claims procedure to address future damage claims through 2013. PG&E received $266 million for costs incurred through the end of 2010. PG&E submitted claims for the years 2011 through 2013 which were reviewed by DOE. PG&E received costs for allowed categories, not all categories were reimbursable under the settlement. The total recovery to PG&E from DOE for both litigation damages and administrative settlement claims is $366,779,284.[145]

In compliance with Ordering Paragraph (OP) 12 of D.14-12-082, PG&E provided testimony regarding the settlements, awards and other resolution of damage claims completed in the triennial period based on DOE's failure to accept SNF. PG&E has also complied with OP 12 of D.14-12-082 directive to

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142 All nuclear power plant operators filed lawsuits against DOE to recover costs to store SNF on site after it was due to be picked. Exh 14 (PG&E/Maggard) at 3.

143 *Id*.

144 *Id*.

145 Exh 14 (PG&E/Maggard) at 4-6.

provide information on how the recoveries allocated to the Unit that incurred the cost and ensure that the appropriate share of net proceeds is commensurate with payment of the underlying costs supporting the resolved claims. PG&E was also required to address whether the payments from DOE were placed in the related NDTF or returned to ratepayers in a manner approved by the Commission.

PG&E provided testimony summarizing the 2014 General Rate Case Settlement for Refunding DOE Litigation and Claims Net Proceeds to Customers.[146] In D.07-03-044 the Commission established the Department of Energy Litigation Balancing Account (DOELBA) to track PG&E's litigation costs and proceeds received from DOE for the cost of SNF storage on site. This decision directed PG&E to file an application setting forth a proposal to credit the litigation proceeds to customers, net of its litigation costs, once it began to receive reimbursements for DOE.

The Commission adopted a Joint Proposal for Procedure for Crediting to Customers the Net Proceeds Recorded in the DOEBLA in D.14-08-032. This proposal requires PG&E to refund HBPP litigation settlement proceeds (net litigation expenses) to customers through the Nuclear Decommissioning Adjustment Mechanism (NDAM) and to refund DCPP litigation settlement proceeds (net litigation expenses) to customers through the Utility Generation Balancing Account (UGBA). The proposal sets forth the process for allocating the litigation settlement proceeds and the administrative claims proceeds through these accounts.[147]

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[146] Exh 14 (PG&E/Maggard) at 4-6.

[147] Exh 14 (PG&E/Maggard) at 4-6.

PG&E provides testimony that identifies all settlement and claims payments to-date, allocation of settlement and claims payments to the NDAM and UGBA, and all refunds provided to customers during the 2012 NDCTP period.[148] PG&E in this proceeding and in its 2017 GRC proposes to continue to credit the DOE claims proceeds as described above and in its testimony for the 2017-2019 period.[149]

TURN urges the Commission to:

- Find that the federal government will honor its obligation to pay for incremental spent fuel management costs attributable to its breach of the standard contract.
- Adjust any ratepayer revenues requirements sought in 2017 to include only a portion of incremental spent fuel management costs that will be reimbursed by the federal government. TURN recommends including between 5-50% of such costs.
- Direct PG&E to survey the rate treatment provided by other state utility commissions for similar costs to be reimbursed by the federal government and submit a report in the next NDCTP. Alternatively, the Commission could authorize the creation of an independent panel, similar to the one authorized in D.10-07-047, to perform this work.
- Direct PG&E to provide a report, in the next NDCTP, explaining all issues relating to limitations on removing any excess funding from the nuclear decommissioning trusts prior to the termination of a site license.
- Direct PG&E to continue to report, in future NDCTPS, on collection of spent fuel management damages from the federal government and provide updates relating to the status of settlements and litigation claims. These updates should include a

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[148] *Id*.

[149] Exh 14 (PG&E/Maggard) at 6).

> summary of developments across the nuclear industry and not be limited only to PG&E's direct experience.[150]

TURN made a similar proposal in the 2012 NDCTP, which was opposed by PG&E and the other utilities. This proposal was rejected in the prior NDCTP. PG&E continues to oppose the proposal on essentially the same grounds as it did previously.[151]

PG&E asserts that TURN has failed to identify any changed circumstance since the 2012 NDCTP that would justify overturning the Commission's prior decision on this issue. According to PG&E it would be imprudent for the Commission to reduce the cost estimate for DCPP and HBPP based on an assumption that theoretical future DOE payments are going to be received. PG&E states that TURN's proposal is not consistent with Commission policy. This could result in future ratepayers bearing an unfair share of decommissioning costs. PG&E also argues that TURN's proposal would be contrary to the California Nuclear Facilities Decommissioning Act.[152]

TURN argues two key points in support of its position: 1) it asserts there is a settled expectation that DOE will pay the actual costs incurred by the utilities for onsite SNF storage; and 2) "failure to consider these future damage payments violates principles of intergenerational equity by forcing current customers to make contributions towards costs that will ultimately be reimbursed by" DOE.[153] TURN cites to several federal agency reports that presume federal liability

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[150] TURN Opening Brief at 50; also see Exh 33 (TURN/Lacy) at 27-46 and Exh 34 (TURN/Lacy).

[151] PG&E Opening Brief at 20-25.

[152] PG&E Opening Brief at 20-25.

[153] TURN Opening Brief at 50-51.

extends until the SNF is picked-up. TURN also argues that state utility commissions in Texas and Florida have relied on expectations of future reimbursements from the federal government to account for decommissioning costs related to SNF management.[154]

We again recognize that TURN raises an important issue concerning the potential for intergenerational inequities; however we continue to find that insufficient information establishes a substantial likelihood of recovery, and to what extent that recovery will cover all SNF management costs. The DOE litigation requires on-going utility claims in discrete time periods as costs are incurred. PG&E has reported consistent with the requirements of D.14-12-082 that the litigation and claims proceeds (net litigation expenses) either have been or will be refunded to customers consistent with the Joint Proposal for Procedure for Crediting to Customers the Net Proceeds Recorded in the DOELBA.[155] PG&E also testified and TURN did not disagree that the settlement in place at the time of evidentiary hearings was due to expire at the end of 2016, and an extension had not yet been agreed to by PG&E and DOE. Therefore there is not complete certainty as to the terms of any extension.

We decline to adopt TURN's proposal at this time, based on the speculative proceeds of future litigation and administrative claims which is not sufficient to establish a substantial likelihood of recovery and amounts.

We do expect PG&E to continue to refund amounts received consistent with the process described above, and to disclose as part of the next NDCTP application all settlements/extensions of current settlement, awards, or other

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154 TURN Opening Brief at 51-56; Exh 33 (TURN/Lacy) at 27-46 and Exh 46 (TURN/Lacy).

155 EXh 14 (PG&E/Maggard) at 6; RT at 156:6-8.

resolutions of damage claims completed in the next triennial period concerning DOE's failure to accept SNF. PG&E is also directed to provide an updated report regarding implementation of the Joint Proposal for Procedure for Crediting to Customers the Net Proceeds Recorded in the DOELBA.

## 6. Rates of Return on Nuclear Decommissioning Trust Funds and Trust Fund Contribution

Contributions to the NDTF are calculated by application of the rates of return to the approved and escalated cost estimates. The Commission reviews all of the assumptions and estimates in this proceeding in order to help ensure the trust fund contributions will be sufficient to fully fund decommissioning of the nuclear plants.

No party opposed PG&E's proposed earnings and escalation assumptions to determine the annual contributions necessary to fund the Nuclear Decommissioning Trust. No party opposed PG&E's proposed conversion to revenue requirements. The Commission finds the assumptions and proposed conversion to revenue requirements reasonable.

### 6.1. PG&E Assumed Returns on NDTF Assets

PG&E presented through testimony calculated overall expected return on the NDTF assets as the average of the expected return on equity and the expected return on fixed income investments, weighted by asset allocation.[156]

PG&E assumed a return of 7.7% on equities based on published twenty-year equity forecasts of the Russell Investment Group, 70% United States equity and 30% global non-U.S. equity.[157] The Commission previously accepted

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[156] Exh 11 (PG&E/Huntley) at 3.

[157] Exh 11 (PG&E/Huntley) at 4.

PG&E's assumptions on equity return based on the Russell forecasts in the 2012 NDCTP.[158] The Commission finds that the Russell forecasts may again be relied upon in this NDCTP.

PG&E assumed a 3.6% rate of return for fixed income based on weighted average of two fixed income benchmarks. 70% invested against the Barclays Capital U.S. Treasury Bond Index. PG&E forecasts a 3.4% return on this portion of the NDCT portfolio based on information published by Russell. PG&E provided testimony stating that 30% of the fixed income of the portfolio is invested against a custom benchmark, including corporate, high yield, asset-backed, municipal and Treasury bonds. PG&E also provided testimony that it forecasts an expected return of 4.25% on this portion of the portfolio.[159]

The Commission finds these forecasts to be reasonable.

### 6.2. PG&E Escalation Assumptions

PG&E sets forth its escalation assumptions in testimony provided by Shaun Halverson and in its Opening Brief.[160] Annual contributions to the NDTF are calculated by taking the decommissioning cost estimates for DCPP and HBPP (2014$) and escalating them to future years in which decommissioning activities are planned to occur. Costs are then assigned to five main categories: PG&E labor; equipment and materials, contract labor, LLRW burial costs; and other. The escalation factors are applied to annual costs to arrive at forecasted nominal estimates. For each of the five categories, PG&E proposes to escalate costs to the

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[158] D.14-12-082 at 120 and COL 31.

[159] Exh 11 (PG&E/Huntley) at 4-5.

[160] Exh 12 (PG&E/Halverson) at 5; and PG&E Opening Brief at 36.

period when decommissioning activities will be incurred using the escalation rates set forth in in Tables 8-3 and 8-5.[161]

PG&E set forth its proposed annual escalation rates per each of the five categories as set forth below:

| Cost Category | Diablo Canyon | HBPP |
|---|---|---|
| PG&E Labor | 2.92% | 2.91% |
| Equipment and Materials | 2.09% | 1.64% |
| Contract Labor | 2.20% | 3.07% |
| LLRW | 6.64% | 5.0% |
| Other | 1.78% | 1.97% |

No party disputed the reasonableness of these assumptions.

### 6.3. PG&E Adjustment of Estimated NDTF Annual Revenue Requirements

ORA argued that the most up-to-date trust fund balances should be used by PG&E when calculating its nuclear decommissioning revenue requirement. PG&E and ORA agreed prior to submission of Opening Briefs that PG&E will adjust its estimated NDTF annual revenue requirement to reflect the 2016 year-end balance.[162] PG&E will need to obtain a new Internal Revenue Service (IRS) Schedule of Ruling Amounts (SRA) that reflects the updated funding assumptions approved by the Commission in this proceeding. PG&E also notes in its Opening Brief that the Federal Treasury regulations require that the SRA be calculated based on the most recent year-end Trust fund balances.[163]

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161 Exh 12 (PG&E/Halverson) at 7, Table 8-3, and at 11, Table 8-5.

162 Exh 15 (PG&E Rebuttal Testimony) at 33-35; ORA Opening Brief at footnote 4; and PG&E Opening Brief at 36-37.

163 PG&E Opening Brief at 36; and Exh 12 (PG&E/Halverson) at 13.

PG&E will be required to file an AL within 30 days of the final decision in this proceeding for DCPP and HBPP to update the annual decommissioning revenue requirement and contribution amount based on the assumptions adopted in this proceeding using fund balances as of December 31, 2016. This approach is consistent with the approach authorized in the 2012 NDCTP[164] and no party has opposed the proposed adjustment.

### 6.4. NDCTP Revenue Requirement Update to Reflect 2017 General Rate Case (GRC) Decision

PG&E estimates certain expenses used to determine revenue requirements that are general in nature and then allocates these expenses among its lines of business. PG&E argues that litigating these issues in the GRC "avoids duplicative and costly efforts and potential conflicting case records and decisions."[165]

PG&E proposes to update the NDTCP revenue requirement through an AL filing that will reflect appropriate allocations determined in PG&E's 2017 GRC consistent with the approach adopted in prior Commission decisions.[166]

Based on the foregoing, we find PG&E's adjusted contribution amount for DCPP just and reasonable. In addition, we find PG&E's requested revenue requirement for SAFSTOR at HBPP to be reasonable to be recovered through NDAM.

No party in this proceeding opposed this approach.

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164 D.14-12-082 at OP 3.

165 PG&E Opening Brief at 37.

166 Exh 13 (PG&E/Cano) at 5 and FN3; D.11-05-018, OP 32; D.07-03-044; and D.04-05-055.

## 7. PG&E's Compliance with Prior Commission Decisions

The Commission directed PG&E in D.14-12-082 to provide testimony in this NDCTP to demonstrate compliance with prior Commission NDCTP decisions. We find that PG&E has generally complied with prior Commission NDCTP directives.

PG&E was directed to provide information in a common summary format for identifying certain assumptions and trust fund forecasts for PG&E, SCE, and SDG&E.[167] PG&E provided this information in the common format as Attachment A to PG&E's Application. TURN in its Opening Brief states that PG&E did provide a common summary format, but it did not compare key information from the cost estimate for DCPP with similar assumptions made for decommissioning SONGS. TURN believes this is a step backward from the 2012 NDCTP. PG&E counters with the fact that it was unable to provide a comparison with SCE/SDG&E's updated estimate as the estimate is not yet available. We find given the SCE and SDG&E updated estimate is not yet available that PG&E has complied with this directive. We do direct PG&E to coordinate with SCE and SDG&E in preparing the common format summary for the 2018 NDCTPS.

Based on the testimony provided in this NDCTP we find that PG&E has complied with the additional prior NDCTP directives. These directives include:

- Report the pro rata share of funds accumulated for NRC license termination and provide copies of the most recent assurance letters sent to the NRC;[168]

[167] D.11-07-003 at OP 2.

[168] Exh 1 (PG&E/Sharp) Attachment 1 and Attachment B.

- Consult with the Energy Division, develop and submit through the AL process a spreadsheet for requesting NDTF disbursements for HBPP;[169]
- making reasonable efforts to retain and utilize sufficient qualified and experienced personnel to effectively, safely, and efficiently pursue any physical decommissioning-related activities for the nuclear generation facilities under its control;[170]
- provide testimony as to the annual cost impacts of retaining spent nuclear fuel at DCPP in wet versus dry storage;[171]
- maintain a written record of decisions about the cost, scope or timing of major decommissioning projects or activities at HBPP that results in a variation from the prior estimates by +/-10%.[172]
- track and explain differences between actual and forecast SAFSTOR O&M expenses;[173]
- provide a summary of actual NDTF performance during the previous 3 years compared with previous NDCTP forecast performance;[174]
- Ensure the NDTF committee members timely receive certain information;[175] and
- Disclosure of all settlements, awards, or other resolution of damage claims resolved during the triennia period which are

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169 AL 4379-E approved on March 21, 2014, AL-4564-E referenced in Exh 1 (PG&E/Sharp) at 10.

170 Exh 7 (PG&E/Sharp) at 106-107.

171 Exh 2 (PG&E/Sharp) at 32 and 40.

172 Exh 5 (PG&E/Sharp) at 46.

173 Exh 10 (PG&E/Sharp) at 6-7.

174 Exh 11 (PG&E/Huntley) Table 7-3 and Table 7-4 at 8-9.

175 Exh 11 (PG&E/Huntley) at 11.

based on DOE failure to accept SNF and explain how the recoveries were allocated.[176]

Although we find that PG&E has complied with these directives, this decision provides continued and additional reporting directives to PG&E for the next NDCTP below.

## 8. Reporting and Format Requirements for Next NDCTP

PG&E is directed to continue to comply with the reporting requirements adopted in prior NDCTP proceedings. These directives were adopted to provide clarity and transparency as to the information and assumptions presented in the NDCTP proceeding. In the next NDCTP PG&E is to use the most updated DCE for each of the utilities in presenting information using the common summary format agreed to by the utilities. This includes a comparison of key information from the cost estimate of DCPP with the assumptions for decommissioning of SONGS. An updated DCE for SONGS will be available prior to the next NDCTP (2018) and PG&E is expected to include this information using the common summary format.

PG&E is directed to provide updated information and disclose all settlements, awards, other resolutions of damage claims resolved during the triennial period based on DOE failure to accept SNF and explain how recoveries were allocated. PG&E is also directed to provide any new information as to an estimated time frame for DOE to begin pick-up of SNF at DCPP and HBPP, or change in circumstance as to any progress with approvals for a permanent or long-term off-site repository for SNF.

[176] Exh 14 (PG&E/Maggard) Table 10-1 and 10-2 specifically and throughout exhibit.

PG&E is directed to provide testimony concerning expedited dry cask loading both pre-and post-shut down for DCPP. PG&E is to provide any updated information concerning expediting the 7-year timeframe for transfer of SNF from wet to dry storage directed in this decision.

PG&E is directed to provide testimony summarizing further exploration of the application of Executive Order D-62-02 to the disposition of construction debris at DCPP. This testimony is to include a summary of consultations with the Department, Water Board, DTSC, and CCC. The testimony is also to include a status update concerning the environmental reviews required for retiring DCPP, the site specific plan required in A.16-08-006, and further exploration as to whether to remove or maintain the breakwater.

PG&E is to include a comparison of its current proposed DCE with the last two prior DCEs approved through the NDCTP.

## 9. Categorization and Need for Hearing

The Commission preliminarily categorized this Application as ratesetting as defined in Rule 1.3(a)(e) and anticipated that this proceeding would require evidentiary hearings in ALJ 176-3374 on March 17, 2016. The assigned Commissioner's scoping ruling affirmed the preliminary categorization of this proceeding as ratesetting and the need for hearings.

## 10. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ______________, and reply comments were filed on ________________ by __________________.

## 11. Assignment of Proceeding

Martha Guzman-Aceves is the assigned Commissioner and Darcie L. Houck is the assigned ALJ in this proceeding.

## Findings of Fact

1. Pacific Gas and Electric Company filed A.16-03-006, its 2015 NDCTP on March 1, 2016.
2. Pacific Gas and Electric Company owns the Diablo Canyon Power Plant Units 1 and 2, and Humboldt Bay Power Plant Unit 3.
3. Every nuclear power plant operator is required to enter a standard spent nuclear fuel disposal agreement with the Department of Energy (DOE); these agreements provided that DOE will start accepting spent nuclear fuel starting January 31, 1998 to transport it to a permanent repository. No permanent U.S. repository has been established.
4. Pacific Gas and Electric Company assumed, for cost estimation purposes, that the Department of Energy will begin to accept spent nuclear fuel for long-term storage in 2028; the record provides little or no support for any date other than 2028.
5. Pacific Gas and Electric Company along with other nuclear plant operators, sued the Department of Energy to recover costs incurred to store spent nuclear fuel on-site after it was due to be picked up; the recovery varied between the utilities and was limited by time period to costs previously incurred.
6. The record supports no longer than a 7-year wet cooling period for nuclear decommissioning cost triennial proceedings consistent with industry practice.
7. Pacific Gas and Electric Company estimates forecasting future decommissioning costs which were prepared by recognized experts who used

utility information and generally accepted methods for developing the submitted cost analyses.

8. Pacific Gas and Electric Company(PG&E) applied a 25% contingency to the decommissioning cost estimate submitted with its Application in this proceeding; by contingency, PG&E means "performance contingency", i.e., unknown but historically inevitable.

9. Pacific Gas and Electric Company has complied with the reporting and approval process directed in the last nuclear decommissioning cost triennial proceeding.

10. Transparent cost accounting and linkage to prior cost estimates should enhance timely review and understanding of the basis for changes in scope or cost.

11. Pacific Gas and Electric Company's total cost estimate for decommissioning Diablo Canyon Power Plant Units 1 and 2 is $3,779,202,000 (2014$); the total estimate is approximately $1,494,000,000 (65%) more than the approved 2012 nuclear decommissioning cost triennial proceeding cost estimate.

12. Pacific Gas and Electric Company submitted evidence that it had complied with orders from prior Commission decisions.

13. Contributions by Pacific Gas and Electric Company to the nuclear decommissioning trust fund are calculated by application of the rates of return to the approved and escalated cost estimates.

14. In its Application, Pacific Gas and Electric Company estimated its annual revenue requirement to be $117.324 million for Diablo Canyon Power Plant Units 1 and 2, and $62.924 million for Humboldt Bay Power Plant decommissioning.

15. In its Application, Pacific Gas and Electric Company estimated its annual collection through Commission-jurisdictional electric rates for Humboldt Bay

Power Plant Unit 3 SAFSTOR O&M at $4.493 million in 2017, $4.475 million in 2018 and $3.885 million in 2019 and thereafter.

16. Pacific Gas Electric Company has established two master trusts to hold decommissioning funds; the trusts differ with respect to whether contributions to them qualify for an income tax deduction under Internal Revenue Code Section 468A.

17. In this proceeding, Pacific Gas and Electric Company has calculated separate escalation rates for: 1) labor; 2) equipment and material; 3) contract labor; 4) low level radioactive waste burial costs; and 5) other.

18. Pacific Gas and Electric Company provided evidence to support its escalation rates for labor, equipment and materials, contract labor, low level radioactive waste burial costs, and other categories.

19. Conservative forecasted yields for the trust funds serve the public interest and these yields should bear some relation to actual investments within a portfolio.

20. Pacific Gas and Electric Company developed and provided evidence supporting its forecast for rates of return on the equities and fixed income portions of its trust funds for the qualified and non-qualified trusts.

21. Pacific Gas and Electric Company (PG&E) estimated rate of return on equity of 7.7% and PG&E's estimated rate of return on fixed income of 3.6% are reasonable.

22. Nuclear decommissioning trust funds are unique in operation and purpose, which makes their management responsive to some concerns and factors uncommon to other investment funds.

23. To obtain a schedule of Rulings from the Internal Revenue Service, Pacific Gas and Electric Company relies on Year End trust fund balances to calculate contribution levels which maximize tax benefit.

24. Pacific Gas and Electric Company initially sought approval of an estimated annual revenue requirement of $117.324 million for Diablo Canyon Power Plant Units 1 and 2

25. Pacific Gas and Electric Company's requested contribution for decommissioning costs for Diablo Canyon Power Plant reflects an increase of roughly 65% over the estimate adopted in 2012 and a 107% increase over the adopted 2009 estimate.

26. Pacific Gas and Electric Company's remaining cost to decommission Humboldt Bay Power Plant Unit 3 of $531.3 million (2014$) (total estimated cost of $1,054.8 million) is reasonable and supported by the record.

27. Pacific Gas and Electric Company's activities and associated costs of $371 million for completed Humboldt Bay Power Plant Unit 3 decommissioning work were reasonable and prudently incurred.

28. Pacific Gas and Electric Company's forecast of $3.4 million for SAFSTOR O&M expense for HBPP Unit 3 for 2017; $3.3 million for 218; and $2.7 million for 2019 is reasonable and supported by the record.

29. The variances in actual versus forecast SAFSTOR expenses for the prior review period are reasonable.

30. To be useful to the Commission and the parties, the two annual advice letters (AL) must be tied to the nuclear decommissioning cost estimate (DCE) and show expenditures and related progress toward specific major milestones in the decommissioning process. The Forecast and Recorded Decommissioning Disbursements ALs must include direct references to the DCE to tie forecasted

and recorded disbursements to the DCE as well as include status reports that show progress in terms of costs and timelines for each major component of the decommissioning plan.

31. All disbursements from the nuclear decommissioning trust funds are provisional and subject to an obligation to refund any improper costs to the Trust Fund.

32. After-the-fact reasonableness reviews of expenditures for decommissioning of Humboldt Bay Power Plant and Diablo Canyon Power Plant should be conducted in the nuclear decommissioning cost triennial proceeding, unless otherwise scheduled.

## Conclusions of Law

1. The overall applicable standard of review for the numerous requests in the Application filed by Pacific Gas and Electric Company in this proceeding is one of reasonableness, specifically whether the decommissioning cost assumptions are reasonable, decommissioning activities are reasonable and prudent, and proposed revenue requirements result in just and reasonable rates.

2. The Atomic Energy Act of 1954[177] provided the federal government with exclusive jurisdiction to license the transfer, delivery, receipt, acquisition, possession, and use of nuclear materials; states retain traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost, and other related concerns.

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[177] 42 U.S.C. § 2011 et seq.

3. The California Nuclear Facility Decommissioning Act of 1985[178] requires, inter alia, each electrical utility owning, in whole or part, or operating a nuclear facility, located in California or elsewhere, to provide the Commission with periodic decommissioning cost estimates which include descriptions of changes in regulation, technology, and economics affecting the estimate, descriptions of additions and deletions to the facility, and all assumptions about the remaining useful life of the facilities.

4. It is reasonable to assume for cost estimation purposes that Department of Energy will not begin to accept spent nuclear fuel for long-term storage prior to 2028.

5. It is reasonable to assume for cost estimation purposes that some spent nuclear fuel assemblies will require 7 years of wet cooling. In the 2018 Nuclear Decommissioning Cost Triennial Proceeding, the Commission would benefit from Pacific Gas and Electric Company providing information comparing annual cost impacts of strategies to reduce wet cooling periods, including assessment of expedited dry cask loading pre and post-shutdown.

6. Assumptions suitable for high level cost elimination purposes do not compel the same assumptions by the utilities when considering the prudency and reasonableness of future actual decommissioning decisions and resulting costs.

7. A nuclear plant licensee, such as Pacific Gas Electric Company is required to submit its spent fuel management plan to the Nuclear Regulatory Commission for review.

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[178] Pub. Util. Code § 8321 et seq.

8. The record is insufficient for the Commission to conclude that future Department of Energy damage awards are a predictable certainty which is sufficient to reduce the decommissioning cost estimate to reflect potential future damage awards.

9. The reasonableness of a contingency factor may vary between nuclear plants and at different stages of decommissioning.

10. Pacific Gas and Electric Company is in compliance with prior decisions applicable to decommissioning.

11. It is reasonable for Pacific Gas and Electric Company to use the Common Summary Format directed in the prior proceeding to provide a comprehensive comparison of cost estimations from different facilities.

12. It is reasonable to reduce Pacific Gas and Electric Company's 2015 decommissioning cost estimate for Diablo Canyon Power Plant Units 1 and 2 by a total of $1.358 billion on the grounds the request lacked adequate support to demonstrate the requests were reasonable in nature and amount; the remainder of $2.421 billion is a reasonable cost estimate and should be adopted.

13. Pacific Gas and Electric Company's assumption for the return on equity of 7.7% is reasonable.

14. Pacific Gas and Electric Company's assumption for the return on fixed income investments, estimated rates of 3.6% are reasonable.

15. The Commission concludes that the most recent update of trust fund balances for purposes of all facilities is the trust fund balances as of December 31, 2016 which should be used when calculating their contributions.

16. It is reasonable for Pacific Gas and Electric Company to collect the full amount necessary to make annual contributions based on the escalation rates and rates of return found reasonable herein.

17. It is reasonable for Pacific Gas and Electric Company to collect through Commission-adopted jurisdictional electric rates for funding HBPP Unit 3 SAFSTOR O&M, the annual revenue requirement, as updated, effective January 1, 2017, $4.493 million for 2017; $4.475 million for 2018; and $3.885 million for 2019, the actual revenue requirement to be adjusted to reflect the December 31, 2016 Trust Fund balances.

18. It is reasonable for Pacific Gas and Electric Company to collect through Commission-adopted jurisdictional electric rates an annual revenue requirement for the Humboldt Bay Power Plant (HBPP) Unit 3 effective January 1, 2017, the actual revenue requirement to be adjusted to reflect the HBPP decommissioning cost estimate of $62.924 million, and the actual December 31, 2016 Trust Fund balances.

19. It is reasonable for Pacific Gas and Electric Company to continue revenue requirement associated with the nuclear decommissioning trust contributions and Humboldt Bay Power Plant SAFSTOR O&M through a non-by passable charge as specified in Public Utilities Code Section 379, and to continue to utilize the Nuclear Decommissioning Adjustment Mechanism as authorized in D.99-10-057.

20. It reasonable for Pacific Gas and Electric Company to collect through Commission-adopted jurisdictional electric rates, an annual revenue requirement to be adjusted to reflect the Diablo Canyon Power Plant decommissioning cost estimate as modified herein, and actual December 31, 2016 Trust Fund balances.

21. The respective decommissioning cost estimate for Pacific Gas and Electric should be approved consistent with the reductions set forth in this decision.

22. The Forecast and Recorded Decommissioning Disbursements Tier 2 ALs should be filed annually and must contain information supporting the requested

disbursement tied to the nuclear decommissioning cost estimate and show expenditures and related progress toward specific major milestones in the decommissioning process.

23. All disbursements from the Nuclear Decommissioning Trust Funds are provisional and subject to an obligation to refund any improper costs to the Trust Fund.

24. Discharging our duty to review decommissioning costs as pursuant to Pub. Util. Code §§ 451 and 8327 requires that PG&E file after-the-fact reasonableness reviews of expenditures for decommissioning Humboldt Bay Power Plant and Diablo Canyon Power Plant in the Nuclear Decommissioning Cost Triennial Proceeding, unless otherwise scheduled.

25. Discharging our duty to review decommissioning costs as pursuant to Pub. Util. Code §§ 451 and 8327 requires that when Pacific Gas and Electric Company (PG&E) completes a major component of nuclear decommissioning for Humboldt Bay Power Plant and Diablo Canyon Power Plant, PG&E should submit a separate reasonableness application with a comprehensive showing the decommissioning activities and costs from the conceptual plan through the actual recorded costs tied to line items in the decommissioning cost estimate.

26. Further scheduling for reasonableness reviews of nuclear decommissioning costs for Humboldt Bay Power Plant and Diablo Canyon Power Plant will be set in the Nuclear Decommissioning Cost Triennial Proceeding.

27. As required by Pub. Util. Code § 451 all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified," as provided in § 454.

28. Pacific Gas and Electric Company remains responsible for all decommissioning activities whether conducted by Pacific Gas and Electric Company employees or a contractor.

29. Pub. Util. Code § 451 requires safe operation of an electric system. It is a long-standing and continuing responsibility, not a one-time obligation.

30. The burden of proof is on Pacific Gas and Electric Company to demonstrate the reasonableness of the rate request.

31. The standard of proof is that of a preponderance of evidence, which means such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.

32. This decision should be effective upon approval by the Commission to allow Pacific Gas and Electric Company to collect the amounts authorized in this decision.

## O R D E R

**IT IS ORDERED** that:

1. Within ten (10) days of the effective date of this Decision, Pacific Gas and Electric (PG&E) shall file a Tier 2 compliance advice letter (AL) with the Commission's Energy Division, which shall include the calculated revenue requirement as described and adjusted in the Decision. Any resulting rate change shall be incorporated with the next available consolidated rate change following the effective date of this order, subject to Energy Division determining that the revised tariffs are in compliance with this order. The compliance AL shall describe how PG&E will implement the terms adopted in this Decision, including updating the revenue requirements to incorporate the December 31,

2016 nuclear decommissioning trust fund balances for the Diablo Canyon Power Plant, and the Humboldt Bay Power Plant Nuclear Decommissioning Trust Funds. The updated information shall serve as the basis for the Internal Revenue Service Schedule of Ruling Amounts for years 2016 and 2017. An adjustment to the Nuclear Decommissioning Adjustment Mechanism balancing account shall be made to address any difference in the revenue collected in rates and the annual revenue requirements, as described and updated in the compliance AL.

2. Pacific Gas and Electric Company shall serve testimony in its next triennial review of nuclear decommissioning trusts and related decommissioning activities that demonstrates they have made all reasonable efforts to retain and utilize sufficient qualified and experienced personnel to effectively, safely, and efficiently pursue any physical decommissioning related activities for the nuclear generation facilities under their control.

3. Pacific Gas and Electric Company(PG&E) shall organize a meeting, within 60 days of the date this decision is issued, to work with Energy Division and other interested parties to determine how PG&E's cost accounting system for Diablo Canyon Power Plant appropriately facilitates tracking decommissioning expenditures by major subprojects within a decommissioning phase, allows for comparison to previously approved estimates of activities, costs, and schedule, and requires written record of key decisions about cost, scope, or timing of a major project or activity (i.e. varies by plus or minus 10%), including the nature of the decision, who made it, factors considered, and whether and what alternatives were considered consistent with the common summary format and the milestone being developed in A.16-03-004.

4. Pacific Gas and Electric Company (PG&E) shall develop, in consultation with the Energy Division and other interested parties, a cost categorization

structure for tracking expenditures as discussed herein, which includes a reasonable path to compare the decommissioning costs previously estimated to actual costs expended. PG&E shall present the cost categorization structure, including how it conforms with the requirements of Ordering Paragraph 3 (immediately above), as supplemental testimony in support of its application associated with its detailed site-specific decommissioning cost estimate prepared as part of A.16-08-006.

5. Pacific Gas and Electric Company will file its detailed site-specific decommissioning cost estimate for Diablo Canyon Power Plant once completed in the following triennial proceeding. The site-specific decommissioning cost shall include an assessment for expediting dry cask loading. This assessment shall include both pre-shutdown and post shut options and costs for expediting dry cask loading.

6. Pacific Gas and Electric Company must file annually Forecast and Recorded Decommissioning Disbursements Tier 2 Advice Letters (AL); each such AL must show information supporting the requested disbursement tied to the Nuclear Decommissioning Cost Estimate and show expenditures and related progress toward specific major milestones in the decommissioning process.

7. Pacific Gas and Electric Company shall provide testimony in the next nuclear decommissioning triennial proceeding consistent with section 8, Reporting and Format Requirements for Next NDCTP, of this Decision. This information will include a summary and results of consultation with the CCC, State Lands Commission, Department of Public Health, California State Water Resources Control Board, and the Department of Toxic Substances Control concerning the application of Executive Order D-62-02 to disposal of

construction debris and whether the breakwater will be required to be removed at Diablo Canyon Power Plant.

8. All disbursements from the Nuclear Decommissioning Trust Funds are provisional and subject to an obligation to refund any improper costs to the Trust Funds.

9. Pacific Gas and Electric Company must file after-the-fact reasonableness reviews of expenditures for decommissioning Humboldt Bay Power Plant in the Nuclear Decommissioning Cost Triennial Proceedings consistent with the provisions set forth herein and D.14-02-024, unless otherwise scheduled.

10. Pacific Gas and Electric Company (PG&E) shall provide a status update regarding the Department of Energy Litigation that includes an assessment of when spent nuclear fuel will be picked up from Humboldt Bay Power Plant and Diablo Canyon Power Plant, as well as a report regarding the status of the settlement between PG&E and Department of Energy concerning reimbursement for spent nuclear fuel management costs and how PG&E is accounting/crediting funds back to ratepayers consistent with Section 8 of this Decision.

11. Further scheduling for reasonableness reviews of nuclear decommissioning costs for Diablo Canyon Power Plant and Humboldt Bay Power Plant will be set in the Nuclear Decommissioning Cost Triennial Proceedings to filed in 2018.

12. All outstanding matters requested by any party not specifically addressed herein are deemed denied for purposes of this triennial proceeding.

13. Application 16-03-006 is closed.

Dated_____________2017, at San Francisco, California.